EXH. JJJ-3
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: JOSHUA J. JACOBS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-240004 Docket UG-240005

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

JOSHUA J. JACOBS

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

2023 ELECTRIC PROGRESS REPORT

CHAPTERS 1–9

PUGET SOUND ENERGY

2023 ELECTRIC PROGRESS REPORT

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PUGET SOUND ENERGY

About PSE

As Washington State's oldest local energy company, Puget Sound Energy serves more than 1.2 million electric customers and more than 900,000 natural gas customers in ten 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.

A subsidiary of Puget Energy, PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources, and far-sighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient. For more information, visit pse.com.

Our electric service territory includes all of Kitsap, Skagit, Thurston, and Whatcom counties, and parts of Island, King (not Seattle), Kittitas and Pierce (not Tacoma) counties.

Our natural gas service territory includes: Parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties

Figure 1.1 below shows PSE's electric and gas service territories.

Figure 1.1 Puget Sound Energy Natural Gas and Electric Service Territories

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DEFINITIONS & ACRONYMS

PUGET SOUND ENERGY

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.
AC	Alternating current
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
AMI	Area median income
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
ATB	Annual Technology Baseline, an annual, publically available report published by NREL, and presents a consistent set of electricity generating technology cost and performance data
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.

Term/Acronym	Definition
Baseload combustion turbines	Baseload combustion turbines are designed to operate economically and efficiently over long periods of time. 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
BIPOC	Black, Indigenous, and People of Color
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.
CAPEX	Capital expenditures required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
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
CCA	Climate Commitment Act
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.

Term/Acronym	Definition
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
CO^2	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

Term/Acronym	Definition
DMS	Distribution management system
DNV	An energy consultant
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.
EAG	PSE's Equity Advisory Group
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
EPR	Electric Progress Report
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.
ESP	Electric service platform
ESS	Energy storage systems

DEFINITIONS AND ACRONYMS

Term/Acronym	Definition
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
FPL	Federal poverty level
FSC	Floating surface collector
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
HDR	Energy consultant
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.
IIJA	Infrastructure Investment and Jobs Act
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
IRA	Inflation Reduction Act
IRP	Integrated resource plan

Term/Acronym	Definition
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	One thousand dekatherms or 10,000 therms
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.
MIP	Mixed integer programming, a mathematic optimization technique with combines elements of linear programming and integer programming
MMBtu	Million British thermal units
MMtCO2e	Million metric tons of CO2 equivalent
MSA	Metropolitan statistical area
MSCG	Morgan Stanley Commodities Group
MW	Megawatt

Term/Acronym	Definition
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 sustained output capacity of an electric-generating resource.
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 Laboratory
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.
NSRDB	NREL's National Solar Radiation Database
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

Term/Acronym	Definition
PACW	PacifiCorp West
PCA	Power cost adjustment (electric)
PCORC	Power cost only rate case
Peak capacity contribution	The nameplate capacity of a particular resource multiplied by the ELCC for that resource. For example, 100 MW of eastern Washington solar nameplate capacity, which has a summer ELCC of 54%, has a summer peak capacity contribution of 54 MW.
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 hydroelectric energy storage
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
Planning reserve margin or PRM	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
PNNL	Pacific Northwest National Laboratory
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
POI	Point on interconnection
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

Term/Acronym	Definition
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
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 or PHES	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 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.
RECAP	Renewable Energy Capacity Planning, E3's resource adequacy analysis model
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	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

Term/Acronym	Definition
	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
RFQ	Request for quote
RHA	Renewable Hydrogen Alliance
RICE	Reciprocating internal combustion engine – also referred to as recip peakers.
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
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	NREL's System Advisor Model
SAP	Systems Applications and Products in Data Processing
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 Reference 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

Term/Acronym	Definition
SMR	Small modular reactor
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 capacity	Defines the quantity of generation development available in specific geographic regions.
Transmission costs	Transmission costs model the cost of transmitting power from a generating resource to PSE's service territory
Transmission losses	This refers to energy lost to heat as power is carried from one location to another.
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.
Tranche	A capacity segment on ELCC saturation curve
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.

Term/Acronym	Definition
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 or Westcoast	Westcoast Energy, Inc.
Wholesale market purchases	Generally short-term purchases of electric power made on the wholesale market.
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
ZLD	Zero liquid discharge

EXECUTIVE SUMMARY
CHAPTER ONE

Contents

1. Introduction

Puget Sound Energy (PSE) is Washington State's largest and oldest utility, serving 1.5 million customers in ten counties over 6,000 square miles. History reflects how PSE has shared customers' environmental concerns over the years while balancing expectations for uncompromised reliability, affordability, and safety. Puget Sound Energy was an early leader in clean energy — from our oldest hydroelectric facility, Snoqualmie Falls built in 1898, to our first wind facility, Hopkins Ridge, developed in 2005, to establishing a pathway to remove coal-fired generation by the end of 2025. Our commitment to clean energy and reducing greenhouse gas emissions has only strengthened in recent years, as evidenced by our support of the passage of the Clean Energy Transformation Act (CETA) and the Climate Commitment Act (CCA).

In this 2023 Electric Progress Report (2023 Electric Report or report), we identified the need to build and/or acquire a significant amount of resources to comply with the CETA and meet resource adequacy requirements — more than 6,700 megawatts (MW) of nameplate capacity by 2030. This report outlines the resources and actions to get us there.

A Series of Firsts

This document is PSE's first electric progress report. A product of the CETA, it is designed to streamline reporting as we work toward our clean energy goals. This report is also our first opportunity to reinforce the commitments in PSE's 2021 Clean Energy Implementation Plan (CEIP), which includes eliminating coal-fired resources by 2025, achieving greenhouse gas neutrality by 2030, and supplying 100 percent renewable and non-emitting electric energy by 2045.

This is the first resource plan to incorporate climate change temperature predictions in the analysis, and this made an unmistakable mark on our resource needs. As a result of this analysis, we learned that even though the summer peak is increasing, PSE is still a winter peaking utility. Although our most significant peak demand will still occur in winter, we must also account for summer peaks. The resources we rely on to get us through cold winter nights will not be the same as those that get us through hot summer days.

This report also expands our approach to quantifying customer benefits in the analysis to ensure a more equitable transition to clean energy. The resulting resource plan is far more diverse and relies more on clean, intermittent resources such as wind, solar, and storage. The plan also reduces market reliance compared to prior resource plans because we recognize that recent significant changes in the wholesale electric market make it increasingly risky and unreliable to rely on the market. Although markets will continue to play a critical role in optimizing PSE's portfolio, we can no longer rely on traditional energy markets to meet peak capacity needs.

An All-of-the-above Approach

All these factors drove us to look at our portfolio of resources in new and diverse ways. The portfolio builds a wide range of new renewable and storage resources — an all-of-the-above approach — at an unprecedented scale and pace. The amount of new, non-emitting generation resources PSE will need by 2030 is more than we have accumulated in our 100-year history. It will require us to develop resources rapidly while we adhere to our procurement principles and policies to meet our CETA goals.

Our analysis also revealed that we will need significant grid improvements that allow increasing amounts of intermittent resources to work in concert. The grid will require considerable development in transmission capacity to bring utility-scale wind and solar to our region and allow the rapid advancement of new and emerging technologies such as green hydrogen.

Our plan illustrates significant investment in wind and solar resources combined with energy storage will shape the foundation of the energy system of the future. We also assume that technologies emerging over the coming 15 years will help us maintain a reliable system. We are not pursuing a single long-term technology solution but will explore multiple emerging technologies in the coming years. We will take a pragmatic, diversified approach and engage with others in the region to take concrete steps to move multiple technologies forward. We will work together to ensure that future resources are available to maintain the reliability and affordability our customers expect as we create a cleaner and more equitable system.

Mitigating Risk

There is a risk that some of these technologies will not emerge as viable at the pace we need. We are mitigating that risk in several ways. For example, we assumed multiple fuel options for peaking facilities. We are active partners in establishing Washington as a green hydrogen leader, which includes working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington.[1] Although not part of the preferred portfolio, we see advanced nuclear reactors as potentially a necessary part of our region's future energy supply mix and will continue to investigate the technology as a potential fit for future PSE resource needs. Puget Sound Energy and the region will need emerging resources like hydrogen hubs and/or advanced nuclear reactors to become commercially viable to help integrate renewables and ensure a reliable grid in the future. For that reason, PSE intends on taking an active role in exploring such technologies to help ensure progress is made toward meeting the needs of our customers and successfully meeting the requirements of state policy.

We are proud to be the Pacific Northwest's largest utility producer of renewable energy, but we know that our journey toward an equitable clean energy future has only begun. The resource plan included in this 2023 Electric Report is another critical next step highlighting the opportunities for PSE to continue leading the way on renewable energy for our state and region.

2. Resource Planning Foundations

This 2023 Electric Report is an update to the 2021 Integrated Resource Plan (IRP) required under Washington Utilities and Transportation Commission (WUTC) rules for electric investor-owned utilities as of December 2020.[2] Those changes require electric utilities to file an electric IRP every four years and an update, or progress report, two

1 https://ffi.com.au/news/centralia/
2 WAC 480-100-625

years later. This 2023 Electric Report is a planning exercise that evaluates how PSE will meet customer electric supply needs. The analysis considers policies, costs, changing economic conditions, and the existing energy system to develop a plan to meet the needs of our customers at the lowest reasonable cost over the next 20+ years.

Throughout the resource planning process for this report, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Build a reliable, diversified power portfolio of non-emitting resources
- Ensure an equitable clean energy transition for all PSE customers
- Ensure resource adequacy while delivering a clean energy transition
- Ensure resource planning aligns with PSE's Clean Energy Implementation Plan (CEIP) to meet our interim targets and CETA obligations

Recognizing that the 2023 Electric Report does not make resource or program implementation decisions is important. The report is a long-term view of what resources appear to be cost-effective while maximizing benefits and minimizing burdens, based on the best information we have today about the future. The forecasts and resource additions in the 2023 Electric Report will change in future IRPs as technology advances, customer use patterns change, clean fuel options evolve, resource costs change, the wholesale energy market evolve, and new policies are established.

3. Change Drivers

We developed this report during a time of extraordinary change as policymakers, the utility industry, and the public confront the challenge of climate change and the necessity to transition to a clean and equitable energy future. The following describes four areas of focus that impact the resource plan described in this report.

3.1. Address Regulatory Changes

The 2023 Electric Report includes updates in response to new legislation enacted since the 2021 IRP. These updates include the Climate Commitment Act, updates to CETA rules, Washington State building code efficiency improvements, and portions of the Inflation Reduction Act (IRA). We incorporated as much of the IRA as possible, resulting in an estimated savings of approximately $10 billion over the next 20+ years from production and investment tax credits. However, because the law was enacted late in our planning process, we could not consider all the nuances of the bill, nor could we incorporate the policies and rules the federal government has not developed yet to implement the IRA. We will continue to analyze and integrate the impacts of the IRA for the 2025 IRP.

➔ A complete discussion of the legislative policy updates is in Chapter Four: Legislative and Policy Change.

3.2. Embed Equity

The 2023 Electric Report represents our continued progress in a journey to embed equity into the resource planning process. We began incorporating equity in 2021 by assessing highly impacted communities and developing initial customer benefit indicators. Since then, we've made progress by defining vulnerable populations and creating customer benefit indicators with input from interested parties, including the Equity Advisory Group (EAG) formed during the 2021 CEIP process. We recognize this is one step of many toward ensuring an equitable clean energy transition. Equity is complex to measure and assess, especially in energy system planning. However, we continue to refine our analysis and work with interested parties to embed equity throughout the resource planning process.

CETA requires that all customers benefit from the transition to clean energy through the equitable distribution of energy and non-energy benefits and the reduction of burdens to vulnerable populations and highly impacted communities.

For this report, we expanded the 2021 IRP approach to building a preferred portfolio to include a portfolio benefit analysis using customer benefit indicators (CBIs) developed for the 2021 CEIP with extensive input from the EAG. Our goal in using customer benefit indicators (CBIs) is to identify a preferred portfolio that balances customer benefits with portfolio costs while reducing burdens to vulnerable populations and highly impacted communities. Our approach is evolving and will continue to improve and develop for the 2025 IRP and future CEIP cycles.

➔ Details on the portfolio benefits analysis are in Chapter Five: Key Analytical Assumptions.

3.3. Incorporate Impacts of Climate Change

The 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. We heard from interested parties that it is vital to incorporate climate change because it affects future demand, and we agree. We included climate change in the base demand forecast, the resource adequacy analysis, and stochastic scenarios. Before this report, PSE used temperatures from the previous 30 years to model the expected normal temperature for the future. This approach was a common utility practice but did not recognize predicted climate change impacts on temperatures. We used climate change projections, modeled recently by climate change scientists for the region in time for this 2023 Electric Report, to calculate a normal temperature assumption that reflects climate change. No industry standards or best practices for incorporating climate change into a demand forecast exist. Including climate change in this report for the first time is a significant milestone, but we recognize this methodology needs to be refined and will evolve in future planning efforts.

➔ Please refer to Chapter Six: Demand Forecast for details regarding how we incorporated climate change into our demand forecast.

3.4. Reduce Market Reliance

The supply and demand fundamentals of the wholesale electric market have changed significantly in recent years. The availability of dispatchable generation resources is declining, and market power prices and volatility are increasing. These factors make reliance on the Western Interconnect market increasingly risky, so we plan to decrease market reliance during high demand peak hours, from almost 1,500 MW to zero MW by 2029.

For decades, PSE's customers have benefitted from an over-supplied market. Under such conditions, firm capacity was available at a low cost. The market outlook is different today. While markets will continue to play a critical role in optimizing PSE's portfolio, we can no longer rely on traditional energy markets to meet peak capacity needs.

The future of electricity consists of a diversified portfolio of non-emitting resources. A diverse portfolio reduces vulnerabilities due to market price, supply fluctuations, and political unrest. Having multiple, reliable generating resources allows a utility to continue to provide power without disruption if one energy source fails. A diverse energy portfolio reduces environmental impacts, improves reliability, and promotes innovation to meet our customers' needs. Resource diversity is the key to reducing emissions while preserving reliability and affordability.

➔ We provide more details on the various portfolios considered in Chapter Eight: Electric Analysis.

3.5. Accessibility and Plain Language

While creating the 2023 Electric Progress Report, we took measures to improve the accessibility of our written documents, public meetings, and website content. In this and future documents, we are committed to removing participation barriers and attracting more members of the public into the resource planning process. We are continuously evaluating our content and working to improve readability and accessibility for all while encouraging interested members of the public to get involved in our planning processes.

➔ Appendix A: Public Participation contains additional detailed information about public feedback in this IRP cycle.

4. Preferred Portfolio

The preferred portfolio, which requires over 6,700 MW of new generation by 2030, is a portfolio of diverse resources that can fulfill our CETA commitments and achieve carbon neutrality by 2030 and a carbon-free electric energy supply by 2045. As described in Table 3.1, this portfolio significantly increases conservation, demand response, renewable resources, and energy storage. However, given the large amounts of variable energy resources such as wind and solar, and energy-limited resources such as energy storage, we rely on newer technologies, specifically hydrogen, as a fuel to meet peak energy needs to achieve a carbon-free energy supply by 2045 while maintaining reliability and resource adequacy.

We acknowledge the risk of relying on an uncertain fuel source, so we intentionally diversified this portfolio to reduce risk. Additionally, in future IRP cycles, we will continue to evaluate and consider emerging technologies, including green hydrogen and advanced nuclear small modular reactors (SMR).

Table 1.1: Electric Preferred Portfolio, Resource Additions (Nameplate Capacity)

Resource Additions (Nameplate MW)	Total by 2030	Total by 2045
Demand-side Resources	**618**	**1,265**
Conservation[1]	281	818
Demand Response	337	446
Distributed Energy Resources	**739**	**2,392**
DER Solar	552	2,124
Net Metered Solar	*284*	*1,393*
CEIP Solar	*79*	*79*
New DER Solar	*189*	*652*
DER Storage[2]	187	267
Supply-side Resources	**5,360**	**11,174**
CETA-compliant Peaking Capacity[3]	711	1,588
Wind	1,400	3,650
Solar	700	2,290
Green Direct	100	100
Hybrid (Total Nameplate)	1,450	1,748
Hybrid Wind	*600*	*800*
Hybrid Solar	*400*	*398*
Hybrid Storage	*450*	*550*
Biomass	-	-
Advanced Nuclear (SMRs)	-	-
Standalone Storage	1,000	1,800
Total	**6,717**	**14,830**

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
3. CETA-qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA-qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

➔ Please see Chapter Three: Resource Plan for a complete description of the preferred portfolio.

CLEAN ENERGY ACTION PLAN
CHAPTER TWO

PUGET SOUND ENERGY

Contents

1. Introduction

Washington State's Clean Energy Action Plan (CEAP) is a new aspect of Puget Sound Energy's (PSE's) Integrated Resource Plan (IRP) process. Introduced in the Clean Energy Transformation Act (CETA) in 2019, the CEAP identifies steps utilities can take over the next 10 years to meet the requirements of CETA. This is PSE's first Electric Progress Report and the first to include a CEAP update. As with any new requirement or assessment, the CEAP will evolve, and future IRPs will benefit from the lessons we learned in previous planning processes.

Puget Sound Energy is committed to achieving the requirements of CETA and carbon neutrality by 2030 and a carbon-free electric energy supply by 2045, and the CEAP presented here reflects these goals. Bridging PSE's Clean Energy Implementation Plan (CEIP) and IRP, the CEAP informs our decisions about specific and interim targets and actions over ten years, per RCW 19.280.030[1].

Table 2.1 presents near-term renewable and non-emitting — or clean energy — targets starting in the 2021 IRP and progressing through this progress report. The 2021 IRP established a clean energy target with a linear ramp from existing renewable energy generation to the 80 percent target in 2030. The 2021 CEIP expanded this target to make aggressive progress near-term toward the 80 percent goal. This 2023 Electric Progress Report (2023 Electric Report) retains the 63 percent clean energy target for 2025 established in the 2021 CEIP; however, given an increase in the load forecast, this report's resource plan requires additional renewable and non-emitting generation to meet the same target.

Table 2.1: Renewable and Non-emitting Energy Targets for 2025

Document	Clean Energy Target[1] by 2025 (%)	Clean Energy Generation to Meet Target[1] (MWh)
2021 IRP	56	10,046,493
2021 CEIP	63	11,381,593
2023 Progress Report	63	12,324,846

Notes: Clean energy targets represent a percent or quantity (MWh) of renewable or non-emitting energy of delivered load. The delivered load is adjusted for projected future demand-side resources (conservation, demand response, select distributed energy resources), PURPA contracts, and voluntary renewable programs.

2. Requirements

The 2021 IRP marked a significant departure from past IRPs largely due to CETA. The new rules, WAC 480-100-620 (12),[2] outline the requirements for this report. The utility must develop a 10-year clean energy action plan for implementing RCW 19.405.030[1]□ .

In this CEAP, the utility must include the following:

- A 10-year action plan that is the lowest reasonable cost (see section 3)

1 RCW 19.280.030
2 WAC 480-100-620

- Establish resource adequacy requirement (see section 3.2)
- Identify any need to develop new or to expand or upgrade existing bulk transmission and distribution facilities (see section 5)
- Identify cost-effective conservation potential assessment (CPA) (see section 3.1)
- Identify how the utility will meet the requirements of the clean energy transformation standards (see section 4)
- Identify potential cost-effective demand response (see section 3.4)
- Identify renewable resources, non-emitting electric generation, and distributed energy resources and how they contribute to meeting the resource adequacy requirement (see section 3.3)
- Identify the nature and extend for alternative compliance reliance (see section 6)
- Incorporate the social cost of greenhouse gasses as a cost adder (see section 7)

3. Ten-year Resource Additions

From the 2023 Electric Progress Report 22-year period, Table 2.1 summarizes the 10-year outlook for the resource mix in PSE's preferred portfolio. The portfolio benefit analysis, which considers the equitable distribution of benefits and how burdens may be reduced over the CEAP's ten-year horizon, informed our final selection of resources while ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs, and addressed market risk.

Table 2.2: 10-year Annual Incremental Resource Additions Preferred Portfolio

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Conservation[1]	33	32	44	36	36	60	41	42	78	43	445
Demand Response	71	65	71	47	49	16	17	17	17	16	387
DER Solar[2]	97	75	51	70	73	93	91	98	98	102	850
Net Metered Solar	*38*	*21*	*21*	*40*	*40*	*61*	*61*	*67*	*67*	*71*	*490*
CEIP Solar	*55*	*24*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*79*
New DER Solar	*4*	*30*	*30*	*30*	*33*	*32*	*30*	*31*	*31*	*31*	*281*
DER Storage[3]	21	18	29	32	29	28	30	28	4	4	223
CETA-qualifying Peaking Capacity[4]	237	0	237	0	237	0	0	0	0	0	711
Wind	300	300	500	0	0	0	400	200	100	100	1,900
Solar	100	0	0	0	200	400	0	0	0	0	698
Hybrid Total	150	150	400	0	150	600	0	0	0	0	1449
Hybrid Wind	*0*	*100*	*200*	*0*	*100*	*200*	*0*	*0*	*0*	*0*	*600*

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total 2024–2033
Hybrid Solar	*100*	*0*	*100*	*0*	*0*	*200*	*0*	*0*	*0*	*0*	*399*
Hybrid Storage	*50*	*50*	*100*	*0*	*50*	*200*	*0*	*0*	*0*	*0*	*450*
Standalone Storage	0	100	600	300	0	0	0	0	100	100	1,200
Total	1010	740	1932	485	774	1198	579	385	396	364	7,862

Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) solar includes customer solar photovoltaic (PV), Clean Energy Implementation Plan (CEIP) solar additions, non-wires alternatives, and ground and rooftop solar additions.
3. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
4. CETA-qualifying peaking capacity is functionally similar to natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives.

3.1. Conservation Potential Assessment

We analyzed demand-side resource (DSR) alternatives in a conservation potential assessment (CPA) to develop a supply curve used as an input to the portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings the model captured without raising the overall electric portfolio cost. This study identified the cost-effective level of conservation, which includes non-energy benefits from the portfolio benefit analysis to include in the portfolio. We evaluated the amount of cost-effective conservation to meet the portfolio's capacity and energy needs, optimizing the lowest cost and considering distributed and centralized resources.

➔ See Appendix E: CPA and Demand Response Assessment for the full CPA Assessment. A complete discussion of how we chose the conservation levels for the preferred portfolio is in Chapter Three: Resource Plan.

Figure 2.3: 10-year Achievable Technical Potential Conservation Savings (Energy aMW and Peak MW)

Demand-side Resources	Total Savings (aMW)	Winter Peak Savings (MW)	Summer Peak Savings (MW)
Energy Efficiency	167	214	212
Distribution Efficiency	11	11	10
Codes and Standards	159	196	245

3.1.1. Impacts and Actions

This electric report informs the target setting process and, through this analysis, we identified 10-year savings of 167 aMW as cost-effective. We will use this to inform the draft 2023 Energy Independence Act (EIA) target for the 2024-

2025 biennium after adjusting for intra-year ramping and savings at the meter. Under the EIA, utilities must pursue all cost-effective, reliable, and feasible conservation. Puget Sound Energy fulfills these requirements by undertaking additional analysis to identify the conservation potential over 10 years and set two-year targets. Setting the final two-year targets is part of PSE's biennial conservation plan process, which will take place over the next few months and builds on the information in this electric progress report.

3.2. Resource Adequacy

We 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.

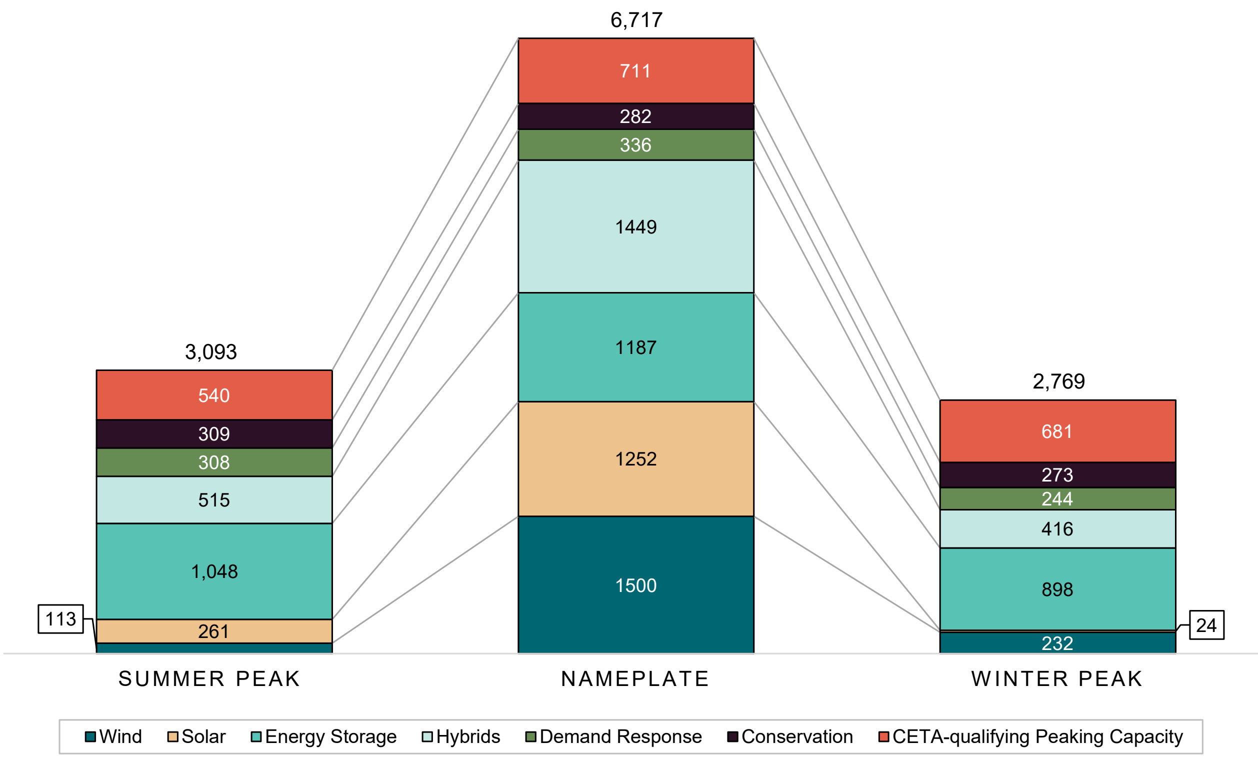
We have established a five percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. The LOLP analysis measures the likelihood of a load curtailment event in any given simulation regardless of the frequency, duration, and magnitude of the curtailment(s). Therefore, the possibility of capacity being lower than the load anytime in the year cannot exceed five percent.

Assessing the peak capacity each resource can reliably provide is an integral part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro, and solar) and other resources (thermal, storage, demand response, and contract), we calculate the effective load-carrying capacity (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.

We analyzed summer and winter peak capacity for this report, and the analysis indicated that the winter peak is higher than the summer peak. With the increase of renewable energy and energy storage in the portfolio, those resources contribute to the summer peak need better than the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need.

Because the peak capacity contribution of each resource does not match the nameplate energy values, we need more resources to meet the peak need. For example, solar's 24 MW winter peak capacity contribution requires over 1,200 MW of installed nameplate capacity. After adjusting for peak capacity contribution, 6,717 MW of new resources installed nameplate capacity equals 3,093 MW summer peak capacity and 2,769 MW winter peak capacity, as detailed in Figure 2.1.

Figure 2.1: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW) for 2030



➔ See Chapter Seven: Resource Adequacy Analysis and Appendix L: Resource Adequacy for a complete description of the resource adequacy modeling.

3.3. Renewable and Non-emitting Resources

We modeled several types of renewable and non-emitting utility-scale resources for this Electric Progress Report. Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter. These resources include wind, solar, pumped hydro energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines using alternative fuels such as biodiesel and hydrogen, and advanced nuclear small modular reactors (SMR).

Distributed energy resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to virtual power plants (VPPs). This report included demand response, distributed solar, and distributed storage programs as generic DERs.

➔ A full description of resources modeled for this progress report is in Appendix D: Generic Resource Alternatives, with a brief description in Chapter Five: Key Analytical Assumptions.

3.3.1. Impacts and Actions

Biodiesel

Biodiesel is a commercially available fuel that can be combusted in existing and new peaking plants. Biodiesel provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. Biodiesel is energy-dense and can be stored on site for short periods — one to two months — to provide reliability in the event green hydrogen or renewable natural gas supplies are exhausted or unavailable.

We will continue to monitor and engage with regional biodiesel manufacturers to determine the limits of biodiesel fuel supply. We anticipate a shift in biodiesel supply as the transportation sector is rapidly electrified and alternative fuels, such as biodiesel, become increasingly available to other industries.

Renewable Diesel

Renewable diesel — frequently referred to as R99 — is a commercially available fuel that can be combusted in various existing and new peaking plants. R99 provides a carbon-neutral alternative to existing backup fuels like petroleum-derived diesel. R99 is energy dense and can be stored on site (for periods measured in years) to provide reliability if green hydrogen or renewable natural gas supplies are exhausted or unavailable. Puget Sound Energy successfully tested R99 fuel in the Crystal Mountain generator and is coordinating with authorities to test R99 in a Frederickson generator in 2023.

We will continue to monitor and engage with regional R99 manufacturers to determine the limits of the R99 fuel supply. We anticipate an increase in R99 supply in 2024 as the transportation sector is rapidly electrified and alternative fuels, such as R99, become increasingly available to other industries.

Biodiesel and renewable diesel are derived from non-petroleum feedstocks like vegetable oil, animal fats, municipal waste, agricultural biomass, and woody biomass. Biodiesel is produced using a transesterification separation method, and renewable diesel uses a hydrogenation process. Renewable diesel meets all of the ASTM–D975 specifications. Renewable diesel can be blended with or replace petroleum-derived diesel without affecting engine operations or air operating permit requirements. Renewable diesel has a carbon intensity of approximately 60 percent less than petroleum diesel and reduced NOx, particulate matter, and VOC emissions.

Hydrogen

Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas stored for long periods until needed during a peak event. During a peak event, green hydrogen is combusted with either existing retrofitted equipment or at new peaking plants. Until recently, high costs have dissuaded the development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

Puget Sound Energy aims to be a leader in developing hydrogen infrastructure to bring the benefits of green hydrogen to the Pacific Northwest. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association[3], which is seeking to establish a network of suppliers, storage, and off-takers in the region as part of the Department of Energy's Hydrogen Hub (H2Hub) Funding Opportunity as part of the Infrastructure Investment and Jobs Act (IIJA). In addition to our work with Pacific Northwest Hydrogen Association, we are also working with Fortescue Future Industries and other regional interested parties to explore the development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington[4].

Beyond these initial efforts, we may explore pilot programs soon to learn more about blending hydrogen in existing, retrofitted, and new peaking plants. We will also continue to research fuel supply and security considerations.

Advanced Nuclear and Other Emerging Technologies

Clean energy dispatched on demand will be a key element of a decarbonized power grid. Energy storage, such as batteries, improves the ability of wind and solar resources to follow demand, but the energy-limited nature of energy storage systems constrains their effectiveness in longer-duration peak events. We are currently missing cost-effective clean energy resources, which follow load and generate power through long-duration peak events. Several emerging resources have the potential to fill this niche but require advancements in operability and commercial availability. We will continue to monitor the development of technologies such as advanced nuclear small module reactors (SMR), carbon capture and sequestration, and deep-well geothermal.

Energy Storage

Energy storage will be an essential component of a decarbonized power system to shift variable energy resources and load. As energy storage is added to PSE's system, we will learn how to use this new resource to optimize operational efficiency. We are reviewing energy storage submittals as part of the ongoing 2021 All-Source Request for Proposal (RFP).

We will also monitor advances in energy storage technology, such as new battery chemistries and long-duration batteries, or other storage mediums, such as gravity- or compression-based storage systems. We will evaluate these technologies as they become commercially viable.

3.4. 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 programs require action by the customer; others can be largely automated and are usually referred to as direct load control programs. For example, an

[3] https://pnwh2.com/
[4] https://ffi.com.au/news/centralia/

automated program might warm a customer's home or property earlier than usual with no action required on the part of the customer.

One example of a program that requires customer action is asking a wastewater plant to curtail pumping during certain peak energy need hours if they can. Because customers can always opt out of an event, demand response programs include some risk. If PSE relies on a certain amount of load reduction from demand response to handle a peak event, but customers opt out, we must use generating resources to fill the customer's needs.

We organized demand response programs modeled for this 2023 Electric Report in four categories:

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

➔ See Appendix E: Conservation Potential and Demand Response Assessments for the full CPA Assessment. We included a complete discussion of how we chose the demand response programs for the preferred portfolio in Chapter Three: Resource Plan Decisions.

Figure 2.4 lists the estimated 10-year achievable technical potential for demand response programs modeled for this report's residential, commercial, and industrial sectors. The table shows the attainable potential of each demand response program in MW, and the winter and summer peak need it fills to illustrate the total potential impact of demand response on system peak.

Table 2.4: 10-year Achievable Technical Potential Demand Response Programs for Model Year 2033 (MW)

Program	Category	Nameplate	Winter Peak	Summer Peak
Signal-capable Standard Water Heater[1]	Residential	74	61	51
Signal-capable Electric Heat Pump Water[1]	Residential	16	14	9
Signal-capable Heating, Ventilation, and Air Conditioning[1]	Residential, Commercial	102	73	98
Bring Your Own Smart (Internet-connected) Thermostat	Residential, Commercial	83	65	64
Signal-capable Electric Vehicle Charger[1]	Residential	21	15	20
Reduced (Lower) Electric Usage at Utility's Request	Commercial, Industrial	20	14	21
Time of Day Rates (Optional)	Residential, Commercial, Industrial	58	33	77
Electric Rate Allowing Electricity Cut Off in Periods of High Demand	Commercial	12	9	11

Note:

1. Capable of receiving internet, cellular, or radio signals.

3.4.1. Impacts and Actions

Distributed energy resources, including demand response, are a significant component of PSE's preferred portfolio from the 2023 Electric Progress Report and represent a piece of our strategy to achieve the targets laid out under CETA. Puget Sound Energy issued a DER Request for Proposal (RFP) in 2022. We are still working through the analysis and will have an updated target in the 2023 CEIP Biennial update.

4. Equitable Transition to Clean Energy

The Clean Energy Transformation Act (CETA) sets out important new expectations for the clean energy transition: that utilities must ensure that all customers benefit from the transition to clean energy.

4.1. Assess Current Conditions

To move toward an equitable transition to clean energy, we performed an economic, health, and environmental benefits (EHEB) assessment (the assessment) in 2021 to guide us as we developed our CEAP and CEIP. The purpose of the assessment was two-fold: first, to use the definitions we provided in our CEIP for named communities to identify highly impacted communities and vulnerable populations within our service area, and second, to measure disparate impacts to these communities using specific customer benefit indicators.

➔ See the updated assessment in Appendix J: Economic, Health, and Environmental Assessment of Current Conditions.

The initial qualitative and quantitative customer benefit indicators we developed through the assessment provide a snapshot 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. PSE built upon those initial customer benefit indicators in the assessment in developing its CEIP. Due to the timing of the IRP process and the CEIP adjudication, the proposed customer benefit indicators included in the CEIP may change based on the upcoming Washington Utilities and Transportation Commission decision on PSE's CEIP and in the future through public participation and input from PSE's Equity Advisory Group. The customer benefit indicators help measure progress toward achieving an equitable distribution of benefits and reducing burdens.

4.2. Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits and a reduction of burdens to vulnerable populations and highly impacted communities in the transition to a clean energy future is to include customer benefit indicators (CBIs) in the preferred portfolio development process. For this 2023 Electric Progress

Report, PSE used the CBIs established in the 2021 CEIP through extensive public participation and consultation with our equity advisory group.

We expanded on applying CBIs to the portfolio analysis with input from interested parties. First, we linked CBIs to specific portfolio modeling outputs to reflect customer benefit indicators in developing the preferred portfolio. We then combined these outputs into broader CBI areas, providing a context for interpreting the portfolio outputs. We indexed each portfolio from the sensitivity analyses on how well it performed in each CBI area to understand which benefits or burdens it may confer on our customers. Portfolios had to score well in several CBI areas to be considered in a preferred portfolio.

➔ See Chapter Three: Resource Plan, Chapter Eight: Electric Analysis, and Appendix H: Electric Analysis and Portfolio Model for more detail on the customer benefit indicator framework.

In summary, we have taken several actions that put us on a pathway to ensure all customers benefit from the transition to clean energy:

- Developed a public participation plan for the CEIP to obtain input on the equitable distribution of benefit and burdens
- Established the Equity Advisory Group
- Refined customer benefit indicators and metrics with the EAG and the CEIP public participation process
- Updated the portfolio benefits analysis to incorporate the customer benefit indicators and related metrics in the 2023 Electric Progress Report and future IRPs or CEIPs

Identifying and using customer benefit indicators is a developing process. Future IRPs will benefit from more input from the Equity Advisory Group (EAG) and the CEIP public participation process.

4.3. Vulnerable Populations and Highly Impacted Communities

As part of our work for the CEAP, we reviewed the CBI baseline data, often broken down into metrics for vulnerable populations and highly impacted communities, published in the 2021 CEIP. This report provides more detailed information about the 2020 and 2021 CBI data.

We will publish the metrics for 2022 for all CBI data included in Appendix J: Economic, Health and Environmental Assessment of Current Conditions of this report in our 2023 biennial CEIP update. We incorporate vulnerable populations and highly impacted communities in the IRP process by considering these groups while developing the achievable technical potentials for energy efficiency programs as part of the CPA discussed in Appendix E: Conservation Potential and Demand Response Assessments. The generic supply side resources we studied as part of the IRP lack detailed enough geographic information to establish relationships between resource selection and impacts on named communities.

➔ See Appendix J: Economic, Health, and Environmental Assessment of Current Conditions for details on the changes to the analyses.

5. Resource Deliverability

We will work to optimize our use of PSE's existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system may need significant expansion, optimization, and possible upgrades in the long term 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. Table 2.5 shows the regional transmission need for new resources outside PSE.

Table 2.5 Regional Transmission Need Based on 2023 Preferred Portfolio (MW)

Region	2030 (MW)	2033 (MW)
East of the Cascades (Central and Eastern Washington)	3,449	3,447
Rocky Mountain Region (Montana and Wyoming)	400	800
Cross Cascades Total	3,849	4,247
British Columbia	0	0

➔ See Appendix J: Regional Transmission Resources from the 2021 IRP on specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment. The 10-year delivery system plan is in this report's Appendix K: Delivery System Planning.

Our delivery system needs investments to deliver energy to our 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 K: Delivery System Planning identifies work needed to ensure safe, reliable, resilient, smart, and flexible energy delivery to customers, regardless of resource fuel source. This work includes specific upgrades to the transmission system to meet NERC compliance requirements, other evolving regulations related to DER integration and markets, and distribution system upgrades 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 of 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. We summarized the key investment areas in the following section.

5.1. Impacts and Actions

Puget Sound Energy is pursuing the acquisition of new additional transmission capacity and optimization of existing transmission capacity rights required to facilitate the delivery of its preferred resource portfolio. We are exploring ongoing opportunities to contract with the Bonneville Power Administration (BPA) for additional transmission rights by submitting transmission service requests (TSRs) and participating in BPA's annual cluster study. The BPA annual cluster study results may trigger requirements for funding BPA system reinforcement projects needed to award the requested TSR(s). Funding these reinforcement projects will be critical to adding capacity to the regional transmission system and projects delivering to PSE's system.

Puget Sound Energy seeks to repurpose specific portions of our transmission portfolio to enhance our value to align with the preferred resource portfolio. Existing Mid-C transmission capacity allocated for market purchases could be strategically redirected for new renewable projects and projects delivering to Mid-C. Colstrip Units 3 & 4 transmission rights could be repurposed for new Montana resource deliveries. In addition, standalone PSE generation facilities could be further developed to co-locate with new renewable projects for optimized energy delivery over shared transmission (e.g., Lower Snake River, Wild Horse, Goldendale).

6. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

Under CETA, utilities can meet up to 20 percent of the 2030 greenhouse gas neutral standard with an alternative compliance option. Utilities can use these alternative compliance options from January 1, 2030, to December 31, 2044. An alternative compliance option includes any combination of the following:

- 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
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing unbundled renewable energy credits (RECs)

For this report, we modeled unbundled RECs to achieve CETA compliance 2030–2044, where renewable and non-emitting energy could be less than 100 percent of delivered energy annually. The preferred portfolio only incurs one alternative compliance payment in 2030 of $3.18 million worth of unbundled RECs to make up for 3.4 percent of delivered energy. For all future years of the CEAP horizon, the preferred portfolio meets the 100 percent standard without the need for alternative compliance options.

➔ See Chapter Five: Key Analytical Assumptions for a discussion on alternative compliance assumptions and costs. Appendix I: Electric Analysis Inputs and Results for portfolio modeling results.

7. Social Cost of Greenhouse Gases

The social cost of greenhouse gases (SCGHG) was included per WAC 480-100-620(12)(i).[2]

➔ General assumptions for the SCGHG are in Chapter Five: Key Analytical Assumptions, and a detailed modeling description of the SCGHG is in Appendix G: Electric Price Models.

RESOURCE PLAN
CHAPTER THREE

Contents

1. Introduction

This chapter presents Puget Sound Energy's preferred portfolio for the 2023 Electric Progress Report (2023 Electric Report). Our preferred portfolio is the result of robust Integrated Resource Plan (IRP) analyses developed with input from interested parties. Informed by our deterministic portfolio, risk, and portfolio benefit analyses, this portfolio meets the Clean Energy Transformation Act (CETA) requirements.

Puget Sound Energy is the Pacific Northwest's largest utility producer of renewable energy. We currently own and contract more than 10 million MWh of renewable and non-emitting energy, and we forecast this will grow to more than 30 million MWh by 2045.

Throughout the resource planning process for the 2023 Electric Report, we focused on the following key objectives, which lay the foundation for this and all future resource plans:

- Achieve the renewable energy targets under CETA — meet at least 80 percent of PSE's demand with renewable and non-emitting energy and achieve carbon neutrality by 2030, and meet 100 percent of PSE's demand with renewable and non-emitting resources by 2045.
- Build a reliable, diversified power portfolio of renewable and non-emitting resources.
- Continue to be a clean energy leader in the Pacific Northwest and beyond.
- Ensure an equitable transition to clean energy for all PSE customers.
- Ensure our resource planning aligns with PSE's Clean Energy Implementation Plan (CEIP) to meet our interim targets and CETA obligations.
- Ensure resource adequacy while transitioning to clean energy.

We used three distinct types of analysis to develop, refine, and identify the preferred portfolio:

1. The deterministic portfolio analysis solves for the least-cost solution and assumes perfect foresight about the future.
2. The risk analysis examines the preferred portfolio's performance concerning uncertainty in hydroelectric, wind and solar conditions, electric and natural gas prices, customer demand, and unplanned plant-forced outages.
3. The portfolio benefit analysis incorporates equity into the IRP process by measuring potential equity-related benefits to customers within a given portfolio. Because the IRP process is inherently forward-looking, this analysis seeks to identify portfolios containing a mix of electric resources that can enable more equitable customer outcomes in the future. It is important to note the IRP process generally lacks the detail to assess specific existing or future programs and actions that address equity. However, the IRP process can provide a pathway that ensures we acquire the electric resources necessary to implement more equitable programs and measures.

➔ See Chapter Five: Key Analytical Assumptions and Chapter Eight: Electric Analysis for details on these analyses, including methodologies and results.

We present this chapter in the following three sections. Section 2 summarizes the preferred portfolio and describes how the resource additions will meet our projected demand growth. Section 3 describes the contributors to our near-term capacity deficit and how this drives the resource additions in the preferred portfolio. Section 4 presents our process for developing and selecting a preferred portfolio and includes our portfolio benefit analysis results.

2. Preferred Portfolio

Puget Sound Energy is committed to reaching the CETA goals and achieving greenhouse gas (GHG) neutrality by 2030 and a GHG-free electric energy supply by 2045. The electric resource plan shows our current path to meet CETA commitments. Our plan prioritizes delivering cost-effective, reliable conservation and demand response and distributed and centralized renewable and non-emitting resources to our customers at the lowest reasonable cost. The plan reduces direct PSE emissions and achieves GHG neutrality by 2030 through clean energy investments.

We have made many updates and changes since PSE's 2021 IRP. The preferred portfolio resource additions for the 2023 Progress Report include significant increases in renewable resources to meet the CETA requirements and peak demand. We provide a detailed discussion of these changes in Chapter Eight: Electric Analysis and the following summary:

- Capacity Resources: We saw increased capacity resources due to increasing peak demands over the 2021 IRP and reduced market reliance. With the increased peak capacity contribution and lower resource costs, we saw more energy storage resources added to the 2023 preferred portfolio than the 2021 IRP preferred portfolio.
- Clean Energy Resources: Overall, there is an increase in renewable resource additions to meet CETA requirements due to the increase in the demand forecast. A complete discussion of changes to the demand forecast is in Chapter Six: Demand Forecasts.
- Conservation: Overall, the 2023 Progress Report CPA potential is down from the 2021 IRP by approximately 13 percent by 2045. The reduction in the CPA is due to the newly incorporated impact of climate change assumptions, which reduced savings in the later years of the study, and a new statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. We added the impact of this statute, which moved some of the potential from energy efficiency into codes and standards, and the updated building stock assessments, which have more efficiency penetration compared to the last stock assessment.
- Distributed Energy Resources: The 2023 progress report is consistent with the CEIP targets through 2025, and then we see an increase in net-metering solar based on the new forecast from current trends and economics, including rebates from the inflation reduction act.

This section presents the preferred portfolio, describes how the combination of resource additions will meet our projected demand growth, and explains how diversifying resource technology is paramount to reducing technology risk. The preferred portfolio further clarifies the following near-term and long-term priorities.

Near-term Priorities (2024–2029):

- Add diverse commercially available resources to meet CETA energy and resource adequacy needs
- Add utility-scale and distributed resources to achieve the renewable or non-emitting energy targets specified in PSE's 2021 CEIP
- Begin commercial activity to acquire bulk transmission to transport renewable energy from distant renewable energy zones to our customers
- Begin shifting our planning frameworks to align with WRAP requirements as more long-term information becomes available
- Continue to acquire conservation resources
- Continue to develop and refine methods to embed equity into resource decisions.
- Continue to participate in the Western Resource Adequacy Program (WRAP) on an operational basis
- Explore commercial opportunities for advanced nuclear small modular reactors (SMR) capacity and other non-emitting technologies
- Lead and actively participate in developing the region's hydrogen hub infrastructure
- Pursue demand response programs that can effectively help lower peak demand
- Reduce reliance on short-term market purchases in response to the changing western energy market

Long-term Priorities (2030–2045):

- Complete acquisition and development of additional transmission capacity (e.g., Cross Cascades, Idaho, Wyoming, Montana, B.C.) to deliver additional clean energy to our customers
- Develop and acquire generating resources that take longer to develop to meet CETA non-emitting generation obligations while maintaining resource adequacy and peak demand.
- Examine repowering or upgrading existing thermal resources and renewable generation to better position PSE to achieve the 2045 goal of an emission-free generation portfolio.
- Explore new capacity options to drive diversity in our energy supply

2.1. Resource Additions Summary

Table 3.1 describes our preferred portfolio of resource additions. With this combination of conservation, demand response, renewable resources, energy storage, and CETA-qualifying peaking capacity, PSE will reach GHG neutrality by 2030. However, given the large amounts of variable energy resources, such as wind and solar, and energy-limited resources, such as energy storage, we will need to rely on newer technologies, such as hydrogen, to reach a GHG-free energy supply by 2045 while maintaining reliability and resource adequacy. Although the high cost of advanced nuclear SMR deterred us from having it in the preferred portfolio, we will continue to monitor the technology.

Table 3.1: Electric Preferred Portfolio, Resource Additions Incremental Nameplate Capacity (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand Side Resources	**201**	**417**	**618**	**646**	**1,265**
Conservation[1]	65	216	281	537	818
Demand Response	136	201	337	110	446
Distributed Energy Resources	**212**	**527**	**739**	**1,652**	**2,392**
DER Solar	172	380	552	1,572	2,124
Net Metered Solar	*59*	*225*	284	*1,109*	*1,393*
CEIP Solar	*79*	-	79	-	*79*
New DER Solar	*34*	*155*	*189*	*463*	*652*
DER Storage[2]	40	147	187	80	267
Supply Side Resources	**1,337**	**4,023**	**5,360**	**5,814**	**11,174**
CETA-qualifying Peaking Capacity[3]	237	474	711	877	1,588
Wind	600	800	1400	2,250	3,650
Solar	100	600	700	1,590	2,290
Green Direct	-	100	100	-	100
Hybrid (Total Nameplate)	300	1,150	1450	298	1,748
Hybrid Wind	*100*	*500*	*600*	*200*	*800*
Hybrid Solar	*100*	*300*	*400*	-	*398*
Hybrid Storage	*100*	*350*	*450*	*100*	*550*
Biomass	-	-	-	-	-
Nuclear	-	-	-	-	-
Standalone Storage	100	900	1000	800	1,800
Total	**1,750**	**4,967**	**6,717**	**8,112**	**14,830**

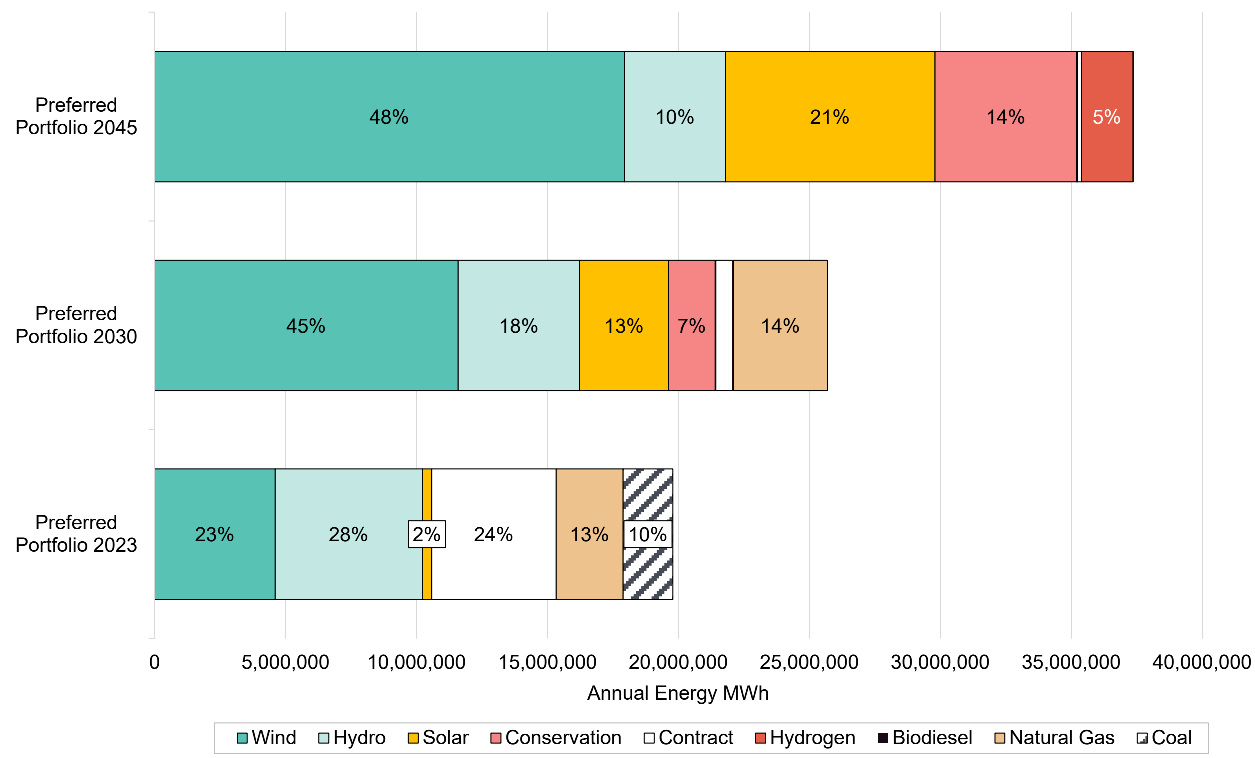
Notes:

1. Conservation in winter peak capacity includes energy efficiency, codes and standards, and distribution efficiency.
2. Distributed Energy Resources (DER) storage includes CEIP storage additions, non-wires alternatives, and distributed storage additions.
3. CETA-qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel.

Figure 3.1 illustrates the projected annual energy production in 2023 and the future with the preferred portfolio. Wind resources are the largest share of capacity additions in the preferred portfolio, accounting for 36 percent of all energy-producing resources added to the planning horizon. However, wind resources produce 48 percent of the total annual energy in 2045, far more than its nameplate capacity indicates. Conversely, CETA-qualifying peaking capacity accounts for 13 percent of nameplate capacity (excluding storage) added by 2045 but supplies only 6 percent of the annual energy in 2045. Figure 3.1 illustrates that with the preferred portfolio, solar and wind remain the primary energy supply for meeting CETA, supplying nearly 70 percent of the portfolio's

CETA qualifying peaking capacity is functionally like natural gas peaking capacity but operates using non-emitting hydrogen or biodiesel fuel. We describe CETA qualifying peaking capacity in Chapter Five: Key Analytical Assumptions, and present alternative fuel assumptions in Appendix D: Generic Resource Alternatives. **RCW 19.405.020 (34)** annual energy in 2045. While CETA-qualifying peaking capacity resources are essential for resource adequacy, as discussed later in this chapter, they don't contribute substantially to the CETA-qualifying energy need.

Figure 3.1: Forecasted Annual Energy Production (Excluding Storage Dispatch)



2.2. Meeting Future Growth

The 2023 Electric Report shows we will meet future sales growth by combining utility-scale, demand-side (conservation), and distributed energy resources (DERs) described in Table 3.1. Distributed energy resources include storage systems, solar generation, or demand response that provides specific benefits to the transmission and distribution systems and simultaneously supports resource needs. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. Distributed Energy Resources make lower peak capacity contributions and have higher costs. However, they are essential in balancing utility-scale renewable investments, transmission constraints, and local distribution system needs. The 2023 analysis also shows these resources enable larger equity benefits.

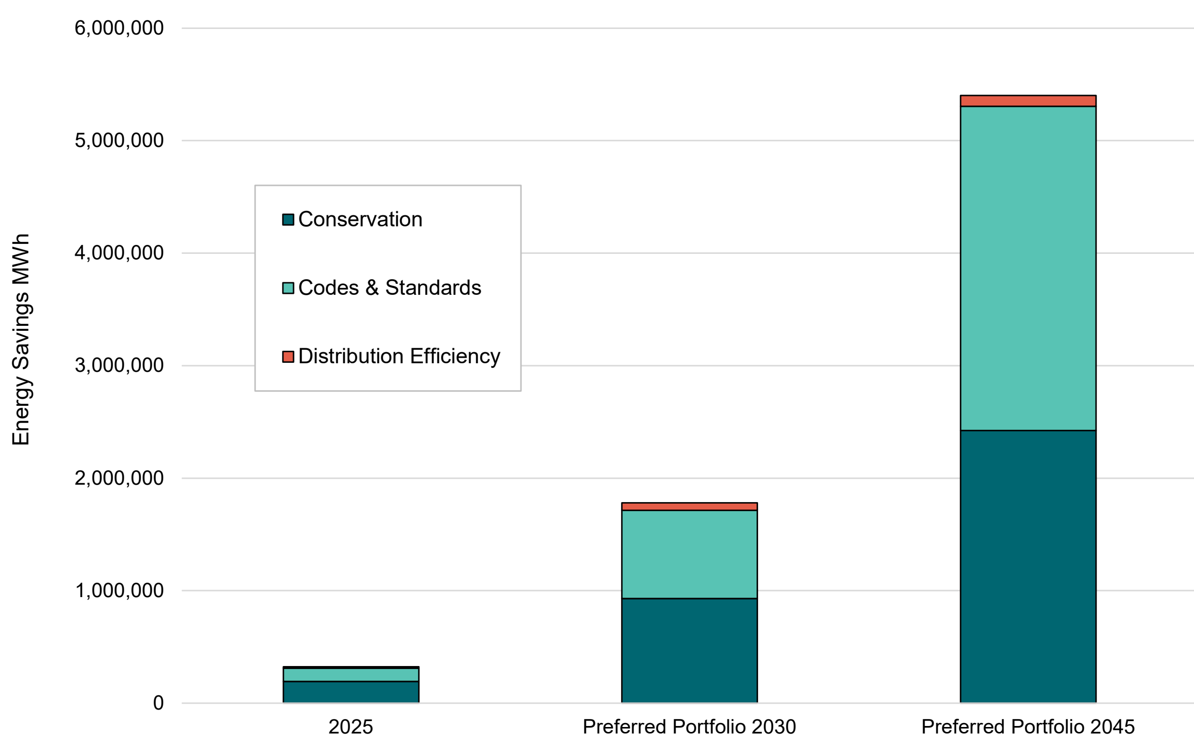
In the following section, we detail how the combination of resources in this plan will meet demand growth.

2.2.1. Conservation

For this analysis, conservation includes new energy efficiency measures, new codes and standard gains in efficiency, and distribution efficiency. Figure 3.2 describes the new energy savings from the preferred portfolio conservation measures.

➔ Appendix E: Conservation Potential Assessment contains a detailed discussion of the building codes and energy efficiency measures we modeled.

Figure 3.2: Preferred Portfolio Conservation Savings (MWh)

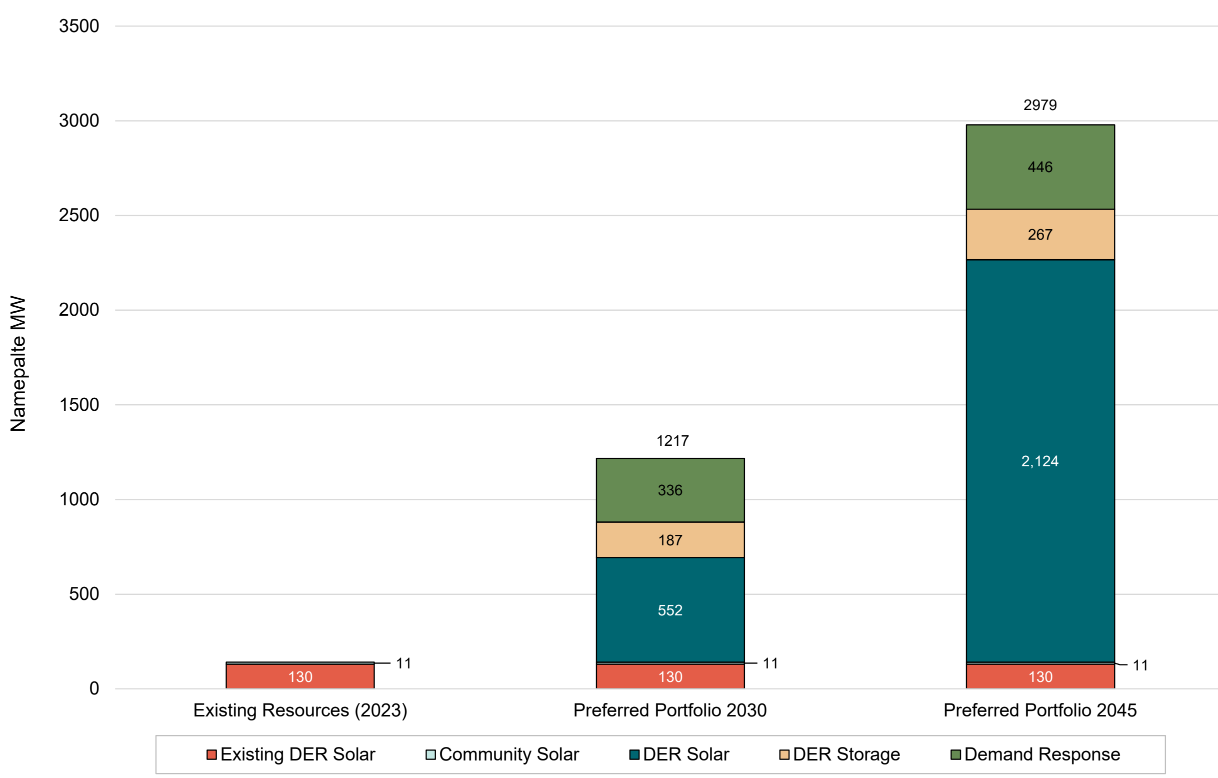


2.2.2. Distributed Energy Resources

Distributed energy resources are any resources located below the substation level. The customer or PSE can install DER. We included demand response, solar, and energy storage as distributed resources for this analysis. Our system includes 130 MW of customer-installed rooftop solar through net metering and 11 MW of community solar. We estimate we will add 552 MW of distributed solar and 187 MW of storage to the portfolio by 2030, growing to 2,124 MW of solar and 267 MW of energy storage by 2045. Demand response programs are peak savings options offered to customers, including direct load control for indoor heating and air conditioning thermostats and water heaters, managed electric vehicle charging, and critical peak pricing. Some distributed resources cost more than utility-scale programs but potentially enable larger equity benefits. Thoughtfully implemented, distributed resources can enable more equitable outcomes for customers in the clean-energy transition. We considered DERs necessary when developing our preferred resource plan, as discussed in Section 4 of this chapter.

Figure 3.3 shows the distributed resource capacity added to the preferred portfolio.

Figure 3.3: Preferred Portfolio Distributed Resource Additions (Nameplate MW)



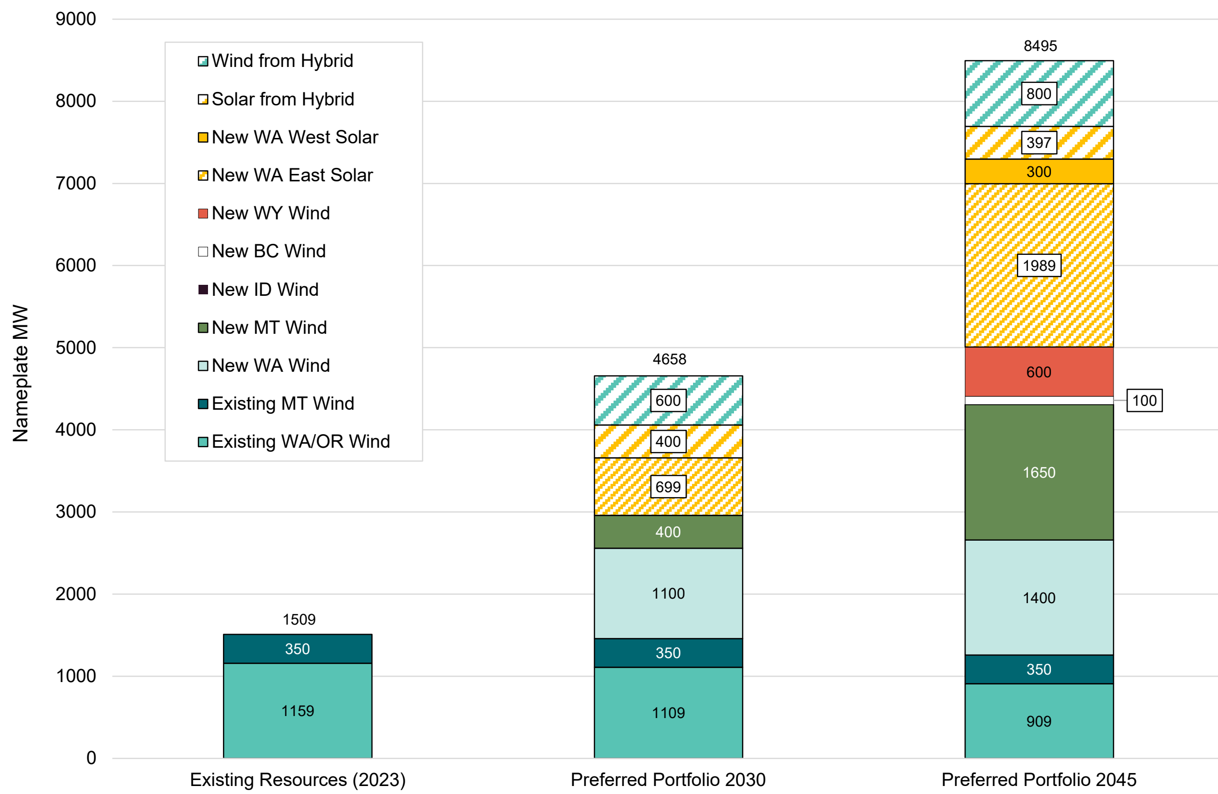
2.2.3. Clean Energy Resources

Qualifying clean energy (renewable and non-emitting) resources under CETA include wind, solar, advanced nuclear SMR, and alternative fuels such as biodiesel and hydrogen. Along with distributed energy resources, we must add many large utility-scale resources to the portfolio to meet the clean energy requirements. Figure 3.4 presents the utility-scale renewable resource additions in the preferred portfolio.

The scale and diversity of renewables PSE needs will require access to renewables outside Washington State and around the Pacific Northwest region, such as Montana, Wyoming, Idaho, and British Columbia. We will work to optimize our existing regional transmission portfolio to meet our growing need for renewable resources in the near term. However, the Pacific Northwest transmission system likely will need to be significantly expanded, optimized, and possibly upgraded to keep pace with the growing demand for clean energy. Puget Sound Energy will have to invest in the transmission system to deliver energy to customers from the edge of our territory and support the integration of distributed energy resources and demand response within the delivery grid.

The preferred portfolio adds almost 3,200 MW of new wind and solar resources to meet the CETA clean energy requirements by 2030. Of the 3,200 MW of wind and solar additions, 2,800 MW are resources in Washington State that will need cross-Cascades transmission. The remaining 400 MW are in Montana and will use Montana transmission.

Figure 3.4: Preferred Portfolio Wind and Solar Additions (MW)



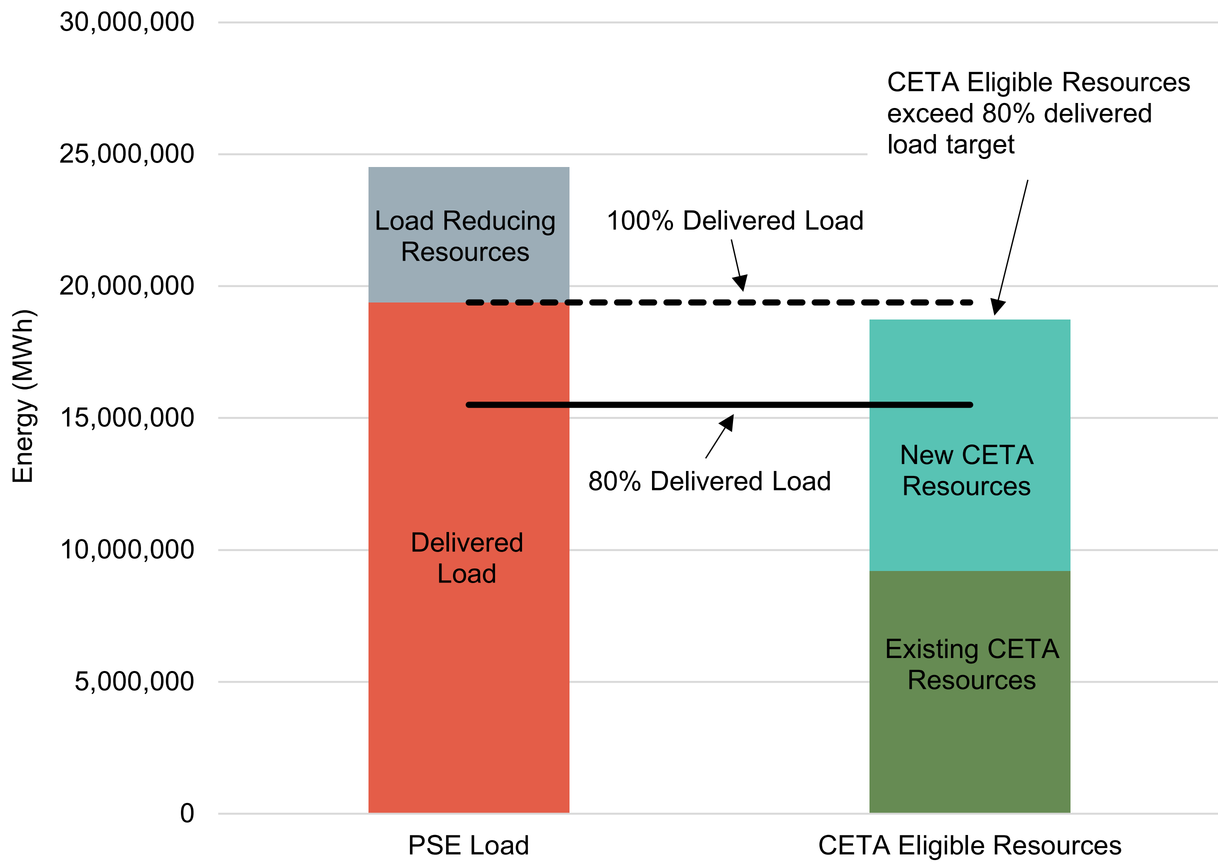
Risk of Meeting CETA Requirements

In 2030, we must meet at least 80 percent of retail sales with renewable or non-emitting resources. Figure 3.5 is the breakdown of the 2030 CETA requirement. As we can see from the chart, the preferred portfolio is well above the 80 percent requirement. For CETA compliance, we take the requirement on the adjusted retail sales after conservation, demand response, PURPA contracts[1], and voluntary renewable programs, including solar net-metering, Green Direct, and community solar. The gray bar in the chart represents the load-reducing resources, and the red bar is retail sales

[1] Public Utility Regulatory Policy Act (PURPA) qualifying facilities (QFs) are smaller generating units that use renewable resources, such as solar and wind energy, or alternative technologies, such as cogeneration.

after adjustment for load-reducing resources. The top of the red bar would be 100 percent, and the black line is 80 percent of the retail sales.

Figure 3.5: CETA Compliance in 2030 (Annual Energy MWh)



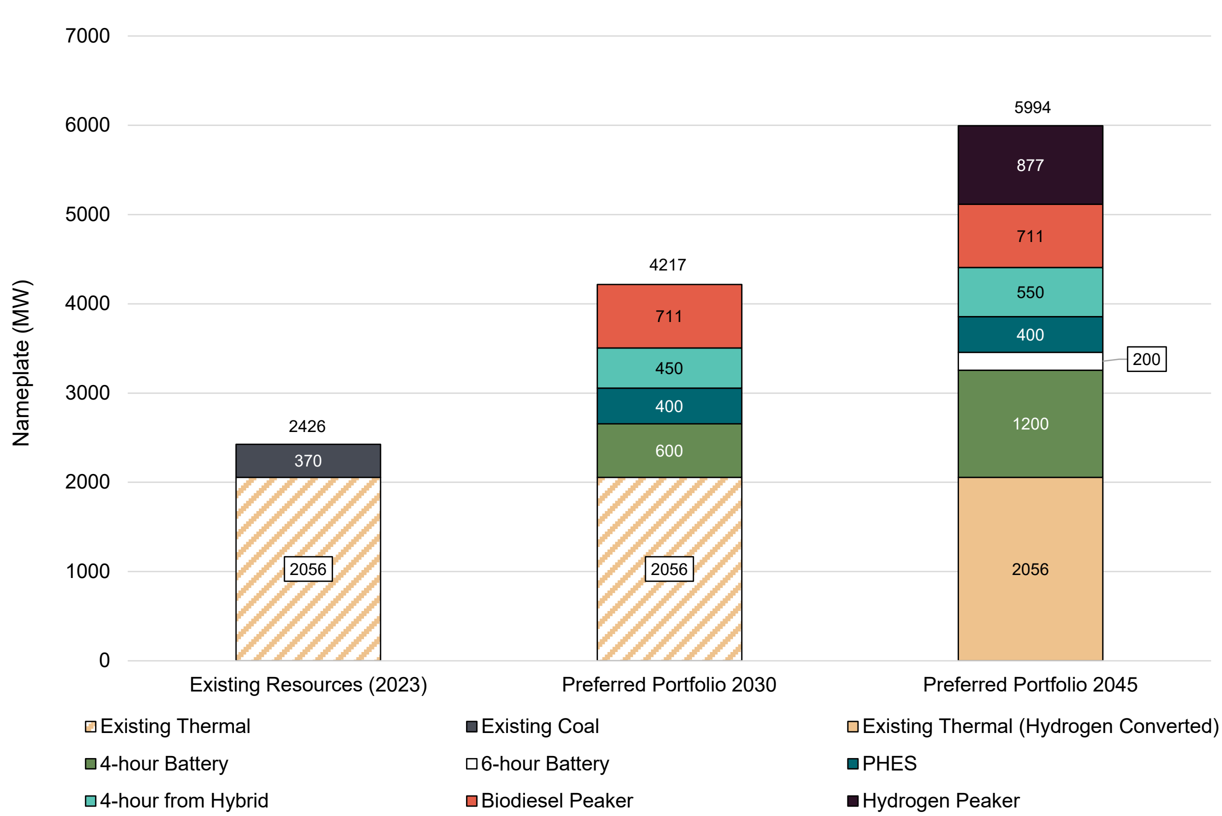
As part of the stochastic risk analysis, one of the future risks tested was whether the preferred portfolio would meet the CETA requirements under different conditions, such as changes in the demand forecast, hydroelectric generation, wind generation, and solar generation. Under all these conditions, renewable resource generation stays well above the base target for annual energy, ranging in 2030 from 80 percent at the lowest to 124 percent on the highest end, with half of the forecasted simulations in the range of 93 percent to 105 percent.

➔ Chapter Eight: Electric Analysis presents a complete discussion of the stochastic portfolio analysis.

2.2.4. Capacity Resources

Qualifying resources under CETA analyzed in this report include peaking capacity, energy storage, and advanced nuclear SMR. The peaking capacity we modeled includes CETA-qualifying fuels such as biodiesel and hydrogen, referred to herein as CETA-qualifying peaking capacity. We assumed hydrogen fuel would be available starting in 2030. We assumed natural gas to hydrogen blending would begin at 30 percent hydrogen in 2030 and increase to 100 percent by 2045. We left more than 2,000 MW of existing thermal resource capacity in the portfolio and converted it to hydrogen to maintain system reliability through resource adequacy. We modeled existing thermal resources with an option to retire them economically or convert them to hydrogen starting in 2030. As shown in Figure 3.6, the model added three additional peakers that will use biodiesel as fuel by 2030 and more than 800 MW of new hydrogen peakers by 2045. The model selected 1,450 MW of new energy storage by 2030, growing to 2,350 MW by 2045 to help meet resource adequacy and ancillary services. Energy storage resources are not energy-producing resources; they store the energy produced from other resources to be available during peak hours.

Figure 3.6: Preferred Portfolio CETA-qualifying Capacity Additions (Nameplate MW)



Hydrogen Fuel Risk

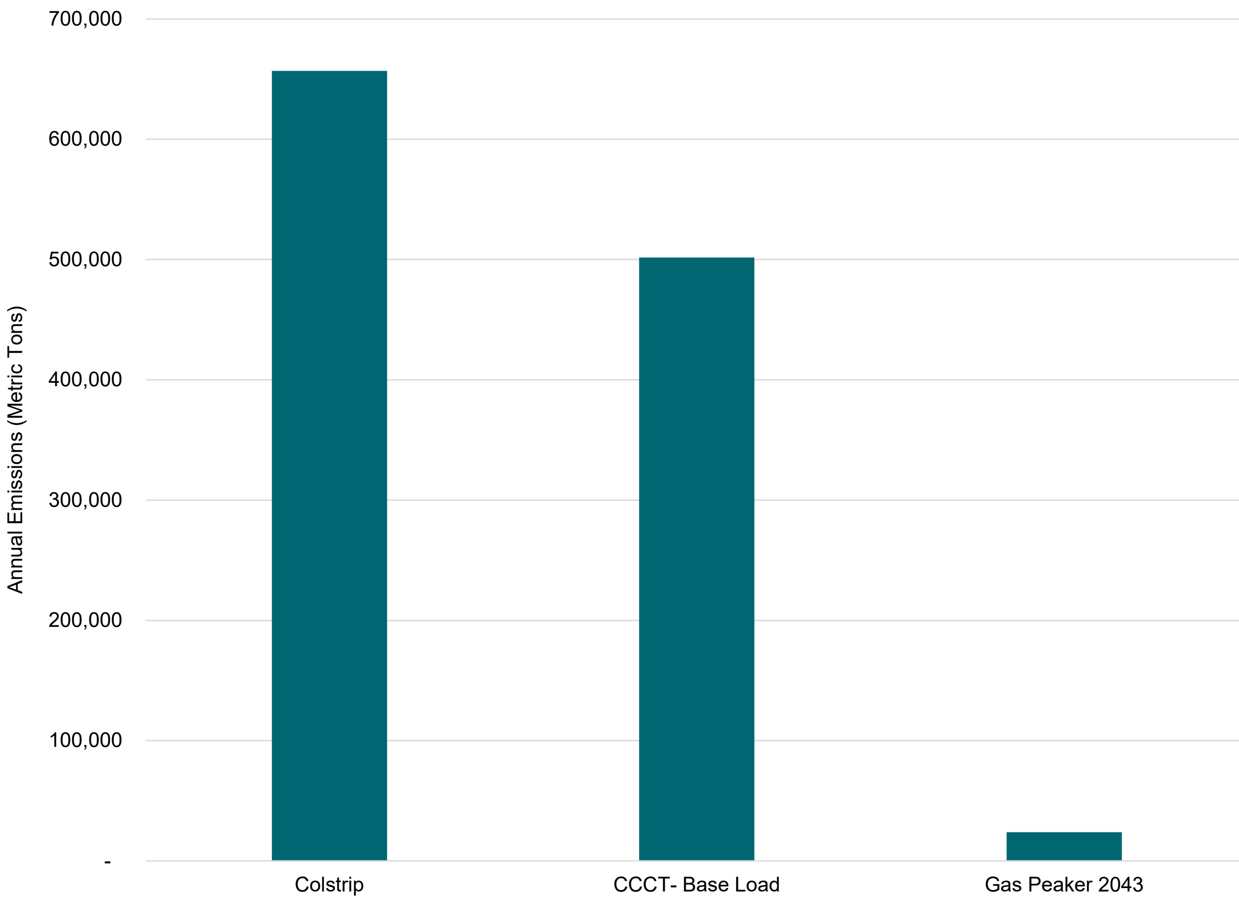
Green hydrogen has the potential to aid in the decarbonization of the electric sector without compromising reliability standards. Electrolyzers convert surplus renewable energy to hydrogen gas, which is stored for long periods until it is needed during a peak event. During a peak event, green hydrogen is combusted with either retrofitted existing equipment or at new peaking plants. Until recently, high costs have dissuaded development of hydrogen infrastructure for the energy sector, but production tax credits included in the Inflation Reduction Act have the potential to put green hydrogen in cost-parity with more conventional fuels.

In the preferred portfolio, the new hydrogen peakers start in 2039, giving us several years to understand the fuel supply before making resource acquisitions. Integrated Resource Plan meeting participants asked, "What if PSE built peakers assuming they blend to full hydrogen, but hydrogen is not available as planned?" First, we would not start building or acquiring a hydrogen peaker until 2035, which gives us more time to understand the hydrogen supply and availability. Second, we can build dual-fueled peakers using biodiesel as a backup fuel. Puget Sound Energy has eight peaking units with a backup fuel supply. We are experts in the process and requirements to set up and maintain a backup fuel supply. Like the existing peaker units, the backup is available in a tank on the property in case of primary fuel supply interruptions. Puget Sound Energy holds a place on the board of the Pacific Northwest Hydrogen Association and is working with other regional parties to explore development of a hydrogen production facility at the former Centralia coal mine in Centralia, Washington.

➔ A discussion of the work that PSE is doing on Hydrogen is in Chapter Two: Clean Energy Action Plan.

Finally, we looked at what would happen in a worst-case scenario where the frame peaker had to run on natural gas. In this event, for the limited hours the plant must run for peak contribution, the equivalent forecasted emissions would be 16,000 metric tons annually. Figure 3.7 illustrates the equivalent emissions on an equal-sized coal-fired plant (Colstrip) and a combined cycle combustion turbine (CCCT) baseload gas plant for comparison.

Figure 3.7: Annual Greenhouse Gas Emissions based on equivalent 237 MW (Metric tons CO2e)



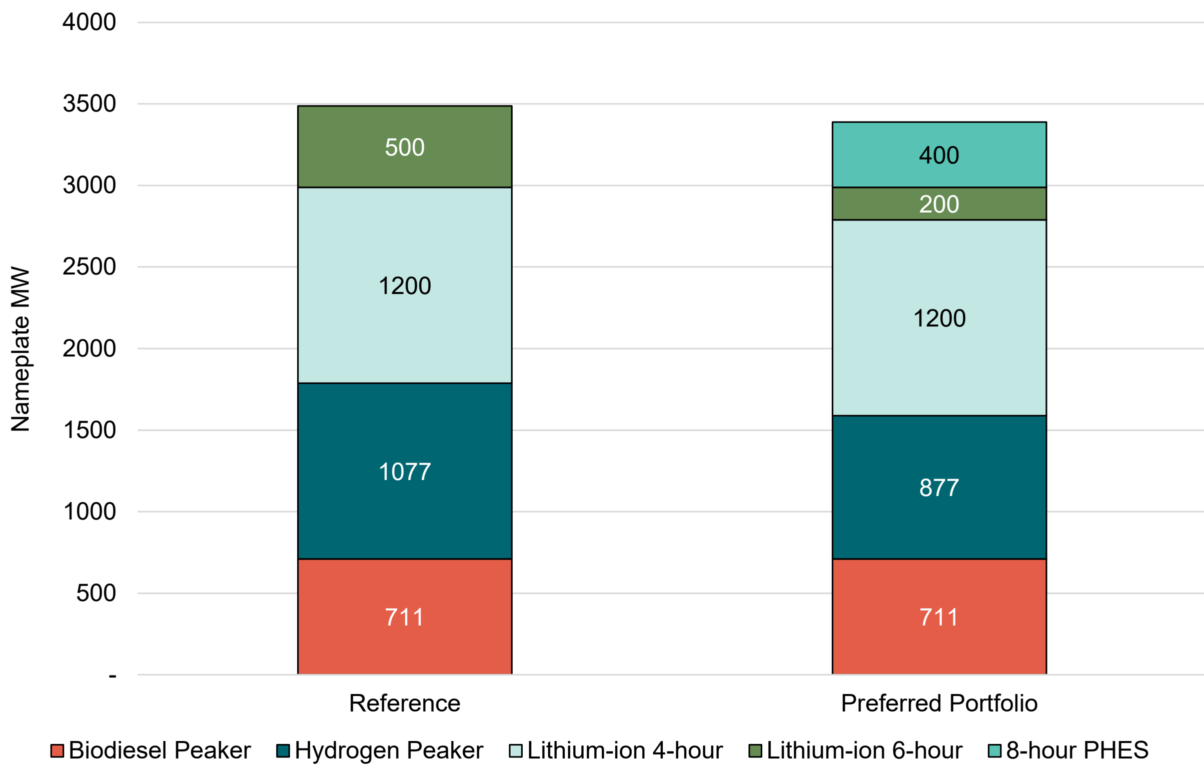
2.3. Diversifying the Portfolio

As PSE and the region seek to decarbonize systems, the future of electricity is a diverse portfolio of renewable and non-emitting resources. A diverse energy mix is essential for energy security because it is less dependent on a single fuel source, reducing vulnerabilities due to market price, supply fluctuations, and political unrest. Multiple, reliable generation sources allow a utility to provide power without disruption if one energy source fails. A diverse portfolio can reduce environmental impacts, improve reliability, and promote innovation to meet the needs of more than 1.5 million PSE customers. Resource diversity is the key to reducing emissions while preserving reliability and affordability.

The initial least-cost reference portfolio we developed for the 2023 Electric Report relies primarily on a few resources because we designed the model to select the lowest-cost resources available. However, we need to consider factors such as risk and feasibility when considering resources to include in the preferred portfolio. For example, the least-cost reference portfolio relies heavily on 4-hour batteries and hydrogen as a fuel because 4-hour batteries are the lowest-cost energy storage resource, and hydrogen is the lowest-cost, CETA-qualifying fuel source for thermal resources. To develop the preferred portfolio, we adjusted the least-cost reference portfolio to bring more diversity and lower its inherent technology and feasibility risks.

Figure 3.8 shows how we adjusted the storage resources in the preferred portfolio from the reference case to create a diverse portfolio that relies on multiple resources to meet demand. Figure 3.8 shows how diversifying storage resources results in less hydrogen peaker capacity.

Figure 3.8: New Energy Storage and Peaking Capacity Nameplate Additions by 2045 (MW)



Energy Storage

The least-cost reference portfolio will add 1,000 MW of four-hour batteries by 2030 because they are the lowest-cost energy storage resources. We adjusted the types of energy storage resources for the preferred portfolio to include more diverse technologies. For the preferred portfolio, we added 200 MW of pumped hydroelectric energy storage (PHES) in Montana and 400 MW of new Montana wind along with the existing 350 MW of wind. We added 200 MW of PHES in the Pacific Northwest to the preferred portfolio for 400 MW of PHES. The remaining energy storage is a mix of four-hour and six-hour batteries.

Advanced Nuclear Small Modular Reactors

In the least-cost reference portfolio, we modeled building more than 800 MW of new hydrogen peakers by 2045 in addition to the 2,000 MW of existing resources converted from natural gas to hydrogen. By 2045, we projected hydrogen to account for 36 percent of the peak capacity contribution. This least-cost reference portfolio relies heavily on a single fuel source with an unknown supply, creating risk. To diversify the portfolio, we can explore other technologies, such as advanced nuclear SMR, to include in future preferred portfolios. There are many unknowns around new advanced nuclear SMR technology. Although the high cost of advanced nuclear SMR deterred us from having it in the preferred portfolio, we will continue to monitor the technology. As advanced nuclear SMR technology matures, it could be a resource to help reduce the risks of relying on only a few technologies and a way to meet the CETA 100 percent requirement by 2045.

3. Resource Adequacy

The Pacific Northwest electricity industry is transitioning as governments and system planners implement major decarbonization policies. Operators and utilities are retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, PSE and other utilities are rethinking how we plan our systems, especially concerning resource adequacy. As we transition to 100 percent clean energy by 2045, we must ensure customers have reliable electricity and smoothly transition to a decarbonized system.

The resource adequacy analysis for this 2023 Electric Report resulted in a capacity deficit of 2,629 MW, more than double the 2021 IRP capacity deficit projected for 2029. This large deficit drives the large capacity additions in the preferred portfolio. This section describes the elements contributing to this deficit, including updates to the planning reserve margin, our reduction in market reliance, and variable resource peak capacity contributions.

3.1. Planning Reserve Margin Updates

The resource adequacy analysis for this 2023 Electric Report led us to increase the planning reserve margin to 23.8 percent in 2029, resulting in a capacity deficit of 2,629 MW. Two main elements contributed to the rise in the planning reserve margin:

- Climate change data in the load forecast and peak temperatures — when we accounted for average temperature trends, it only slightly lowered the one-in-two winter peak and increased the summer peak. Although summer peak temperatures increased, they do not come close to the winter peak level in this

2023 Electric Report's planning horizon. However, temperature volatility increased, which we accounted for in the resource adequacy and contributed to the overall increase in the planning reserve margin.

- Increase in peak demand — although the one-in-two winter peak lowered slightly, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was larger than the decrease from the climate change data, resulting in an overall increase to the one-in-two peak demand.

Climate change data also showed changes in the duration and frequency of loss of load events, which affected the capacity deficit. The data showed a decrease in event duration, less frequent events in the winter and more frequent events in the summer. Including climate change data increased the effective load-carrying capacity (ELCC) for solar and shorter-duration storage resources (those that discharge energy at the rated power output for less than 10 hours). Climate change data also shows the historical spring runoff is happening earlier in the year, which changes hydropower availability and the profile of hydroelectric generation and leaves less water for the summer.

3.2. Reduced Market Reliance

The western energy market has had surplus capacity for more than a decade. Given PSE's available firm transmission to the Mid-Columbia market hub, purchasing energy supply from the regional power market has been a cost-effective way to meet demand. However, the supply and demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: supplies have tightened, and pricing volatility has increased.

In response to these changing conditions, we plan to replace short-term market supplies with firm resource adequacy qualifying capacity contracts compliant with CETA, meet our resource adequacy requirements, and align with a potential regional resource adequacy program. The preferred portfolio includes added firm capacity resources and reduced short-term market purchases.

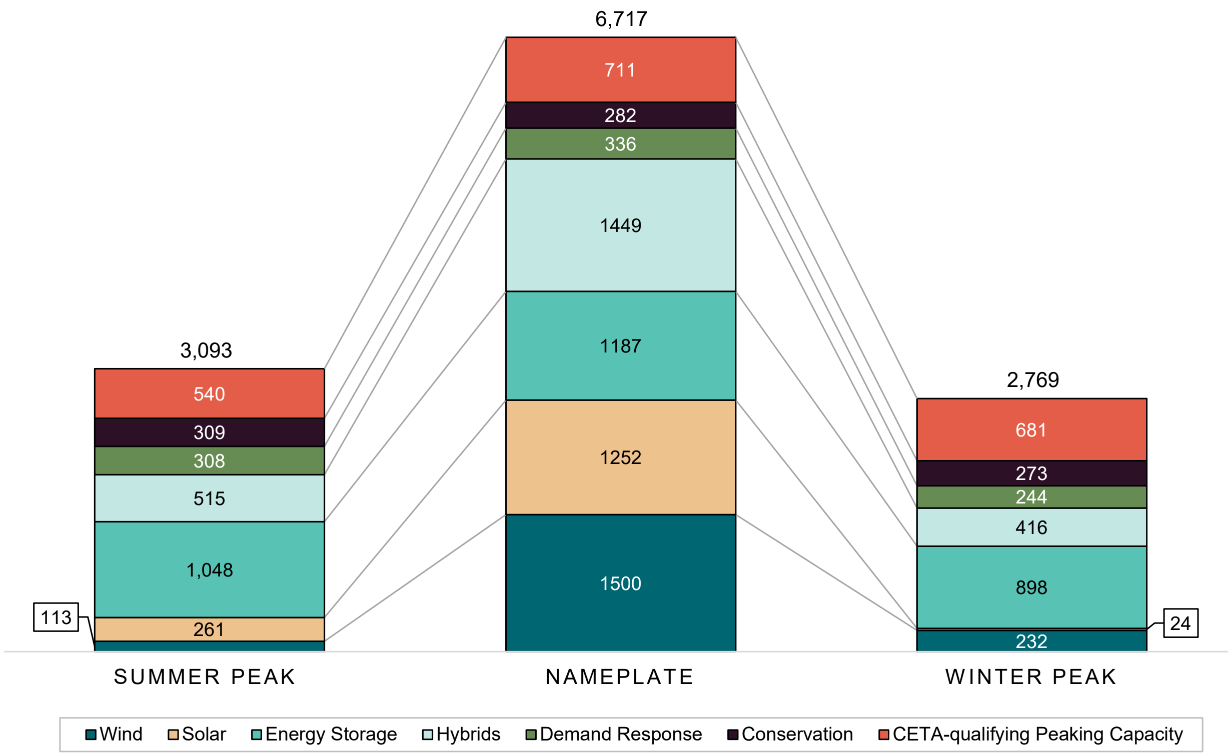
Our approach allows us to survey the market for available resource adequacy qualifying agreements and enables us to develop regional resource adequacy program requirements to help inform PSE's future needs. Given the tightening of energy markets and our preparations for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce PSE's reliance on short-term wholesale market purchases.

This approach has challenges, such as permitting and building generating and storage resources and transmission to meet growing demands in an increasingly complex permitting landscape. Although those challenges are real, we are confident the resource plan in this 2023 Electric Report indicates a path to reach our clean energy goals and achieve the clean energy future our customers expect.

3.3. Peak Capacity Contribution

Electric resources, particularly variable resources such as solar and wind, rarely perform at nameplate capacity during peak need. Therefore, ensuring resource adequacy relies on evaluating a resource's peak capacity contribution, which is the nameplate capacity combined with the ELCC. After adjusting for the peak capacity contribution of each resource, we need more resources to meet the peak need than the nameplate capacity suggests. For example, solar's 24 MW peak capacity contribution requires over 1100 MW of installed nameplate capacity. After adjusting for peak capacity contribution, over 6,700 MW of new resources installed nameplate capacity adjusts to over 3,000 MW summer peak capacity and over 2,700 MW winter peak capacity, as detailed in Figure 3.9.

Figure 3.9: Nameplate Capacity Adjusted to Peak Capacity Contributions (MW)



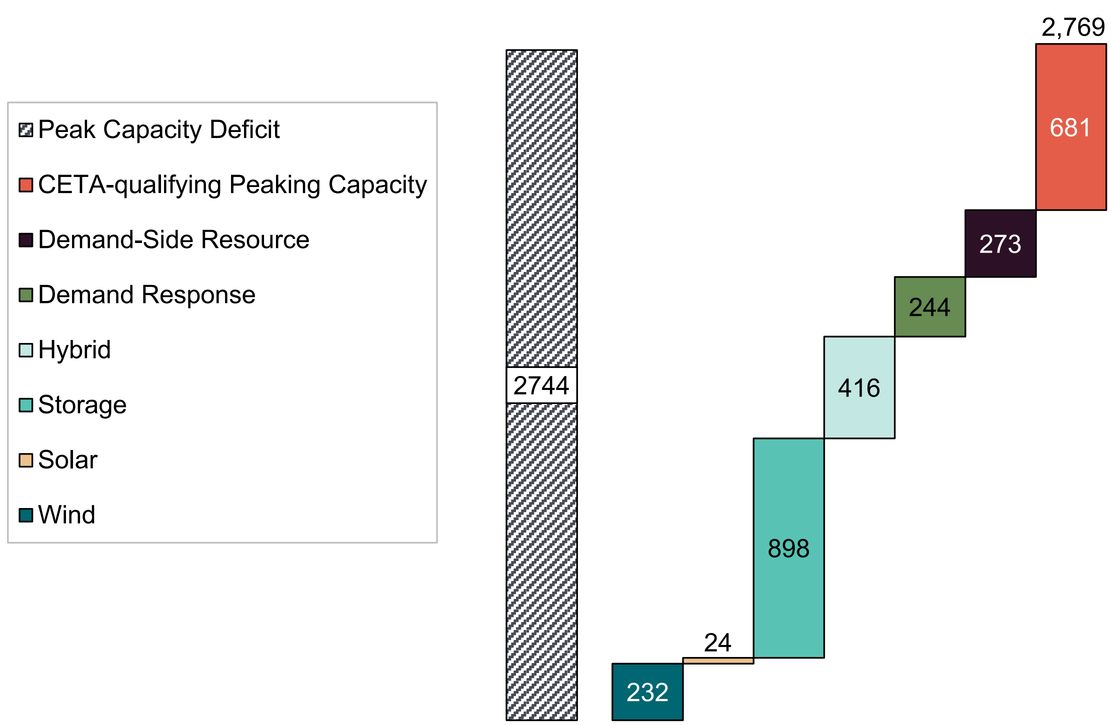
3.3.1. Winter Peak Drives Resource Capacity Additions

We analyzed summer and winter peak capacity. Consistent with prior years, the winter peak is higher than the summer peak. We noted that the increase of renewable energy and energy storage in the preferred portfolio contributed to meeting the summer peak need better than they contributed to the winter. For example, solar has a four percent peak capacity contribution in the winter but a 55 percent contribution in the summer. We added solar to the portfolio because it meets the CETA requirement and the summer peak need, but it does very little to meet the winter peak need. Given that the preferred portfolio meets the 2030 CETA target and renewable resource additions meet the summer peak capacity need, the winter peak need drives new peaking capacity in the preferred portfolio. The preferred portfolio builds 711 MW of CETA-qualifying peaking nameplate capacity by 2029 (Table 3.1), and assuming a 96 percent ELCC in winter (see Appendix D: Generic Resource Alternatives for operating assumptions), this adds 681 MW of peaking capacity. These additions balance the winter peak and create more than 250 MW summer peak surplus.

Figure 3.10 shows the breakdown of the effective winter peak capacity contribution for new resources. Note that this figure combines the nameplate capacities provided in Table 3.1 with respective ELCCs found in Appendix D: Generic Resource Alternatives.

➔ Please see Chapter Seven: Resource Adequacy Analysis for a detailed winter and summer peak needs discussion.

Figure 3.10: Meeting Winter Peak Need for 2030 — New Resource Additions Effective Capacity (MW)



4. Developing the Preferred Portfolio

This section describes how we developed candidate diversified portfolios. We also discuss the trends we observed across all candidate diversified portfolios in the near- and long-term and evaluate the costs of each candidate diversified portfolio. Finally, we present the results of our portfolio benefit analysis and summarize the selection of our preferred portfolio.

4.1. Candidate Diverse Portfolios

The first step to developing a preferred portfolio is to start with a least-cost portfolio. A least-cost portfolio meets constraints in a lowest-cost way. These constraints are:

- CETA renewable and clean-energy requirements
- Hourly customer demand for the year
- Peak capacity plus a planning reserve margin
- Reduced market reliance at peak
- Transmission access for new resources

The least-cost portfolio gave us a starting point which we then adjusted to identify a feasible portfolio of diverse resources that consider equity and create customer benefits while maintaining reliability and affordability. We refined the least-cost portfolio to maximize benefits and reduce burdens to vulnerable populations and highly impacted communities consistent with CETA. Figure 3.11 shows a progression of diversified portfolios ranging from the least diverse portfolio (11 A1) to the most diverse portfolio (11 A5), with each step adding a scheduled resource to increase the portfolio's diversity. We modeled portfolios 11 B1 and 11 B2 at the request of interested parties to exclude advanced nuclear SMR additions and are like the least and most diversified portfolios (11 A1 and 11 A5)

To create a diverse portfolio, we:

1. Start with the least cost reference portfolio,
2. Make incremental changes to the portfolio to test the sensitivity of the adjustment to resource builds and portfolio cost,
3. Create a portfolio with different options from part 2, considering equity, cost, feasibility, reliability, and diversity of energy supply.

Figure 3.11: Components of the Diverse Portfolios

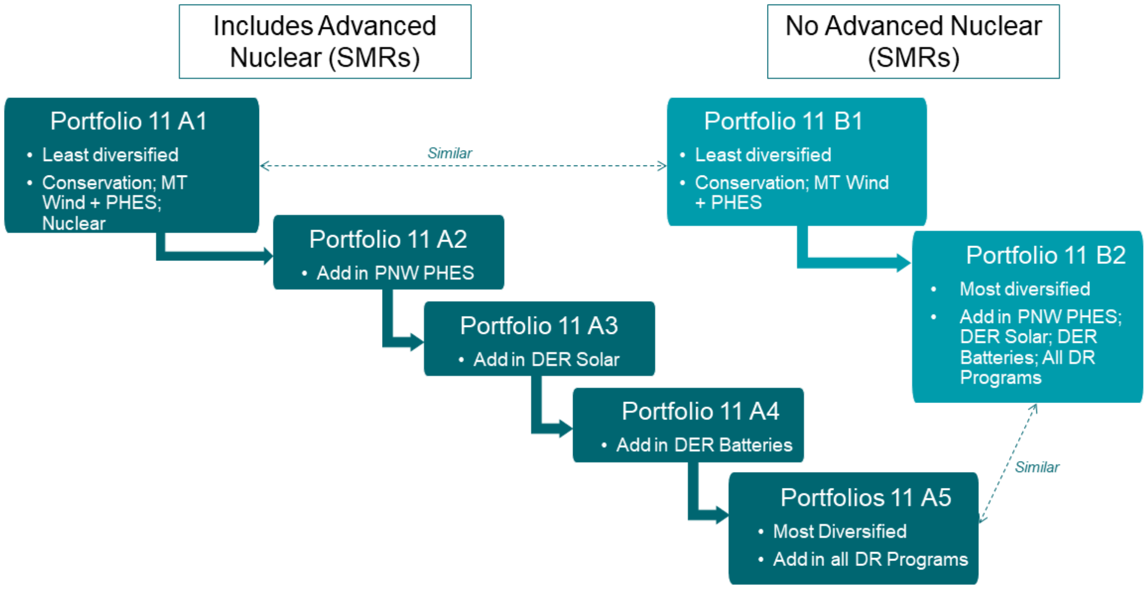
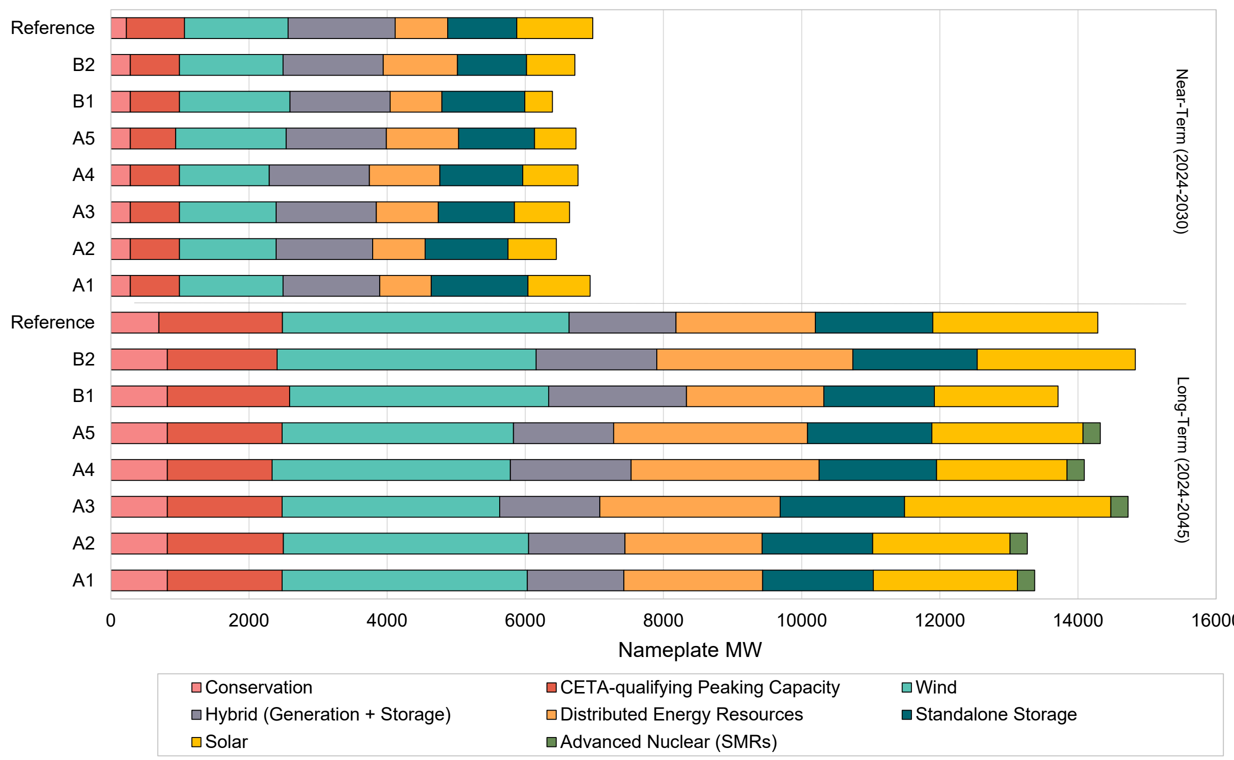


Figure 3.12 shows a breakdown of nameplate resource additions by portfolio. The portfolios are very similar in the near term (2024–2030). Puget Sound Energy needs many resources to meet CETA and resource adequacy, and there are few commercially available technologies today. All the diverse portfolios have equal amounts of conservation and CETA-qualifying peaking capacity, with the rest of the resources comprising demand response, wind, solar, energy storage, or a hybrid of renewable resources plus energy storage. For the longer term (2031–2045), the resource mix becomes more distinct between portfolios, although the need for conservation and CETA-qualifying peaking capacity is a stable addition across all portfolios.

Figure 3.12: Resource Builds (Nameplate MW)

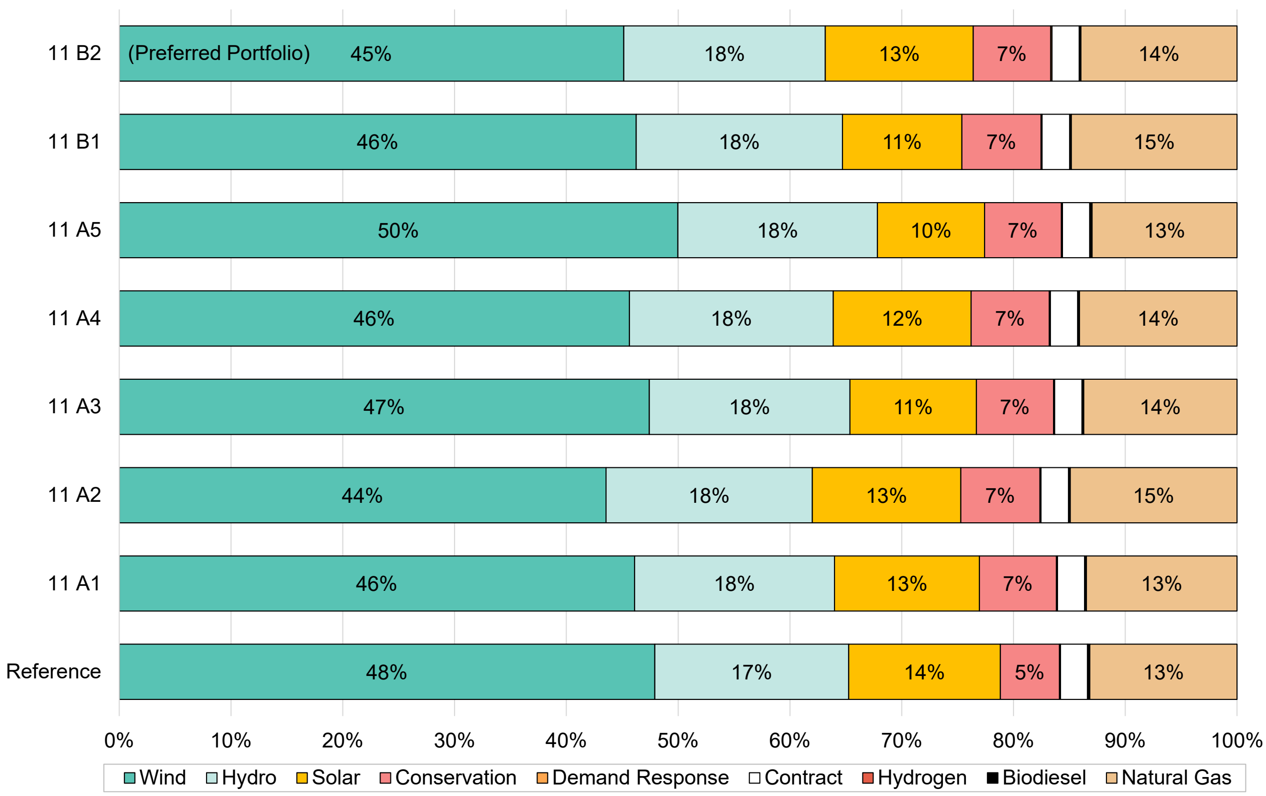


4.1.1. Near-term Resources (2024–2029)

The utility-scale and demand-side resource builds in the near term are similar across the diversified portfolios. In all the diversified portfolios, we need three peaking generation facilities by 2030 to maintain reliability as we add new variable resources. By 2030, we will add almost 1,500 MW of new energy storage to help meet resource adequacy and ancillary services. Energy storage resources are not energy-producing; they just store the energy produced from other resources, so it is available during peak hours. Given that we added more than 3,000 MW of variable energy resources by 2030 to meet the CETA requirements, we will need the energy storage resources to help store energy in low-demand hours to be used later in high-demand hours. The primary difference between the diversified portfolios is the amount of distributed energy resources. We listened to interested parties and PSE's Equity Advisory Group (EAG) and heard the importance of adding more distributed resources to the portfolio and increasing customer participation in these programs. However, no matter which portfolio we use for the preferred portfolio, the near-term resources are the same for utility-scale resources: we need to meet CETA requirements and resource adequacy, and there are limited options available to achieve these needs in the next six years.

Figure 3.13 presents each diversified portfolio's 2030 annual energy production by fuel type.

Figure 3.13: Annual Energy 2030 — Percent of Generation by Fuel Type

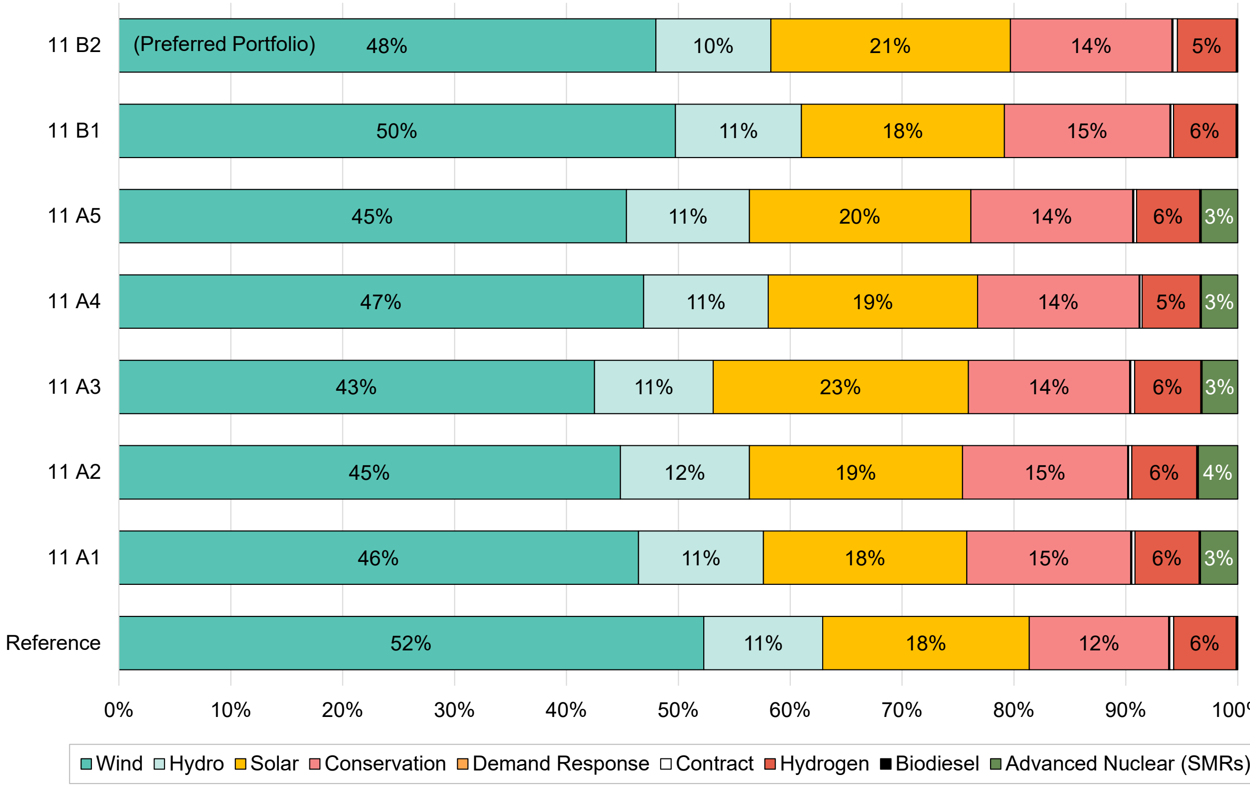


4.1.2. Long-term Resources (2030–2045)

As we look further into the future, the resources become less certain. Technological advancements are needed to achieve 100 percent clean energy by 2045. These advances could involve using alternative fuels such as hydrogen in combustion turbines or through advanced nuclear SMR technology. Both options are promising but present unique risks and costs. We will continue to explore these and other resource options in subsequent and future IRP cycles. Regardless of the technologies available long-term, it does not change near-term resources and resource options.

Figure 3.14 presents each diversified portfolio's 2045 annual energy production by fuel type.

Figure 3.14: Annual Energy 2045 – by Fuel Type (percent of generation)



4.1.3. Portfolio Costs

The portfolio costs include all those associated with construction, interconnection, transmission, fuel, and operations and maintenance of new generating resources, along with the costs to operate and maintain existing resources. We divided the portfolio costs into near-term resource additions before 2030 (Table 3.3) and longer-term, 21-year decisions for 2045 (Table 3.4). Figure 3.15 shows the annual portfolio costs for 2024–2029; annual portfolio costs for the entire planning period of 2024-2045 are in Chapter Eight: Electric Analysis.

In the near term, the combination of increasing distributed resources, conservation, demand response, and diversifying the portfolio delays adding one peaking generation facility until after 2030 but increases the cost over the reference case by $700–$880 million in the next six years.

Figure 3.15: Annual Portfolio Costs with Emissions 2024–2029 ($ Billions)

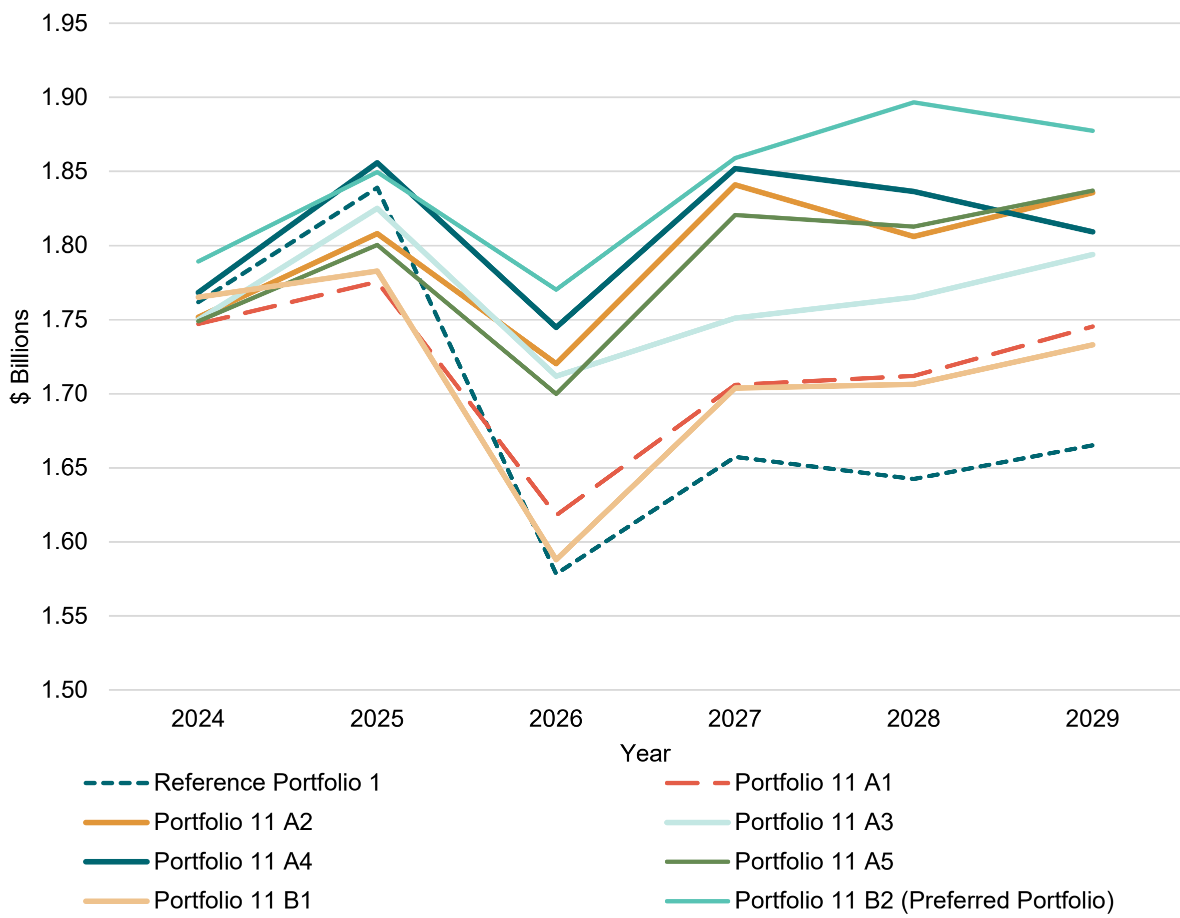


Table 3.3: Near-term (6-year) Net Present Values — 2024–2029 ($ Billions)

Portfolio	Portfolio Cost with SCGHG	Portfolio Cost without SCGHG	Social Cost of Greenhouse Gases (SCGHG)
Reference	8.14	6.05	2.08
11 A1	8.24	6.49	1.75
11 A2	8.59	6.70	1.89
11 A3	8.47	6.67	1.80
11 A4	8.68	6.75	1.93
11 A5	8.55	6.75	1.80
11 B1	8.22	6.32	1.91
11 B2 (Preferred Portfolio)	8.81	6.93	1.88

In the long-term, adding these distributed resources to the portfolio increases the cost over the reference case by $1.7 - $2.8 billion, as seen in portfolios 11 B1 and 11 A5, respectively (Table 3.4).

Diversifying the portfolio and increasing equity metrics through increased distributed resources, as described in Section 2.4.2, increases the cost of the portfolio both in the near- and long-term time horizon.

Table 3.4: Long-term (21-year) Net Present Values — 2024–2045 ($ Billions)

Portfolio	Portfolio Cost with SCGHG	Portfolio Cost without SCGHG	Social Cost of Greenhouse Gases (SCGHG)
Reference	17.61	20.85	3.24
11 A1	20.01	22.83	2.82
11 A2	20.32	23.25	2.93
11 A3	20.44	23.27	2.83
11 A4	20.74	23.64	2.90
11 A5	20.89	23.67	2.78
11 B1	18.09	21.09	3.00
11 B2 (Preferred Portfolio)	19.56	22.51	2.95

➔ Chapter Eight: Electric Analysis presents a complete discussion of portfolio sensitivity cost.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model we use for portfolio modeling, only solves the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable customer outcomes while also considering the cost. The preferred portfolio provides the best pathway to improve equitable outcomes of all our portfolios evaluated in this 2023 Electric Report. This outcome was driven primarily by increasing customer opportunities to participate in distributed energy and demand response programs.

The portfolio benefit analysis tool measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative customer benefit indicators (CBIs) and their metrics. Customer Benefit Indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this 2023 Electric Report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

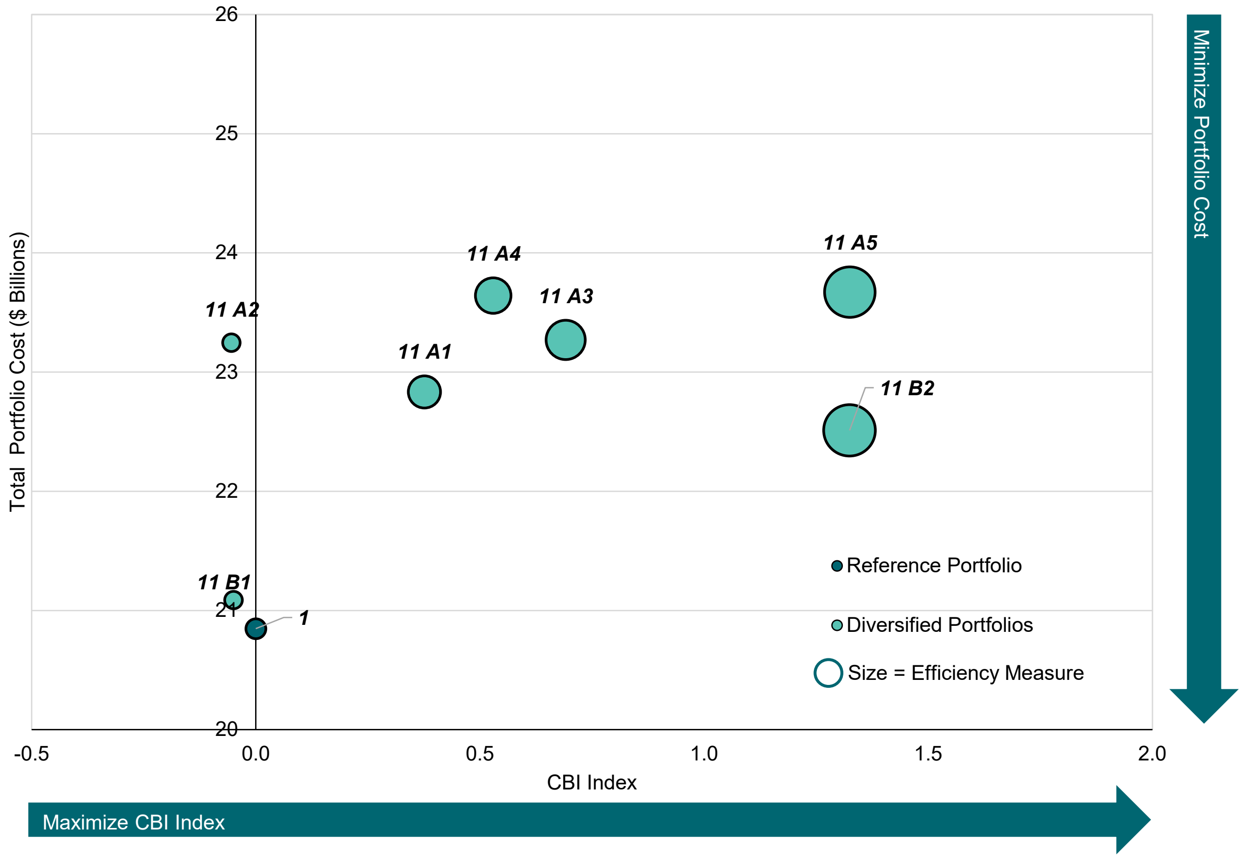
- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources.
- **Improved affordability of clean energy** — measured by the total portfolio cost.
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio.
- **Increase the number of jobs** — measured by the number of estimated jobs generated for each portfolio.
- **Increases participation in Energy Efficiency, Distributed Energy Resources, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs.
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq2 generated per portfolio.
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs.

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (sans the portfolio cost) normalized to the reference, least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index juxtaposes each portfolio's total cost (direct and externality costs). The plot (Figure 3.11) illustrates the tradeoff between increasing portfolio benefits and the associated metrics and costs. Compared to the reference portfolio, the most efficient portfolios have the highest CBI indices with minimal increase in portfolio cost and sit closest to the bottom right corner of the plot.

Figure 3.16 shows the results generated by the portfolio benefit analysis tool for all diversified portfolios analyzed in this 2023 Electric Report. We can see portfolio 11 B2 is the most efficient of the diversified portfolios because it lies furthest to the right with the highest CBI index, one of the reasons we selected portfolio 11 B2 as the preferred portfolio. It has the highest overall CBI index at 1.32 and is the most diversified portfolio without advanced nuclear SMR that we evaluated in the 2023 Electric Report.

[2] CO2-eq or CO2-equivelant is a measure used to compare the emissions from various greenhouse gases based on their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

Figure 3.16: Portfolio Benefit Analysis Tool Results



The high CBI index of portfolio 11 B2 comes from improvements in all the CBIs we considered in this analysis except for jobs, which varied slightly from the reference portfolio by less than half a standard deviation (index = -0.41). The benefits in the preferred portfolio include some of the highest potential customer participation numbers for DER solar, DER storage, and demand response programs at 87,492, 18,524, and 750,943 participants, respectively. Compared to the reference portfolio, the preferred portfolio also reduces greenhouse gas and other harmful emissions (Table 3.2).

Table 3.2: Portfolio CBI Metrics

CBI Metric	1 Reference	11 A5 Diversified Portfolio	11 B2 Diversified Portfolio
Cost ($, Billions)	20.85	23.67	22.51
GHG Emissions (Short Tons)	48,824,734	41,543,008	44,372,601
SO_2 Emissions (Short Tons)	28,841	28,836	28,759
NO_x Emissions (Short Tons)	11,426	10,307	10,805
PM Emissions (Short Tons)	9,036	8,873	8,940
Jobs (Total)	45,736	40,757	43,795
Energy Efficiency Added (MW)	695	818	818

CBI Metric	1 Reference	11 A5 Diversified Portfolio	11 B2 Diversified Portfolio
DR Peak Capacity (MW)	291	320	320
DER Solar Participation (Total New Participants)	12,115	83,903	87,492
DR Participation (Total New Participants)	513,238	750,943	750,943
DER Storage Participation (Total New Participants)	8,125	18,524	18,524

The results of the portfolio benefit analysis indicate that increasingly distributed and demand-side resources significantly increase the potential for more equitable outcomes for customers. Compared to the reference portfolio, portfolio 11 B2 has the following additions:

- **Conservation** — increases to 371 MW by 2045, 113 MW above the least-cost conservation.
- **Demand Response** — increases to 446 MW by 2045, an increase of 41 MW above the least-cost portfolio.
- **Distributed solar** — added 30 MW per year from 2026–2045, a total of 630 MW added by 2045 above the least cost portfolio.
- **Distributed storage** — added 25 MW per year from 2026–2031, a total of 150 MW added distributed storage above the least cost portfolio.

Portfolio 11 B2 achieved the highest CBI index of all portfolios evaluated in this 2023 Electric Report. In pursuing this portfolio, we will adopt a pathway forward for acquiring the resources necessary for a more equitable distribution of customer energy and non-energy burdens and benefits.

4.3. Portfolio Selection

We chose portfolio 11 B2 as the preferred portfolio because it presents a diverse mix of centralized renewable and non-emitting resources, reliable conservation, demand response, and distributed resources, and enables the most equity-related benefits of all the portfolios we evaluated. Furthermore, this portfolio reduces direct PSE emissions, achieves carbon neutrality by 2030, and is non-emitting by 2045. This portfolio is higher cost than most of the other diversified portfolios we evaluated. However, this outcome was driven primarily by increasing customer opportunities to participate in distributed energy and demand response programs, which we determined with feedback from PSE's EAG and other interested parties, were essential components of a preferred portfolio.

LEGISLATIVE AND POLICY CHANGE

CHAPTER FOUR

Contents

1. Introduction

Policy changes and the subsequent legislative changes in the energy sector have increased rapidly in the last five years. Puget Sound Energy (PSE) continues to respond to the quickly shifting landscape with plans that guide the resource acquisition process. This chapter outlines recent state and federal energy legislative and policy changes and how they informed the development of the 2023 Electric Progress Report (2023 Electric Report).

On the state level, we incorporated rules from the Clean Energy Transformation Act (CETA), the Climate Commitment Act (CCA), and new building codes. We also included the impacts of the federal Inflation Reduction Act (IRA) in this report.

2. Clean Energy Transformation Act

Clean Energy Transformation Act requires utilities to meet the following mandates:

- One hundred percent of retail utility sales must be greenhouse gas neutral by 2030, with 80 percent of those sales met with renewable and non-emitting resources and 20 percent with other clean investment options, which may include unbundled renewable energy credits.
- Renewable and non-emitting resources must meet one hundred percent of retail utility sales by 2045.
- Utilities must eliminate coal from their allocation of electricity to Washington retail customers after 2025.

This chapter addresses CETA rulemaking enacted after the 2021 IRP was published.

2.1. Washington Utilities and Transportation Commission

The Washington Utilities and Transportation Commission (Commission) concluded one CETA rulemaking in 2022, which established rules for electricity purchases from centralized markets, the prohibition of double counting, and the treatment of energy storage. The rules include additional contracting requirements, reporting contracts, and detail other data PSE must submit to the Commission.

2.1.1. Market Purchases and Double Counting

In the Market Purchases and Double Counting Rulemaking, the Commission issued an order on June 29, 2022, establishing rules for energy storage and prohibiting the double counting of clean energy attributes. This order also creates contracting and annual reporting requirements for data associated with the utility's resources and operations.

These rules require that PSE demonstrate compliance with the clean energy standards in CETA by acquiring electricity and associated renewable energy credits (RECs) or non-power attributes. Puget Sound Energy must show that we can deliver clean electricity to our system. We must also report on the source and characteristics of the electricity claimed for compliance.

This new rule did not affect modeling for the 2023 Electric Report.

2.1.2. Impact and Actions

As part of this report, we count the generation from CETA-qualifying renewable and non-emitting resources to meet CETA requirements, including wind, solar, nuclear, and renewable fuels (biodiesel and hydrogen), along with load reducers such as conservation, demand response, and customer voluntary renewable programs. Energy storage resources, such as batteries and pumped hydro storage, are treated as non-generating resources. Energy storage allows us to shift renewable energy to times of greater need, so the renewable energy used to charge those storage facilities is counted toward CETA requirements.

➔ A full description of PSE's existing CETA-qualifying resources is in Appendix C: Existing Resource Inventory, and a description of the new resources we modeled is available in Chapter Five: Key Analytical Assumptions and Appendix D: Generic Resource Alternatives.

In its order, adopting rules for market purchases, double counting, and other issues related to CETA, the Commission said further rulemaking and deliberation is needed regarding its interpretation of electricity use to ensure consistency and reliability across Washington's energy market and among electric utilities. PSE will incorporate these topics into our planning processes as appropriate as the Commission completes their rulemaking processes.

2.1.3. Incorporating Equity in Resource Planning

The CETA requires that "all customers are benefiting from the transition to clean energy through the equitable distribution of energy and nonenergy benefits and the reduction of burdens to vulnerable populations and highly impacted communities."[1] Equity is complex to measure and assess, especially in energy system planning; it is an important and new area to develop for resource planning since the enactment of CETA.

2.1.4. Impact and Actions

While PSE has considered equity in its low-income conservation programs in the past, the 2021 IRP saw a significant expansion of equity considerations. The 2021 IRP expanded its consideration of equity through the Economic, Health and Environmental Benefits Assessment (linked below) and the Customer Benefits Analysis (described in Chapter 3: Resource Plan. Since the 2021 IRP, we formed and convened an Equity Advisory Group (EAG) and engaged with this and other advisory groups, community-based organizations, and customers to better understand clean energy values in developing the 2021 Clean Energy Implementation Plan (CEIP). Input from these conversations shaped how we approached equity in this report.

The EAG comprises representatives from various community advocacy interests to advise PSE on the equitable transition to clean energy. The EAG also includes frontline customers. We encourage participation from environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations. In the 2021 CEIP, the EAG initially advised on equity elements related to understanding the

[1] RCW 19.405.060

benefits and burdens customers may face, defining vulnerability factors, guiding principles for program implementation, and helped develop customer benefit indicators used in this report.

We revised and updated the customer benefits analysis used in the 2021 IRP to enhance the portfolio benefit analysis in this 2023 Electric Report. The portfolio benefit analysis incorporates a revised set of customer benefit indicators developed in the 2021 CEIP through collaboration among PSE staff, the EAG, and interested parties. The portfolio benefit analysis also incorporates methodological updates, informed by discussion with interested parties, to better quantify the distribution of portfolio-level metrics related to the customer benefit indicators. A full description of the portfolio benefit analysis and its results is available in Chapter Eight.

We also updated the Economic, Health, and Environmental Benefits Assessment in the 2023 Electric Report to reflect recent developments in identifying named communities. Named communities are customers burdened by social, economic, health, and environmental impacts, including highly impacted communities and vulnerable populations. We defined Highly Impacted Communities in our Department of Health Cumulative Impact Analysis, which we updated in August 2022. Puget Sound Energy staff collaborated with the EAG to define Vulnerable Populations as part of the 2021 CEIP and we used that definition in this report.

➔ A full description of the Economic, Health, and environmental Benefits assessment and its results is available in Appendix J: Economic, Health and Environmental Assessment of Current Conditions.

2.2. Clean Energy Implementation Plan

The Clean Energy Implementation Plan (CEIP) is a state-mandated four-year roadmap guiding PSE's clean energy investments for 2022–2025.

2.2.1. CEIP Overview

Consistent with CETA rules, we filed the company's first CEIP in December 2021. The plan illustrated our path toward meeting the requirements of CETA and the specific actions we will take from 2022–2025 to meet those goals. The CEIP proposed an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. The CEIP also proposed targets and specific actions that include:

- 23.7 MW of Demand Response
- 25 MW of Distributed Energy Resources (DER) storage
- 50 MW of utility-scale storage
- 80 MW of DER solar,
- 1,073,434 MWh of energy efficiency, as determined in the 2022–2023 Biennial Conservation Plan

By rule, the Commission can approve, deny, or approve with conditions the filed CEIP. We are still waiting for a decision from the Commission on PSE's CEIP. However, we continue moving forward on specific actions to implement the CEIP by the end of 2025. These efforts include ongoing public participation with advisory groups and interested parties, completing the All-source and DER/DR resource acquisition processes, and beginning to develop tariff filings for new DER programs.

We used the 2021 IRP as the foundation for Puget Sound Energy's first CEIP. We will use the 2023 report to inform the 2023 biennial CEIP update. The 2023 report includes critical updates to the inputs and assumptions used in the AURORA modeling, which will directly feed into the 2023 biennial CEIP Update. The 2023 Electric Report rules (WAC 480-100-625)[2] require updates for the following items: load forecast, conservation, resources costs, state and federal requirements, significant economic and market changes, and other elements identified in the CEIP.

➔ See Chapter Eight: Electric Analysis for a discussion on substantive changes for the 2023 Electric Report.

2.2.2. Impact and Actions

The 2023 Electric Report includes the following CEIP targets and actions:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar
- Updates to the customer benefit indicators

We did not include targets for energy efficiency and demand response from the 2021 CEIP since we conducted a new conservation potential assessment and demand response assessment for the 2023 Electric Report. We used the new assessments to create new economic and achievable energy efficiency and demand response resource options in the preferred portfolio.

Another critical CETA goal bridging the 2023 Electric Report to the 2023 biennial CEIP update is including and embedding equity in decision-making and resource selection, via the revised customer benefit indicators and the portfolio benefit analysis, as described in Section 2.1.2 and detailed in Chapter Eight.

2.3. Climate Change

Under WAC 480-100-620 (10)(b), "at least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."[3] Temperature data that reflects climate change is a critical piece of our planning analysis. This crucial information impacts the demand forecast and influences how much energy PSE will need to serve our customers.

[2] WAC 480-100-625
[3] WAC 480-100-620

2.3.1. PSE Actions

The 2023 Electric Report is our first effort incorporating climate change data into the baseline forecast. We incorporated climate change in two key aspects of the analysis. First, we included climate change in the load forecast, as described in Chapter Six: Demand Forecast. We also included climate change impacts on regional loads and hydro generation in this report. We also included climate change in the resource adequacy analysis, the planning reserve margin, and the peak capacity contribution of resources, as described in Chapter Seven: Resource Adequacy.

2.4. Department of Health Cumulative Impact Analysis

The Clean Energy Transformation Act (CETA) directs the DOH to develop a CETA Cumulative Impact Analysis (CIA) of the impacts of climate change and fossil fuels on population health to designated highly impacted communities. The DOH released an initial CIA in February 2021 and an update in August 2022.

2.4.1. Impact and Actions

We used the results of the CIA to inform planning in our transition to clean energy. The CIA helps us identify, measure, and track equity-related metrics in several ways. Primarily, the CIA directs which communities we should geographically identify as highly impacted. Highly impacted communities may experience more public health and environmental burdens than other segments of our service area. Identifying, measuring, and tracking equity-related metrics in highly impacted communities helps us move toward an equitable transition to clean energy. By highlighting these highly impacted communities, we can identify disparities within our service territory, target specific actions to alleviate existing burdens, and benefit frontline communities.

The CIA also provides valuable data to support equity-related analysis. The DOH Environmental Health Disparities Map is a component of the CIA that offers a range of environmental and public health metrics that we use in our Environmental, Health, and Economic Benefits and Burdens Analysis.

➔ More information is available in the Environmental, Health, and Economic Benefits and Burdens Analysis in Appendix H: Electric Analysis and Portfolio Model.

2.5. Department of Ecology

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

Ecology adopted a new rule on January 6, 2021, that establishes: WAC-173-446[4]

- A general process to determine eligible energy transformation projects

[4] https://ecology.wa.gov/Regulations-Permits/Laws-rules-rulemaking/Rulemaking/WAC-173-446

- A process and requirements for developing standards, methodologies, and procedures to evaluate energy transformation projects
- The default unspecified emissions factor in CETA

2.5.1. Impact and Actions

We did not evaluate any specific energy transformation projects as alternative compliance in this 2023 Electric Report. Instead, we bound the cost of alternative compliance measures using a forecast of renewable energy credit purchases to represent the lower bound and a 100 percent renewable portfolio by 2030 to represent the upper bound.

➔ A full description of the alternative compliance assumptions and methodology is available in Chapter Five: Key Analytical Assumptions.

We use the unspecified emission factor for the emission rate of the unspecified market purchases in the portfolio.

➔ You will find an accounting of the emissions from generating thermal resources and unspecified market purchases in the results from Chapter Eight: Electric Analysis and App_I_Input_Carbon_Prices spreadsheet from Appendix H: Electric Analysis and Portfolio Model.

3. Climate Commitment Act

In 2021, the Washington State Legislature passed the Climate Commitment Act (CCA) establishing a comprehensive cap-and-invest program to reduce statewide greenhouse gas (GHG) emissions through a price on emissions. The law directs Ecology to develop rules to implement and administer the program beginning January 1, 2023. As part of this process, Ecology adopted the final program rules on September 29, 2022. Puget Sound Energy is preparing to comply with this state law in alignment with our Beyond Net Zero Carbon (BNZC) commitments and aspirations.

3.1. Program Overview

The cap-and-invest program sets an overall cap on state GHG emissions, which declines over time in line with the state's statutory GHG emissions limits. Covered entities must report their GHG emissions to Ecology and obtain allowances to cover them. An allowance is a mechanism created by the Ecology equal to one metric ton of GHG emissions and may be directly distributed by Ecology, purchased at auction, or traded with others in the program. The program aims to establish a greenhouse gas emissions price and create a marketplace for covered entities to find the most efficient means to reduce emissions. The CCA mandates the state to equitably invest revenues raised through state-run allowance auctions in projects that reduce emissions and address climate resiliency and environmental justice, among other priorities.

3.2. Impacts and Actions

As an electric and natural gas utility, PSE is covered under the CCA. We will report emissions and have annual compliance obligations under the program.

Electric utilities subject to CETA are allocated no-cost allowances to mitigate the cost burden of the CCA program on electric customers until 2045. Allocations must be consistent with a supply and demand forecast approved by the Commission. Utilities may consign allowances to auction for the benefit of ratepayers, deposit them for compliance, bank them for future compliance, or a combination of these actions. All proceeds from the consignment of allowances must benefit ratepayers with priority to mitigating rate impacts to low-income customers.

Natural gas utilities must also comply with the CCA, and how they do may impact electric utilities, such as through a shift to more electrification of customer end uses. Our 2023 Gas Utility IRP includes an electrification analysis citing impacts on possible future electric infrastructure requirements. The 2023 Gas IRP analysis highlights the importance of a dual-fuel energy system as we transition to a low-carbon economy. Since this is a progress and an update of assumptions from the 2021 IRP, the results for the electrification scenarios are in the 2023 Gas Utility IRP; such studies are beyond the scope of this 2023 Electric Report. Combining this analysis with the 2023 Gas IRP also allowed us to better integrate the analysis between the electric and gas portfolios. We anticipate electrification analysis may influence future electric IRPs.

Puget Sound Energy must comply with the CCA; as a result, we expect price impacts for all our customers. We will work hard to mitigate those impacts through decarbonization efforts to manage our allowances.

In this progress report, we modeled CCA prices as a direct cost applied to economic dispatch on greenhouse gas emissions to reflect the opportunity cost of emission allowances introduced by the CCA. A full explanation of the methodology and assumptions we used to model the impacts of the CCA is available in Chapter Five.

Please visit the Washington State Department of Ecology's CCA rulemaking website to learn more about this state program.

4. Energy Efficiency Technology, Codes and Standards, and Electrification

Energy efficiency technology and changing codes and standards impact customer choices and energy efficiency programs. For example, when federal minimum lighting performance standards included screw-in LED lighting, PSE could no longer offer LEDs as energy efficiency program offerings. Although LEDs continue to achieve savings, we can no longer take credit for those savings in our incentive programs.

The two energy codes that impact our customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to focus on greenhouse gas emissions and energy efficiency. These changes emphasize the electrification of systems formerly fueled by natural gas. Since February 2021, the 2018 WSEC no longer gives builders efficiency credits for new single-family homes that install natural gas space or water heating; instead, it gives them credits for installing electric heat pumps for heat and hot water.

4.1. Impact and Actions

The codes and standards included in the 2023 Electric Report CPA and demand forecast include:

- 2018 WSEC
- Provision of RCW 19.27A.160

In 2021, the Seattle Energy Code[5] created significant barriers to using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will use various types of heat pump technology to meet the demands of these systems. The Seattle Energy Code will affect the gas utility that serves the city of Seattle, but the change in demand for electricity will impact Seattle City Light, the electric utility for the city of Seattle, and will not affect PSE's electric system.

Another provision included in the 2023 Electric Report CPA is a statutory requirement (RCW 19.27A.160) that directs the WSEC revision process to achieve a 70 percent reduction in energy consumption by 2031 compared to a 2006 code baseline.[6]

➔ See Appendix E: Conservation Potential and Demand Response Assessment for details on the CPA.

The Washington State Building Codes Council (WSBCC) has proposed mandating builders install electric heat pumps in new commercial buildings and multi-family homes instead of natural gas heating and cooling technologies. The WSBCC is also developing residential building codes, which would encourage using electric heat pumps in new residential buildings and penalize using natural gas heating appliances. These proposals are currently under consideration for adoption as part of the WSEC. Although not modeled in this analysis these changes would likely affect PSE by increasing the electric energy and peak demand more than forecasted. The amount of difference in the peak demand forecast will be affected by the technology installed in these new buildings.

Washington State issued the WSBCC proposed code updates after we conducted the 2023 Electric Report CPA so, it is not included in this report.

5. Inflation Reduction Act

The Inflation Reduction Act (IRA) was passed and signed into law in August 2022 and represented the single most significant federal investment in clean energy and climate-focused solutions in U.S. history — approximately $370

5 The cities of Bellingham and Shoreline also passed similar gas bans in their jurisdictions in 2022.
6 RCW 19.27A.160

billion. The IRA addresses climate change by providing tax incentives and consumer rebates to move project developers and households toward lower-carbon or zero-carbon technologies. The two main incentives applicable to renewable projects are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs), both scheduled to phase out before the IRA was enacted.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before the IRA was enacted, PTCs had expired for any new projects placed in service in 2022 and beyond. The IRA bill extends PTCs to 100 percent for eligible projects placed in service before the end of 2032[7]; solar projects have also been added back into the eligible technology definitions of the PTC for the first time since 2005. The IRA also gives taxpayers new authority to transfer their credits to parties with tax appetite, providing taxpayers an additional means to monetize earned credits.

Investment Tax Credits provide an energy tax credit based on the percentage of the investment in the project. Before the IRA was enacted, the old ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent through 2032[8]. Taxpayers will also have new authority to transfer their credits to parties with tax appetite, giving taxpayers an additional monetization option for earned credits.

Previously, the ITC for battery storage projects was restricted to only battery storage projects paired with solar or other renewable energy generation assets in a hybrid configuration. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change ensures the tax credits support a more flexible system because the battery can charge from the grid and its paired solar project.

The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how projects are built. The rules give project developers incentives to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities.

5.1. Impact and Actions

We included the updated and extended PTC and ITC tax credits in the 2023 Electric Report analysis. We also extended the ITC to stand-alone energy storage — batteries, pumped hydro storage, and nuclear. The inclusion of the IRA in the analysis results in over $10 billion in projected savings to the customer.

Many other provisions in the IRA may impact electricity demand. For example, electric vehicle adoption rates may increase due to provisions of the IRA that provide buyer and charging facility owners tax incentives, incentives to help

[7] The existing PTC and ITC are extended at full value through 2024. After 2024, the existing PTCs and ITCs will expire. In their place, functionally similar clean energy production tax credits and clean energy investment tax credits take effect with broader flexibility to capture a greater number of eligible technology neutral energy sources. The new credits are similar value and definition to the prior credits if prevailing wage and apprenticeship requirements are met. Taxpayers are allowed to elect which credit they choose when placing an eligible project into service.

[8] See footnote 3.

consumers add rooftop solar and battery storage options, rebates intended to help low and moderate-income households achieve higher levels of energy efficiency and a host of other provisions. However, because the law was enacted late in our planning process, we could not add these policies to our demand forecast and could not consider all the nuances of the bill.

KEY ANALYTICAL ASSUMPTIONS
CHAPTER FIVE

Contents

1. Introduction

This chapter describes the forecasts, estimates, and assumptions Puget Sound Energy developed for the 2023 Electric Progress Report (2023 Electric Report). These assumptions span the horizon from 2024-2045 for the 2023 Electric Report. Additional details of the analyses are in Chapter Eight: Electric Analysis and in the related appendices.

This section on electric analysis includes the assumptions we used to create different economic conditions and operational considerations that affect portfolio costs and risks. Inputs included the electric demand forecast, price assumptions for natural gas and CO_2 costs, assumptions about cost and characteristics for existing and generic resources, and transmission considerations. We also included delivery system planning assumptions.

Next, we described electric portfolio sensitivities. Sensitivities start with the optimized, least-cost reference portfolio and change resource assumptions, environmental regulations, or other conditions to examine the effect of each change on the portfolio. We used these sensitivities to help build the preferred portfolio.

Last, we described our considerations for modeling electric supply-side resources as power purchase agreements or ownership agreements in the technology model section.

2. Electric Portfolio Analysis Assumptions

We analyzed a single reference case scenario for this 2023 Electric Report. A single scenario contrasts with a full Integrated Resource Plan (IRP), where multiple scenarios are typically analyzed to test how different economic conditions impact the portfolio optimization results. Instead of numerous scenarios, we used stochastic analysis for this 2023 Electric Report to measure the robustness of the preferred portfolio across a range of economic conditions.

The following section features the primary assumptions for the reference scenario.

2.1. Embed Equity with the Portfolio Benefit Analysis Tool

AURORA, the production cost model software we used for portfolio modeling in this report, is designed to find the lowest-cost portfolio given a set of constraints. Therefore, one of the best ways to influence the results of the AURORA portfolio model is to alter the cost of resources. For example, we incorporated the SCGHG in the AURORA portfolio model as an externality cost, which increases the cost of emitting resources, discouraging the model from including emitting resources in the final portfolio selection. Unfortunately, equity metrics do not have a specified dollar value, like the SCGHG, that we can incorporate into the portfolio model.

We needed another method to embed equity into the portfolio analysis and the 2023 Electric Report, so we created the portfolio benefit analysis tool. This new tool provides a measure of equity-related metrics outside the AURORA model that we can use to inform the portfolio development iteratively.

The portfolio benefit analysis tool is a spreadsheet-based model that relates the relative value added from improving Customer Benefit Indicators (CBIs) with the cost of a given portfolio. The portfolio benefit analysis tool builds on the approach we used in the 2021 IRP to incorporate equity. The tool allowed us to add interested party input to inform our process for the 2023 Electric Report. We anticipate we will continue improving how we incorporate CBIs in portfolio modeling. We describe the methodology we deployed in the portfolio benefit analysis tool in Appendix H: Electric Analysis and Portfolio Model, the portfolio benefit analysis tool Excel workbook that contains the data and the numerical analysis results in Appendix I: Electric Analysis Inputs and Results, and a discussion of the results in Chapter Eight: Electric Analysis.

2.2. Puget Sound Energy Customer Demand

The 2023 Electric Report demand forecast used in the analysis represents an estimate of energy sales, customer counts, and peak demand over 22 years.[1] Significant inputs include the following:

- Demographic changes
- Impacts of climate change
- Information about regional and national economic growth
- Known large load additions or deletions
- Prices
- Seasonality and other customer usage and behavior factors
- Weather

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

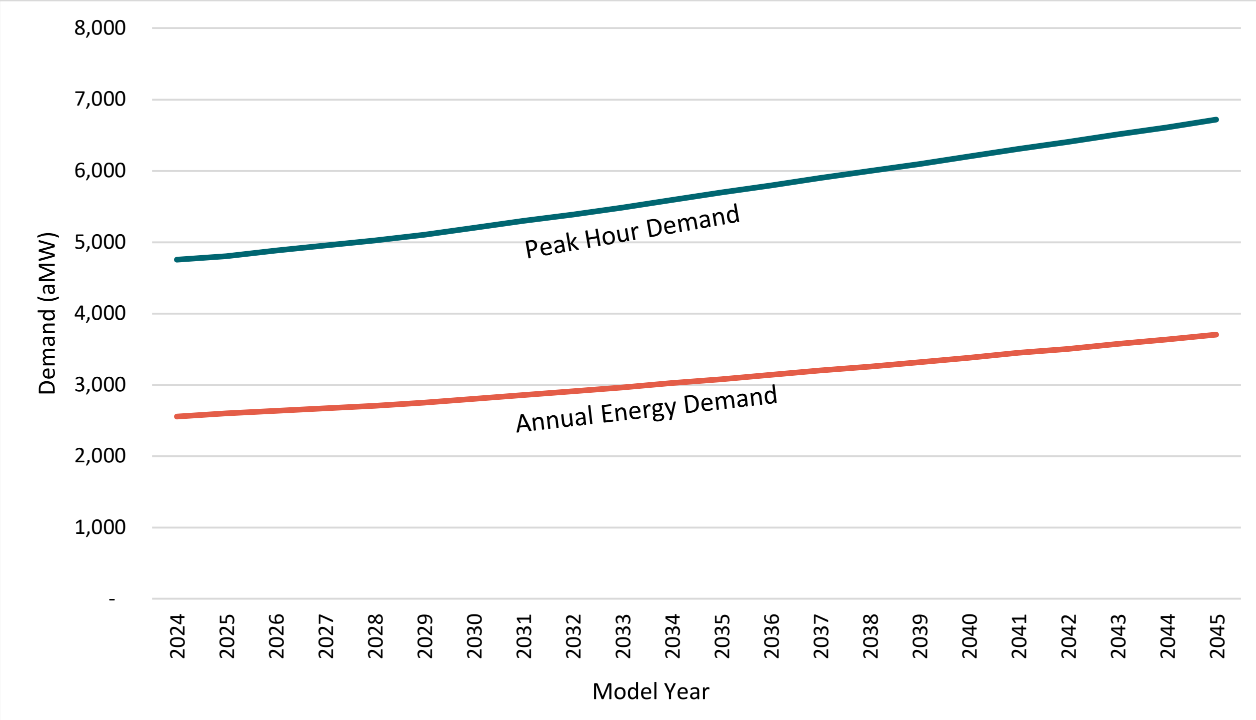
The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we develop. By the time the IRP is completed, we may have updated our demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning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

Figure 5.1 shows the electric peak demand and annual energy demand forecasts without the effects of conservation. The forecasts include sales (delivered load) plus system losses, which we represented in average energy demand over the year. The electric peak demand forecast is for a one-hour low temperature in winter at Sea-Tac airport, which we represented in total demand need at peak.

➔ See Chapter Six: Demand Forecasts, for a detailed discussion of the demand forecasts and Appendix F: Demand Forecasting Models, for the analytical models used to develop them.

1 For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but, demand grows faster in some parts of the service territory than others.

Figure 5.1: 2023 Progress Report Electric Annual Energy and Peak Hour Demand Forecasts



2.3. Natural Gas Price Inputs

For natural gas price assumptions in this 2023 Electric Report, we used a combination of forward-market prices and fundamental forecasts acquired in spring 2022 from Wood Mackenzie.[2]

- Beyond 2030, we used the Wood Mackenzie long-run natural gas price forecasts published in May 2022.
- For 2029 and 2030, we used a combination of forward market prices from 2028 and selected Wood Mackenzie prices from 2031 to minimize abrupt shifts when transitioning from one dataset to another.
- From 2022–2028, we used the three-month average of forward-market prices from May 12, 2022. Forward market prices reflect the price of natural gas purchased at a given time for future delivery.
- In 2029, the monthly price is the sum of two-thirds of the forward market price for that month in 2028 plus one-third of the 2031 Wood Mackenzie price forecast for that month.
- In 2030, the monthly price is the sum of one-third of the forward market price for that month in 2028 plus two-thirds of the 2031 Wood Mackenzie price forecast for that month.

We used three natural gas price forecasts, mid, low, and high, to develop a range of gas prices for the stochastic analysis. However, we used only the mid natural gas prices in the reference scenario for this 2023 Electric Report.

[2] Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American, international factors, Canadian markets, and liquefied natural gas exports. Under our agreement with Wood Mackenzie seasonal and annual natural gas price trends are confidential and cannot be shared as part of this report.

2.3.1. Mid Natural Gas Prices

The mid natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022. We used the mid natural gas price forecast in the reference case for this 2023 Electric Report.

2.3.2. Low Natural Gas Prices

We developed the low natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the low and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the low natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

2.3.3. High Natural Gas Prices

We developed the high natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the high and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the high natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

Figure 5.2 illustrates the range of 22-year levelized natural gas prices used in this analysis compared to the 22-year levelized natural gas prices PSE used in the 2021 IRP.

Figure 5.2: Levelized Natural Gas Prices Used in Scenarios, 2023 Progress Report vs. 2021 IRP (Sumas Hub, 22-year Levelized, Nominal $)

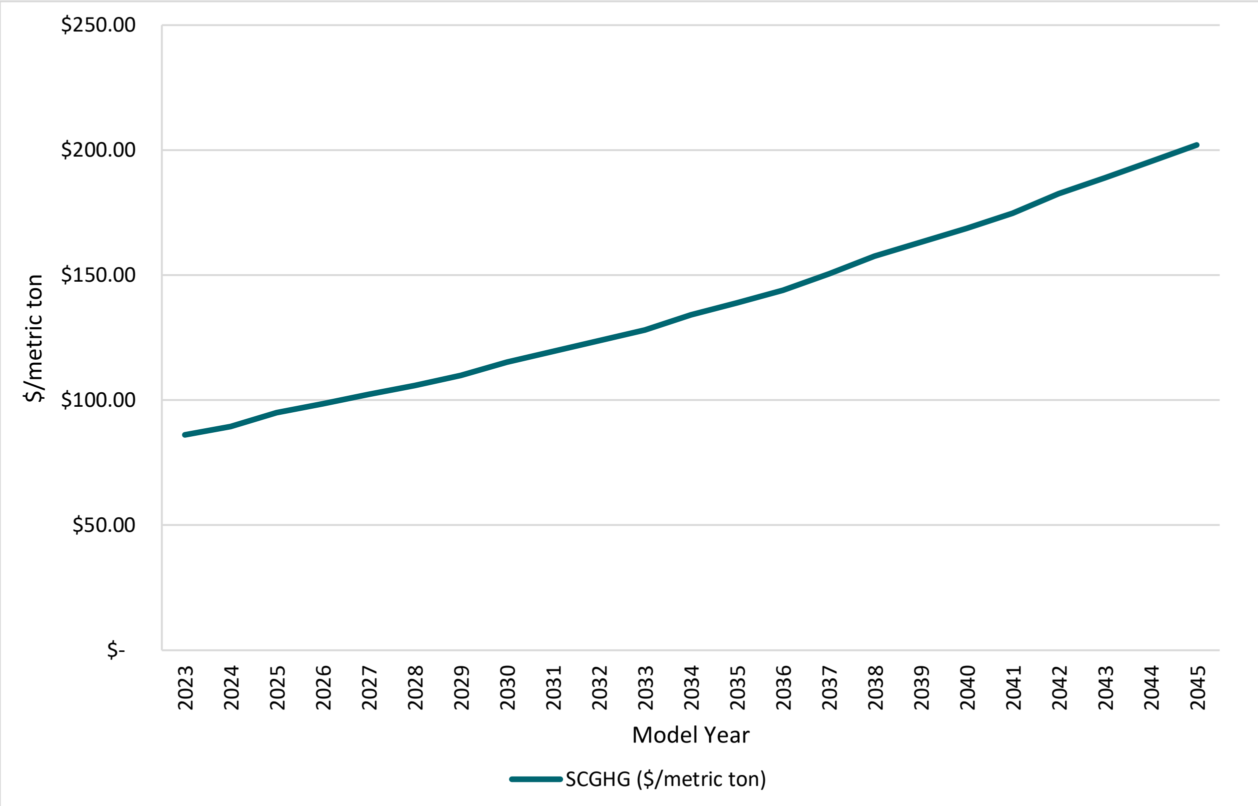
2.4. Carbon Dioxide Price Inputs

We modeled the Social Cost of Greenhouse Gases (SCGHG) and an allowance price for the Climate Commitment Act (CCA) in the 2023 Electric Report. In the following sections, we provide each price's forecasts and applications.

2.4.1. Social Cost of Greenhouse Gases

The SCGHG cited in the Clean Energy Transformation Act (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. We adjusted the prices for inflation (nominal dollars) resulting in a cost range from $86 per ton in 2023 to $202 per ton in 2045, as shown in Figure 5.3.

Figure 5.3: Social Cost of Greenhouse Gases in the 2023 Progress Report



We applied the SCGHG as a planning adder on emitting resources, so the SCGHG is applied when we optimize build decisions for new resources and retirement decisions for existing emitting resources. The reference case models the SCGHG as a fixed cost adder, which does not impact the dispatch schedule of emitting resources. However, we include a sensitivity that models the SCGHG as dispatch cost.

➔ See Appendix H: Electric Analysis and Portfolio Model for the complete discussion of how we modeled the SCGHG.

2.4.2. Upstream Carbon Dioxide Emissions for Natural Gas

The upstream emission rate represents the carbon dioxide, methane, and nitrous oxide releases associated with natural gas extraction, processing, and transport along the supply chain. We converted these gases to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[3]

3 The Environmental Protection Agency 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, we used emission rates published by the Puget Sound Clean Air Agency[4] (PSCAA). The PSCAA used two models to determine these rates, GHGenius[5] and GREET.[6] 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. Table 5.1 provides the results of the GHGenius and GREET models.

Table 5.1: Upstream Natural Gas Emissions Rates

Model	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 for the SCGHG emissions. We did not apply the upstream emission rate to the CCA allowance price.

2.4.3. Climate Commitment Act Allowance Price

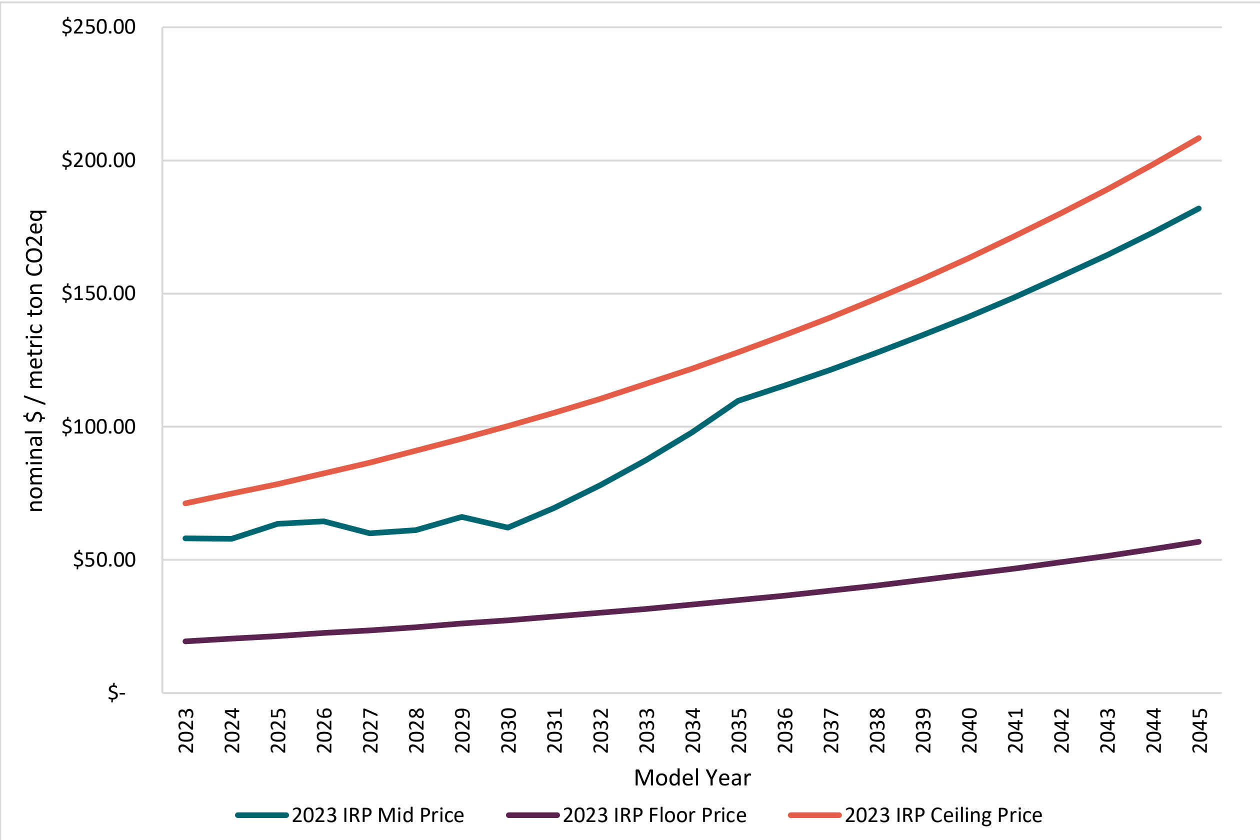
The Washington State legislature passed the CCA in 2021; it goes into effect in 2023. The CCA is a cap-and-invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances representing permitted emissions. The resulting market establishes an opportunity cost for emitting greenhouse gases. We added an emission price to greenhouse gas emissions in the electric price forecast model for emitting resources within Washington State to model this opportunity cost. In the price forecast model, we only added the emission price to Washington State emitting resources to ensure the model reflects any change in dispatch without impacting that of resources outside Washington State not subject to the rule. To accurately reflect all costs imposed by the CCA, we added a hurdle rate on transmission market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_2eq per MWh (RCW 19.405.070).[7]

Figure 5.4 shows the emission prices we used to model the CCA allowance price, an ensemble of two price forecasts from the Washington Department of Ecology (Ecology) and the California Energy Commission (CEC). Ecology issued an analysis of the CCA, which included estimated allowance price forecasts across a range of program and market assumptions.[8] We suggest a linkage to the California carbon market is a likely scenario; therefore, we adopted an ensemble pricing scheme that begins with pricing at the rate specified by the Ecology CA Linkage 2030 case, then

4 Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019.
5 GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca.
6 GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.
7 RCW 19.405.070
8 Preliminary Regulatory Analyses for Chapter 173-446 WAC, Climate Commitment Act Program

transitions to the CEC 2021 Integrated Energy Policy Report[9] allowance price forecast for the remainder of the modeling horizon.

Figure 5.4: Climate Commitment Act Allowance Pricing in the 2023 Progress Report



2.5. Climate Change

This 2023 Electric Progress Report is the first time Puget Sound Energy has included the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest (PNW) in an electric progress report. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC)[10], Part II, and selected three scenarios representing a range of possible climate outcomes. Puget Sound Energy adopted these same three climate change scenarios:

- CanESM2_RCP85_BCD_VIC_P1, coded as A.
- CCSM4_RCP85_BCD_VIP_P, coded as C.
- CNRM-CM5_RCP85_MACA_VIC_P3, coded as G.

[9] 2021 Integrated Energy Policy Report (ca.gov)
[10] https://usace.contentdm.oclc.org/digital/collection/p266001coll1/id/9936

The three climate change scenarios we adopted uniquely impact the PNW load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the 2023 Electric Progress Report analysis averaged the effects of each climate change scenario to develop a single climate change case, which retains trends in all three climate change scenarios.

➔ For more information on assumptions for incorporating climate change, see Chapter Six: Demand Forecast.

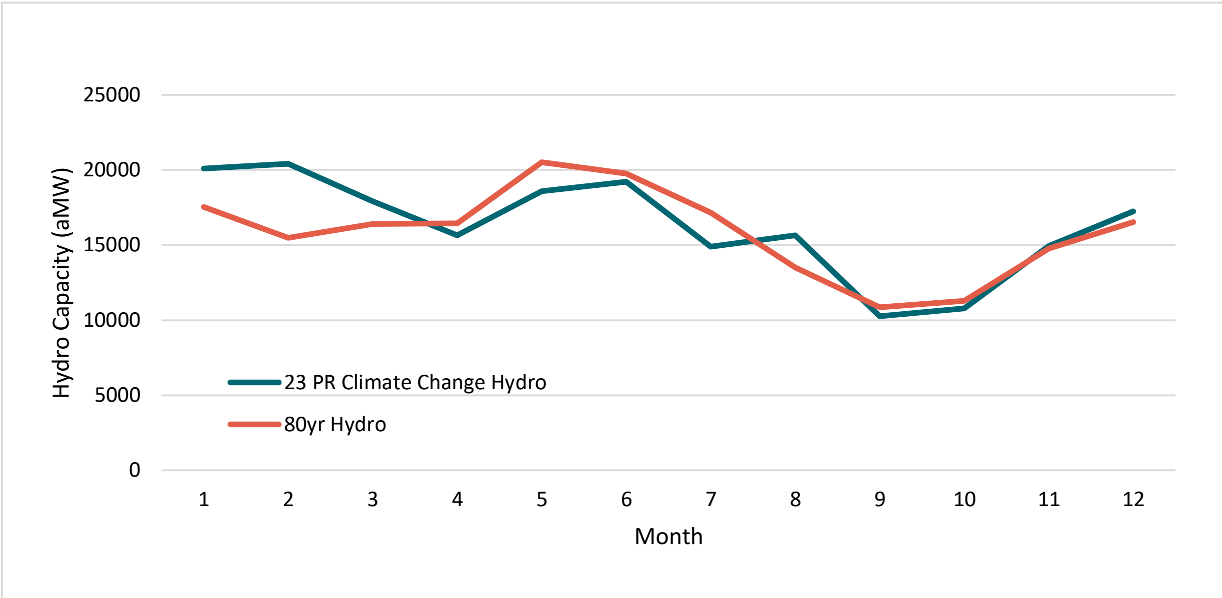
2.5.1. Hydroelectric Assumptions

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the climate change scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[11] regional resource adequacy model using streamflow data representative of the climate change scenarios.

We held the average hydroelectric forecast fixed for all the modeled years. Figure 5.5 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year. This plot represents the PNW average hydroelectric capacity; trends for individual hydroelectric facilities will vary.

[11] https://www.nwcouncil.org/2021powerplan_genesys-model/

Figure 5.5: Pacific Northwest Climate Change Hydroelectric Forecast, Average of All Hydroelectric Facilities



2.6. Electric Price Inputs

We must create a wholesale electric price forecast as an input to the portfolio model to represent the wholesale power market. In this context, electric 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 prevailing economic conditions. This wholesale electric price forecast is an essential input since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating a wholesale electric price forecast requires performing WECC-wide AURORA model runs. The AURORA database starts with inputs and assumptions from the Energy Exemplar 2020 WECC Zonal database v1.0.1. We then include updates such as regional demand, natural gas prices, CO_2 prices, clean energy policies, and resource retirements and builds.

Figure 5.6 presents the annual average electric price forecast used in the 2023 Progress Report.

➔ See Appendix G: Electric Price Models for a detailed description of the methodology used to develop wholesale electric prices

Figure 5.6: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time (Nominal $/MWh)

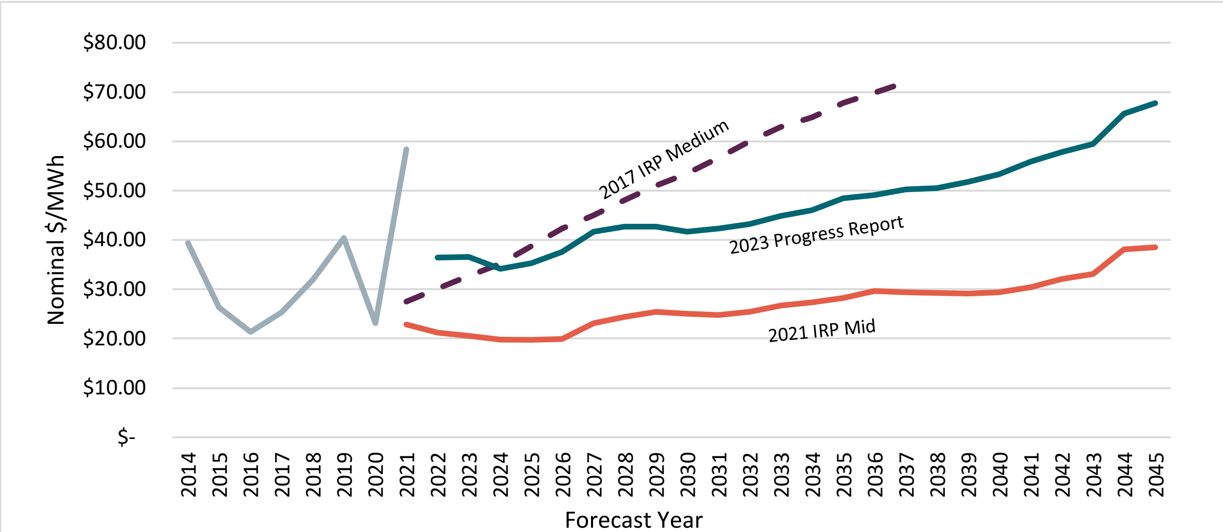
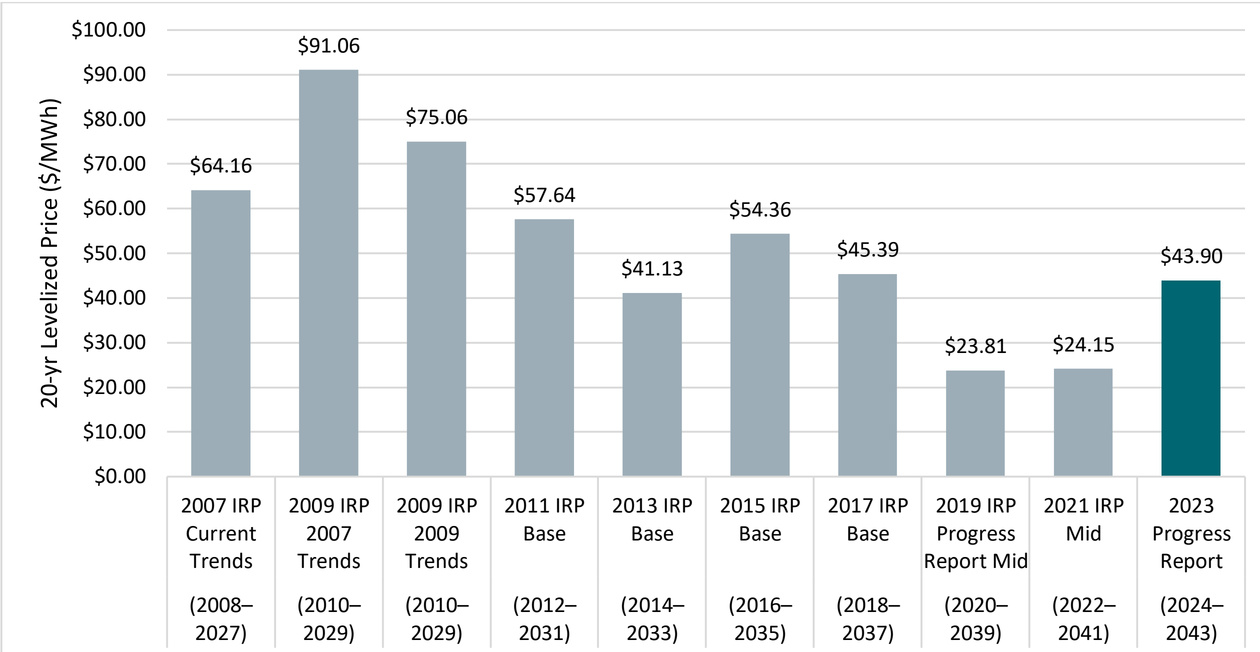


Figure 5.7 compares the 2023 electric price forecast to past IRP electric price forecasts. In previous IRPs, the downward revisions in forecast power prices corresponded to those in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations drives much of the downward revision in forecasted power prices. The 2017 IRP base scenario included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions. The increase in electric prices in the 2023 Electric Progress Report is from several significant model updates, including increased natural gas prices, increased storage resources, revised methodology on clean energy policy modeling, and the addition of carbon allowance pricing from the CCA.

➔ Please find more details on the impacts of these updates in Appendix G: Electric Price Models.

Figure 5.7: Comparison of 2023 20-year Levelized Electric Prices Compared to Past IRPs ($/MWh)



2.7. Electric Resource Assumptions

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

➔ See Appendix D: Generic Resource Alternatives, for detailed descriptions of the supply-side resources listed here and Appendix E: Conservation Potential Assessment and Demand Response Assessment, for detailed information on demand-side resource potentials.

2.7.1. Demand-side Resources

Demand-side resources contribute to meeting energy-need by reducing demand. An integrated resource plan includes both supply- and demand-side resources. We accounted for the contribution that demand-side programs make to meeting resource needs as a reduction in demand for the IRP analysis. Demand-side resources include energy efficiency measures (also referred to as conservation), generation efficiency measures, and distribution efficiency measures.

Energy Efficiency Measures

Energy efficiency measures reduce the level of energy used to accomplish a given amount of work. We group the wide variety of energy efficiency measures available into 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. Energy efficiency also includes small-scale electric distributed generation, such as combined heat and power.

Generation Efficiency

Generation efficiency comes from improvements at PSE generating plants.

Distribution Efficiency

Distribution efficiency comes from voltage reduction and phase balancing. Voltage reduction is reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

2.7.2. Distributed Energy Resources

Distributed Energy Resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to form Virtual Power Plants (VPPs). We included demand response, distributed solar, and distributed storage programs as generic DERs in this 2023 Electric Report.

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 close to the customer's load source. We modeled distributed solar as a residential-scale resource in western Washington. We summarize the capacity factors for solar resources modeled in Table 5.2. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.2: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
DER Ground Solar	Residential-scale, fixed-tilt, ground mounted	17
DER Rooftop Solar	Residential-scale, fixed-tilt, rooftop mounted	17

Distributed Battery Energy Storage

Distributed battery energy storage systems refer to small-scale lithium-ion battery installations close to the customer's load. We modeled distributed storage as a residential-scale, three-hour duration battery with a nameplate capacity of 5 MW.

Non-wires Alternatives

We consider non-wires alternatives when developing solutions to specific, long-term needs identified in the transmission and distribution systems. The resources we study benefit from the capacity to address system deficiencies while supporting resource needs. We can deploy them across the transmission and distribution systems, providing flexibility in addressing system deficiencies. The non-wires alternatives we considered during the planning process include energy storage systems and solar generation.

2.7.3. Supply-side Resources

Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter and include wind, solar, pumped hydroelectric energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines, and advanced nuclear small modular reactors (SMR). The following section describes the supply-side resources applied to this 2023 Electric Report.

Wind

We modeled wind 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 resource is in Table 5.3. Consulting firm DNV provided the wind production profile data used in the AURORA model.

Table 5.3: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
British Columbia	40.9
Eastern Washington	37.2
Central Montana	41.3
Eastern Montana	47.7
Idaho	15.0
Eastern Wyoming	46.4
Western Wyoming	36.1
Offshore Washington	42.1

Solar

We modeled solar 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 utility scale solar resources modeled is in Table 5.4. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.4: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Idaho	Utility-scale, single-axis tracker	27.3
Eastern Washington	Utility-scale, single-axis tracker	25.0

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington	Utility-scale, single-axis tracker	20.2
Eastern Wyoming	Utility-scale, single-axis tracker	28.9
Western Wyoming	Utility-scale, single-axis tracker	30.0

Energy Storage

Energy storage encompasses a range of technologies capable of converting kinetic energy into stored potential energy for later use. Energy storage removes the need for electricity generation to match the energy demand instantaneously. As such, energy storage can help to mitigate some of the challenges associated with variable energy resources such as wind and solar. A wide variety of energy storage technologies exist and span a range of development conditions from theoretical to commercially available. We discuss the current status of several storage technologies in Appendix D: Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage. Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage.

Baseload and Peakers

Baseload generators are designed to operate economically and efficiently over long periods of time, 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 to meet spikes in need. Unlike baseload resources, they are not intended to operate economically for long periods of time.

Hybrid Resources

In addition to stand-alone generation and energy storage resources, we modeled hybrid resources, which combine two or more resources at the same location to take advantage of synergies between the resources. We modeled three types of hybrid resources: eastern Washington solar + four-hour lithium-ion battery, eastern Washington wind + four-hour lithium-ion battery, and eastern Washington wind + solar + four-hour lithium-ion battery.

Baseload Thermal Plants

Baseload thermal plants or combined-cycle combustion turbines (CCCT) are F-type, 1 x 1 engines with wet cooling towers. We assumed they would generate 348 MW plus 19 MW of duct firing and be in PSE's service territory. We designed and intended these resources to operate at base load, defined as running more than 60 percent of the hours in a year.

Frame Peakers

Frame peakers or simple-cycle combustion turbines (SCCT) are F-type, wet-cooled turbines. We assumed they would generate 237 MW and be in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Recip Peakers

Recip peakers, or reciprocating engines, are small 18.2 MW engines with wet cooling located in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Alternative Fuels

In addition to natural gas, this 2023 Electric Report includes low-carbon alternative fuels, including hydrogen and biodiesel. Given current incentives in the Inflation Reduction Act,[12] green hydrogen fuel may become cost-effective compared to natural gas after accounting for the social cost of greenhouse gases and the impacts of the CCA. Biodiesel may also provide a viable, low-carbon alternative fuel for capacity resources during peak critical hours.

➔ We provide a description and the modeling assumptions used for these alternative fuels in Appendix I: Electric Analysis Inputs and Results.

Advanced Nuclear Small Modular Reactor

We modeled advanced nuclear (SMR) for the first time in the 2023 Electric Report. An SMR is a cluster of relatively small nuclear reactors at the same site that share land and infrastructure, although each reactor may be operated independently. The reactor technology is similar to that used in nuclear-powered submarines. While the exact specifications for SMR systems can vary, we chose to model this resource with a configuration of up to a 50MW module for this 2023 Electric Progress Report.

➔ We provide a complete description of SMR technology in Appendix D: Generic Resource Alternatives.

2.8. Electric Resource Cost Assumptions

We sourced generic resource capital cost assumptions from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB)[13] for most resources in the 2023 Electric Report, consistent with our Clean Energy Implementation Plan (CEIP). This method is different from the approach we took in the 2021 IRP, which used different generic resource cost assumptions. The NREL did not include reciprocating peaker technology in the 2022 ATB; therefore, we sourced capital cost data for this generic resource from the U.S Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2022 (2022 AEO).

Interconnection costs are not included as part of the capital cost for generic resources in the 2022 ATB or 2022 AEO and can account for a significant portion of the capital cost of some resource types. We added interconnection cost

12 https://www.congress.gov/bill/117th-congress/house-bill/5376/text
13 https://atb.nrel.gov/electricity/2022/technologies

estimates to each resource type based on the spur line length needed to interconnect each generic resource to the transmission grid to account for this omission.

We expect generic resource capital costs to decline as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the 2022 ATB. The 2022 ATB provides three cost curves for each resource: low, mid, and constant technology cost scenarios. We selected the mid-technology cost scenario for the IRP cost curves, representing the most likely future cost projection.

We sourced generic resource O&M costs from the 2022 ATB for all generic resource technologies except thermal technologies. We sourced generic CCCT and frame peaker fixed O&M from averaging our existing costs, as reported in the 2021 FERC Form 1s. We adopted the fixed O&M that were reported for the Port Westward 2 facility as the generic reciprocating peaker fixed O&M.[14] We adopted variable O&M from the CAISO Variable Operations and Maintenance Cost Review, Final Proposal.[15]

The 2022 ATB did not provide O&M costs for most hybrid configurations presented in the 2023 Electric Report. We combined the fixed O&M for each component within the hybrid system to calculate these costs and used the respective capacities to generate a weighted average. The 2022 ATB provided a fixed O&M cost associated with a solar plus four-hour li-ion battery storage hybrid system, which is higher than the weighted average. Though the literature indicated this O&M was based on stand-alone solar and battery fixed O&M, NREL did not present the precise method of combining these costs in the 2022 ATB. To maintain consistency with other hybrid systems in the 2023 Electric Report, we used a weighted average for the solar plus battery storage hybrid resource. We show all hybrid resource fixed O&M as a time series.

➔ See Appendix D: Generic Resource Alternatives, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.

Table 5.5 summarizes generic resource cost assumptions.

Table 5.5: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
CCCT	348	2024	22.67	6.16	963	22	987
Frame Peaker	237	2024	9.52	1.02	879[4]	26	944
Recip Peaker	219	2024	14.53	1.16	2019	26	2045
WA Utility Solar East & West	100	2024	19.35	0.00	1074	156	1230
Idaho Utility Solar	400	2026	19.35	0.00	1074	463	1537

[14] https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home
[15] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Variable-operations-maintenance-cost-review

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
WY Utility Solar East & West	400	2026	19.35	0.00	1074	463	1537
DER Solar — Rooftop and Ground-mounted WA West	5	2024	25.48	0.00	2,287	0	2,287
Offshore Wind	100	2030	70.78	0.00	4,137	590	4,728
BC Wind	100	2024	41.79	0.00	1,308	422	1,730
WA Wind	100	2024	41.79	0.00	1,308	156	1,464
MT Wind	100	2024	41.79	0.00	1,308	1,164	2,472
ID Wind	400	2026	41.79	0.00	1,308	463	1,772
WY Wind	400	2026	41.79	0.00	1,308	463	1,772
Pumped Storage — WA, OR, Closed Loop, 8-hour	100	2029	17.82	0.51	3,404	506	3,910
Pumped Storage — MT Closed Loop 8-hour	100	2029	17.82	0.51	3,404	198	3,602
Battery 2-hour Li-Ion	100	2024	20.12	0.00	746	58	804
Battery 4-hour Li-Ion	100	2024	32.76	0.00	1,256	58	1,314
Battery 6-hour Li-Ion	100	2024	45.49	0.00	1,765	58	1,823
DER Batteries 3-hour	5	2024	98.06	0.00	3,923	0	3,923
Wind + Battery	150	2024	38.35	0.00	1,093	217	1,310
Solar + Battery WA	150	2024	23.39	0.00	976	170[5]	1,147
Wind + Solar + Battery WA	250	2024	30.69	0.00	932	257[5]	1,190
Biomass	15	2024	151.00	5.80	4,332	573[5]	4,906
Advanced Nuclear SMR	50	2028	114.00	2.84	10,918	13	10,930

Notes:

1. Variable O&M costs do not include the cost of fuel for thermal resources.
2. Capital Costs, Vintage 2023. CAPEX (capital expenditures) required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
3. Interconnection costs consist of the transmission, substation, and natural gas pipeline infrastructure. The interconnection cost of offshore wind only includes onshore interconnection, and we included marine cable costs in the capital cost of the resource.
4. Frame peaker CAPEX includes costs for on-site biodiesel storage
5. Wind + Battery and Solar + Battery resources received a 40 percent interconnection cost-benefit, and the Wind + Solar + Battery resource received a 55 percent interconnection cost-benefit.

➔ See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type. See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type.

2.9. Flexibility Considerations

The 2023 Electric Report flexibility study reflects 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, various resources can impact costs and how the portfolio operates. For example, batteries could avoid the dispatch of thermal plants form ramping up and down.

For the sub-hourly flexibility analysis, we used a model called PLEXOS. First, we created a current portfolio case based on PSE's existing resources. We started the current portfolio case by making a simulation that reflects a complete picture of PSE as a Balancing Authority (BA) and our connection to the market. We represented PSE's Balancing Authority Area (BAA) load and generation on a day-ahead and real-time, 15-minute basis. We also included opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the Energy Imbalance Market (EIM) in 15-minute increments. For this analysis, we simulated 2029 for both hour-ahead and real-time and then took the difference in total portfolio cost between the two simulations.

We tested the impact of a range of potential new resources, each individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the existing portfolio case cost, we identified the cost reduction as a benefit of adding the new resource.

Table 5.6 shows the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.17/kW-year. We applied these cost savings back to the fixed O&M of the generic resource as a reduction to the cost.

Table 5.6: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kW-yr)
CCCT	5.17
Frame Peaker	9.65
Recip Peaker	28.14
Lithium-ion battery 2-hour	7.43
Lithium-ion battery 4-hour	47.21
Lithium-ion battery 6-hour	8.58
Pumped Storage Hydroelectric 8-hour	2.82
Demand Response	19.39

➔ See Appendix H: Electric Analysis and Portfolio Model, for a detailed description of the methodology used to develop the flexibility benefit.

2.10. Regional Transmission Constraints

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

2.10.1. Transmission Capacity Constraints

Transmission capacity constraints have become a vital modeling consideration as we transition 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 we can generally site in locations convenient to transmission, produce power at a controllable rate, and dispatch as needed to meet shifting demand, renewable resources are site-specific and produce power intermittently. The limiting factors of renewable resources have two significant impacts on the power system: 1) we must acquire a greater quantity of renewable resources 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 our service territory. A wind farm in one location will produce a different amount of power than the same wind farm in another place. This situation makes it essential to consider whether there is enough transmission capacity to carry power from remote renewable resources to our service territory.

2.10.2. Assumptions

To model transmission capacity constraints, we created eight resource group regions and set limits on the generation capacity built in each region. We based resource group regions on the geographic relationships of the generic resources modeled in the 2023 Electric Report. Table 5.7 summarizes the resource group regions and the generic resources available in each group.

Table 5.7: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	PSE Territory[1]	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	British Columbia	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			
BC Wind						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 2-hour Li-Ion	X							
Battery 4-hour Li-Ion	X							
Battery 6-hour Li-Ion	X							
Solar + battery		X			X			
Wind + battery		X			X			
Solar + wind + battery		X			X			
Wind + pumped storage							X	
Biomass	X			X				
Advanced Nuclear SMR		X						

Note:
1. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed

We based capacity limits on our experience with available transmission capability (ATC) on the Bonneville Power Administration's (BPA) system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies (2020, 2021, & 2022), regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building, and acquisition are complex processes with various possible outcomes; therefore, we developed a range of plausible transmission limits and timelines for each region. To structure these ranges, we organized the transmission limits into tiers; uncertainty increases from tier to tier based on our ability to acquire that quantity of transmission.

The tiers include:

- **Tier 1:** Transmission capacity that we could likely acquire in 2023–2025. This transmission capacity draws primarily from repurposing our existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that we could acquire in 2025–2030 but is less certain than Tier 1. This transmission capacity adds new transmission resources to our portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that we could acquire beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from adding long lead-time, major transmission system upgrades, or new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 4:** Tier 4 represents a generally unconstrained transmission system.

In this report's reference case, we modeled transmission limits by tier with increasing transmission limits over time. By 2040, transmission will be unconstrained. In the context of this report, unconstrained transmission signifies there is enough time to acquire or build new transmission resources to match the resource mix provided by the model.

Table 5.8 summarizes the transmission limits by tier for each resource group region.

Table 5.8: Transmission Capacity Limitations by Resource Group Region (Added Transmission MW by Tier)

Resource Group Region	Tier 1 (by 2025)	Tier 2 (by 2030)	Tier 3 (by 2035)	Tier 4 (by 2040)
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	640	2,310	2,510	Unconstrained
Central Washington	250	600	850	Unconstrained
Western Washington	0	100	635	Unconstrained
Southern Washington/Gorge	340	2,010	2,390	Unconstrained
British Columbia	200(c)	200(c)	200(c)	Unconstrained
Montana	0	400(c)	400(c)	Unconstrained
Idaho and Wyoming	0	400	600	Unconstrained
TOTAL	1,430	6,020	7,585	Unconstrained

Notes:

a. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed.
b. Not constrained in the resource model, assumes adequate PSE transmission capacity to serve future load.
c. Indicates we rounded transmission constraints to align with generic resource capacity ranges.

The rationale for each transmission capacity limitation by resource group region follows.

Eastern Washington

Through BPA Cluster Study requests, we may obtain 150, 600, or 650 MW for transmission to the Lower Snake River region for Tiers 1, 2, and 3, respectively. By co-locating a 150 MW solar resource at an existing wind facility, we could add 150 MW of Tier 1 transmission. We may acquire an additional 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission from developer submittals and resource retirements.

Central Washington

We may obtain 250, 500, or 750 MW of transmission for Tiers 1, 2, and 3, respectively, using a portion of the existing 1,500 MW of Mid-C transmission we currently use for market purchases for dual purposes. An additional 100 MW of transmission may be available in Tier 1 to deliver Kittitas area solar via the Grant County PUD system.

Western Washington

We assume no additional transmission is available in Tier 1. Tier 2 may add 100 MW of BPA transmission after the TransAlta purchased power agreement (PPA) expires 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 add 200 MW of third-party transmission rights from developer submittals, resource retirements, or offshore wind development.

Southern Washington / Gorge

We may obtain 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission rights from developer submittals or resource retirements. Tiers 2 and 3 may also add 330 MW of dual-purpose transmission (Tier 2 100 MW, Tier 3 230 MW) to prioritize renewable generation co-located with the Goldendale CCCT.

British Columbia

We may obtain up to 160 MW of long-term transmission from BC Hydro by 2025. Any additional transmission between PSE and British Columbia would require a transmission study and likely system upgrades.

Montana

We may obtain 370 MW for Tier 2 of transmission from repurposing transmission freed up by removing Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho

Puget Sound Energy may pursue transmission capacity on the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

Puget Sound Energy Territory

For the 2023 Electric Report, we assumed that the PSE system in western Washington is unconstrained. This assumption 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, including transmission and distribution system upgrades.

2.10.3. 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. The BPA assumes a flat 1.9 percent line loss across its 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, we assumed a similar loss given the similar distance. Table 5.9 summarizes the transmission line losses assumed by the resource group region.

Table 5.9: 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
British Columbia	1.9
Montana	4.6
Idaho and Wyoming	4.6

2.10.4. 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 ($/kW-year) and a variable component measured in dollars per megawatt-hour ($/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 our service territory. Balancing service tariffs vary by resource type; wind balancing service tariffs are usually more expensive than solar balancing serving tariffs, given the greater inter-hour variability of wind resources. Variable transmission costs are primarily composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Table 5.10 summarizes fixed and variable transmission costs by generic resource type.

We based the wheeling tariffs from Idaho and Wyoming on tariff service over Gateway West, Boardman to Hemingway, and the BPA main grid. For transmission cost modeling, we assumed the cost of three wheels (PacifiCorp, Idaho Power, and BPA) with a reduction to two wheels (PacifiCorp and BPA) after the Gateway West segments are fully completed (estimated 2030 according to PacifiCorp IRP).

Table 5.10: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-year)	Variable Transmission Cost ($/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	27.80	0.26
WA Solar West — Utility-scale	5.24	0.26
Idaho Solar — Utility-scale	57.66	0.26
WY Solar East — Utility-scale	101.12[b]	0.26
WY Solar West — Utility-scale	101.12[b]	0.26
DER WA Solar — Rooftop	0.00[a]	0.26
DER WA Solar — Ground-mount	0.00[a]	0.26
WA Wind	31.21	0.26
BC Wind	61.69	0.26
MT Wind — East	59.10	0.26
MT Wind — Central	59.10	0.26
ID Wind	61.07	0.26
WY Wind East	97.31[b]	0.26
WY Wind West	97.31[b]	0.26
Offshore Wind	31.21	0.26
WA/OR Pumped Storage	22.58	0.26
MT Pumped Storage	50.47	0.26
Battery 2-hour Li-ion	0.00[a]	0.00
Battery 4-hour Li-ion	0.00[a]	0.00
Battery 6-hour Li-ion	0.00[a]	0.00
Solar + Battery	27.80	0.26
Wind + Battery	31.21	0.26
Solar + Wind + Battery	31.21	0.26
Wind + Pumped Storage	59.10	0.26
Biomass	22.58	0.26
Advanced Nuclear SMR	22.58	0.26

Notes:

a. Fixed transmission cost is not applied because we assumed the resource would be built within the PSE service territory.

b. Wyoming transmission cost reflects wheel through Idaho Power territory, reduction in cost modeled in 2030 when Gateway West transmission becomes available. See Appendix H: Electric Analysis and Portfolio Model for further details on modeled transmission cost.

2.11. Electric Delivery System Planning Assumptions

Puget Sound Energy uses a structured approach to developing infrastructure plans that support various customer needs, including effective DER integration. Our process and the associated planning assumptions are in Figure 5.8 and Table 5.11, respectively.

Figure 5.8: Delivery System Planning Operating Model

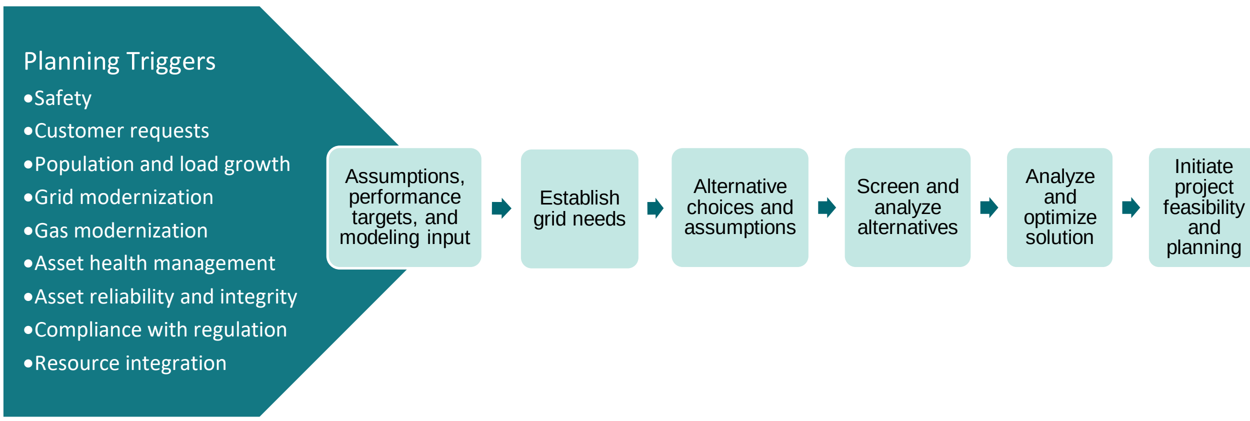


Table 5.11: Delivery System Planning Assumptions

Assumptions	Description
Demand and Peak Demand Growth	Uses county-level demand forecast applied based on historic load patterns of substations with known point loads adjusted for
Energy Efficiency	Highly optimistic 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Interconnection requests with completed Large/Small Generator Interconnection Agreements included
Aging Infrastructure	Known concerns included in the 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

2.11.1. Delivery System Planning Non-wires Alternatives Forecast

We included a distributed energy resources forecast in the 2023 Electric Report that evaluates where we identified DERs as a potential non-wires solution for meeting delivery system needs. We then extrapolated the forecast based on load growth assumptions. As needs arrive on the planning horizon, further analysis relative to specific values and potential will test these assumptions.

The non-wires alternatives we considered during the delivery system planning (DSP) process include demand response, targeted energy efficiency, energy storage systems, and solar generation, among others. We considered these resources independently and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions align with needs primarily driven by capacity or resiliency. As we continue integrating DER into system solutions, we must answer critical questions about DER's operational flexibility and associated cyber-security considerations.

We used the following assumptions to develop a DER forecast to solve identified system needs over the 0-to-10-year time frame.

- Based on industry knowledge and consultant input for summer needs, we determined 3 to 4 MW was a reasonable size for utility-scale photovoltaic (PV).
- Due to the practical sizing of DER solutions, we did not consider projects with needs larger than 20 MW.
- We applied average historical percentages to determine energy efficiency, demand response, and energy storage potential.

We used the same assumptions for needs identified in the 10- to 20-year timeframe but extrapolated the value 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). We made additional considerations to account for the planning process. We assumed the needs we identified before 2023 would take two to three years to complete based on a new planning process and the learning curve associated with implementing new technologies. We assumed the needs identified after 2023 would be built when it first appeared on the system as the planning process matures and we gain experience siting DER. Figure 5.9 presents the forecast of DER resources added to the system as non-wires alternatives.

Figure 5.9: Forecasted DER Installation by Year and Type

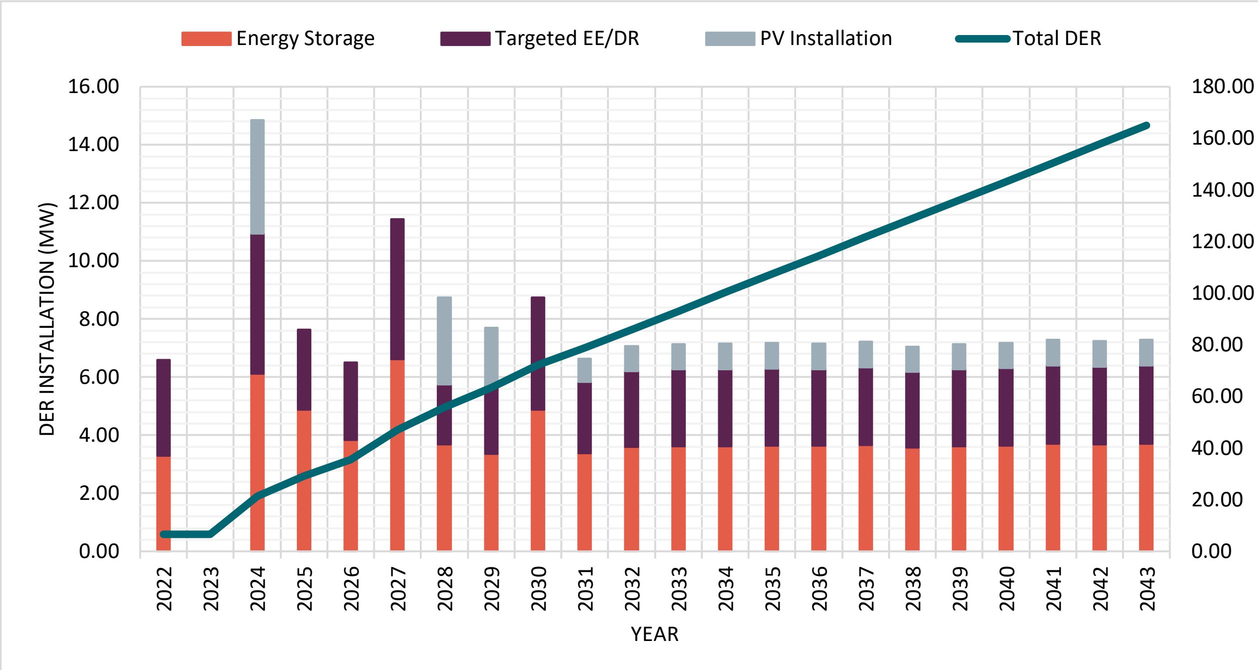


Table 5.12 presents the projected transmission and distribution deferrals resulting from the non-wires alternatives DER additions.

Table 5.12: Projected T&D Deferral by Project Type by 2040

Project Type	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects[1]	7.1	6	0	13.1
Planned Substation Capacity Projects	17.6	12.4	3.9	33.9
Future Potential System Needs	59	42.6	16.4	118
Total	83.7	61	20.3	165

Note: [1]As identified in the PSE Plan for Attachment K

We modeled the energy storage and solar PV forecasts in the AURORA portfolio model as generating resource to represent the DSP non-wires alternatives. We included the targeted energy efficiency/demand response forecast as part of the cost-effective energy efficiency and demand response evaluation the model.

2.12. Transmission and Distribution Benefit

The transmission and distribution (T&D) benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Electric Progress Report included a T&D benefit of $74.70/kW-year for DER batteries. This estimated $74.70/kW-year is forecasted based on our additional transmission and delivery system needs under such a scenario. This increase is a significant change from the $12.93/kW-year we used in the 2021 IRP which used backward-looking metrics instead of the revised forward-looking scenario described.

2.13. Electric Generation Retirements

We modeled the economic retirement of existing thermal resources for this 2023 Electric Report. We assumed Colstrip would be removed from PSE's portfolio by December 31, 2025; based on economics, the model can retire Colstrip earlier. We assumed the other thermal plants would run through the planning horizon but could retire early based on economics.

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

2.14. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

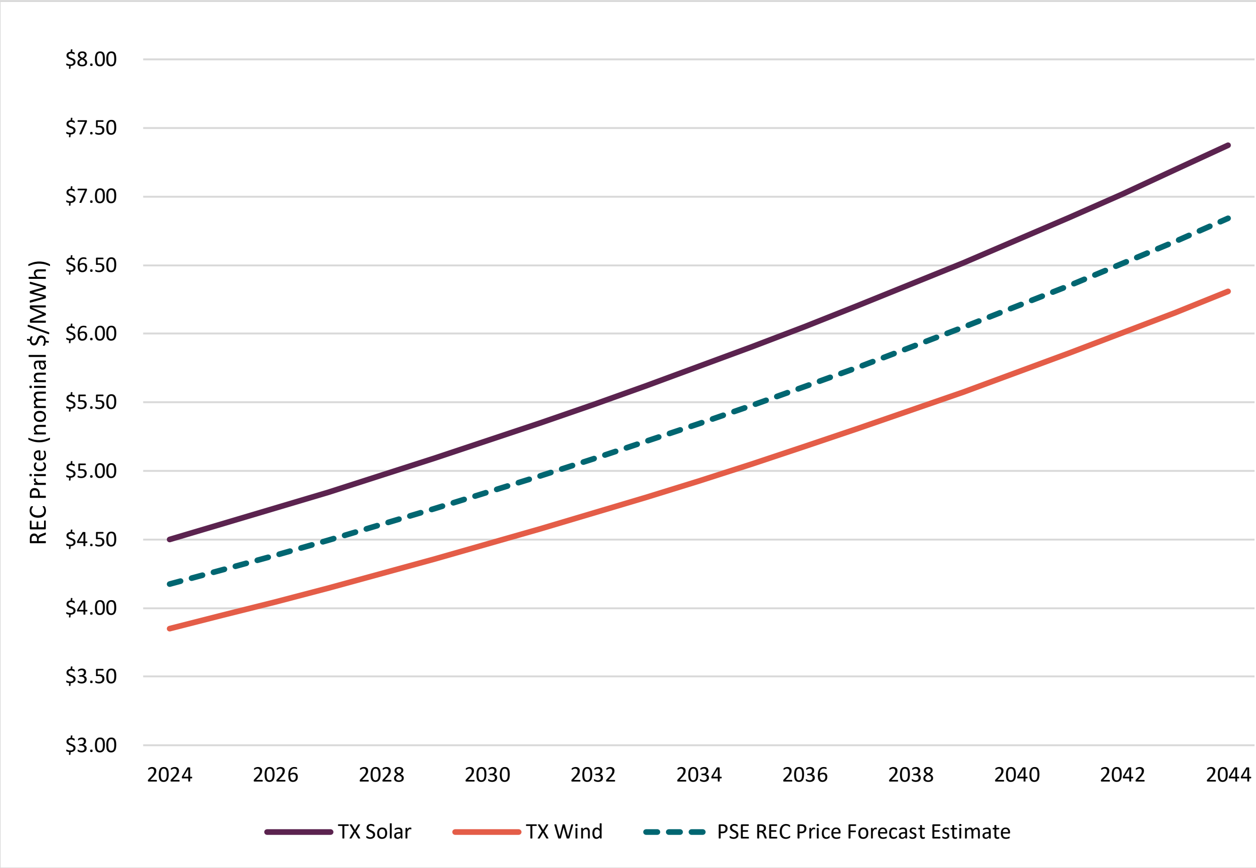
The CETA requires 100 percent greenhouse gas (GHG) neutrality by 2030, with a minimum of 80 percent of energy delivered met with renewable or non-emitting resources and the remaining energy delivered met by alternative options. Options for meeting the up to 20 percent remaining energy delivered include:

- 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
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing carbon offsets
- Purchasing unbundled renewable energy credits

This 2023 Electric Report evaluated two methods to reach 100 percent GHG neutrality by 2030. For the first option, we assumed that we would purchase unbundled renewable energy credits (RECs) for up to 20 percent of the load not met by renewable generation starting in 2030 and decreasing to zero in 2045. The quantity of unbundled RECs purchased depends on the quantity of delivered energy not met by CETA-compliant resources. For example, if a given portfolio generated 85 percent of delivered energy with CETA-compliant resources in 2030, the remaining 15 percent would be compensated by purchasing unbundled RECs to achieve greenhouse gas-neutral compliance.

We reviewed REC markets nationwide to determine a suitable price forecast for unbundled RECs. The Texas wind and solar REC markets represent a stable, high-volume market with years of data available for review. Therefore, we selected an average of the Texas wind and solar REC price forecast as the REC price for achieving GHG neutrality compliance through the purchase of unbundled RECs. Figure 5.10 shows the Texas REC prices over the modeling horizon.

Figure 5.10: Forecasted Renewable Energy Credit Price Purchased to Achieve GHG Neutrality in Nominal $ per MWh



For the second option, we wanted to understand the impact of meeting 20 percent of the load with renewable resources to meet 100 percent of PSE's load with renewable resources by 2030. We modeled sensitivity 12 which retires all existing natural gas generation by 2030 and allows for addition of only renewable resources, thereby achieving 100 percent renewable energy by 2030.

➔ See Chapter Eight: Electric Analysis for the results of sensitivity 12 in detail.

We may meet actual compliance through other mechanisms that we are still developing. We will determine these mechanisms in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. We will analyze these mechanisms as the Department of Ecology develops guidance on 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.

3. Electric Portfolio Sensitivities

Sensitivity analysis is an essential component of the IRP process. After generating a reference portfolio, which is the optimized, least-cost set of resources to meet the base set of constraints, we model sensitivities that change a resource, environmental regulation, or condition to examine the effect of the change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. In this 2023 Electric Report, we included key sensitivities necessary to develop a preferred portfolio in the analysis. We started with sensitivities that changed a single resource or assumption, such as adding more conservation programs or scheduled addition of pumped hydroelectric storage resources. These simple sensitivities provide context for how a given resource, which may not be part of the least-cost portfolio, may provide value, such as reduced greenhouse gas emissions or increased equity benefits. We then combined several of these simple changes to create diversified portfolios.

Diversified portfolios layer several minor changes to create a portfolio that provides even greater potential benefits. We modeled several diversified portfolios ranging from two to six small changes. These diversified portfolios become the candidate portfolios from which we will select a preferred portfolio based on its attributes related to cost, equity benefits, and feasibility.

The following sections provide an overview of the assumptions made for each sensitivity analyzed in this report. We provide their results and discussion in Chapter Eight: Electric Analysis. .

3.1. Reference Portfolio

The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios. We used the assumptions described in the Electric Portfolio Analysis Assumptions section to develop the reference portfolio. We refer to the reference portfolio as sensitivity 1 throughout this report.

3.2. Conservation Alternatives

Adding higher conservation measures, we analyzed two sensitivities to assess portfolio builds and cost changes.

- Reference: 258 MW of new conservation will be added to the reference portfolio by 2045.
- Sensitivity 2: This sensitivity increases new conservation measures to 486 MW by 2045, an increase of 228 MW above the reference portfolio conservation.
- Sensitivity 3: This sensitivity increases new conservation measures to 382 MW by 2045, an increase of 123 MW above the reference portfolio conservation.

The reference, sensitivity 2 and sensitivity 3 portfolios all have codes and standards included for 437 MW by 2045. New energy efficiency up to bundle 3 was selected in reference portfolio for 258 MW by 2045. Although we did not select a distribution efficiency in the reference portfolio, we included a forecasted addition of distribution efficiency in sensitivity 2 and sensitivity 3 for a total of 11 MW by 2045. We included a forecasted addition of 475 MW by 2045 of energy efficiency in sensitivity 2 by having all measures through conservation bundle 10. We included a lower amount of the forecasted addition of 371 MW by 2045 of energy efficiency in sensitivity 3 by including all measures through conservation bundle 7. Table 5.13 shows the forecasted additions for demand-side resources for the portfolios.

Table 5.13: Demand-side Resources (MW for Reference, Sensitivity 2 Bundle 10, and Sensitivity 3 Bundle 7)

MW by 2045	1 Reference	2 Bundle 10	3 Bundle 7
Codes and Standards	437	437	437
New Distribution Efficiency	0	11	11
New Energy Efficiency	258	475	371
Total	695	923	818

3.3. Distributed Energy Resources Alternatives

We analyzed two sensitivities to assess changes in portfolio builds and costs with additional distributed energy resources (DERs).

- Reference: 1,494 MW of distributed solar and 117 MW of distributed storage will be added to the reference portfolio by 2045.
- Sensitivity 4: This sensitivity adds 600 MW of additional distributed solar by 2045, resulting in 2,094 MW of distributed solar by 2045.
- Sensitivity 5: This sensitivity adds 150 MW of additional distributed storage by 2045, resulting in 267 MW of distributed storage by 2045.

The reference portfolio, sensitivity 4 and sensitivity 5, all include DER forecasts for customer-sited solar, non-wires alternatives, and new programs identified in the CEIP. Based on the results of the reference portfolio, we did not find it economical to add any additional DERs due to the higher cost relative to utility-scale resources. Sensitivity 4 explores the impact of adding distributed solar above the established forecasts by adding 30 MW of distributed rooftop solar each year from 2026 to 2045. Sensitivity 5 examines the impact of adding distributed storage above the established forecast by adding 25 MW of distributed battery storage each year from 2026 to 2031.

3.4. Pumped Hydroelectric Storage Alternatives

We analyzed three sensitivities to assess changes in portfolio builds and cost by adding pumped hydroelectric storage (PHES) resources.

- Reference: PHES is selected on an economic basis, resulting in zero MW of PHES added to the reference portfolio.

- Sensitivity 6: This sensitivity adds 200 MW of Montana PHES and 400 MW of eastern Montana wind in 2026.
- Sensitivity 7: This sensitivity adds 200 MW of Montana PHES, 200 MW of central Montana wind, and 200 MW of eastern Montana wind in 2026.
- Sensitivity 8: This sensitivity adds 200 MW Pacific Northwest PHES in 2026.

Energy storage is a critical component of a CETA-compliant portfolio. The reference portfolio selected battery storage as a cost-effective storage resource. We explored diversifying the portfolio by adding PHES and battery energy storage in sensitivities 6, 7, and 8.

In sensitivities 6 and 7, we added 200 MW of Montana PHES in 2026. Energy from Montana resources currently gets to PSE via the Colstrip transmission line. The Colstrip transmission line has an available capacity of 750 MW for PSE to use. Given this restriction, we decided to overbuild Montana resources to provide surplus energy to charge the PHES resource and simultaneously maximize the throughput of energy over the Colstrip line to PSE. In sensitivity 6, we added 400 MW of eastern Montana wind to the existing 350 MW of Clearwater wind. In sensitivity 7, we added 200 MW of eastern Montana wind and 200 MW of central Montana wind in addition to the existing 350 MW of Clearwater wind. The Montana PHES and wind resources have a combined maximum output of 750 MW (the Colstrip transmission capacity limit), and excess energy is stored in the PHES resource.

In sensitivity 8, we added 200 MW of Pacific Northwest PHES in 2026. Since transmission capacity is less constrained in Washington and Oregon, we did not model any resource overbuild in sensitivity 8.

3.5. Advanced Nuclear Small Modular Reactors

We analyzed a sensitivity that added advanced nuclear SMR to the portfolio to assess changes in builds and cost.

- Reference: Advanced nuclear SMR is selected on an economic basis, resulting in zero MW of advanced nuclear SMR added to the reference portfolio.
- Sensitivity 9: This sensitivity adds 250 MW of advanced nuclear SMR in 2032.

The reference portfolio is updated to include a forecast in 2032 of 5 units of 50 MW advanced nuclear SMR resources for 250 MW. This advanced nuclear SMR provides a combination of dispatchability, reliability, and emission-free production benefits, making it an attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

3.6. No New Thermal Resources Before 2030

We analyzed a sensitivity where new thermal resources were unavailable before 2030 to assess changes in builds and cost.

- Reference: Thermal resources include natural gas peakers, blended natural gas and hydrogen peakers, and biodiesel peakers available for economical addition throughout the modeling horizon.
- Sensitivity 10: This sensitivity limited the availability of thermal resources before the year 2030. After 2030, we permitted natural gas, blended natural gas and hydrogen and biodiesel peakers in the portfolio.

This sensitivity aims to reduce the amount of thermal, or combustion, resources added to portfolio. No combustion resources are permitted to be added to the portfolio before the year 2030.

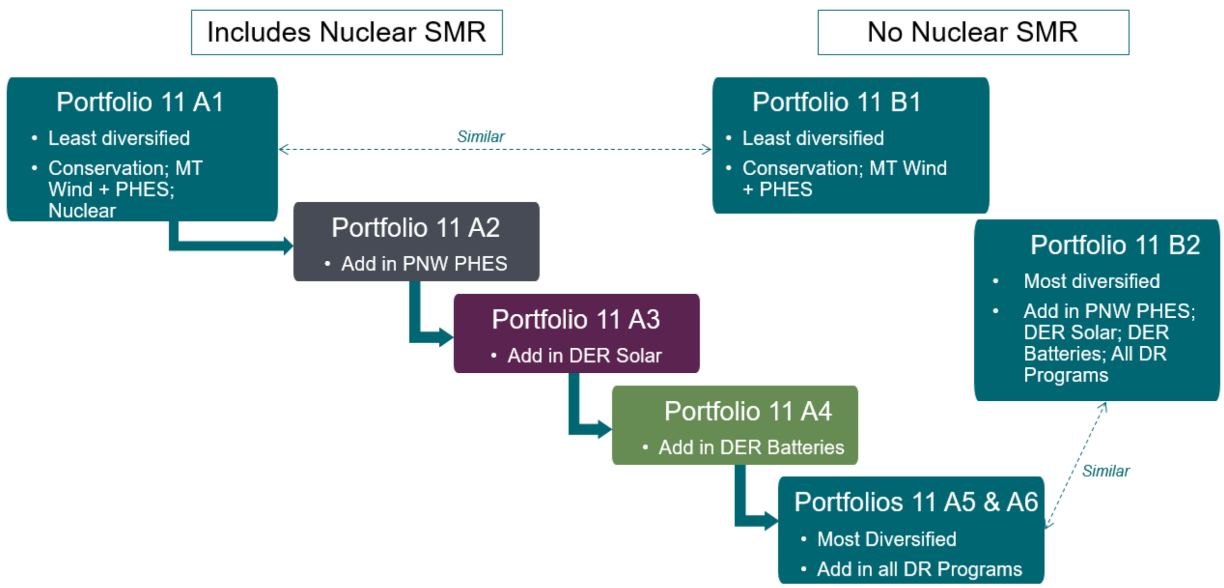
3.7. Diversified Portfolios

In comparison to the least-cost reference portfolio, the diversified portfolios broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. All diversified portfolios are based on the least-cost reference portfolio. Portfolios 11 A1 through 11 A5 explore layering in combinations of sensitivities 3 through 9. At the request of interested parties, portfolios 11 B1 and 11 B2 replicate the least and most diversified portfolios, 11 A1 and 11 A5, respectively, but without adding advanced nuclear SMR technology to the portfolio.

- Reference: New resources are acquired when cost-effective and needed.
- Sensitivity 11 A1: This sensitivity is the least diversified portfolio we developed in this report and therefore serves as the baseline diversified portfolio. Built on the least-cost reference portfolio, this portfolio increases conservation to 371 aMW by 2045 (Sensitivity 3), adds 400 MW of eastern Montana wind and 200 MW of Montana PHES in 2026 (Sensitivity 6), and adds 250 MW of advanced nuclear SMR in 2032 (Sensitivity 9).
- Sensitivity 11 A2: Same as 11 A1 but adds 200 MW of Pacific Northwest PHES in 2026 (Sensitivity 8).
- Sensitivity 11 A3: Same as 11 A2 but adds 30 MW of distributed solar resources annually from 2026 through 2045 (Sensitivity 4).
- Sensitivity 11 A4: Same as 11 A3 but adds 25 MW of distributed battery resources annually from 2026 through 2031 (Sensitivity 5).
- Sensitivity 11 A5: Same as 11 A4 but adds all demand response programs.
- Sensitivity 11 B1: Same as 11 A1 but without advanced nuclear SMR.
- Sensitivity 11 B2: Same as 11 A5 but without advanced nuclear SMR.

Figure 5.11 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 5.11: Diversified Portfolio Schema



3.8. 100 Percent Renewable and Non-emitting by 2030

This sensitivity examines the impacts of retiring all existing thermal resources by 2030 and removing the ability to build any new thermal regardless of fuel type.

- Reference: The baseline assumes we will transition existing thermal to a 30 percent hydrogen blend starting in 2030 and ramp up to 100 percent hydrogen by 2045. New thermal fueled by natural gas, biodiesel, and hydrogen are all available as new resource options.
- Sensitivity 12: All existing thermal is retired on a ramped schedule from the late 2020s to 2030. All thermal resource options, including alternative fuels, are excluded from the modeling scenario producing a portfolio that is effectively 100 percent non-emitting by 2030.

We initially assumed we would retire existing thermal options for this sensitivity and remove new thermal options. However, we needed to adjust other assumptions to facilitate the long-term capacity expansion model. Those adjustments included removing all transmission capacity constraints, expanding available quantities of each resource type, and allowing the model to build advanced nuclear SMR in 2025. We made these changes to increase access to additional resources over the reference portfolio to help meet the large capacity deficit early in the modeling horizon.

With these changes implemented, the model solved in the preliminary stages when sampling settings were relatively coarse. But when we increased the sampling resolution for the final sensitivity run, the model could not converge on a solution.

3.9. High Carbon Price

We analyzed this sensitivity to explore the impact of a higher-than-expected greenhouse gas allowance price in the market established by the Climate Commitment Act.

- Reference: We modeled an ensemble allowance price as a direct cost on greenhouse gas emissions using the Washington Department of Ecology Linkage to California from 2024 to 2029, transitioning to the mid allowance price forecast created by the California Energy Commission in 2030.
- Sensitivity 13: We used the Washington Department of Ecology price ceiling as the allowance price as a direct cost of greenhouse gas emissions.

Figure 5.4 illustrates the relationship between the PSE ensemble price and the Department of Ecology ceiling price as described in Section 2.4 of this Chapter.

3.10. No Hydrogen Fuel Available

This sensitivity examines a future where green hydrogen fuel is unavailable for the electric sector.

- Reference: Hydrogen fuel blending at a rate of 30 percent in 2030 and increasing to 100% by 2045 is available for new blended fuel peakers and existing natural gas plants.
- Sensitivity 14: Hydrogen is unavailable, so existing natural gas plants burn only natural gas, and blended fuel peakers are not available for economic addition to the portfolio.

Interest and commercialization of large-scale green hydrogen production are at an all-time high, largely thanks to production and investment tax credits established by the Inflation Reduction Act. However, green hydrogen production is not guaranteed to materialize in the volumes needed to support the electric power sector. This sensitivity assumes a future with no green hydrogen for combustion in existing or new peaking resources modeled in this report.

3.11. Social Cost of Greenhouse Gases in Dispatch

This sensitivity compares different methodologies to apply the SCGHG as externality or dispatch costs and their effect on portfolios.

- Reference: We modeled the SCGHG as an externality cost in the long-term capacity expansion (LTCE) model. We omitted the SCGHG in the dispatch decision for emitting resources in the LTCE run.
- Sensitivity 15: We modeled the SCGHG as dispatch cost in the long-term capacity expansion model. We included the SCGHG in the dispatch decision for emitting resources in the LTCE run.

We omitted the SCGHG in the dispatch decision for emitting resources in the hourly dispatch run for the Baseline and Sensitivity 15. Figure 5.3 provides the social cost of greenhouse gases.

4. Purchasing Versus Owning Electric Resources

The 2023 Electric Report determines the supply-side capacity, renewable energy, and energy need, which sets the supply-side targets for future detailed planning in the Clean Energy Implementation Plan and the acquisition process. The Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. We also considered market opportunities outside the RFP and resource-build decisions when making prudent resource acquisition decisions. The 2023 Electric Report assumes ownership of supply-side resources since the cost of power purchase agreements (PPA) is confidential.

In build-versus-buy, build refers to resource acquisitions involving asset ownership. Ownership could occur anywhere along the development cycle of a project. The company could develop or purchase the project anytime during the development cycle. Buy refers to purchasing the output of the plant through a PPA.

In general, quantitative and qualitative evaluations for build-and-buy proposals are conducted similarly in the Request for Proposal process to meet the company's needs, consistent with WAC 480-107,[16] solving for the lowest reasonable cost for customers. We evaluate qualitative project risks in the same way for both acquisitions. Quantitative evaluations for build options include ownership costs such as operating expenses, depreciation, and return on invested capital. Developers embed similar costs in the total price of PPAs, but we have no visibility on the breakdown of those costs.

The supplier of the PPA makes the financial investment for the utility. Rating agencies view PPAs as a financial obligation to the utility, representing a debt-financed capital investment in generation capacity. Rating agencies add/impute debt to the balance sheet to reflect the financial obligations to account for the company's credit exposure. The request for proposal (RFP) process includes an adjustment for imputed debt for PPAs to account for the impact on credit ratings. The cost of imputed debt is a consideration in the evaluation process but is not recoverable in rates.

The CETA provides a provision allowing for a return on expenses incurred from the PPA of no less than the authorized cost of debt and no greater than the rate of return. We did not include the PPA return in the evaluation process. The statutorily authorized PPA return has yet to be requested or approved in a General Rate Case proceeding.

Several factors could influence pricing differences between the buy and build scenarios. Independent power producers (IPP) have tax advantages over utilities since the tax rules differ. A carve-out in the tax code allows IPPs to depreciate the cost of investments upfront, whereas utilities depreciate the cost over time. This situation provides a tax shield on the front end to IPPs. Independent power producers are also more able to maximize the benefits of investment tax credits. The tax code limits the utilities' ability to fully utilize ITC for the customer benefit on ITCs on solar. Developers have more flexibility in how they finance projects with their capital structure. In the build scenario, our equipment selection and design specifications must meet PSE standards for ownership, whereas a supplier might be more inclined to be driven by cost. We can better control how the plant operates and be good community stewards when we own it.

[16] WAC 480-107

DEMAND FORECASTS
CHAPTER SIX

PUGET SOUND ENERGY

Contents

1. Introduction

The demand forecasts Puget Sound Energy (PSE) developed for this 2023 Electric Progress Report (2023 Electric Report) calculate the amount of electricity required to meet customers' needs over the more than 20-year study period, 2024–2045. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand is the total electricity needed to meet customer needs yearly (megawatt hours [MWh], or average megawatts [aMW]).
- Peak demand is the single highest hour of electricity demanded by customers each season, winter or summer (MW).

Puget Sound Energy incorporated crucial climate change data into the demand forecast for the first time in this report. We heard from interested parties that climate change is important because it affects future demand and needs, and we agree. We included climate change in the base demand forecast and in other analyses such as the stochastic scenarios.

Climate change already affects how our electricity customers use energy, and we expect that impact will increase. We expect summer and winter average and peak temperatures to get warmer. The energy and peak demand forecasts now incorporate climate change temperature effects. We also incorporated climate change in the resource adequacy (RA) analysis, the stochastic scenarios, and the conservation potential assessment (CPA). Including climate change in energy planning is crucial since it affects our customers.

Overall, we expect electric energy demand, before additional demand-side resources (DSR) identified in the 2023 Electric Report's base demand forecast, to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045. This growth rate increased our forecast from 2,551 aMW in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 Integrated Resource Plan (IRP).

We expect base peak demand before additional DSR to increase at a 1.7 percent annual growth rate, from 4,753 MW in 2024 to 6,717 MW in 2045. This rate is also faster than the 1.2 percent average annual growth rate forecasted in the 2021 IRP and resulted in higher total peak demand at the end of the study period. New customers and electric vehicles are the principal drivers of the growth. Demand from customers using electric vehicles increases residential and commercial use per customer across the entire forecast period.

The 2023 Electric Report base demand forecasts also include the effects of climate change. Warming temperatures decrease energy usage in the winter and increase it in the summer. That phenomenon increases both the winter and summer normal peak temperatures; therefore, the peak forecast includes demand decreases in the winter and increases in the summer.

Table 6.1: Drivers Included and Not Included in the Base Demand Forecasts

Drivers	Demand Forecast Before Additional DSR	Demand Forecast After Additional DSR
Climate change temperatures	Yes	Yes
PSE energy efficiency programs for 2022–2023	Yes	Yes
Codes and standards effects through 2023	Yes	Yes
Demand-side solar installed through 2023	Yes	Yes
PSE energy efficiency programs for 2024 and beyond	No	Yes
Codes and standards for 2024 and beyond (Including Bellingham natural gas ban)	No	Yes
Demand-side solar installed in 2024 and beyond	No	Yes
Electric vehicle legislation: Zero Emission Vehicle (2020) and Clean Fuel Standard (2021)	Yes	Yes
Electric vehicle legislation: Clean Cars 2030 goal (2022)	No	No
Effects of the Climate Commitment Act or additional electrification	No	No
Inflation Reduction Act effects from the investment tax credit (ITC) on behind-the-meter solar	No	Yes
Inflation Reduction Act effects for DSR projects other than solar	No	No

We prepared stochastic draws in addition to the base demand forecast to model a range of potential economic conditions, weather conditions, and modeling variance in the 2023 Electric Report analysis. These draws included variations in temperature, economic and demographic drivers, electric vehicles, and demand model uncertainty. We also used modeled climate change temperatures to project a distribution of possible future temperature-sensitive demand, thereby modeling a more comprehensive range of warmer and colder conditions than the base demand forecast.

Demand and *load* are often used interchangeably in the energy industry, but they refer to different concepts. In this IRP demand refers to the energy needed to meet customers' needs during a calendar year, including losses, and load refers to demand plus the planning margin and operating reserves required to ensure the reliable and safe operation of the electric system.

1.1. Impacts of Demand-side Resources

When we applied forward projections of additional DSR savings, as shown in Table 6.2, we reduced demand significantly. However, it is necessary to start with forecasts that do not already include forward projections of DSR savings to identify the most cost-effective amount of DSR to include in the resource plan. Throughout this chapter, charts and tables labeled before additional DSR have only DSR measures implemented before the study period begins in 2024. Charts labeled after additional DSR include the cost-effective amount of DSR we identified in the 2023 Electric Report.

1.1.1. Demand Before Demand-side Resources

Why does PSE forecast demand before DSR? The demand forecast before DSR shows us the problem. What if no one acted to change how we use energy? That is not a future we anticipate. Demand-side resources like energy efficiency and demand management programs change energy use. We expect to continue incentivizing DSR. Federal, state, and local governments will continue changing energy codes and standards, and we expect consumers to continue putting solar panels on their roofs. But how much of this will occur, and how will it change the demand forecast? To answer this question, we assume no DSR and treat DSR as a resource in the modeling process. This methodology is industry standard and set forth by WAC 480-100-620[1] as part of the content of an integrated resource plan.

Table 6.2: Effect of Demand-side Resources on Demand Forecasts

2023 Electric Report Base Demand Forecast in 2045	Before Additional DSR	After Additional DSR
Electric Energy Demand (aMW)	3,699	2,949
Electric Peak Demand (MW)	6,717	5,867

2. Climate Change

This 2023 Electric Report marks the first time PSE incorporated climate change into the base energy and peak demand forecasts. Before this 2023 Electric Report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This approach to forecasting is a common utility practice, but it does not recognize predicted climate change. This section provides a detailed description of our approach to developing a normal temperature assumption.

2.1. Priorities First

Puget Sound Energy heard and heeded the clear message from interested parties that climate change is a high priority, and we should incorporate its effects into our planning processes. It is essential to consider climate change in resource planning because PSE customers use electricity to heat in the winter and keep cool in the summer. Over time, we expect less overall heating demand and more cooling demand because of a general average warming trend. We used regional data recently developed by climate change scientists to calculate a normal temperature assumption that reflects climate change.

There are currently no industry standards or best practices for incorporating climate change into a demand forecast. The team at PSE is excited to include climate change in this report and participate in future refinements and the evolution of this methodology.

[1] WAC 480-100-620

We are incorporating climate change into the demand forecast in several ways:

- Energy demand forecast
- Peak demand forecast
- Resource adequacy (RA) analysis
- Stochastic analysis

The climate projections used in the forecast were part of a recent study conducted by the River Management Joint Operating Committee (RMJOC). The RMJOC consists of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the U.S. Bureau of Reclamation. This committee worked with climate scientists to produce many downscaled climate and hydrologic models for the Northwest region as part of their long-term planning.[2] The RMJOC chose 19 downscaled models. Each model is on the representative concentration pathway (RCP) of 8.5. An RCP is a forecast of the amount of warming to the Earth. RCP 8.5 is a high yet common warming forecast used by climate scientists. It represents more warming than other common warming forecasts, such as RCP 4.5 or 6.0.

The Northwest Power and Conservation Council (NWPCC) chose three of these 19 models to work with: CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA. The NWPCC chose these three models because they reflect a wide range of temperatures and hydrologic conditions over time. We used the three climate model projections selected by the NWPCC.

2.2. Determine Climate Change Normal Temperatures

This 2023 Electric Report marks the first time PSE incorporated climate change in the demand forecast and other aspects of planning. Since there is no industry standard approach to integrating climate change, we had to establish how to incorporate this data into our forecasts. The following section explains how we approached the challenge and the questions we asked. We also presented these questions and the analysis results to interested parties on January 20, 2022, and asked them for feedback on our approach.

2.2.1. What is Normal and Why Do We Need It?

When PSE models demand, we study the relationship between historical demand and historical temperatures because the temperature significantly impacts demand. Then, to create a demand forecast, PSE must make assumptions about future temperatures to create a future demand forecast. We refer to the assumed future temperatures as normal temperatures. For energy forecasting, the average heating degree day (HDD) and/or cooling degree day (CDD) for a month expresses the new normal temperature. We used a one-in-two occurrence of a given temperature to forecast peak demand.

We wanted to achieve three goals when we created new normal temperatures:

1. Develop an objective temperature normal, which included deciding what data to use.

[2] River Joint Management Operating Committee (RMJOC): Bonneville Power Administration, United State Army Corps of Engineers, United Stats Bureau of Reclamation (2018). Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part 1:Hydroclimate Projections and Analyses.

2. Incorporate future temperature trends into the assumptions for the base demand forecasts. We provided a scenario in the 2021 IRP with climate change temperatures, but incorporated a more comprehensive approach in this 2023 Electric Report's base demand energy and base demand peak forecasts.
3. Produce the demand forecast in the framework necessary for planning. The 2023 Electric Report's analyses have specific input requirements. For example, we could have run the demand forecast with the climate projections from each of the three models, but this would have created three base forecasts. Instead, we created one demand forecast so we did not have to run the 2023 Electric Report analyses three times.

2.2.2. Choose the Data

We considered the following questions when we decided what data to use to define a new normal temperature:

1. How many years of data should we include when calculating a new normal?

   For the base energy demand forecast, we have historically used the last 30 years of temperatures to determine the normal. This approach created a relatively stable normal, with minor changes yearly. Forecasts that use five- or 10-year derived normal can have much larger swings in the year-to-year normal, creating difficulties for planning. We wanted to avoid this difficulty, so we opted to use a 30-year calculation centered on the year of interest. We used temperatures from the prior 15 and the coming 15 years for each forecast year in the analysis. We performed this calculation for each year of the forecast.

2. Should we use one climate model to predict future temperatures or all three models the NWPCC chose to create the normal?

   Since NWPCC used three models representing a wide range of possible climate outcomes, using all the climate models allowed us to capture a broad range of possible outcomes, so we used all three.

3. Should the forecasted new normal temperature include historical data, climate model projections, or some combination of the two?

   Recent historical data is a way to link climate change projections to what has occurred recently in the region. Incorporating recent data can help determine where the forecast should start. For example, in 2021, the region saw unprecedented hot temperatures, including 107° Fahrenheit at Sea-Tac Airport on June 28, 2021. However, the climate models did not predict a temperature this high until 2035. Based on this assessment, the team at PSE used historical data and forecasted temperatures to calculate a new normal temperature.

4. Should the forecast of normal temperatures be flat, as in past IRPs, or should the forecast reflect a trend?

   We wanted to reflect average temperatures warming over time, so the normal energy forecast reflected this with increasing average temperatures in the winter and increasing average temperatures in the summers.

2.3. Normal Temperature for Energy Demand Forecast

We incorporated the normal temperatures into the base energy demand forecast models through heating degree days (HDDs) and cooling degree days (CDDs). We used the HDDs and CDDs to model future energy demand. HDDs and CDDs are standard ways to express temperatures and are used to estimate how much heating or cooling a customer may operate in response to a given daily temperature. We calculate degree days using a base temperature, typically 65°F, and the average daily temperature. For HDDs, we calculate the value as the amount the daily temperature is below 65°F, and for CDDs, it is the amount the daily temperature is above 65°F. For example, a 70°F-day will have 5 CDDs and 0 HDDs, while a 30°F-day will have 35 HDDs and 0 CDDs, using a base of 65°F. The team used the three climate models described and historical temperatures to create HDDs and CDDs. The climate models and the historical data are from NOAA's Sea-Tac Airport station.

Previously, we calculated HDDs and CDDs using the most recent 30 years of historical temperatures and used that static calculation through the forecast period, creating a flat normal temperature. For the 2023 Electric Report, we calculated the HDDs and CDDs for each year of the forecast using a different set of temperatures. We calculated HDDs and CDDs for each forecast year using temperatures from the prior 15 and the future 15 years, including the year of interest. If the previous 15 years included years where historical temperatures were available, we used historical data. We used temperatures from each of the three climate models for future years. Figures 6.1 and 6.2 show examples of the old and new normal temperatures, which include climate change.

Figure 6.1: Heating Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (HDD base temperature 65)

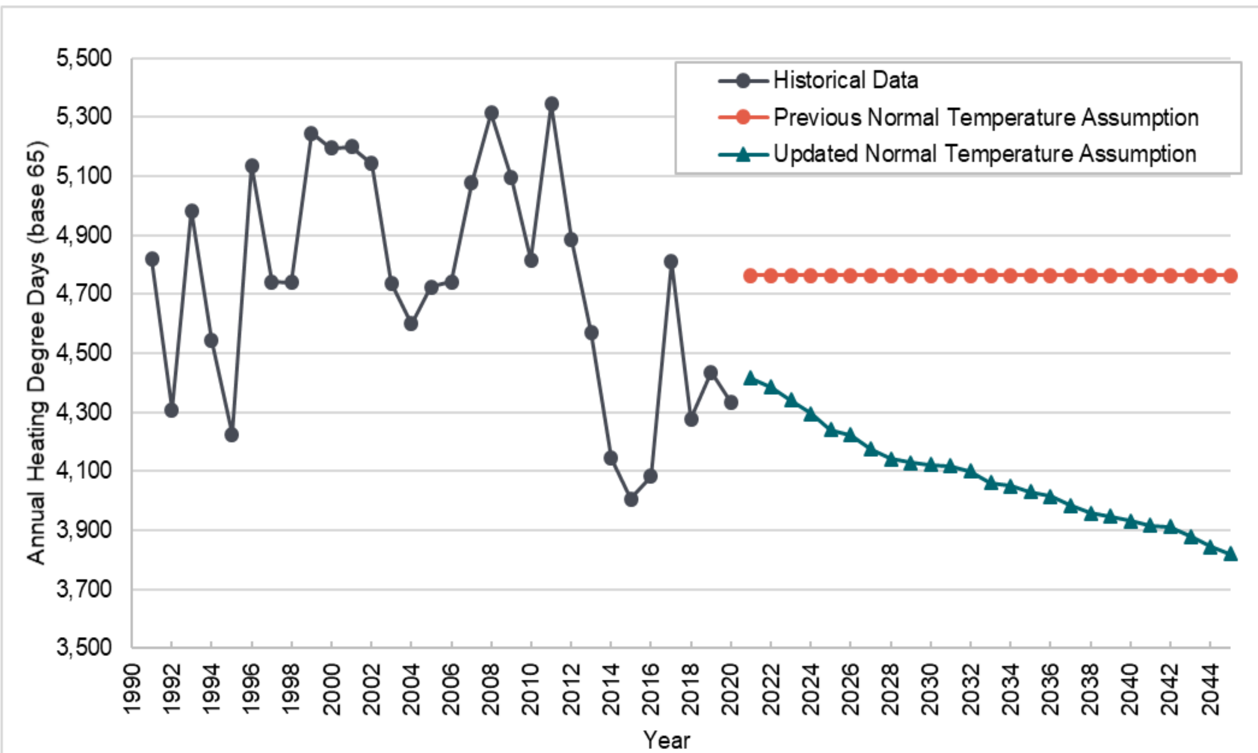
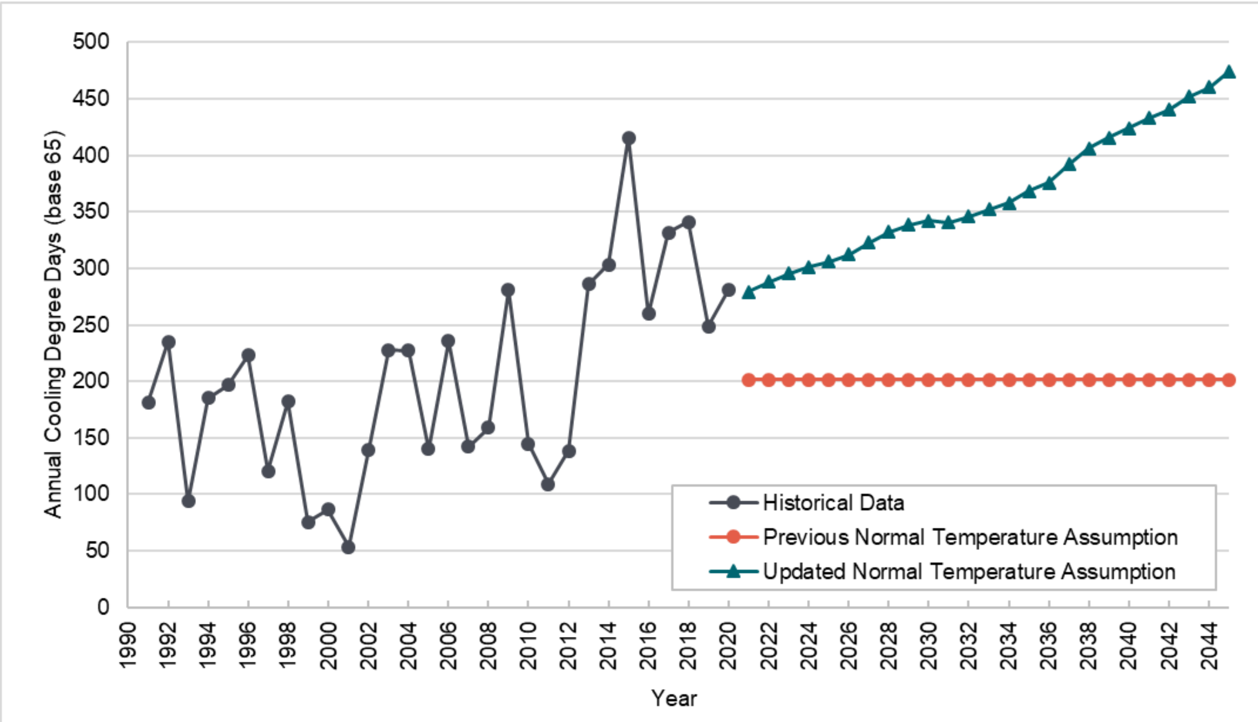


Figure 6.2: Cooling Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (CDD base temperature 65)



➔ See Appendix F: Demand Forecasting Models for more information about calculating the HDDs and CDDs that went into the demand forecast.

2.4. Normal Temperature for Peak Demand Forecast

The peak demand forecast uses a 1-in-2 seasonal peak minimum or maximum temperature during all peak hours. For the electric normal peak, we used a similar methodology as the normal energy demand forecast; we used data from 15 prior and 15 future years, including the year of interest, for the calculation. However, instead of averaging the 30 years of data for the peak, we calculated the 1-in-2 occurrence of a peak hour or median peak temperature.

We performed this calculation for each year in the forecast period: winter morning peaks, winter evening peaks, and summer peaks. The result was a 1-in-2 peak temperature of 25 in 2024, which increases to 26 degrees for winter morning peaks. For winter evening peaks, the 1-in-2 peak temperature is 27 for 2024 –2028 and rises to 28 for the rest of the forecast period. In the summer, the 1-in-2 peak is 94 for 2024–2028, 95 for 2029–2032, and 96 starting in 2033. We smoothed the peak normal temperatures to create a normal peak that increases temperature over time. We show the winter evening, winter morning, and summer peaks in Figures 6.3 and 6.4.

Figure 6.3: Normal Winter Peak Temperatures
Previous Normal and Updated Normals for Morning and Evening (ºF)

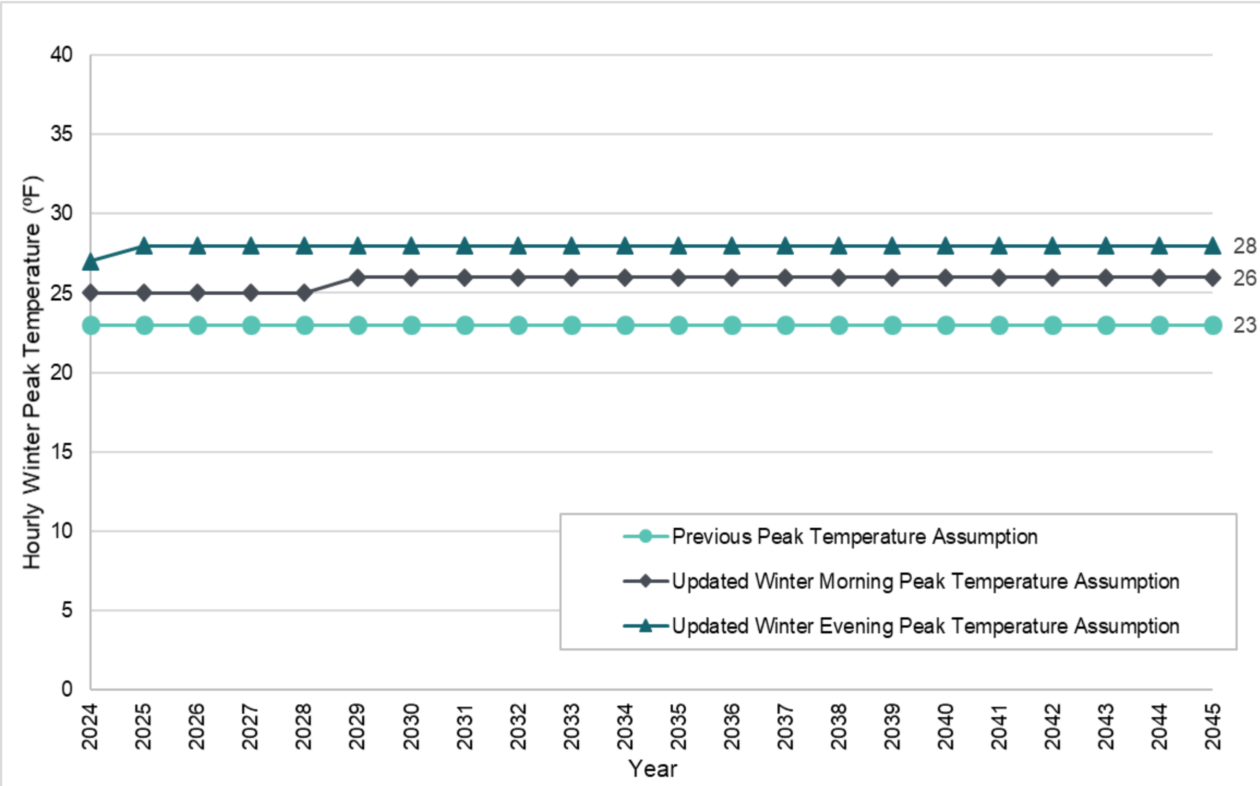
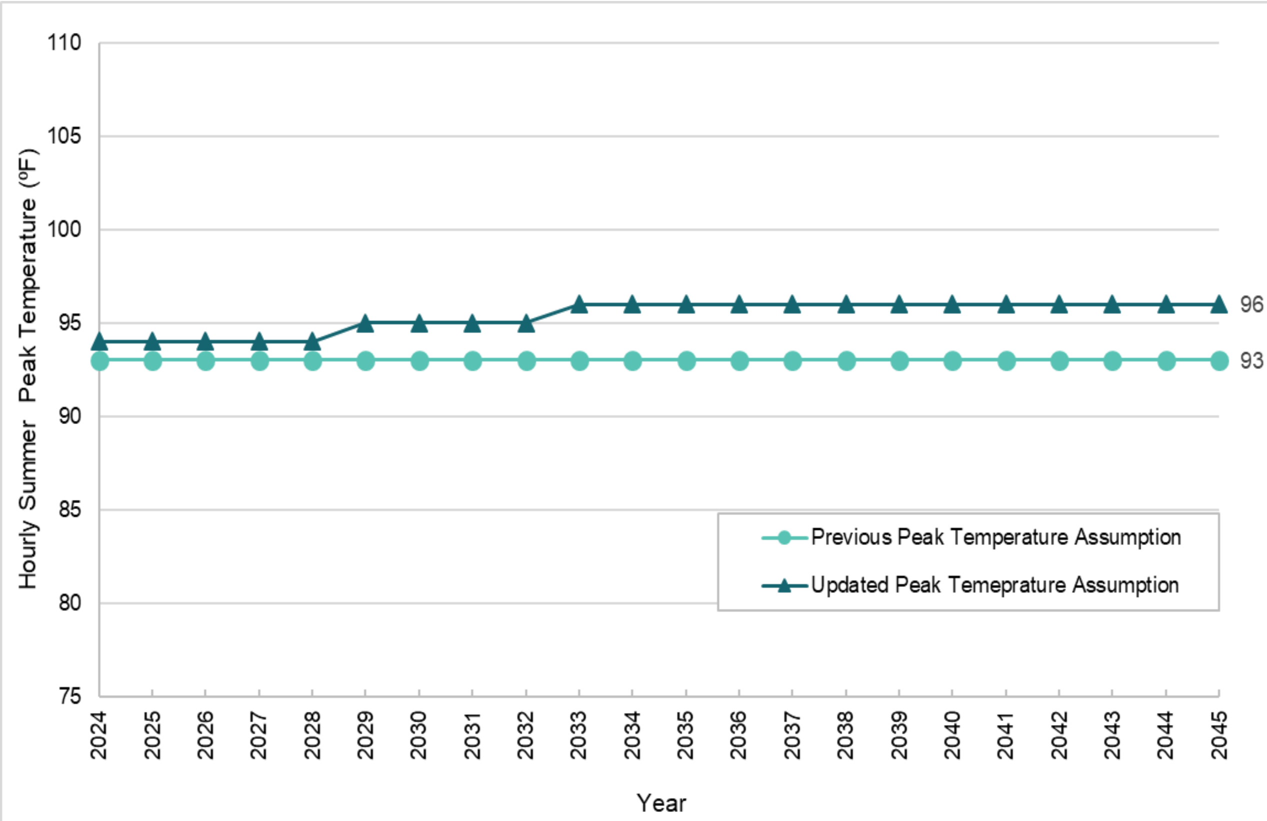


Figure 6.4: Normal Summer Peak Temperatures
Previous Normal and Updated Normal (ºF)



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the peak climate change temperature calculations.

3. Electric Demand Forecast

We present highlights of the 2023 Electric Report base demand forecast developed for the electric service area in Figures 6.5 through 6.7 and Tables 6.3 and 6.4. We summarize the population and employment assumptions for the forecast in this document's Details of Electric Forecast section and explained in detail in Appendix F: Demand Forecasting Models.

The demand forecast included only DSR measures implemented through December 2023 since the demand forecast helps determine the most cost-effective amount of DSR to include in the portfolio for subsequent periods.

3.1. Electric Energy Demand

In the 2023 Electric Report base demand forecast, we expect energy demand before additional DSR to grow at an average rate of 1.8 percent annually from 2024–2045, increasing energy demand from 2,551 aMW in 2024 to 3,699 aMW in 2045.

Puget Sound Energy serves primarily residential and commercial customers, with a minority share of energy demand associated with industrial, resale, and streetlight customer classes. Excluding losses, we projected residential and commercial customer classes to represent 49 percent and 39 percent of energy demand in 2024. During the forecast period, residential demand grows as we add new customers to the system and customers adopt electric vehicles (EVs). This demand growth is partially, but not entirely, offset by decreasing residential heating energy demand — a consequence of adopting trended normal temperatures consistent with climate change impacts.

Commercial energy demand grows similarly: we added new commercial customers to the system, and customers adopt EVs for fleet and other business purposes. The share of commercial demand associated with heating energy demand is less than residential customers; thus, climate change impacts are less severe for the commercial class.

Therefore, rising customer and EV counts drive most of the growth in energy demand and offset climate change impacts before DSR is applied.

Figure 6.5: Electric Energy Demand Forecast before Additional DSR
2023 Electric Report Base Demand Forecast versus 2021 IRP Base Demand Forecast (aMW)

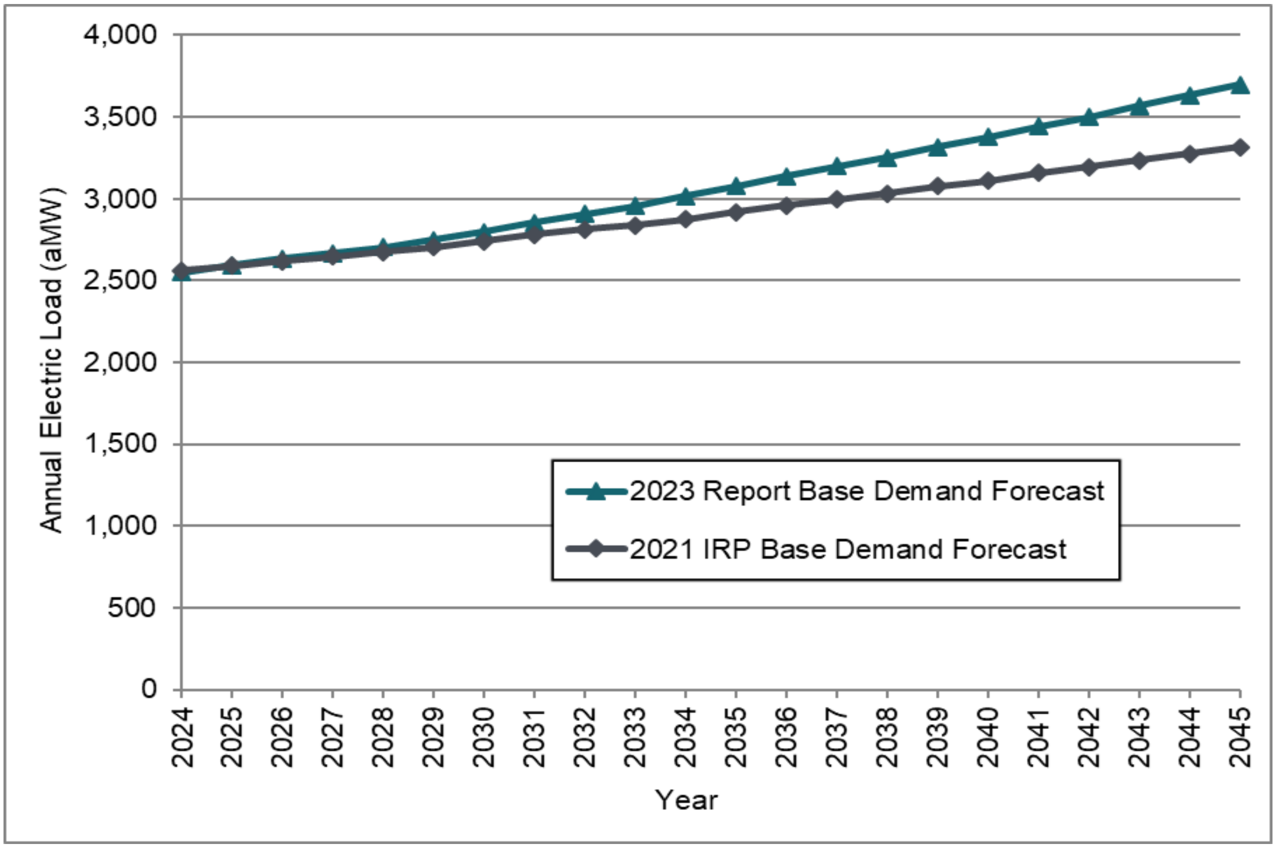


Table 6.3: Electric Energy Base Demand Forecast before Additional DSR (aMW)

Year	2024	2030	2035	2040	2045	AARG 2024-2045 (%)
Base Demand Forecast	2,551	2,799	3,076	3,378	3,699	1.8

3.2. Electric Peak Demand

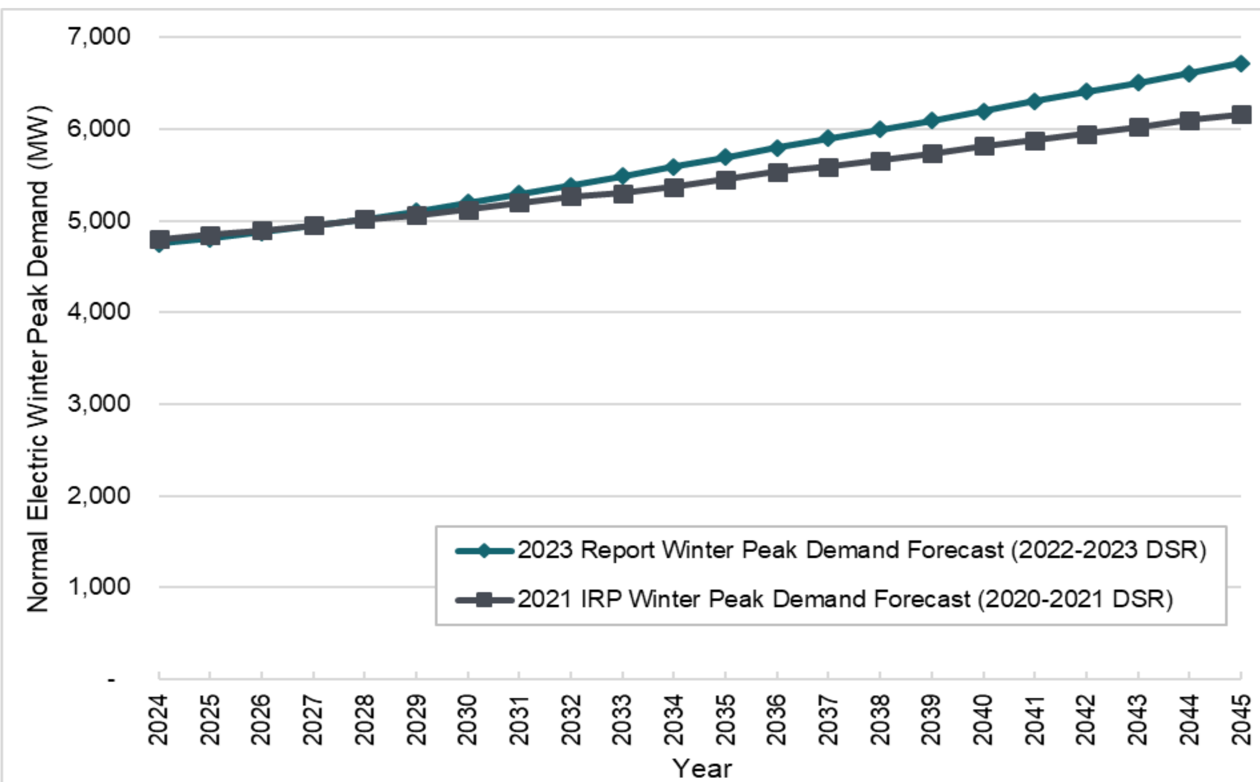
Puget Sound Energy is a winter peaking utility, which means the one hour with the highest demand of the year occurs in the winter. However, summer peaks are growing with warming summer temperatures and increased use of air conditioning and heat pumps for cooling. With the addition of data to reflect climate change modeling and the growing summer peaks, the team updated the capacity expansion model to analyze both winter and summer peaks. We provide a detailed discussion of the capacity expansion model in Appendix G, Electric Analysis Models. Different supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, we consider demand during all hours of the year in resource adequacy modeling to help determine the best resources to meet the customer load. This section describes winter and summer electric peaks.

3.2.1. Winter Electric Peak Demand

We forecasted the normal electric winter peak hour demand with specific assumptions for normal peak conditions. We modeled the winter peak demand forecast with assumptions consistent with a one-in-two probability of occurrence. We define a winter peak event as a mid-week, non-holiday, and evening occurrence in December, with a temperature that reflects the climate change analysis (27- and 28-degrees Fahrenheit). We assumed these conditions because they are the expected conditions (50 percent or 1-in-2 probability) in which a peak event will occur based on historical system characteristics, forward-looking EV demand shapes, and climate change temperature projections.

It is important to note that actual winter peak demand may occur under different conditions, such as in the morning, at different temperatures, or in another month. For the base demand forecast, however, expected conditions are assumed. Please see the discussion on stochastic peak demand and hourly demand scenarios for variation in peak event conditions. Before demand-side resources, the 2023 Electric Report's base peak demand forecast grows at an average annual growth rate of 1.7 percent. This rate would increase peak demand from 4,753 MW in 2024 to 6,717 MW in 2045.

Figure 6.6: Winter Electric Peak Demand Forecast before Additional DSR
2023 Electric Report versus 2021 IRP Base Demand Forecast Hourly Annual Peak (MW)



Winter peak demand in the 2023 Electric Report base demand forecast is higher at the end of the study period (6,717 MW in 2045) than in the 2021 IRP (6,159 MW in 2045). Additionally, the 2023 Electric Report peak demand forecast has a faster average annual growth rate (1.7 percent) than the 2021 IRP (1.2 percent).

The 2023 Electric Report peak demand forecast projects faster growth than the 2021 IRP peak demand forecast because it includes a revised EV forecast that reflects more adoption and additional vehicle classes (medium and heavy duty). Observed actual customer and sales growth in 2020 and 2021 exceeded the 2021 IRP forecast, mainly due to less severe customer growth and demand declines due to economic turmoil. These positive impacts offset the step down in the forecast due to climate change and result in a forecast that starts at a point like the 2021 IRP base peak demand forecast.

3.2.2. Summer Electric Peak Demand

The team modeled the normal electric summer peak hour demand using 94 degrees Fahrenheit (2024–2029), 95 degrees Fahrenheit (2030–2033), and 96 degrees Fahrenheit (2034–2045) as the design temperatures. Summer peaks typically occur in July or August. Figure 6.7 shows the 2023 Electric Report's base peak demand forecast for the winter and summer.

The 2023 Electric Report's base summer peak demand forecast has an average annual growth rate of 2.2 percent, increasing the summer peak demand from 3,820 MW in 2024 to 6,005 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, we assumed PSE will continue to be a winter peaking utility for the planning period of this 2023 Electric Report.

Figure 6.7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR
Hourly Annual Peak (MW)

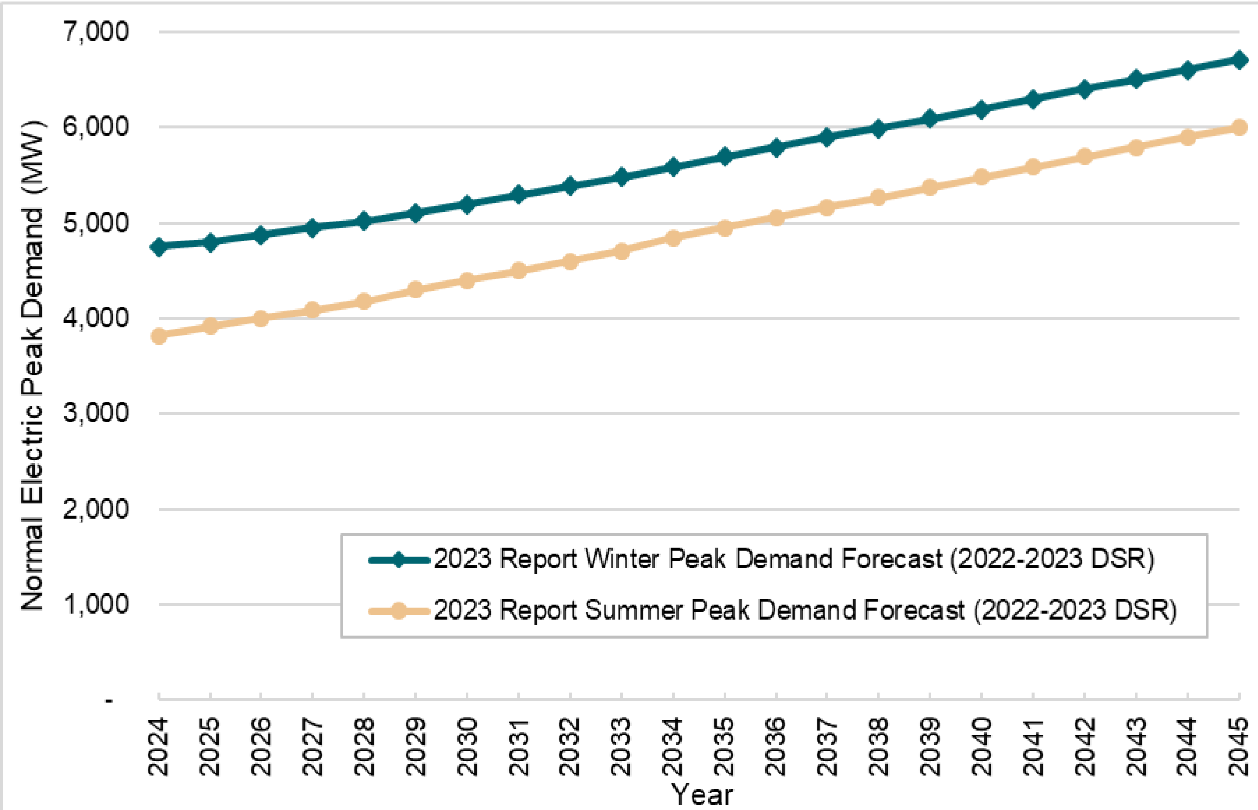


Table 6.4: Electric Peak Demand Forecast before Additional DSR
Winter and Summer Peaks, Hourly Annual Peak (MW)

Year	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Winter Demand Forecast	4,753	5,197	5,693	6,198	6,717	1.7
Summer Demand Forecast	3,820	4,401	4,953	5,481	6,005	2.2

The 2023 Electric Report's winter peak demand forecast consistently stays higher than the summer peak demand forecast for the entire planning horizon. Even with the projected higher growth rate using the climate change data for summer peak demand, the summer peak still does not come close to the winter peak. The spread between the two peaks goes from more than 900 MW in 2024 to more than 700 MW in 2045.

3.3. Impacts of Demand-side Resources

As we explained at the beginning of this chapter, the electric demand forecasts include only demand-side resources implemented through December 2023 since the demand forecast helps determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of DSR on the energy and peak forecasts, we applied the cost-effective amount of DSR determined in this 2023 Electric Report[3] to the base energy and peak demand forecasts for 2024–2045. To account for the 2013 general rate case Global Settlement,[4] we also applied an additional 5 percent of DSR for that period. Teams at PSE use forecasts with DSR for financial and system planning decisions. We illustrate the results in Figures 6.8 thru 6.10.

3.3.1. DSR Impact on Energy Demand

When we applied the DSR bundles chosen in the 2023 Electric Report portfolio analysis to the energy demand forecast:

- Electric energy demand after additional DSR grows at an average annual rate of 0.72 percent from 2024 to 2045
- Electric energy demand in 2045 will be reduced by 21 percent to 2,949 aMW

3.3.2. DSR Impact on Peak Demand

When we applied the DSR bundles chosen in the 2023 portfolio analysis to the winter evening and summer peak demand forecast:

- Electric system winter peak demand in 2045 is reduced 13 percent to 5,867 MW
- Electric system winter peak demand after additional DSR grows at an average annual rate of 1.0 percent from 2024 to 2045
- Electric system summer peak demand in 2045 is reduced 17 percent to 5,003 MW
- Electric system summer peak demand after additional DSR grows at an average annual rate of 1.3 percent from 2024 to 2045

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

[4] For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and To Record Accounting Entries Associated With the Mechanism, Docket UE-121697 and UG-121705, Washington Utilities and Transportation Commission. Page 73 Line 162.

Figure 6.8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Additional DSR

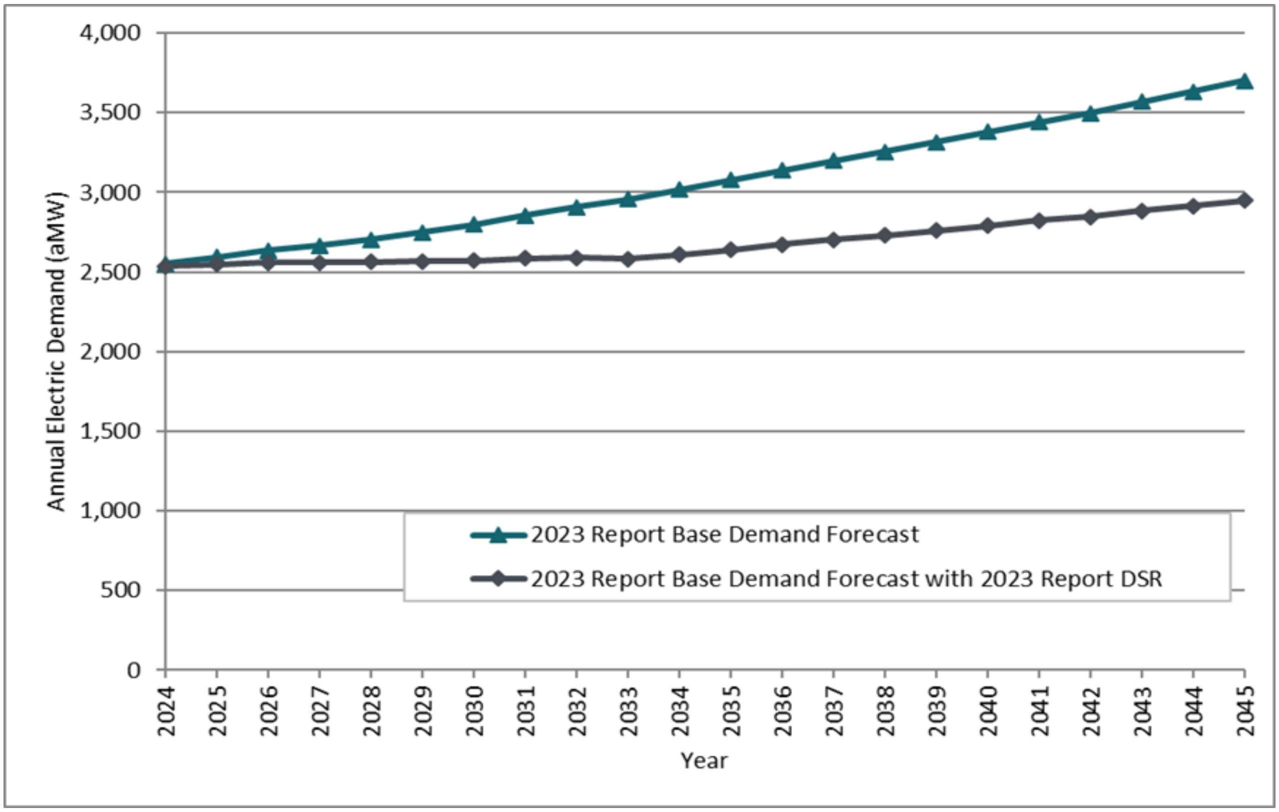


Figure 6.9: Electric Winter Peak Demand Forecast (MW), before Additional DSR and after Additional DSR

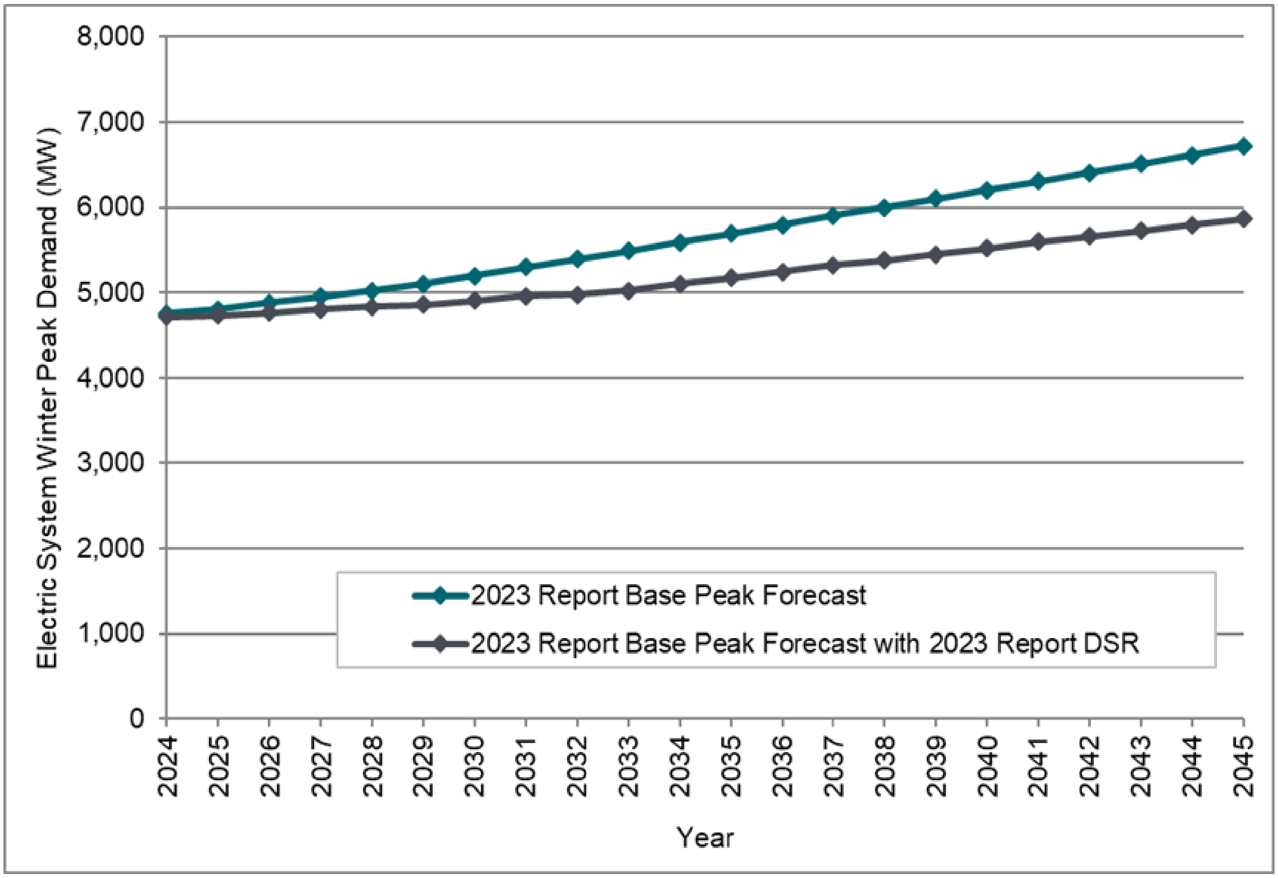
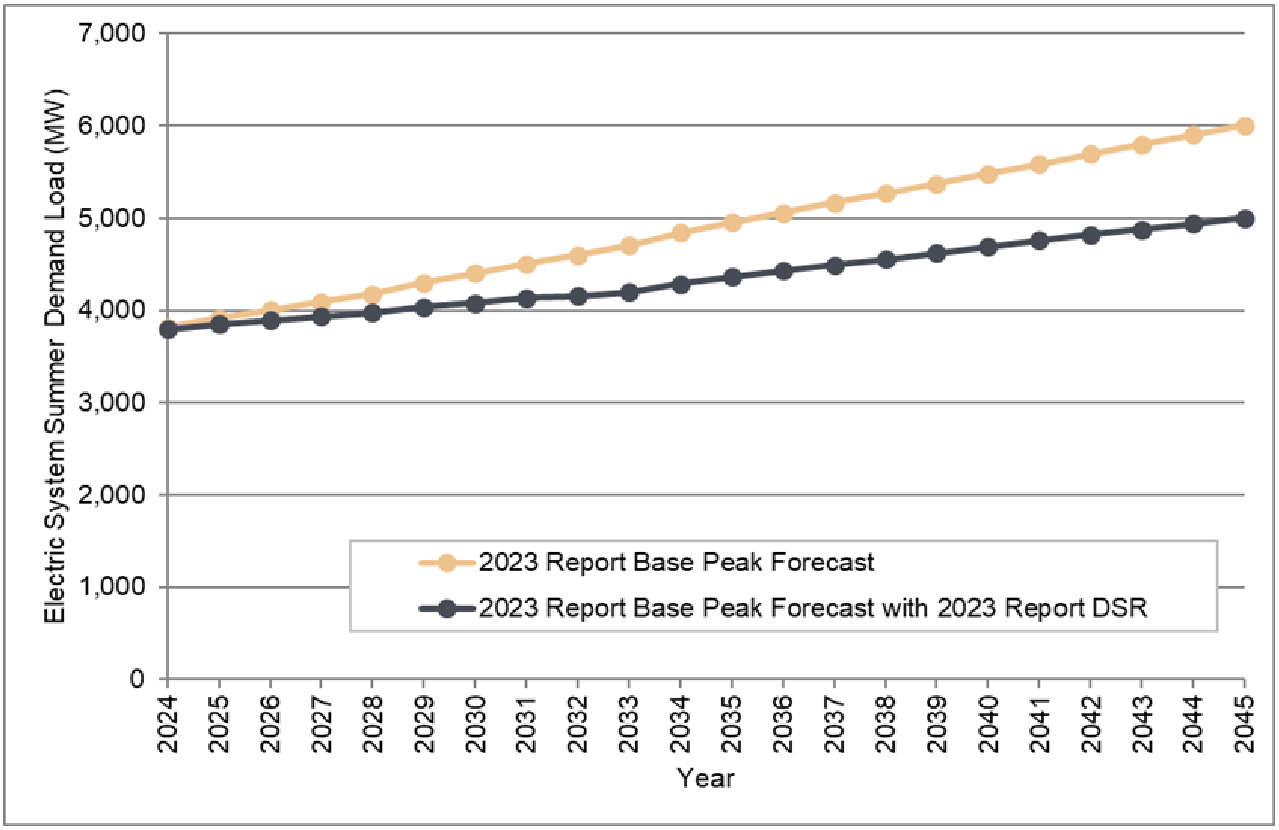


Figure 6.10: Electric Summer Peak Demand Forecast (MW), before Additional DSR and after Additional DSR



3.4. Details of the Electric Forecast

The electric forecast is comprised of demand from several different classes. These classes are residential, commercial, industrial, streetlight, and resale. We show details of each class in the following section.

3.4.1. Electric Customer Counts

We expect system-level customer counts to grow by 1.1 percent per year, from 1.25 million customers in 2024 to 1.57 million in 2045. This rate is faster than the average annual growth rate of 1.0 percent projected in the 2021 IRP base demand forecast.

Residential customers are PSE's largest customer class, with an approximately 88 percent share of electric customers by 2024. During the forecast period from 2024 to 2045, we expect residential customer counts to grow at an average annual rate of 1.1 percent per year. Commercial customers are PSE's second largest customer class, around 11 percent of total customers, and are expected to grow at an average annual rate of 1.3 percent per year over the forecast period. Industrial customer counts, around 0.3 percent of total customers, are expected to decline, following the historical trend of declining industrial activities in the service area. We expect these trends to continue as the economy in PSE's service area shifts toward more commercial and less industrial business sectors.

Table 6.5: December Electric Customer Counts by Class, 2023 Report Base Demand Forecast

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	1,251,677	1,344,744	1,421,065	1,495,183	1,571,637	1.1
Residential	1,101,482	1,182,249	1,247,366	1,309,627	1,373,711	1.1
Commercial	138,449	149,815	160,282	171,484	183,126	1.3
Industrial	3,195	3,093	3,016	2,945	2,869	-0.5
Other	8,543	9,579	10,393	11,119	11,923	1.6

3.4.2. Electric Demand by Class

Over the next 20 years, we expect the residential and commercial classes to have positive demand growth, with the commercial class growing faster than the residential class before additional DSR. New customers and our projected rate of EV adoption create residential and commercial class demand growth.

Table 6.6: Electric Energy Demand by Class, 2023 Report Base Demand Forecast Before Additional DSR

Class	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Total	2,551	2,799	3,076	3,378	3,699	1.8
Residential	1,245	1,379	1,517	1,652	1,763	1.7
Commercial	986	1,085	1,204	1,349	1,534	2.1
Industrial	113	108	106	104	103	-0.5
Other	8	8	9	9	10	1.3
Losses	199	218	240	263	289	-

3.4.3. Electric Use per Customer

We expect residential use per customer, before additional DSR, to increase over the forecast period. Before EV adoption and climate change assumptions, residential use per customer is flat, but new demand from EVs outpaces usage losses due to lower normal HDDs due to the climate change update, resulting in positive net average use per customer demand growth. We expect commercial use per customer to increase over the forecast period due to EV adoption and higher normal CDDs. The non-residential classes have a lower share of energy demand devoted to heating, thus, are less impacted in the winter by lower normal HDDs.

Table 6.7: Electric Use per Customer, 2023 Report Base Demand Forecast Before Additional DSR

Type	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Residential	10.0	10.3	10.7	11.1	11.3	0.5
Commercial	62.8	63.7	66.1	69.4	73.7	0.7
Industrial	310.6	306.6	308.6	311.1	312.2	-0.1

3.4.4. Electric Customer Count and Energy Demand Share by Class

Table 6.8 shows customer counts as a percent of PSE's total electric customers. We show demand share by class in Table 6.9. We expect the share of residential customers and demand to remain stable over the forecast period before adjustment by the final DSR in the report analysis.

Table 6.8: December Customer Count Share by Class

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	88.00	87.41
Commercial	11.06	11.65
Industrial	0.26	0.18
Other	0.68	0.76

Table 6.9: Energy Demand Share by Class, Before Additional DSR

Class	Share in 2024 (%)	Share in 2045 (%)
Residential	48.79	47.67
Commercial	38.67	41.49
Industrial	4.44	2.77
Other	0.30	0.27
Losses	7.80	7.80

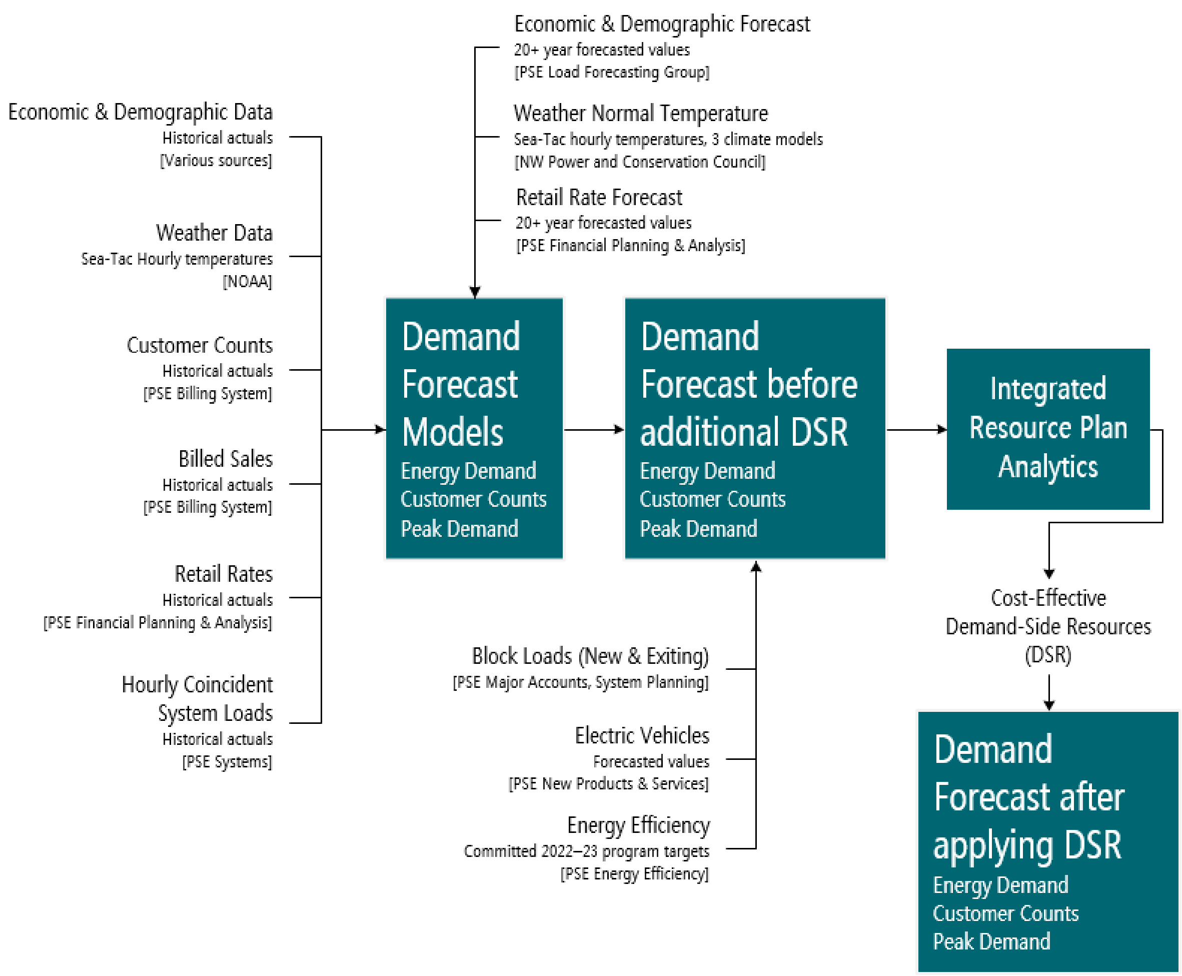
4. Methodology

We create relationships between historical growth and historical conditions to forecast customer demand. Therefore, we can use forecasted future conditions to forecast future growth. In the following section, we discuss how we forecasted demand.

4.1. Forecasting Process

Our regional economic and demographic model uses national and regional data to forecast total employment, employment types, unemployment, personal income, households, and consumer price index (CPI) for the PSE electric service area. We built the regional economic and demographic data used in the model from county-level information acquired from various sources. This economic and demographic information is combined with other PSE internal information to produce the base energy and peak demand forecasts for the service area. We illustrate the demand forecasting process in Figure 6.11 and list the economic and demographic input data sources in Table 6.10.

Figure 6.11: PSE Demand Forecasting Process



We divided customers into classes and service levels that use energy for similar purposes and at comparable retail rates to forecast energy sales and customer counts. We modeled the different classes and service levels using variables specific to their usage patterns. Electric customer classes include residential, commercial, industrial, streetlights, and resale. Although PSE provides electric transmission services to customers who purchase power from third-party suppliers, we did not include demand from these customers in the 2023 Electric Report's demand forecast.

We used multivariate time series econometric regression equations to derive historical relationships between trends and drivers and then employed them to forecast the number of customers and use per customer by class or service level. We multiplied these factors to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, HDDs, CDDs, total employment, manufacturing employment, CPI, and U.S. Gross Domestic Product (GDP). We calculated demand from sales and included transmission and distribution losses in addition to sales. We based weather inputs on NOAA temperature readings at Sea-Tac Airport and incorporated historical and forecasted temperatures, including the effects of climate change. We also projected peak system demand by evaluating the historical relationship between actual peaks, the temperature at peaks, average system demand, day of the week, time of day, holidays, and estimated air conditioning trends. We forecasted peak demand with the future temperature at peak plus expected EV peak demand growth.

➔ See Appendix F: Demand Forecasting Models for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak demand, hourly distribution of electric demand, and forecast uncertainty.

Table 6.10: Sources for County Economic and Demographic Data in Economic and Demographic Model

County-level Data	Source
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from the Quarterly Census of Employment and Wages esd.wa.gov/labormarketinfo
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Population	WA State Employment Security Department (WA ESD) esd.wa.gov/labormarketinfo/report-library
Households, single- and multi-family	U.S. Census www.census.gov
Household size, single- and multi-family	U.S. Census www.census.gov
Aerospace employment, Regional Consumer Price Index (CPI)	Puget Sound Economic Forecaster www.economicforecaster.com

We obtained country-level economic and demographic data from Moody's Analytics.[5] The inputs into PSE's economic and demographic model from Moody's Analytics are gross domestic product (GDP), industrial production index, employment, unemployment rate, personal income, wages and salary disbursements, consumer price index (CPI), housing starts, population, conventional mortgage rate, and the three-month T-bill rate.

4.2. Stochastic Scenarios

We used stochastic analysis[6] to look at variability in our assumptions. We developed 310 stochastic scenarios to examine changes in the economic, demographic, electric vehicle, and temperature assumptions. We also examined model uncertainty in the stochastics. These 310 alternate future pathways for customer growth, energy demand per customer, and peak demand let us test the portfolio to see how it responds to conditions other than the base demand.

5 economy.com
6 Stochastic scenarios are created with a randomly determined set of inputs, which creates a probability distribution.

We created and ran 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions. We show the range of the stochastics in Figures 6.12 through 6.14. Energy demand in 2045 ranges from 2,724 aMW to 4,743 aMW in the energy stochastic scenarios. Winter peak demand in 2045 ranges from 5,160 MW to 8,551 MW, and summer peak demand in 2045 ranges from 4,438 MW to 7,171 MW in the peak stochastic scenarios.

We develop stochastic simulations with outputs from PSE's economic and demographic model, variation in underlying econometric model uncertainty, electric vehicle adoption, and future temperatures from three climate models. We modeled electric energy and peak demand stochastic scenarios using 310 stochastic simulations. The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment, and income. The simulations also capture model uncertainty through stochastic variation of model statistics associated with underlying econometric models of average energy demand per customer, customer growth, and peak demand. We held electric vehicle assumptions constant in 250 scenarios, applied a high EV forecast to 30 scenarios with high economic outlooks relating to total employment, and applied a low EV forecast to another 30 scenarios with low economic scenarios with respect to total employment.

The stochastic scenarios use future temperatures from the CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA models, reflecting higher or lower temperature conditions. We sampled forecasted temperature years 2020–2049 from the three models for the 310 draws.

We ran the 310 electric stochastic scenarios in the AURORA portfolio model to test the portfolio's robustness under various conditions.

➔ Detailed descriptions of the stochastics are available in Chapter Eight: Electric Analysis.

Figure 6.12: Range of Energy Demand in Stochastic Scenarios Around Base Energy Demand Forecast (aMW) Before Additional DSR

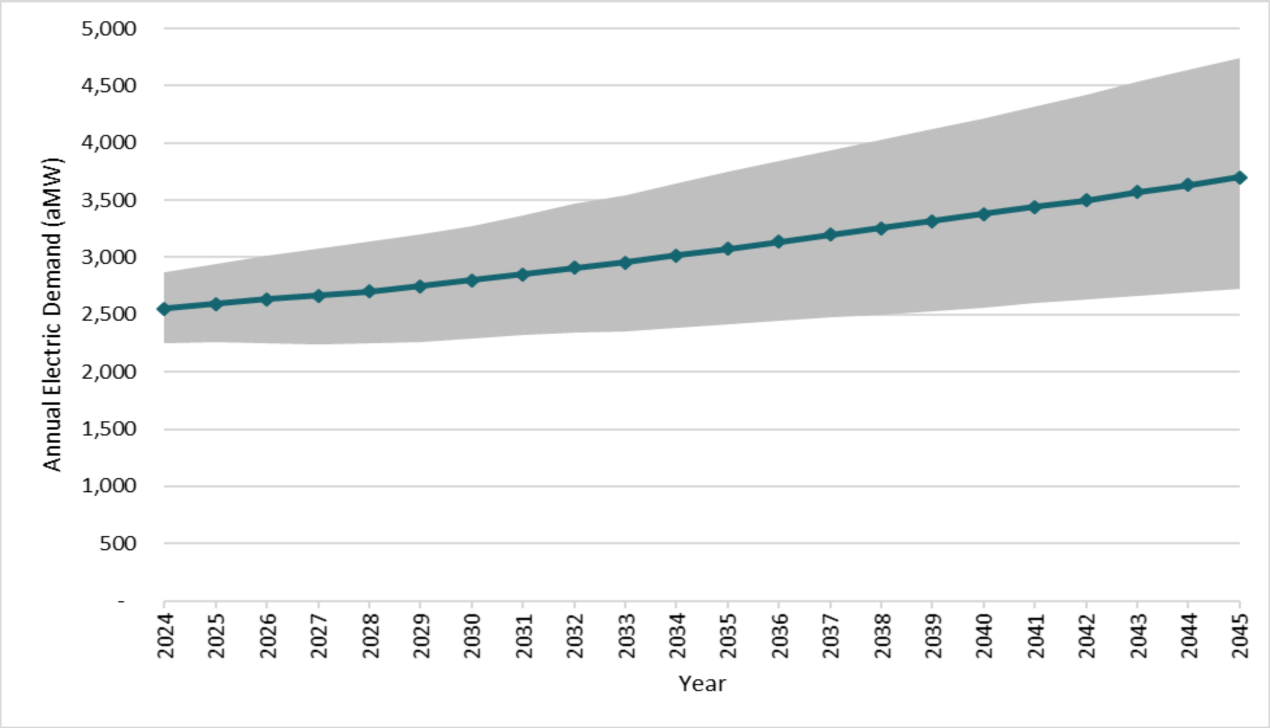


Figure 6.13: Range of Winter Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR

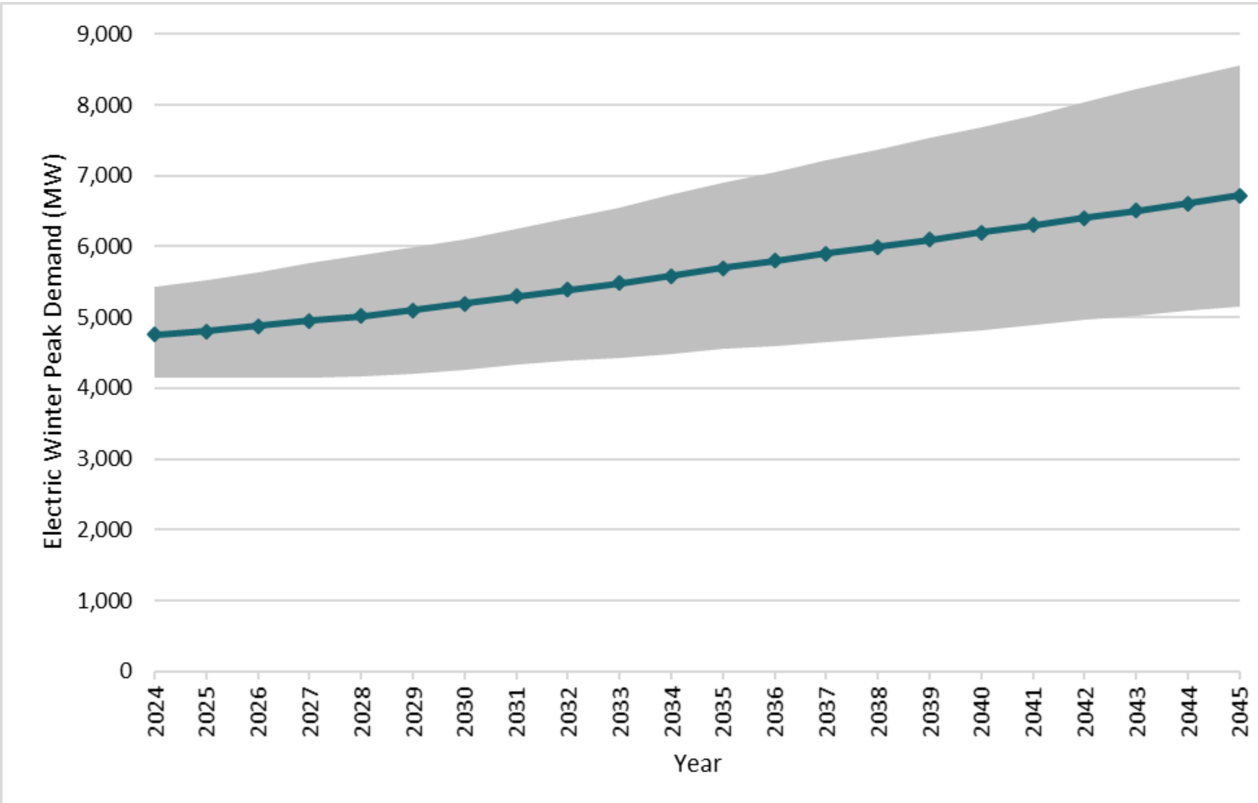
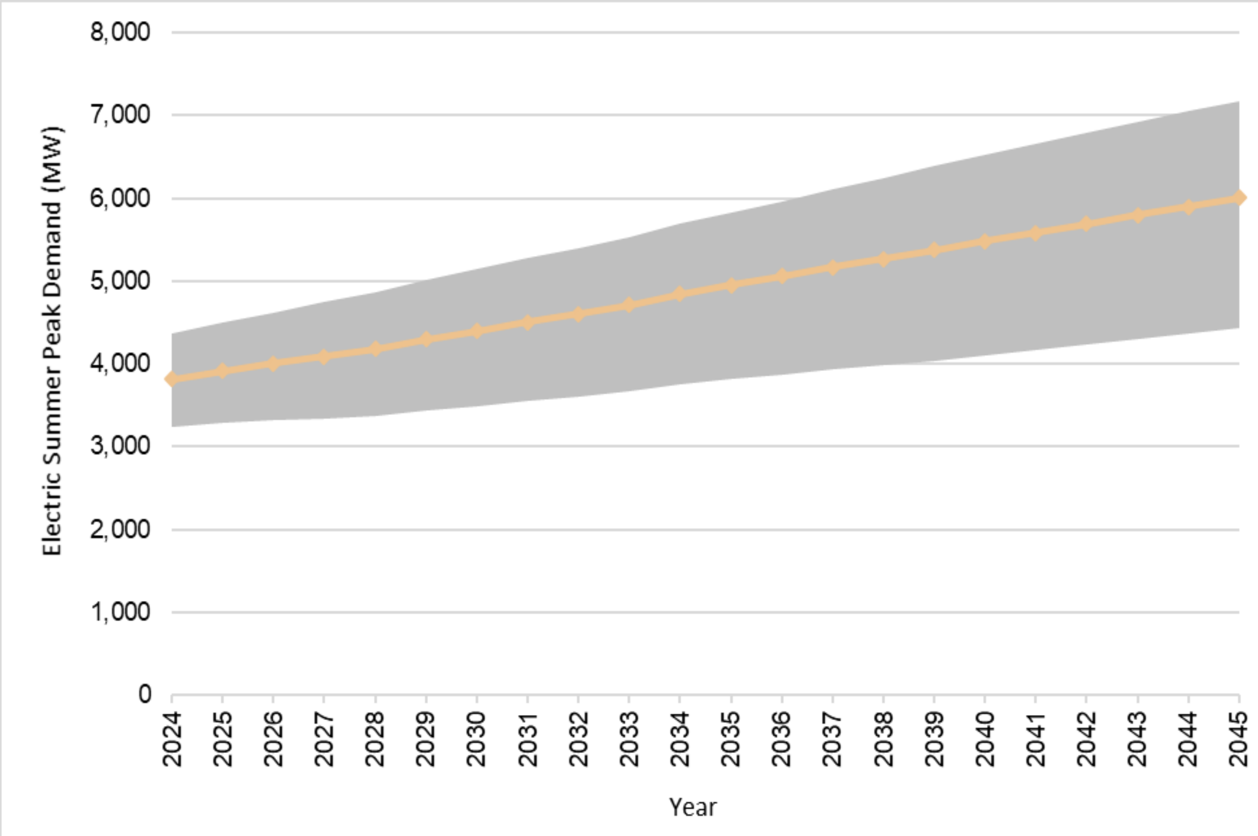


Figure 6.14: Range of Summer Peak Demand in Stochastic Scenarios around Base Peak Demand Forecast (MW) Before Additional DSR



➔ See Appendix F: Demand Forecasting Models for a detailed discussion of the stochastic simulations.

4.3. Resource Adequacy Model Inputs

In addition to the stochastic scenarios mentioned in the previous section, we also developed 90 electric demand draws for the resource adequacy (RA) model. We created these demand draws with stochastic outputs from PSE's economic and demographic model and two consecutive future weather years using the future temperatures from the climate change models. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each future heating season. We created RA demand draws for the hydro years 2028–2029 and 2033–2034.

The RA model also examines adequacy in each hour of a given year; therefore, we scaled the 90 demand draws we used for RA model inputs to hourly demand using the hourly demand model. We created each of the 90 hourly demand forecasts without electric vehicle demand to account for growth in electric vehicles, then added the hourly forecast of electric vehicle demand to each demand forecast to create the final 90 hourly demand forecasts.

We highlight the differences between the RA model inputs and the stochastic scenarios in Table 6.11.

Table 6.11: Differences between the Resource Adequacy Model Inputs and the Stochastic Scenarios

Analysis Attribute	Stochastic Scenarios	Resource Adequacy Model
Number of draws	310	90
Forecasted years	2024–2045	October 2028–September 2029 and October 2033–September 2034
Model detail level	Monthly demand and peak demand	Hourly demand
Economic and demographic variation	Included	Included
Climate change impacts	Yes	Yes
Temperature assumptions	Forecasted temperatures from years 2020–2049 were sampled from the three climate change models — one year chosen for each draw	Forecasted temperatures from years 2020–2049 were used from the three climate change models — two consecutive weather years were chosen for each draw
Electric vehicles	Base forecast used in 250 draws, high used in 30 draws, low used in 30 draws	Base forecast used in each draw
Electrification and other conversion policies	No	No
Purpose	Used in the AURORA portfolio model to test the robustness of the portfolio under various conditions	Used in the resource adequacy modeling that determines the effective load-carrying capabilities (ELCCs)

➔ See Chapter Seven: Resource Adequacy Analysis, and Appendix F: Demand Forecasting Models for a detailed discussion of the hourly model.

4.4. Updates to Inputs and Equations

The following section summarizes updates to the demand forecast inputs and equations made since the 2021 IRP.

4.4.1. Climate Change Forecast

Previous IRPs used the most recent 30 years of historical temperatures to forecast what temperatures will be during the forecast. In this 2023 Electric Report, we used three climate change models by the NWPCC to establish an assumption of future normal temperatures. Section 2 Climate Change of this chapter details how we developed and used climate models in the forecast of this chapter details how we developed and used climate models in the forecast.

4.4.2. Peak Modeling of Morning versus Evening

This 2023 Electric Report explicitly assumes an evening peak and its temperature impacts. Although a winter peak may occur in the morning or the evening, current characteristics of PSE's system demand indicate, on a weather and day-of-week normalized basis, higher levels of demand in the evening (around 200 MW) compared to the morning. This finding is consistent with historically observed December peaks (hour ending 18 on a weekday). Additionally, in the future forecast period, as the EV forecast grows, the difference between morning and evening peaks grows to be more than a few hundred MWs with larger EV peak demand in the evening, thus further decreasing the long-term likelihood of a morning peak occurrence. As part of our evaluation of the climate change temperature models, we recognized that the one-in-two minimum seasonal, hourly temperature for a winter evening is warmer than the morning. Hence, we calculated the typical effect of this assumption in the climate change datasets, which results in around two-degree warming to reflect evening conditions. This update reduced the winter peak demand forecast. This assumption does not impact summer peak temperature projections, as summer peaks always occur in the evening when the temperature is warmest.

4.4.3. 2018 Washington State Energy Code

The 2018 Washington State energy code change took effect in 2021. We considered the impact of this code change from 2021 through 2023 in the 2023 Electric Report forecast to understand the starting point for the forecast in 2024. The Conservation Potential Assessment (CPA) will determine the effects of this code change starting in 2024 and will also include the statutory requirement for the Washington State code cycle to make the code more stringent in terms of energy use. The law requires that the WA State code be improved in each code cycle update to achieve a 70 percent reduction in energy use by 2031 compared to the 2006 WA State code baseline. Therefore, a small amount of this code change is in the forecast, but we will account for most of this code change after the additional DSR forecast.

5. Key Assumptions

To develop PSE's demand forecasts, we must make assumptions about economic growth, energy prices, weather, and loss factors, including certain system-specific conditions. We describe these and other assumptions in the following section.

5.1. Economic Growth

Economic activity has a significant effect on long-term energy demand. Although 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 and cooling, water heating, lighting, cooking, dishwashing, clothes washing, electric vehicles, and other electric plug loads. The growth in the 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 other plug loads. Energy is also a critical input into many industrial production processes. Economic activities in the commercial and industrial sectors are, therefore, essential indicators for the overall trends in energy consumption.

5.1.1. National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the 2023 Electric Report 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. We used the November 2021 Moody's forecast for this 2023 Electric Report.

The Moody's forecast predicts:

- The economy will continue to recover from the COVID-19 pandemic with a return to full employment in 2023, and labor force participation will continue to increase as workers get healthy and children get vaccines.
- The recovery will continue through 2025. After 2025, Moody's predicts the economy will grow modestly in the long term.
- U.S. GDP will continue to grow over the forecast period with a 2.0 percent average annual growth from 2024–2045. This growth rate is lower than the Moody's forecast used in the 2021 IRP, which projected 2.2 percent average annual growth, but some of the 2021 IRP growth was from the projected recovery from COVID-19.

Moody's identified possible risks that could affect the accuracy of this forecast:[7]

- In the near term, supply constraints could cause the economy to grow less quickly.
- Rising long-term interest rates could cause a slump in the economic recovery.
- The congressional stimulus for COVID-19 could be smaller than predicted or not provide the boost to the economy that is predicted.
- The economic effects of COVID-19 are still unpredictable; additional waves that elude the vaccine could halt recovery.

5.1.2. Population Outlook

The Washington State Employment Security Department (WA ESD) average annual growth rate for the counties that make up the electric service area is 0.88 percent for 2024–2045. This rate is down from the 1.0 percent growth rate forecast in the 2021 IRP 2022–2045.

5.1.3. Regional Economic Outlook

We prepare regional economic and demographic forecasts using econometric models based on historical economic data for our service area counties and the United States macroeconomic forecasts.

Puget Sound Energy's electric service area stretches from south Puget Sound to the Canadian border and from central Washington's Kittitas Valley west to the Kitsap Peninsula. Puget Sound Energy serves more than 1.2 million electric customers in eight counties.

[7] Moody's Analytics (2021, November) Forecast Risks. Precis U.S. Macro. Volume 26 Number 8.

Within PSE's service area, demand growth is uneven. Most economic growth is driven by high-tech, information technology, or retail (including online retail). Supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for the largest share of the system electric sales demand today. Other counties are growing, but typically at lower magnitudes, and have added fewer jobs.

We used the following forecast assumptions in the 2023 Electric Report base electric demand forecast:

- We expect an inflow of 898,000 new residents (by birth or migration) to increase the local area population to 5.33 million by 2045, for an average annual growth rate of 0.88 percent. This growth rate is slightly lower than the 2021 IRP forecast, which projected an average annual population growth of 0.9 percent that would have resulted in 5.13 million electric service area residents by 2045.
- We expect employment to grow at an average annual rate of 0.46 percent between 2024 and 2045, smaller than the 0.6 percent annual growth rate forecasted in the 2021 IRP.
- We expect local employers to create about 205,681 total jobs between 2024 and 2045, mainly driven by growth in the commercial sector, compared to about 310,000 jobs forecasted in the 2021 IRP.
- We expect manufacturing employment to decline by 0.32 percent annually between 2024–2050 due to outsourcing manufacturing processes to lower wages or less expensive states or countries and the continuing trend of capital investments that increase productivity.

Table 6.12 shows the population and employment forecasts for PSE's electric service area.

Table 6.12: Population and Employment Growth, Electric Service Counties (1,000s)

Model Driver	2024	2030	2035	2040	2045	AARG 2024–2045 (%)
Population	4,436	4,716	4,938	5,136	5,334	0.88
Employment	2,215	2,291	2,340	2,380	2,421	0.46

5.2. Weather

In this 2023 Electric Report, PSE incorporated Climate Change temperatures from three climate models to calculate the normal temperatures for the base energy demand forecast and the design peak temperature for the base peak demand forecast. Section 2 Climate Change of this chapter and Appendix F: Demand Forecasting Models discuss more details of how we created this forecast.

➔ Appendix F: Demand Forecasting Models discusses more details of how we created this forecast.

5.3. Electric Vehicles

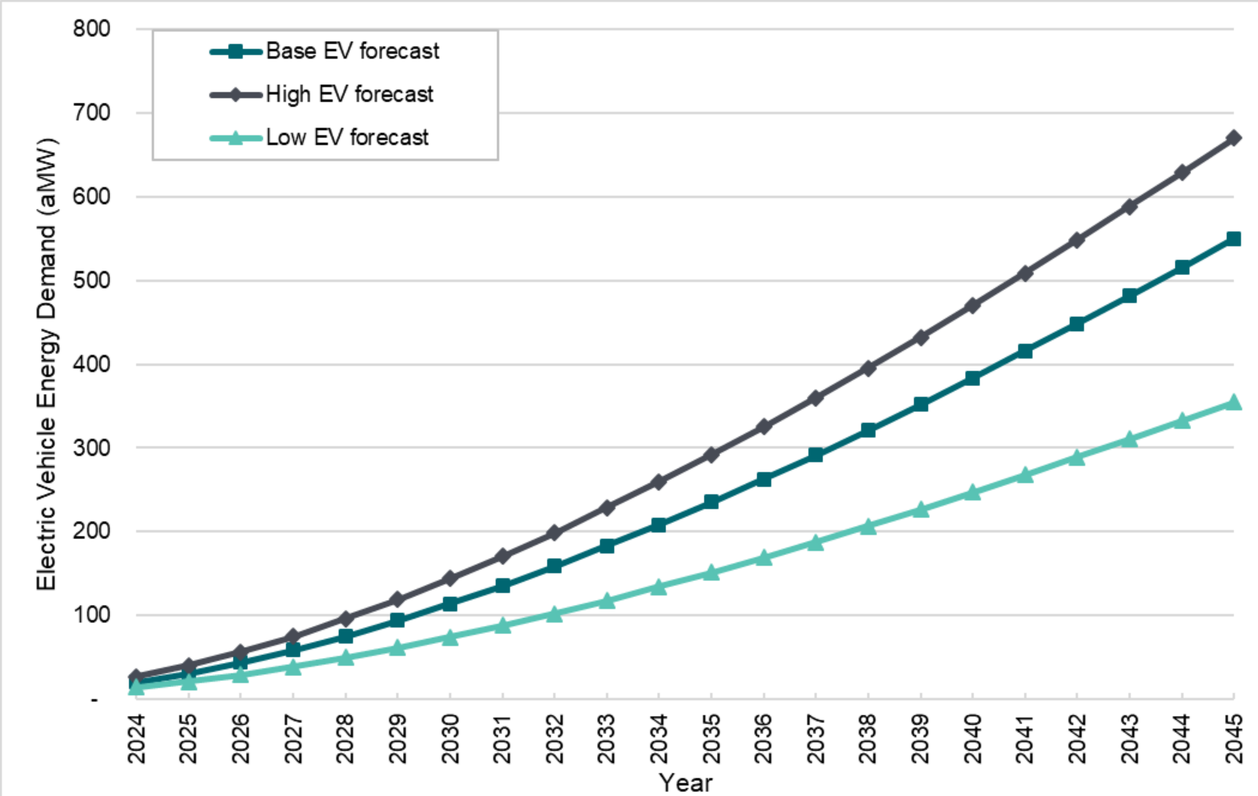
The energy consulting firm Guidehouse created an EV forecast for PSE in late 2021. This EV forecast includes two recent pieces of legislation: the Zero Emission Vehicles law of 2020 and the Clean Fuel Standard law of 2021. The forecast assumes 95,000 EVs on the road in PSE's service area in 2024, including light-, medium-, and heavy-duty vehicles. This forecast will increase to 1,147,000 EVs in 2045. Annual energy sales from new electric vehicles total 183,000 MWh in 2024 and 4,815,000 MWh in 2045.

We assumed that 74 percent of the charging from new EVs would be at residential locations, while the remaining 26 percent would be at commercial sites. This percentage changes during the forecast period as charging at commercial locations becomes more widely available. This percentage also changes as more medium- and heavy-duty electric vehicles become available and cost-effective, resulting in 35 percent of EVs charging on residential accounts and 65 percent charging on commercial accounts in 2045. Electric vehicles, especially medium- and heavy-duty models, are an emerging technology; thus, we anticipate we will revise this forecast on an ongoing basis.

The additional demand from electric vehicles grows to a 19 percent share of total peak demand by 2045 before including the cost-effective DSR identified in the 2023 Electric Report. Figure 6.15 shows the December evening peak demand, and Figure 6.16 shows the annual average energy demand from new electric vehicles. Figure 6.17 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Guidehouse also created high and low EV forecasts for PSE in late 2021. The consulting firm created the high and low EV scenarios representing the 90th and 10th percentile. Figures 6.15 and 6.16 show the high and low electric vehicle energy and peak forecasts used in the stochastic scenarios.

Figure 6.15: Electric Vehicle Average Energy Demand from New Vehicles (aMW)
Base, High, and Low



PSE PUGET SOUND ENERGY

Figure 6.16: Electric Vehicle Peak Demand from New Vehicles (MW)
Base, High, and Low

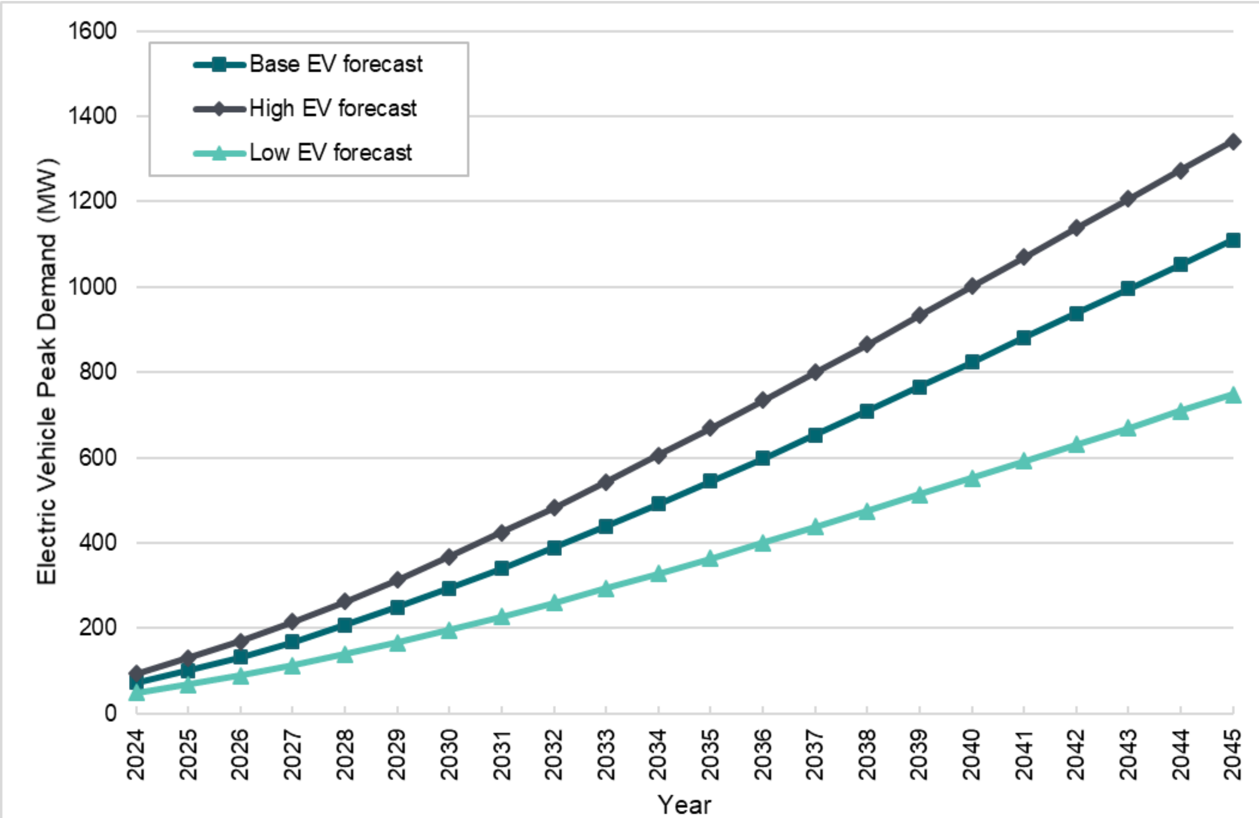
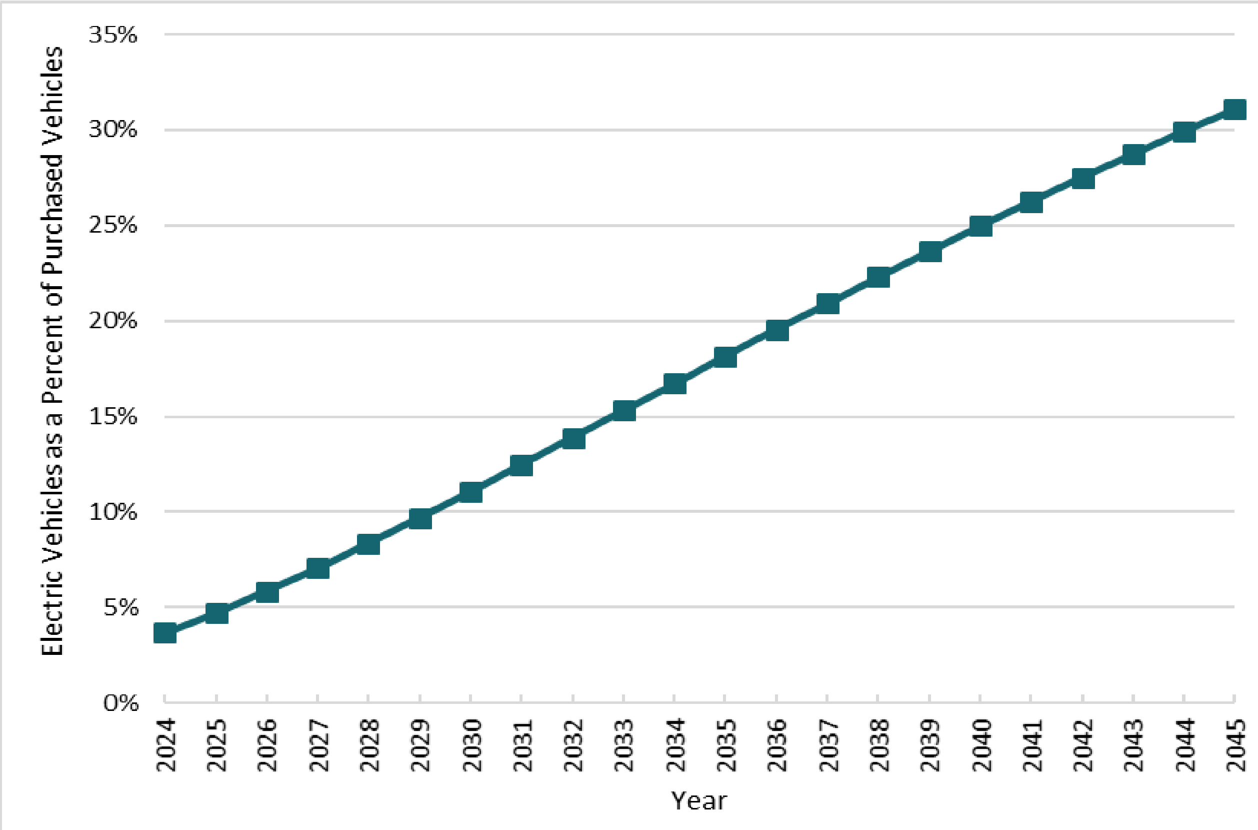


Figure 6.17: Electric Vehicles as a Percent of Purchased Vehicles



5.4. COVID-19 Impacts

After 2022, we made no explicit COVID-19 or remote work adjustments above and beyond the effects of the economic forecast incorporated into the demand forecast using the macroeconomic variables. The result is 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. There exists a great deal of uncertainty around the steady state level of residential and commercial usage once behaviors developed during the pandemic settle.

We performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes. Since the 2023 Electric Report determines the resource need starting in 2024, the stochastic simulations show alternative ways the pandemic could resolve in the future.

5.5. Loss Factors

The electric loss factor is 7.8 percent. The loss factors we assumed in the demand forecast are system-wide average losses during normal operations for the past two to three years.

5.6. Block Load Additions

Beyond typical economic change, the demand forecast also considers known major demand additions and deletions that we would not account for through typical demand growth in the forecast. Most of these additions are from major infrastructure projects. These additions to the forecast are called block loads, and they use the information provided by PSE's system planners or major accounts. The adjustments to non-transport customers will add 85.6 MW of connected demand by 2025 for the electric system. We included these block loads in the commercial class, and King County has most of the additions.

5.7. Schedule Switching

In addition to block loads, PSE accounts for customers switching rate schedules. Customers who purchase their own electricity are called transport customers, and they rely on PSE for distribution services. In this 2023 Electric Report, we removed transport customers from the forecast before determining supply-side resource needs because PSE is not responsible for acquiring supply resources for electric transport customers.

5.8. Interruptible Demand

Puget Sound Energy has 151 electric interruptible customers; six are commercial and industrial customers, and 145 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 12 MW of coincident peak demand. In this 2023 Electric Report, we accounted for the 12 MW of demand that is interruptible from these customers

5.9. Retail Rates

We included retail energy prices — what customers pay for energy — as explanatory variables in the demand forecast models because they affect customer choices about the efficiency level of newly acquired appliances and how they are used — the energy source used to power them. The retail rate forecasts draw on information obtained from internal and external sources.

5.10. Distributed Generation

We did not include distributed generation, including customer-level generation via solar panels, in the demand forecast after 2023; we captured this energy production in the 2023 Electric Report modeling process as a demand-side resource. We include a description in Appendix E: Conservation Potential Assessment and Demand Response Assessment. .

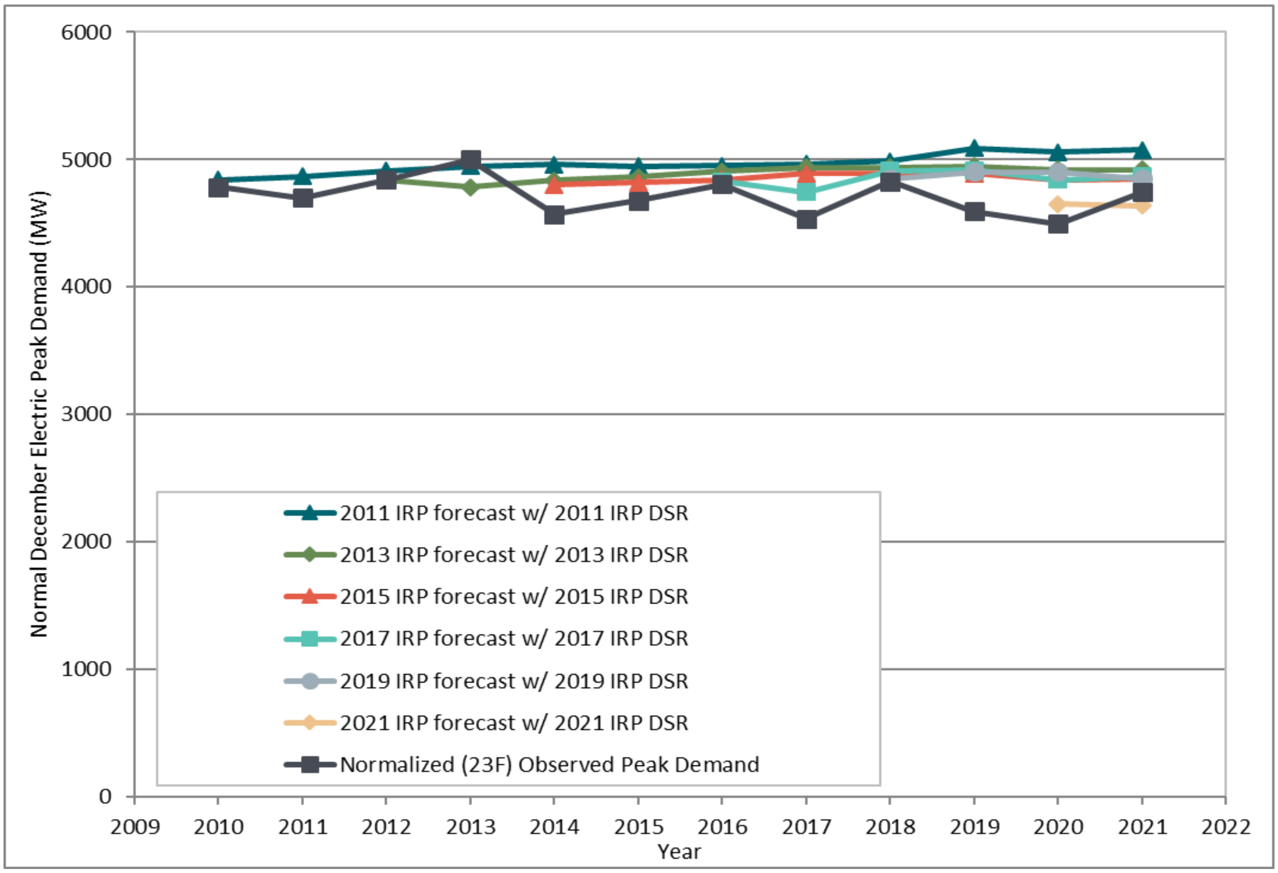
6. Previous Demand Forecasts

The following section compares actual peak demand to previous IRP forecasts. This section also identifies reasons prior forecasts may be off from current weather-normalized actual peaks.

6.1. IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6.18 compares 2011, 2013, 2015, 2017, 2019,[8] and 2021 IRPs' base peak demand forecasts after additional DSR with normalized[9] actual observations. We noted that the normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of the week and time of day of the actual peak. We present the percent difference of normalized actual values compared to each IRP forecast for each year in Table 6.12.

Figure 6.18: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



8 A formal IRP was not filed by PSE in 2019. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the WUTC held an Open Meeting concerning this matter and subsequently issued Order 2, exempting PSE (and other investor owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report in 2019.

9 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.

Table 6.12: Weather Normalized December Electric Peak Demand and Difference from Previous IRP Forecasts

Year	2011 (%)	2013 (%)	2015 (%)	2017 (%)	2019[8] (%)	2021 (%)
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	-
2020	12.6	9.5	7.7	7.7	9.1	3.5
2021	7.1	3.8	2.2	2.6	2.8	-2.2

6.1.1. Reasons for Forecast Variance

As explained throughout this chapter, we based the IRP peak demand forecasts on forecasts of key demand drivers, including expected economic and demographic behavior, DSR, customer usage, and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. As forecasts age, assumptions and conditions may change. Because of these changes, we expect older predictions to be farther off from observed actuals than more recent forecasts. We explain these differences in the next section.

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. We pushed out a complete recovery with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare Moody's forecasts of U.S. housing starts and population growth that we incorporated in the 2011 IRP through the 2019 IRP 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. Puget Sound Energy now uses county population forecasts sourced from Washington's ESD to forecast the population in PSE's service area. We included Moody's forecast of housing starts and population from May 2020 and Nov 2021 in Figures 6.19 and 6.20 for comparison.

Additionally, while the Moody's forecast used in the 2019 IRP did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects of the COVID-19 pandemic. Therefore, Moody's forecasts used before the 2021 IRP have likely overestimated economic growth in 2020, 2021, and 2022. The pandemic's repercussions on the economy and energy demand will likely be unknown during this reporting cycle.

Figure 6.19: Moody's Forecasts of U.S. Housing Starts Compared to Actual U.S. Housing Starts

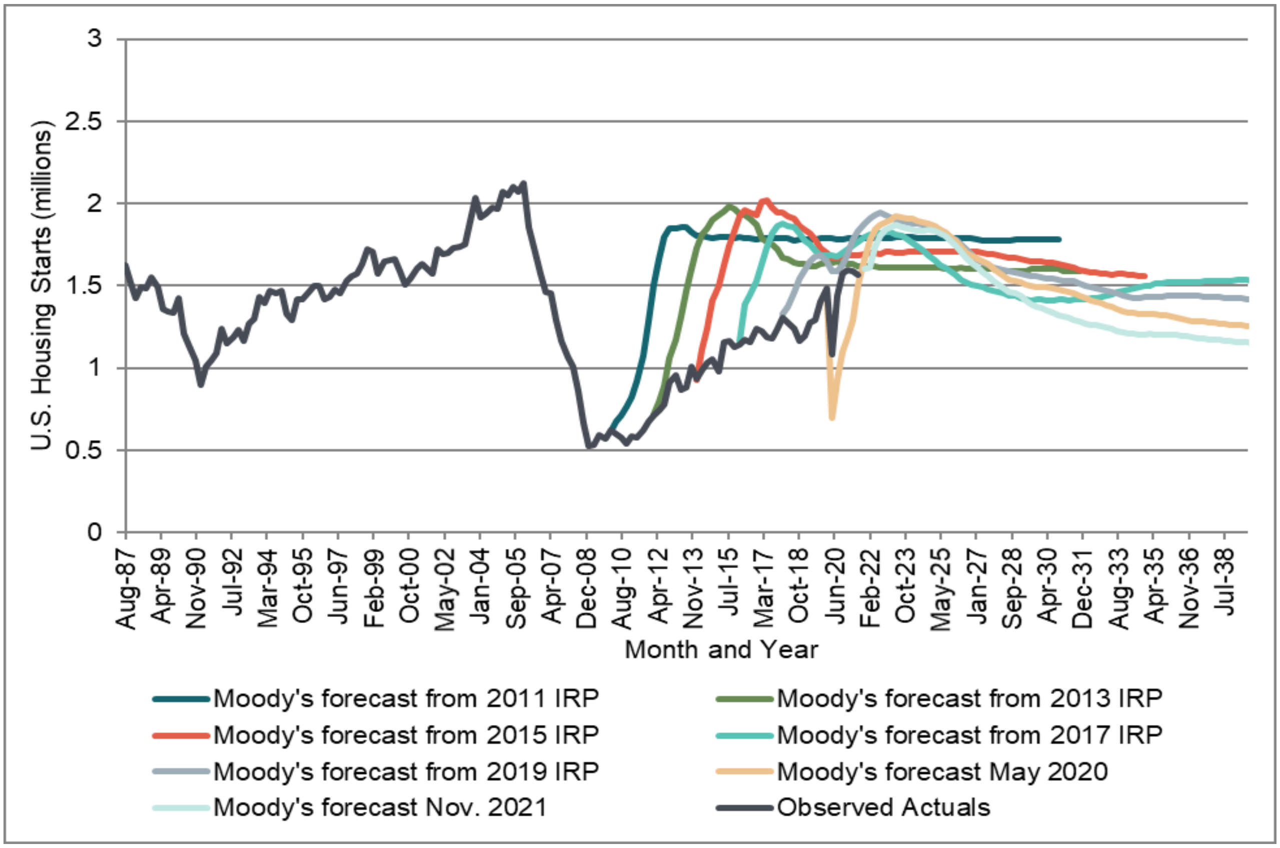
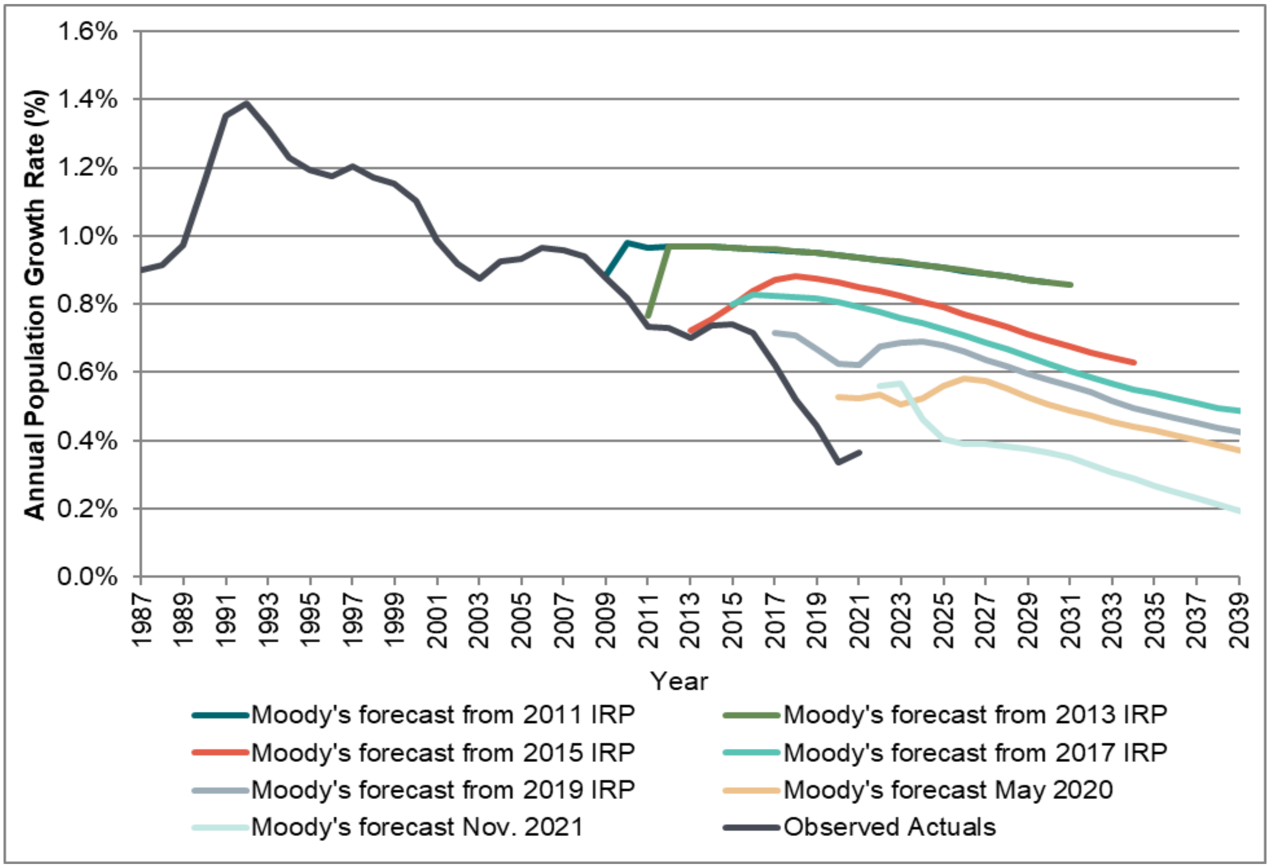


Figure 6.20: Moody's Forecasts of U.S. Population Growth Compared to Actual U.S. Population Growth



Demand-side Resources and Customer Usage

For the comparison in Figure 6.18 of weather-normalized peak observations to the IRP peak demand forecasts after additional DSR, we assumed the forecasted DSR was implemented. However, consumers can adopt energy-efficient technologies above and beyond what utility-sponsored DSR programs and building codes and standards incentivize. This consumer behavior leads to more actual DSR than we forecasted. The DSR programs can also change over time. In later IRPs, we can choose programs that were not cost-effective in the past but we now deem cost-effective. This situation can make an older forecast outdated, the DSR forecast too low, and the load forecast after additional DSR too high.

Also, the Global Settlement from the 2013 General Rate Case (GRC) PSE accelerates electric DSR by 5 percent yearly. We did not consider this additional DSR in comparing IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. We updated the normal weather assumption for the 2011 IRP to the 2021 IRP by rolling off two older years of temperature data and incorporating two new years of temperature data into the 30-year average. Over time, normal heating degree days have been declining, and the forecast of energy demand with normal weather has changed. In this 2023 Electric Report, we incorporated climate change into the normal definition, which altered the 2023 Electric Report base demand forecasts.

Additionally, over time our customers' weather sensitivity has been changing. As consumers implement energy efficiency measures, customers use less energy at a given temperature, including 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, 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 will likely differ from use 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. We included Jefferson County usage in the electric peak demand forecast in the 2011 IRP. Therefore, when comparing that forecast to today's actuals, we expect that forecast to be higher than the actual peak demand.

RESOURCE ADEQUACY ANALYSIS
CHAPTER SEVEN

PUGET SOUND ENERGY

Contents

1. Introduction

The electricity industry in the Pacific Northwest (PNW) is transitioning as governments and system planners implement major decarbonization policies. The sector is retiring significant quantities of coal-fired capacity while adding new renewable generation resources. As a result, Puget Sound Energy (PSE) and other utilities are rethinking how we plan our systems, especially in resource adequacy (RA). As we transition to 100 percent clean energy by 2045, always having enough energy — maintaining resource adequacy — is paramount to ensure customers continue receiving reliable electricity and a smooth transition to a decarbonized system.

Puget Sound Energy contracted with the consulting firm Energy and Environmental Economics (E3) to produce the resource adequacy analysis for this 2023 Electric Progress Report (2023 Electric Report). E3 worked with our data and used their RECAP model to produce the study results. We based the work described in this chapter on the findings of E3's 2021 report, which recommended the following improvements to our resource adequacy modeling:

- Align the treatment of the first hour of loss-of-load events across the scenarios with and without battery storage
- Consider changing climate in evaluating energy demand, hydroelectric generation, and market purchases
- Consider load and renewable correlations. Puget Sound Energy did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future studies, as they could impact resource adequacy for PSE's system.
- Discharge storage at its rated capacity, for its rated duration; does not apply a minimum state of charge to the modeled energy capacity
- Incorporate hydroelectric dispatch capabilities and hydroelectric energy limitations
- Perform GENESYS sensitivity to determine if it would result in an increase in the storage ELCC; PSE did not run this sensitivity. The ELCC of energy storage is very high and there is sufficient energy to charge the energy storage. The GENESYS sensitivity would not add significant value on storage ELCC

Please see the entire docket and public comments on the UTC website.[1] We worked with E3 to meet all the modeling improvements described in the filing.

➔ See Appendix L: Resource Adequacy for more details regarding the filing and PSEs commitments.

Beyond implementing E3's recommendations, the other major change impacting the resource adequacy analysis is PSE's decision to reduce market reliance. In the past, PSE relied on purchases from the short-term wholesale energy markets as a cost-effective strategy to supplement resources to meet demand. This strategy also allowed us to avoid building significant amounts of generation capacity. Although wholesale electricity prices have remained low in recent

[1] utc.wa.gov/casedocket/2021/210220/docsets

years on average, the PNW has experienced periods of high wholesale electricity prices and low short-term market liquidity.

We expect this wholesale market volatility to limit our ability to rely on the market over time. Based on utilities' current plans, several studies discussed in this chapter's market reliance section have projected that the PNW will face a growing capacity shortage over the next decade.[2] Given the tightening of energy markets and to prepare for possible participation in the Western Resource Adequacy Program (WRAP), we plan to reduce our reliance on short-term wholesale market purchases to zero by 2029.

Peak capacity is the maximum capacity need of a system to meet loads.

Perfect capacity is the firm and reliable capacity required to maintain a chosen reliability metric.

The **planning reserve margin** is the generation resource capacity required to provide a minimum acceptable level of reliable service to customers under peak load conditions.

The **peak capacity credit** assigned to a resource is the effective load-carrying capability (ELCC). This value depends highly on the load characteristics and portfolio resource mix, which makes it unique to each utility; it is expressed as a percent of the equivalent nameplate capacity.

➔ For more information on market reliance, please refer to section four of this chapter.

Considering the projected capacity shortages for the NW region, the Western Power Pool (WPP) created the WRAP to provide a programmatic approach for utilities to work together to ensure resource adequacy throughout the region. The WRAP is the first regional reliability planning and compliance program in PNW history.[3] The Western Resource Adequacy Program is discussed in more detail later in this chapter in section six.

➔ The results of how the WRAP program will impact peak needs are in Chapter Eight: Electric Analysis.

1.1. Incorporating Climate Change

Puget Sound Energy's 2023 Electric Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used historical temperatures from the range of temperature variability to create the resource adequacy model. We then iterated through the different temperature years to create hourly load draws that we used in the modeling simulations, but the underlying data did not recognize predicted effects from climate change.

The methodology we used to incorporate climate change in this report is the first step in an evolving process. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. It is essential to consider climate change in resource planning because our customers rely on PSE energy to heat in the winter and stay cool in the summer. With an overall average warming trend, we would expect, on average, less overall heating demand and more cooling demand. We used recently developed regional climate model projections to create

[2] https://www.ethree.com/wp-content/uploads/2019/12/E3-PNW-Capacity-Need-FINAL-Dec-2019.pdf
[3] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

demand draws for the resource adequacy simulation that reflect climate change. We also updated the peak demand forecast, which resulted in normal peak temperatures for summer and winter that increased over time.

➔ Please refer to Chapter Six: Demand Forecast for more details regarding how we incorporated climate change into our demand forecast.

Along with incorporating climate change in the demand forecast, we also updated hydroelectric generation draws. Previously, we used the historical 80-year hydroelectric stream flow data to create a generation forecast based on current operating conditions. The same climate change data we used for the demand forecast also provided stream flow data that we turned into predicted generation for the hydroelectric facilities.

➔ For details regarding the hydroelectric forecast, refer to Chapter Five: Key Analytical Assumptions.

2. Overview of Results

Resource Adequacy measures the ability of generating resources to meet load across a wide range of system conditions, accounting for supply and demand variability. No one can plan a perfectly reliable electrical system; however, we use several reliability metrics in the industry to ensure the system has adequate generation capacity during extreme events. We apply a five percent loss of load probability metric in the resource adequacy study, which means we plan our system to have an expected loss of load event occur once in 20 years. We reflected this in our planning reserve margin in Table 7.1, which shows the 2021 Integrated Resource Plan (IRP) results and the new seasonal analysis we used in this report. Overall, the peak capacity need increased from the 2021 IRP.

Table 7.1: Planning Reserve Margin and Peak Capacity Need — Percent Above Normal and MW Need Above Normal Peak

Study Years and Seasons	2027 Winter (2021 IRP)	2031 Winter (2021 IRP)	2029 Winter (2023)	2029 Summer (2023)	2034 Winter (2023)	2034 Summer (2023)
Planning Reserve Margin (%)	20.7	24.2	23.8	21.2	23.9	26.1
Additional Perfect Capacity Need (MW)	907	1,381	1,272	1,875	1,746	2,856

Table 7.1 shows the additional perfect capacity need comparing the results from the 2021 IRP to the 2023 Electric Report study years. The 2023 Electric Report is the first time we modeled the planning reserve margin for winter and summer. When comparing the results from these two reports, it is important to compare the 2021 IRP study years to the 2023 Electric Report winter results only, as prior IRPs have only evaluated the winter months. When you compare winter results, you see a slight increase in the perfect capacity need from 2027 to the 2029 winter. From this analysis, we found that although PSE is a winter-peaking utility, the additional perfect capacity need is higher in summer. This

high summer need means there are fewer resources available in the summer than in the winter, not that the summer peak is higher than the winter peak.

Table 7.2 compares the 2023 Electric Report and 2021 IRP effective load carrying capability (ELCC) results. The ELCC measures how many megawatts of a resource PSE can plan on to meet the planning reserve margin. We modeled most of the resources with saturation effects; the more resources added of the same location or type, the less effective they are at meeting peak capacity. The results in the table are for the first tranche[4] (the first amount of MW of installed capacity) of each resource — 100 MW for renewable resources and demand response and 250 MW for storage. The ELCC for additional resources declines based on the ELCC saturation results, which we described further in the Key Takeaways section and Appendix L: Resource Adequacy. There is an increase across all renewable resource ELCCs from the 2021 IRP to the 2023 Electric Report. Most significantly, solar and batteries increased due to the seasonal analysis and other modeling changes discussed throughout this chapter in greater detail.

Table 7.2: Effective Load Carrying Capability Results for First 100 MW for Wind and Solar or First 250 MW for Storage

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	47	32	41
Washington	Wind	18	15	13	5
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
Distributed Energy Resources (DER) Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95

4 Tranche is the capacity segment of a resource on the ELCC saturation curve.

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029[2] Winter (%)	2029[2] Summer (%)
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP (2021 IRP modeled ELCC saturation curves for Washington wind and Washington solar only)
2. 2023 Electric Progress Report

2.1. Key Takeaways

Several elements contributed to the increase in the planning reserve margin:

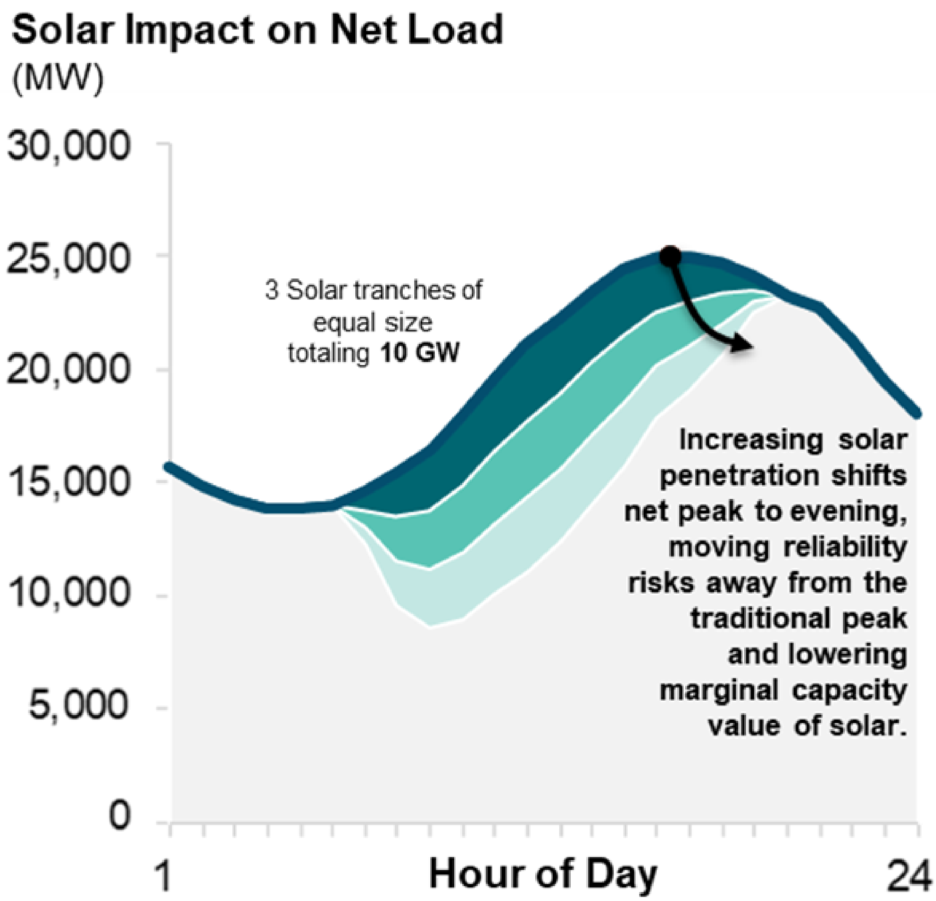
- Including climate change data in the load forecast and peak temperatures slightly lowered the normal winter peak and increased the normal summer peak. Even with the increase in normal summer peak temperatures, the summer peak does not come close to the level of the winter peak through the report's planning horizon.
- Increase in peak demand. Although climate change decreased normal winter loads, the updated electric vehicle (EV) forecast increased the demand. The increase in peak from the EV forecast was more significant than the decrease from the climate change data, resulting in an overall increase in peak demand.
- The analysis looked at winter and summer capacity needs.
- The climate change data also showed changes in the duration and frequency of outage events which impacted the results. The data shows a decrease in event duration, less frequent events in the winter, and more frequent events in the summer, increasing the ELCCs for shorter duration storage resources and solar.
- The hydro generation profile changed when we incorporated climate change into the modeling because the historical spring runoff now happens earlier in the year. The earlier spring runoff changes hydropower availability and leaves less water for the summer.

The saturation effect can have a significant impact on resource ELCCs. In the next section, we explain why it was vital to consider saturation when we evaluated the ELCC of a resource.

2.1.1. Effective Load Carrying Capability Saturation Effect

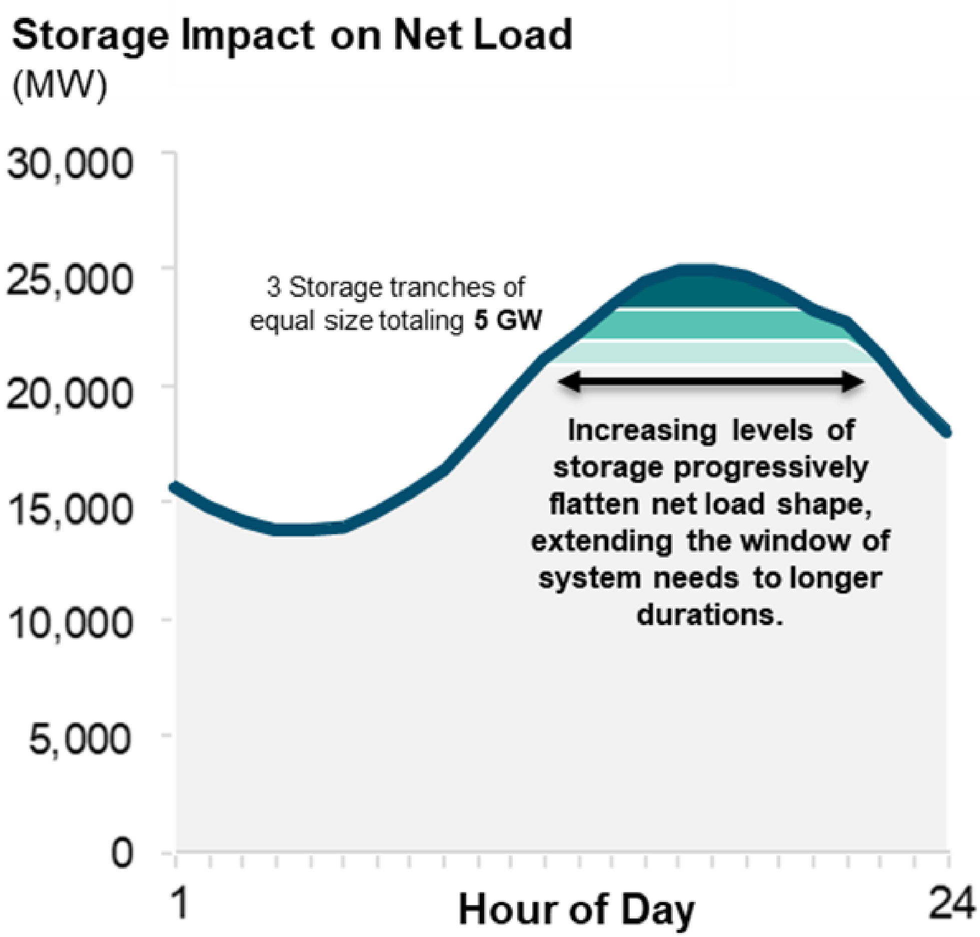
The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. Figure 7.1 shows an example of ELCC saturation — the dynamics for solar on a peak summer day. Note that this is an illustrative example and does not represent PSE's system. The first grouping or tranche of solar produces a lot of energy during peak demand hours, showing a relatively high ELCC. However, when one adds more solar, the net peak demand (load minus renewable generation) shifts into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during the daytime but cannot contribute to the reliability needs at night. Wind resources experience this same saturation effect, except rather than shifting the net load from daytime hours to nighttime hours, wind resources shift the net load from times when wind generation is high to times when wind generation is low.

Figure 7.1: Example of ELCC Saturation Effect for Solar (Does Not Represent PSE's System)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure 7.2 for an example showing storage dynamics on the same peak day. Note that this is an example and does not represent PSE's system.

Figure 7.2: Example of ELCC Saturation Effect for Energy Storage (Does Not Represent PSE's System)



The first tranche of energy storage produces a lot of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as one adds more energy storage, the net peak demand (load minus energy storage generation) flattens and spans a longer period, see Table 7.3. As a result, the ELCC for these later tranches is lower because the storage has already mitigated during the highest peak demand hours but can't contribute the same reliability value longer due to the limited stored energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, in addition to the length of calls but without a need to charge.

Table 7.3: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10

Resource	Season	ELCC 1 100 - 1,000 MW (%)	ELCC 2 1,000 – 1,500 MW (%)	ELCC 3 1,500 MW + (%)
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15

2.2. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This normal peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it is estimated such that there is a 50 percent probability of the true peak load being higher than this forecast and a 50 percent probability of it being lower.

The PRM represents the resource need amount beyond the normal peak load that PSE must maintain one-in-two to satisfy the total resource need and the reliability target of 5 percent loss of load probability (LOLP).

3. Resource Adequacy Analysis Results

This section describes the results of the resource adequacy analysis we prepared for this report. First, we present the capacity credit results for existing and contracted resources, representing how much existing and contracted resources contribute toward satisfying the PRM. Next, we present the total resource need and the PRM. The total resource need represents the capacity needed to satisfy PSE's reliability standard, and the PRM represents this amount relative to the median peak load. Lastly, we present the capacity contribution results for new generic resources.

3.1. Capacity Credit of Existing Portfolio

This section provides the capacity credit for all resources in PSE's portfolio, including hydroelectric, thermal, wind, and solar. This section also shows the capacity credit for other contracts and wholesale market purchases. E3 calculated the ELCC resource values for the three climate models and then averaged the results to get the final ELCC values.

3.1.1. Hydroelectric Resources

Puget Sound Energy owns three hydroelectric plants: Upper Baker, Lower Baker, and Snoqualmie Falls. E3 calculated the ELCC for each resource (see Table 7.4). The summer and winter ELCCs are similar for Upper Baker and Lower Baker. However, Snoqualmie Falls is a run-of-river hydroelectric facility; as a result, the ELCC is lower in summer due to lower summer river flows. The ELCC values in 2034 are like those in 2029.

Table 7.4: Effective Load Carrying Capability for PSE-owned Hydroelectric Resources (MW)

Hydroelectric Resources	Nameplate	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Upper Baker Units 1 and 2	107	70	69	77	79
Lower Baker Units 3 and 4	111	67	66	58	60
Snoqualmie Falls	53	39	39	11	12

We also contract with five Mid-C hydroelectric plants on the Columbia River for power. We calculate the capacity contributions based on the Pacific Northwest Coordination Agreement (PNCA) final regulation (see Table 7.5) for these plants. The capacity contributions are PSE's contractual capacity, less losses, encroachment, and Canadian Entitlement. These capacity contributions are the same for winter and summer.

Table 7.5: Capacity Credit for Mid-C Hydroelectric Resources (MW)

Hydroelectric Resources	2029	2034
Mid-C Rocky Reach	313	313
Mid-C Rock Island	121.2	121.2
Mid-C Wells	115	115
Mid-C Wanapum	6.1	6.1
Mid-C Priest Rapids	5	5

The capacity credit for the Mid-C hydroelectric resources is the same for winter and summer.

3.1.2. Thermal Resources

Puget Sound Energy owns several thermal plants. We calculate the capacity credit based on the plant's rating at different temperature levels (see Table 7.6). In winter, the capacity reflects the capacity rating when operating at an ambient temperature of 23 degrees Fahrenheit. In summer, the capacity reflects the capacity rating when operating at an ambient temperature of 96 degrees Fahrenheit. The efficiency of these thermal plants is lower at higher temperatures. As a result, the summer ratings are lower than the winter ratings.

Table 7.6: Capacity Credit for Thermal Resources (MW)

Thermal Plant	Winter	Summer
Encogen	182	149
Ferndale	266	246
Goldendale	315	268

Thermal Plant	Winter	Summer
Mint Farm	320	270
Sumas	137	117
Frederickson CC	134	104
Fredonia 1	117	91
Fredonia 2	117	91
Fredonia 3	63	46
Fredonia 4	63	46
Whitehorn 2	84	65
Whitehorn 3	84	65
Frederickson 1	84	65
Frederickson 2	84	65

Thermal plants can also have forced outages. Although forced outages do not impact the capacity credit assigned to thermal plants, E3 considered forced outages at these plants to determine the system overall resource need and PRM value The forced outage rates vary for each plant and range from 2.31 percent to 11.3 percent.

3.1.3. Wind and Solar

Puget Sound Energy owns and has contracts for power from several wind and solar projects. These projects include Hopkins Ridge Wind, Wild Horse Wind (including an expansion), Klondike Wind, Lower Snake River Wind, Skookumchuck Wind, Golden Hills Wind, Clearwater Wind, Lund Hill Solar, and Wild Horse Solar. E3 calculated the ELCC for wind and solar resources (see Table 7.7). The ELCC for wind resources is higher in winter (28 percent in 2029) than in summer (14 percent in 2029) because PSE's wind projects, in aggregate, output more energy in the winter. Conversely, the ELCC for solar resources in summer (45 percent in 2029) is higher than in winter (7 percent in 2029) because solar projects output more energy in the summer, and better align with peak demand. The ELCC values in 2034 are like those in 2029.

Table 7.7: Effective Load Carrying Capability for Wind and Solar Resources (MW)

Resources	Nameplate MW	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Wind	1,504	428	421	210	217
Solar	150	10	10	67	69

3.1.4. Other Contracts

In addition to the wind and solar contracts discussed in the proceeding section, PSE has several other contracts. We have a 300 MW power exchange contract with Pacific Gas and Electric Company (PG&E). Under this contract, PG&E must provide PSE with 300 MW of power in winter when needed, and PSE must provide PG&E with 300 MW of power in summer when needed. In addition to this contract, we have a few other small contracts.

➔ A full discussion of the contracts is in Appendix C: Existing Resource Inventory.

See E3's ELCC calculation for these contracts in Table 7.8. The ELCC in summer is negative, which means contracts result in a net increase in the overall resource need when included in the portfolio. The PG&E exchange has the most significant influence because PSE is obligated to send PG&E 300 MW of power in summer when needed, which increases PSE's overall summer resource need. Other contracts partially offset this increase. The ELCC in winter is above 350 MW. The ELCC values in 2034 are like those in 2029.

Table 7.8: Effective Load Carrying Capability for Other Contracts (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Other Contracts	382	376	-179	-185

3.1.5. Market Purchases

In addition to determining the capacity contribution of PSE's resources, E3 also estimated the ELCC of market purchases (see Table 7.9). These market purchases are how much power is available to purchase from the regional market on a short-term basis. We used the Classic GENESYS and the Wholesale Purchase Curtailment Model (WPCM) to determine the availability of market purchases. We have 2,031 MW of transmission from Mid-C to import power via market purchases, but we also use this transmission to deliver power from the Mid-C hydroelectric plants and Wild Horse Wind project.

The ELCCs show that the ELCC for market purchases is lower in summer than in winter. As discussed in Appendix L: Resource Adequacy, GENESYS and the WPCM model show that the PNW has less generation for us to call on in summer than in winter. Moreover, we project that the PNW will have less generation available in summer 2034 than in summer 2029. As a result, the ELCC for summer declines between 2029 and 2034. The ELCC for winter remains similar in 2034.[5]

Table 7.9: Effective Load Carrying Capability for Market Purchases (MW)

Resources	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Market Purchases	1,440	1,434	961	751

3.2. Total Resource Need and Planning Reserve Margin

E3 quantified the total resource need and PRM necessary to satisfy our five percent of LOLP reliability target (see Table 7.10). E3 first quantified the system's capacity shortfall, representing the additional perfect capacity needed to satisfy the reliability target. The capacity shortfall is higher in summer (1,875 MW in 2029) than in winter (1,272 MW in 2029). Although peak demand is lower in summer, the capacity contribution of resources is much lower in summer. Thermal ratings are lower due to higher ambient temperatures, the ELCC of wind and hydroelectric is lower in summer, the PG&E exchange reduces available capacity, and there are fewer market purchases available in summer.

5 https://www.pse.com/-/media/PDFs/IRP/2023/electric/appendix/21_EPR23_AppL_Final.pdf

These factors result in a more significant capacity shortfall in summer than in winter. The capacity shortfalls grow in both seasons as the load increases, but there are more in summer due to greater load growth.

E3 then calculated the total resource need. The total resource need is the sum of capacity contributions across all resources plus the additional perfect capacity needed. The total resource need is higher in winter (6,319 MW in 2029) than in summer (5,329 MW in 2029).

Lastly, E3 calculated the PRM. The PRM percentage is similar across seasons and years, ranging from 26 percent to 28 percent. The key factors influencing the PRM are load variability (beyond the median peak load), operating reserve requirements, thermal forced outages, and Mid-C hydroelectric performance (relative to its capacity contribution).

Table 7.10: Total Resource Need and Planning Reserve Margin (MW)

Resource(s)	2029 Winter	2034 Winter	2029 Summer	2034 Summer
Thermal Plants	2,050	2,050	1,688	1,688
Mid-C Hydro	560	560	560	560
Wind, Solar, Baker, Other Contracts	997	981	244	252
Market Purchases	1,440	1,434	961	751
Additional Perfect Capacity Need	1,272	1,746	1,875	2,856
Total Resource Need	6,319	6,771	5,329	6,107
Median Peak Load	5,004	5,382	4,171	4,831
Planning Reserve Margin	26%	26%	28%	26%

In this analysis, we used one-in-two (P50) peak load forecast to calculate the planning reserve margin.

➔ See Appendix L: Resource Adequacy for more details on peak-load forecast.

3.3. Effective Load Carrying Capability for Incremental Resources

E3 evaluated the capacity contribution of incremental resources to PSE's current resource portfolio. These resources reflect a wide range of resource options, including in-state and out-of-state renewable resources, distributed solar resources, energy storage, demand response, hybrid, and thermal resources.

These resources do not represent specific wind or solar projects bid to PSE through a resource procurement. Instead, they are generic resource options that PSE would expect to receive in future procurements. We considered these generic options in our long-term portfolio analysis, and these capacity contribution values serve as inputs to the portfolio selection.

3.3.1. Generic Wind and Solar Resources

E3 calculated the ELCC for eight wind, two distributed solar, and five utility-scale solar resources (see Table 7.11). These ELCC values are the capacity contribution for the first 100 MW of incremental capacity added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in Appendix L.

In general, the ELCC for wind is higher in winter than in summer, and the ELCC for solar is higher in summer — seasonal generation patterns for these resources. The ELCC differs by location, reflecting differences in average generation and the timing of that generation. The ELCC is higher for resources with higher generation levels when PSE's system has a greater capacity need.

➔ See Appendix L: Resource Adequacy for details about the resource groups and saturation curve for the generic resource.

Table 7.11: Effective Load Carrying Capability for Generic Wind and Solar Resources (First 100 MW)

Resource	Resource Type	Winter (%)	Summer (%)
British Columbia	Wind	34	13
Idaho	Wind	1	1
Montana Central	Wind	39	27
Montana East	Wind	32	19
Offshore	Wind	32	41
Washington	Wind	13	5
Wyoming East	Wind	52	34
Wyoming West	Wind	39	34
Distributed Ground Mount	Distributed Solar	4	28
Distributed Rooftop	Distributed Solar	4	28
Idaho	Utility-scale Solar	8	38
Washington East	Utility-scale Solar	4	55
Washington West	Utility-scale Solar	4	53
Wyoming East	Utility-scale Solar	11	29
Wyoming West	Utility-scale Solar	10	28

3.3.2. Generic Energy Storage ELCC Saturation Curves

We asked E3 to model the ELCC of four types of energy storage resources (see Table 7.12). There are three lithium-ion battery storage resources, with two-hour, four-hour, and six-hour durations, and one eight-hour pumped hydroelectric storage resource. The duration metric specifies the amount of time a storage resource can continuously discharge at its rated capacity when fully charged. For example, a fully charged 100 MW Lithium-ion Battery (four-hour) can discharge at 100 MW for four consecutive hours. The roundtrip efficiency metric specifies the amount of energy conserved when charging and discharging a battery. The forced outage rate, like thermal resources, specifies the probability that a storage resource goes on a forced outage.

Table 7.12: Generic Energy Storage Resources

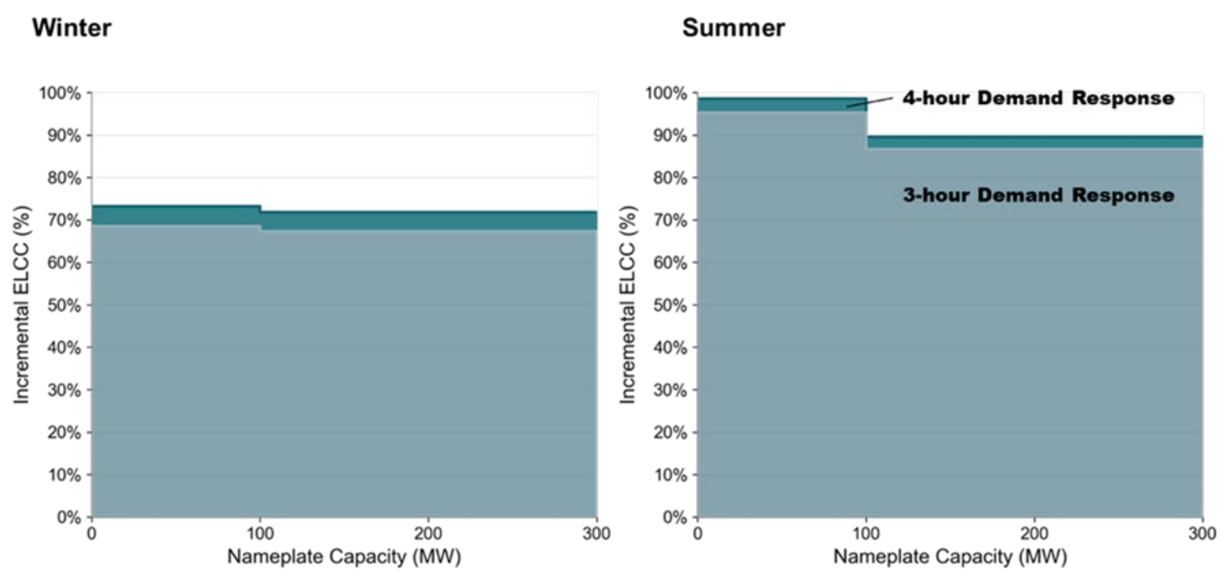
Resources	Technology	Duration	Roundtrip Efficiency (%)	Forced Outage Rate (%)
Lithium-ion Battery (2-hour)	Lithium-ion	2 hours	86	2
Lithium-ion Battery (4-hour)	Lithium-ion	4 hours	87	2
Lithium-ion Battery (6-hour)	Lithium-ion	6 hours	88	2
Pumped Storage (8-hour)	Pumped hydroelectric storage	8 hours	80	1

3.3.3. Generic Demand Response ELCC Saturation Curves

E3 calculated the ELCC saturation curves for two types of generic demand response programs: one with maximum three-hour call durations and another with maximum four-hour call durations (see Figure 7.3). E3 calculated two tranches for demand response: 0–100 MW and 100–300 MW. For both programs, we limited the number of calls to 10 in winter and 10 in summer. Also, PSE cannot call the same demand response program more than once in six hours.

As for storage, the ELCC of demand response diminishes with increasing penetration as the limited duration becomes less effective at addressing PSE's reliability needs at higher penetration levels. The ELCC for demand response is lower in winter than in summer because the duration of loss of load events is longer.

Figure 7.3: Effective Load Carrying Capability Saturation Curves for Demand Response Resources



3.3.4. Generic Hybrid Resources

PSE directed E3 to model the ELCC of four types of hybrid resources (see Table 7.13). We assumed that these hybrid resources would be in Washington State. The solar resource is Washington East Solar, the wind resource is Washington Wind, and the storage resource is Lithium-ion Battery Storage (four-hour). For each hybrid resource, we assumed that the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the capacity of the storage, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce overall costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Table 7.13: Generic Hybrid Resources

Resources	Interconnection MW	Solar MW	Wind MW	Storage MW
Solar + Storage	100	100	-	50
Solar + Storage (Restricted Charging)	100	100	-	50
Wind + Storage	100	-	100	50
Solar + Wind + Storage	200	100	100	50

3.3.5. Generic Thermal Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic thermal resources (see Table 7.14). Three factors influence the capacity contribution of these resources: ambient temperature efficiency ratings, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing thermal plants. The summer rating is lower than the winter rating for combined cycle combustion turbine and frame combustion turbine units. The reciprocating internal combustion engines have the same efficiency ratings in the summer and winter.

Table 7.14: Effective Load Carrying Capability for Generic Natural Gas Resources

Resource	Nameplate Winter (MW)	ELCC Winter (%)	Nameplate Summer (MW)	ELCC Summer (%)
Combined Cycle	367	84	310	92
Frame Turbine	237	96	184	98
Reciprocating Engine	18	96	18	96

4. Market Risk Assessment

Puget Sound Energy has relied on short-term market resources to fill less than 1,500 MW of transmission capacity for more than 15 years. The total firm transmission contracts are 2,030 MW to Mid-C; we then subtract the transmission needed for resources at the Mid-C, which comes to less than 1,500 MW of available transmission left for short-term market purchases. See Appendix C: Existing Resource Inventory for the breakdown of transmission contracts. Relying on the surplus capacity of others in the region was a reasonable strategy when the region had significant surplus peak capacity. Experts predict the region soon will have no significant surplus peak capacity. They expect the region will be short of physical capacity, even under very conservative assumptions. Continuing to rely on short-term market purchases creates physical and financial risks for PSE's customers and shareholders. We need to adapt to changing market conditions.

4.1. Reduce Market Reliance

Due to the growing regional concerns about capacity in the short-term market and our interest in joining the WRAP, we will phase out reliance on short-term market purchases as we make plans to ramp into the WRAP. We reduced market reliance by more than 200 MW per year starting in 2024 and reached zero reliance by 2029 in this report.

Table 7.15 shows the ELCC adjustment to market reliance from E3's models but is not the final market reliance we used in the capacity expansion modeling described in Chapter Eight: Electric Analysis. We phased the market reliance for peak capacity down over time reaching zero by 2029.

Table 7.15: Effective Load Carrying Capability Adjusted MW of Market Reliance from E3 Model

Adjustment	Nameplate	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Transmission Capacity	2,030	2,030	2,030	2,030	2,030
Resources at Mid-C	(512)	(512)	(512)	(512)	(512)
ELCC Adjustments	0	(78)	(557)	(84)	(767)
Total Available Transmission	1,518	1,440	961	1,434	751

4.2. Changing Regional Resource Adequacy

Numerous studies and articles highlight regional resource adequacy concerns. Three respected industry-based organizations periodically issue studies about resource adequacy in the Northwest and have recently raised critical concerns. The North American Electric Reliability Corporation (NERC)[6] studies regional entities and assessment areas, including WECC-NWPP-US & RMRG (Western Interconnection, Northwest Power Pool, and Rocky Mountain Reserve Sharing Group). The Western Electricity Coordinating Council (WECC)[7] evaluates resource adequacy across the entire western interconnection (WECC) and within five subregions, including NWPP-Northwest. The Pacific Northwest Utilities Conference Committee (PNUCC)[8] covers the Northwest regional planning area. All three organization's reports cover a ten-year horizon. Across the West, utilities plan to retire nearly 26 GW coal and natural gas resources over the next decade. Each of their most recent reports concluded that demand and resource variability is increasing rapidly, creating challenges for the bulk power system to provide reliable supply in the near

6 2021 Long-term Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf
7 2021 Western Assessment of Resource Adequacy" ("WARA"), https://www.wecc.org/Administrative/WARA%202021.pdf
8 2022 Northwest Regional Forecast, https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf

term. The WECC put it most directly, stating, "As early as 2025, all subregions (of the WECC) will be unable to maintain 99.98 percent reliability because they will not be able to reduce the hours at risk for loss of load enough, even if they build all planned resource additions and import power."[7] The PNUCC concluded, "The annual energy picture reveals a regional resource deficit by next year (2023), which is three years earlier than last year's estimate."[8] And NERC determined, "The two largest U.S. assessment areas in the Western Interconnection — California/Mexico and the Northwest-Rocky Mountain — have the potential for high load-loss hours and energy shortfalls for 2022 and beyond."[6]

While each organization approached the analysis using its own assumptions and methodologies, some common themes emerge on what is driving the increase in variability:

- Government policies and consumer sentiment are accelerating the move to clean energy
- More frequent and extreme weather events due to climate change
- Retirement of baseload resources and the addition of variable energy resources

Traditional resource adequacy approaches have been based solely on capacity, which worked well when most generation assets were dispatchable and demand was more predictable. The peak capacity shortfall typically occurred during the annual peak capacity hour. In today's climate, however, the drivers affecting the generation and load variability can lead to critical capacity shortfalls that do not coincide with peak demand. Focusing only on capacity fails to account for this variability fully. The PNUCC Northwest Regional Forecast (NRF) is the best source for detailed information on this topic.

$$
\begin{aligned}
&NRF \\
&= \sum (Utility\ loads\ with\ planning\ reserve\ margin) \\
&- (resource\ forecasts\ for\ those\ owned\ \&\ contracted\ by\ utilities) \\
&+ (resource, conservation, demand\ response\ additions\ based\ on\ their\ IRPs)
\end{aligned}
$$

Table 7.16 shows that even with very conservative adjustments to the NRF, we expect the region to be significantly short in the winter of 2029 and extremely short of capacity in the summer of 2029. We made two adjustments to the winter for the following factors:

- Independent Power Purchaser (IPP) Generation: PSE's market survey shows 1,697 MW of IPP resources available today. It may not be reasonable to assume those resources will be uncontracted as the region considers entering the WRAP, but we included those here to be conservative.
- Southwest Imports: The Northwest Power and Conservation Council's Classic GENESYS model assumed 3,400 MW of imports from California would be available to the Pacific Northwest. As California electrifies transportation and buildings, those imports may not be available. We included them in this table to ensure a conservative perspective.

Table 7.16: Adjusted NRF Table Regional Capacity Short Position (MW)

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
PNUCC — Regional NRF Short	4,830	5,240	6,060	5,950

PNUCC - Northwest Regional Forecast	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Identified Available Firm Resources in the Region (Operational)	1,700	-	1,700	-
California Imports	3,400	-	3,400	-
Net Regional Shortage	(270)	5,240	960	5,950

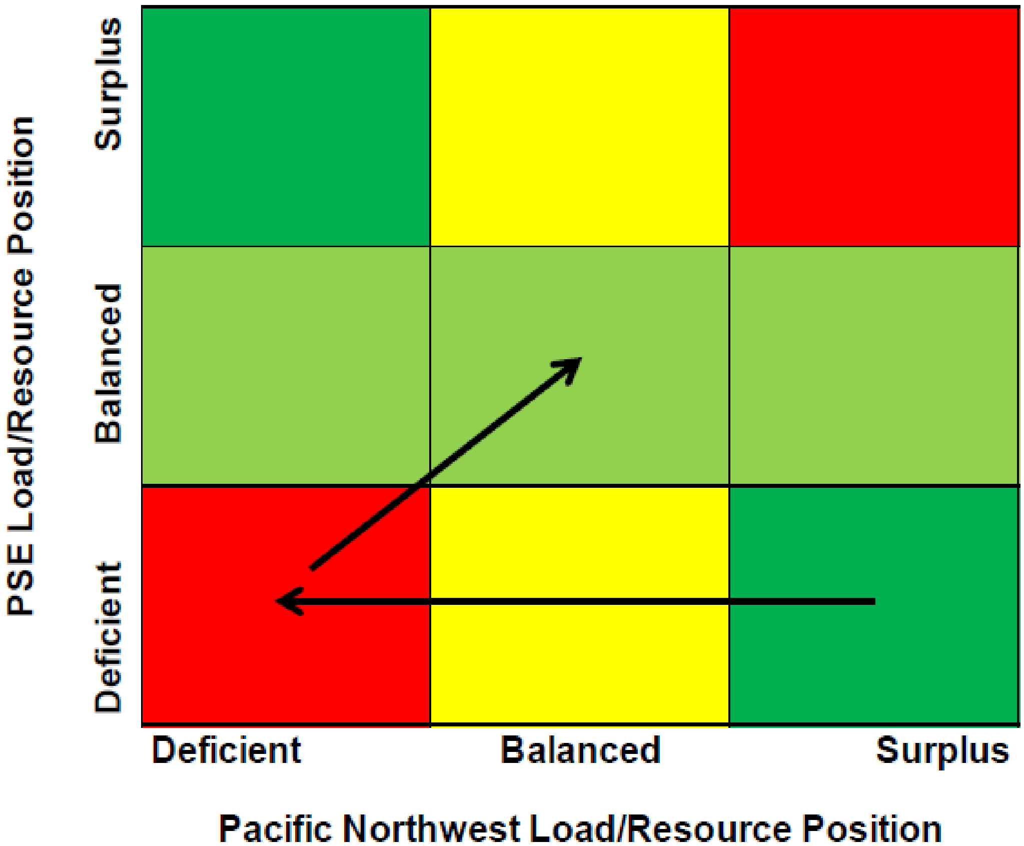
Note: PNUCC data not provided past 2031. PNUCC numbers for 2033 provided from the latest year available.

Table 7.16 highlights that the region will be short on peak capacity even with questionable assumptions on IPP resources and California imports.

4.3. Change Strategic Position

The risk matrix shown in Figure 7.4.provides an illustration of capacity position risk. When the region is surplus, it is prudent for PSE to be physically short — as illustrated by the box in Figure 7.4 with an 'X' below. In that scenario, we manage the financial risk, but we did not have to build unnecessary physical generation capacity. However, as the region grows short of capacity, PSE would shift to the 'Y' box, creating a physical and financial risk. Even if we can hedge the financial risk of relying on short-term market capacity resources, the physical reliability risk may not be manageable. We may not need to build resources to fill that entire market position, though. Puget Sound Energy could sign longer-term contracts to fill this position, if these options are available and do not leave the position to the short-term market. We must move to at least the balanced position in Figure 7.4 for our resource adequacy position going forward.

Figure 7.4: Capacity Position Risk Matrix



4.4. Market Reliance

The 2023 Electric Report reduces our reliance on the short-term market, eventually bringing market reliance to zero by 2029, as reflected in Table 7.17.

Table 7.17: Perfect Capacity Adjusted to Eliminate Short-Term Market Reliance (MW)

Resource	Winter 2029	Summer 2029	Winter 2034	Summer 2034
Mid-C Hydro	560	560	560	560
Thermal	2,050	1,688	2,050	1,688
All other resources	997	244	981	252
Short-term Market Purchases	-	-	-	-
Additional perfect capacity for 5% LOLP	2,712	2,836	3,180	3,607
Total Resources	6,319	5,329	6,771	6,107

5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs modeled in the AURORA database to perform long-term expansion planning and hourly dispatch. The long-term capacity expansion (LTCE) and hourly dispatch optimize new builds and mimic the hourly operation of the existing resources and new builds. New to the 2023 Electric Report is the winter and summer planning reserve margin. We included only the winter planning reserve in the AURORA model in previous IRPs. Starting with the additional perfect capacity for 5 percent LOLP provided by E3, we made minor adjustments to consider more current assumptions for existing resources' ELCC contribution and to eliminate short-term market reliance. We used the resulting seasonal PRM as an input to the AURORA model to serve as a target in the long-term capacity expansion when determining new resource alternatives.

Seasonal resource ELCCs are also new in the 2023 Electric Report and reflect existing and new resources in the AURORA model. In addition, the renewable resource and storage ELCC saturation effect represented by multiple tranches added model complexity and increased run-time significantly. AURORA evaluates new resources for each of the available builds for the year, so the model ends up with a large matrix of all the resource options and costs, contributing to the long run time. A review of the AURORA model study log shows that storage scheduling also contributes to the extended run time. To manage the large-scale optimization problem run-time and meet the IRP study needs, we adjusted new resource ELCCs, consolidating from six tranches to three.

➔ See Appendix L: Resource Adequacy for additional information on new resource ELCC aggregation.

6. Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP)[9] is a compliance-based framework designed to increase regional reliability at a reduced cost for participants. The Western Power Pool (WPP) and a steering committee comprised of western region market participants have proposed a design for a capacity-based RA program. This voluntary program

[9] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

establishes a standardized way to approach the resource adequacy problem across twenty-six regional entities (participants) in the west, with an estimated combined peak load of 65,000 MW.

The WPP conducted an extensive public outreach process over the past few years to create a governance structure to give interested parties a voice in decision-making. Each entity conducts its regional planning and procurement to meet capacity RA. Each Load Responsible Entity (LRE) has its methods for calculating peak load, generation and transmission requirements, and capacity contribution. The LRE management approves new resources, which regulators regulate relative only to that LRE's need. Without transparency and coordination, LREs collectively may rely on market purchases relative to available capacity. Additionally, in the absence of regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be scheduled in such a way as to meet the needs of participants within the footprint during capacity critical hours (CCH).

The individualized nature of the current planning framework can make it difficult for regulators, board members, interested parties, and utilities to understand whether, where, and when the region needs new capacity. The WRAP will increase visibility in the region's resources and transmission and help participants coordinate to fill these gaps collectively as they plan for the future.

The main components of the WRAP compliance framework are the forward showing program (FS) and the operational program (Ops Program) for both winter and summer seasons. These programs seek to balance reasonably conservative planning and the flexibility to protect customers from unreasonable costs.

The FS program establishes regional metrics for various resources' footprint and qualifying capacity contribution (QCC) values, sets deliverability expectations, and determines planning windows for demonstrating adequacy. Participants are required to show that they have contracted for the necessary amount of capacity resources to meet a P50 event plus a PRM. Participants must also demonstrate they have firm transmission rights to deliver at least 75 percent of their FS resources. The FS deadline for demonstrating adequate capacity and transmission is seven months before the beginning of each summer or winter season. The first binding season that a participant may elect is summer 2025. Participants must commit to go binding by summer 2028 to continue in the program.

The Ops program creates a framework to provide participants with pre-arranged access to capacity resources in the program footprint when a Participant is experiencing an extreme event, such as excess load or forced outages.

A key benefit of the WRAP is the ability to leverage the region's load and resource diversity so LREs can carry less PRM during the FS planning window than they would on a stand-alone basis. The Ops program allows participants to collectively manage the risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans.

6.1. Planning Reserve Margin and Effective Load Carrying Capability

We ran a WRAP sensitivity analysis to see how the portfolio for this report would change if we used the WRAP metrics instead of the resource adequacy metrics we developed with E3.

➔ See Appendix L: Resource Adequacy for details regarding the methodology and approach the WPP used.

Table 7.18 WRAP Provided PSE Capacity Need (MW) 2029

Sensitivity	Winter 2029	Summer 2029
One-in-two Peak	4,570	3,447
PSE Planning Reserve Margin	21%[a]	14%[a]
Balancing Reserves	132	122
Less Existing Resources	(3,120)	(2,343)

Note:

a. WRAP PRM percent is an estimate.

Table 7.18 shows the estimated seasonal planning reserve margin and peak capacity shortfall in 2029. Additional resources will fill the peak capacity needs. Table 7.19 shows the resources seasonal peak capacity contribution, by ELCC. The WRAP footprint is split into two solar ELCC zones and 5 wind ELCC zones. The generic solar resources are in Zone Solar VER 1, which contains Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Generic wind resources are distributed in 5 wind zones as shown in Table 7.19.

Table 7.19 WRAP Provided ELCCs for 2029

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
British Columbia Wind	25%	20%	Wind VER 5
Idaho Wind	31%	17%	Wind VER 2
Montana Central Wind	27%	13%	Wind VER 3
Montana East Wind	27%	13%	Wind VER 3
Offshore Wind* (E3's number)	31%	17%	Wind VER 2
Washington Wind	10%	18%	Wind VER 1
Wyoming East Wind	31%	15%	Wind VER 4
Wyoming West Wind	31%	15%	Wind VER 4
DER Ground Mount Solar	3%	23%	Solar VER 1
DER Rooftop Solar	3%	23%	Solar VER 1
Idaho Solar	3%	23%	Solar VER 1
Washington East Solar	3%	23%	Solar VER 1
Washington West Solar	3%	23%	Solar VER 1
Wyoming East Solar	3%	23%	Solar VER 1
Wyoming West Solar	3%	23%	Solar VER 1
Pump Storage	100%	100%	N/A
Nuclear	99%	99%	N/A
Li-ion Battery (2-hour)	40%	40%	N/A
Li-ion Battery (4-hour)	80%	80%	N/A
Li-ion Battery (6-hour)	100%	100%	N/A

Resource	Winter 2029	Summer 2029	WRAP Wind/Solar Zone
100 MW Washington Solar East Solar + 50 MW 4-hour Li-ion Battery	43 MW	63 MW	N/A
100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	50 MW	58 MW	N/A
100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery	5 54MW	81 MW	N/A
200 MW Montana Wind Central + 100 MW 8-hour PHES	154 MW	126 MW	N/A
Frame Turbine	100%	91%	N/A
Reciprocating Engine	N/A	N/A	N/A
Combined Cycle	86%	80%	N/A

ELECTRIC ANALYSIS
CHAPTER EIGHT

Contents

1. Introduction

Results of the electric analysis in Puget Sound Energy's (PSE's) 2023 Electric Progress Report (2023 Electric Report) from the following four-step process are illustrated in Figure 8.1. We described steps one, two, and three in detail in this chapter. We discussed step four in detail in Chapter Three: Resource Plan of the 2023 Electric Report.

Step 1. Establish Resource Needs

We identified three types of resource needs: peak capacity, energy, and CETA-renewable and non-emitting resource needs. Chapter Seven: Resource Adequacy Analysis presents our resource adequacy analysis for the peak need. Appendix C: Existing Resource Inventory describes the existing electric and CETA-eligible resources. Chapter Six: Demand Forecast shows the demand forecast we used to establish the resource needs.

Step 2. Determine Planning Assumptions and Identify Resource Alternatives

In this chapter, we discussed the reference portfolio and sensitivities developed for the 2023 Electric Report. Chapter Five: Key Analytical Assumptions presents the key analytical assumptions and a description of the sensitivities. Appendix D: Generic Resource Alternatives describes electric resource alternatives in detail.

Step 3. Analyze Alternatives Using Deterministic Portfolio, Portfolio Benefit Analysis Tool, and Stochastic Risk Analyses

The deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet needs, given the static assumptions defined in the scenario or sensitivity. We analyzed all scenarios and sensitivities using deterministic optimization analysis.

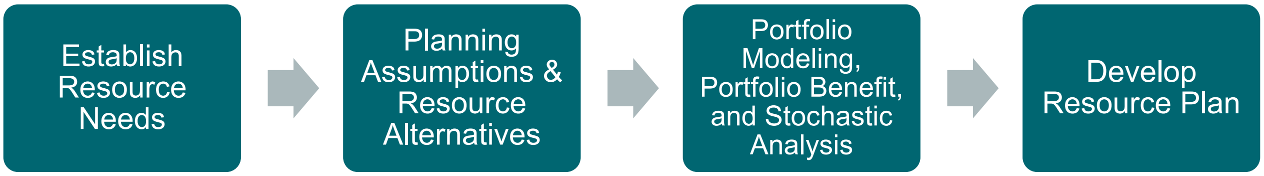
The portfolio benefit analysis tool helps support our understanding of equity-related benefits and the associated costs within each portfolio and informs our work as we strive to select a portfolio best suited to equitable outcomes for customers while also considering cost.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform concerning cost and risk across a wide range of possible future power prices, gas prices, hydroelectric generation, wind generation, loads, and plant forced outages. We analyzed the reference and preferred (sensitivity 11 B2) portfolios using stochastic risk analysis.

Step 4. Develop Resource Plan

We studied the deterministic analysis, the portfolio benefits tool analysis, and the stochastic quantitative analysis results to understand the key findings that led to decisions for the preferred portfolio. We presented the analysis results in this chapter and Appendix H: Electric Analysis and Portfolio Model. Chapter Three: Resource Plan presents the resource plan decisions.

Figure 8.1: 2023 Electric Progress Report Process



2. Clean Energy Transformation Act

The 2021 Integrated Resource Plan (IRP) marked a significant departure from past IRPs due mainly to the passage of the Clean Energy Transformation Act (CETA). The new electric progress report rules, WAC 480-100-625,[1] outline the requirements for this report. Utilities must file a progress report at least every two years after the utility files its IRP, beginning January 1, 2023.

In this mandated report, the utility must update the following:

- Demand forecast
- Demand-side resource assessment, including a new conservation potential assessment
- Resource costs
- The portfolio analysis and preferred portfolio

The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.[2] The progress report must also include other updates necessary due to changing state or federal requirements or significant economic or market forces changes.

2.1. Demand Forecast

Puget Sound Energy's 2023 Electric Progress Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This old approach was a common utility practice but did not recognize predicted climate change, which experts expect will increase temperatures, on average, over time.

> Puget Sound Energy incorporated climate change into the demand forecast for the first time in this report. We heard from interested parties that climate change is important to incorporate because it affects future demand and needs, and PSE agrees. We included climate change in the base demand forecast and the stochastic scenarios.

We know the methodology for incorporating climate change in this report is the first step, and we expect it will evolve. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. Puget Sound Energy provides energy for heating in the winter and cooling in the summer. It is essential to consider climate change in resource planning because of the warming trends that we expect will likely lead to, on average, less heating demand in winter and more cooling demand in summer.

[1] WAC 480-100-625
[2] WAC 480-100-640

Climate scientists recently developed climate model projections for the region, which we will use to calculate a normal temperature assumption that reflects climate change. We also updated the peak demand forecast, which results in normal peak temperatures for summer and winter that increase over time.

We expect electric energy demand to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045 before the additional demand-side resources (DSR) we identified in the 2023 Electric Report's base demand forecast. This growth rate increased our forecast from 2,551 average megawatts (aMW) in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 IRP.

➔ See Chapter Six: Demand Forecast and Appendix F: Demand Forecast Models for details regarding how PSE incorporated climate change into our demand forecast.

2.2. Demand-side Resources

We analyzed DSR alternatives in a conservation potential assessment (CPA) and demand response assessment to develop the supply curve we used as input to the portfolio analysis. The portfolio analysis then determined the potential maximum energy savings captured without raising the overall electric or natural gas portfolio cost. This analysis identified the DSR's cost-effectiveness level to include in the portfolio.

➔ The CPA updated for the 2023 Electric Report is in Appendix E: Conservation Potential and Demand Response Assessments.

Overall, the 2023 Electric Report CPA potential is down from the 2021 IRP by about 13 percent by 2045. Several updates and new data elements contributed to the reduced potential:

- The CPA incorporated a statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. This change in the CPA moved some of the potential from energy efficiency into codes and standards.
- The newly incorporated impact of climate change reduced savings in the later years of the study
- Updated building stock assessments, which have more efficiency penetration compared to the last stock assessment
- Updated savings from the most recent biennium program cycle

The CPA potential is also down in the 2023 Electric Report because of the following factors:

- Climate change reduced the normal winter peaks, thereby reducing the contribution of savings at the peak
- Updated conservation measure load shapes to align with the Northwest Power and Conservation Council's 2021 Power Plan[3]

[3] https://www.nwcouncil.org/2021-northwest-power-plan/

- Updated PSE's system peak definition to reduce the morning and evening windows for very heavy load hours[4]

Demand response peak savings increased due to updates we made to the potential to align with the 2021 Power Plan and an increase in the transmission and distribution deferrals costs.

2.3. Resource Costs

Like the 2021 IRP, we aggregated publicly available generic resource costs from several sources, predominantly from the National Renewable Energy Laboratory's (NREL) 2022 Annual Technology Baseline.[5] We expect generic resource capital costs to decline as technological advances push costs down. The declining cost curves we applied to different resource alternatives came from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB).

➔ A breakdown of the updated generic resource costs is in Chapter Five: Key Analytical Assumptions, with details in Appendix D: Generic Resource Alternatives.

2.4. Portfolio Analysis and Preferred Portfolio

We updated the portfolio analysis for the 2023 Electric Report. The assumptions and documentation of the model are in Chapter Five: Key Analytical Assumptions and Appendix H: Electric Analysis and Portfolio Model. The analysis results are later in this chapter, and we discussed the preferred portfolio in Chapter Three: Resource Plan.

2.5. State and Federal Requirements

Policy changes in the energy industry in Washington State and the United States have rapidly increased in the last decade. The following are the key policy changes impacting this report.

2.5.1. State Laws and Regulations

At the state level, PSE incorporated rules from the Climate Commitment Act (CCA), the Clean Energy Transformation Act (CETA), the Clean Energy Implementation Plan (CEIP), and new building codes.

2.5.2. Federal Laws

The Inflation Reduction Act (IRA) became law in August 2022. The two main incentives in the act applicable to PSE'S resource costs are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs). The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and

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4 In the 2021 IRP, we estimated the peak contribution from energy efficiency savings between peak hours, defined as: weekdays from hour ending (HE) 7–11 a.m. (6–11 a.m.) and HE 6–10 p.m. (5–10 p.m.); in the 2023 IRP this was updated to HE 8–10 a.m. and HE 6–7 p.m.

5 https://atb.nrel.gov/

enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how operators build projects. The rules incentivize project developers to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities. The full effects of the legislation, once implemented, are not known at this time, but we were able to include some of the known effects of the federal IRA in this report.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before Congress enacted the IRA, PTCs expired for any new projects placed in service in 2022 and beyond. The IRA bill now extends PTCs to 100 percent for eligible projects in service before the end of 2032. The PTCs are now technology-neutral, so solar projects now qualify for PTC. We assumed PTC for wind and solar resources as the most economical use of the tax incentives.

Investment Tax Credits provide an energy tax credit based on the project's percentage of investment. Before Congress enacted the IRA, the ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent. Previously, the regulations restricted ITC for battery storage projects to hybrid battery storage projects paired with solar or other renewable energy generation assets. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change makes the system more flexible because the battery can charge from the grid and its paired solar project. We assumed ITC for energy storage resources.

The IRA includes subsidies for utility-scale resources and end-use customer appliances. We do not know how the federal government will implement the subsidies yet, so we cannot incorporate their impact on our customers' behavior. As we learn more about the policies to implement these subsidies, we will reflect the effects in future IRPs.

2.6. Economic or Market Forces

We incorporated the economic and market forces that affect the electric resource plan into the electric and natural gas price forecasts.

2.6.1. Electric Price Forecast

We developed this electric price forecast as part of our 2023 Electric Report. In this context, the electric price is not the rate charged to customers but PSE's price to purchase or sell one MWh of power on the wholesale market, given the prevailing economic conditions. Electric price is an essential input to this analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio. The updated electric price forecast reflects higher avoided energy costs due to updated modeling methodologies and assumptions to the electric price forecast model. The levelized nominal power price for the 2023 Electric Report is $42.90/MWh compared to the 2021 IRP, which was $23.37/MWh.

➔ A detailed account of all updates to the electric price model is in Chapter Five: Key Analytical Assumptions and Appendix G: Electric Price Models.

2.6.2. Natural Gas Price Forecast

The projection for natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices. Recent gas prices are elevated due to energy security concerns in Europe and accelerating coal retirements domestically, which leads to additional gas demand for the power sector and demand driven by liquefied natural gas (LNG) export expansion.

➔ We discuss natural gas in further detail throughout Chapter Five: Key Analytical Assumptions.

2.6.3. Alternative Fuels

For this report, we modeled two types of alternative fuels, hydrogen and biodiesel.

Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and poised to become a key energy carrier in the power sector. Production tax credits in the IRA reduce the market price of green hydrogen by up to $3 per kilogram, making it a cost-competitive energy carrier. We modeled green hydrogen as a fuel source for existing and new combustion turbines starting in 2030.

Biodiesel

Biodiesel is a renewable resource under RCW 19.405.020(34)[6] of CETA. Biodiesel must not be derived from crops raised on land cleared from old-growth or first-growth forests to be considered renewable. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or dedicated crops. We modeled biodiesel as a fuel source for new combustion turbines starting in the model year 2024.

➔ Further discussion of hydrogen and biodiesel as fuel sources is in Appendix D: Generic Resource Alternatives.

[6] RCW 19.405.020

2.7. Elements Found in Clean Energy Implementation Plan

In December 2021, we filed our first CEIP. The plan illustrates PSE's four-year roadmap to meet the requirements of CETA and the specific actions PSE will take from 2022–2025 to meet those goals. The CEIP proposes an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. We used the 63 percent target from the CEIP as the minimum for this 2023 Electric Report. The resource specific targets included in the CEIP and proposed in this report are:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar

We also applied certain customer benefit indicators (CBIs) identified in the CEIP that apply to resource planning.

3. Resource Need

Reliably meeting our customers' needs is the cornerstone of PSE's energy supply portfolio. For resource planning, the physical electricity needs of our customers are simplified and expressed as three resource needs: peak hour capacity need, energy need, and renewable and non-emitting energy need.

3.1. Peak Hour Capacity Need

We determined peak hour capacity need with a resource adequacy analysis that evaluated existing PSE resources compared to the projected peak need over the planning horizon. The capacity shown is the amount of effective capacity needed to maintain the resource adequacy target — the need after applying different resources' effective load carrying capacity (ELCC). Due to market reliance assumptions used in this 2023 Electric Report, the modeling indicates PSE could begin to experience a peak capacity shortfall starting in 2024. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 2,629 MW by 2029. The 2,629 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. Figures 8.2 and 8.3 show the winter and summer peak capacity needs through 2045.

Figure 8.2: Effective Peak Capacity Need — Winter

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)

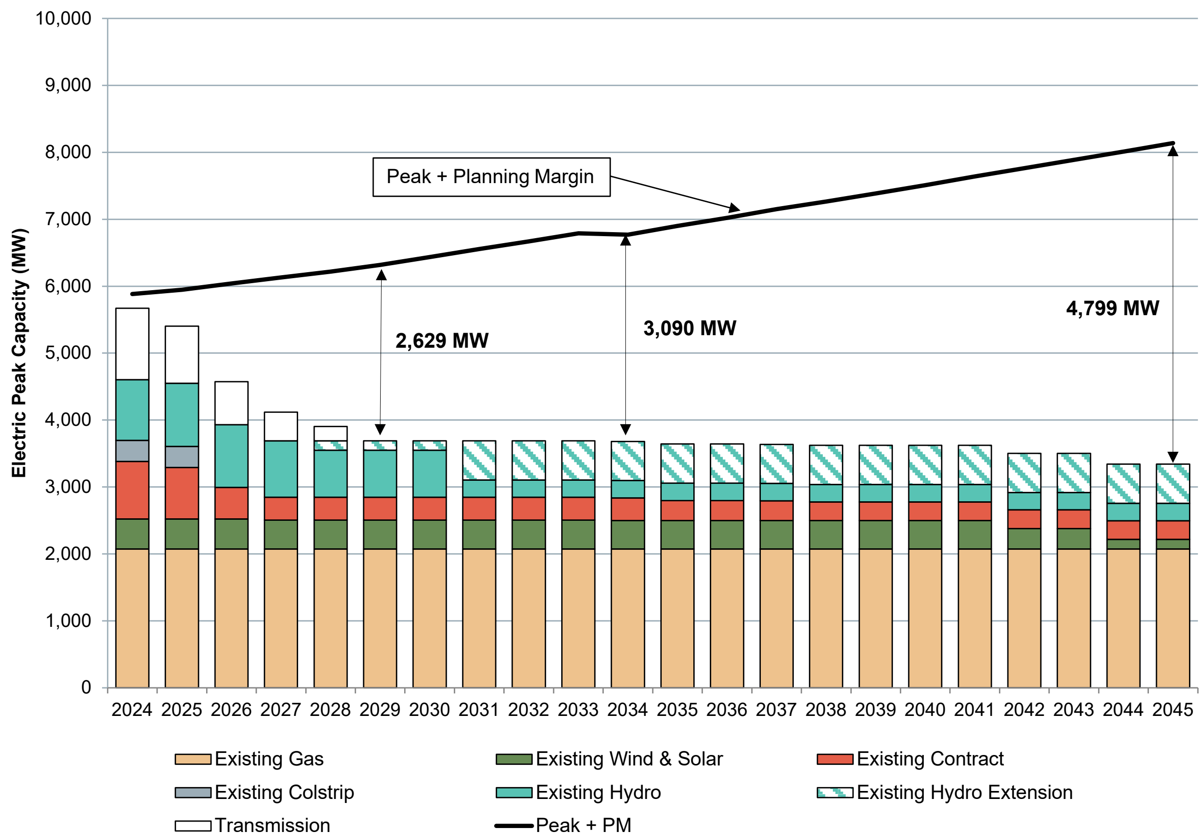
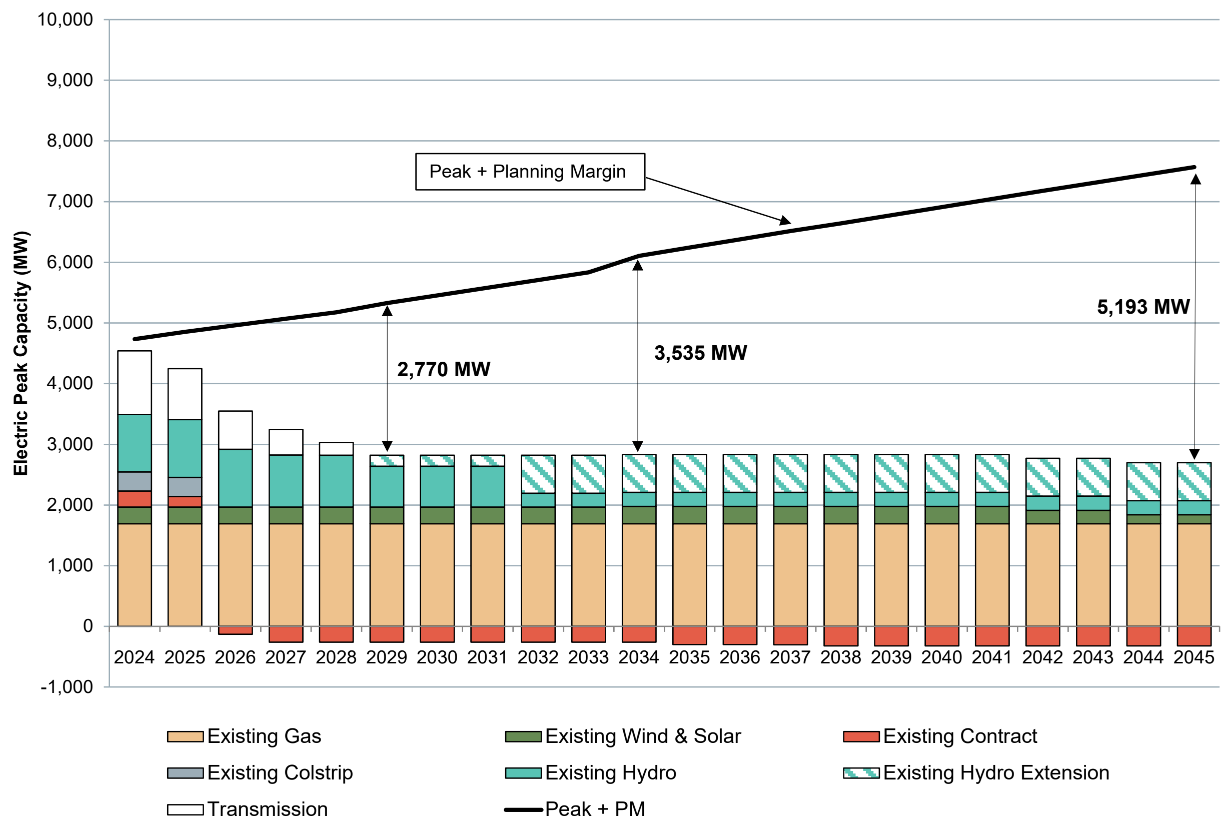


Figure 8.3: Effective Peak Capacity Need — Summer

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)



➔ See Chapter Seven: Resource Adequacy Analysis for a complete discussion of the resource adequacy analysis.

3.2. Energy Need

We must meet our customers' energy needs 24 hours a day, 365 days a year. Our models require the portfolios to supply the energy necessary to meet physical loads and examine how to do this most economically through existing resources, new resources, and purchasing and selling electricity on the energy market. Puget Sound Energy's annual energy need starts at 2,551 aMW for 2024, increases to 2,799 aMW in 2030, and reaches 3,699 aMW in 2045.

➔ See Chapter Six: Demand Forecast for a detailed discussion on energy demand.

3.3. Renewable and Non-emitting Energy Need

In addition to reliably meeting the physical needs of our customers, CETA requires that utilities meet at least 80 percent of electric sales (delivered load) in Washington State by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 8.4 illustrates PSE's renewable and non-emitting energy need. For the long-term IRP analysis, we assumed a linear ramp to achieve the Clean Energy Transformation Standards Act standards in 2030 and 2045 described in RCW 19.405.040;[7] however, actual resource acquisitions through implementation of the CEIP will likely produce a less linear pathway than we show. Before any conservation, the renewable energy need is over 7 million MWh in 2030 to meet the 80 percent clean energy standard. The renewable need is the difference between the green line and the teal bars in Figure 8.4.

[7] RCW 19.405.040

Figure 8.4: Qualifying Energy Need to Meet CETA Requirements
(Before Demand-side Resources)

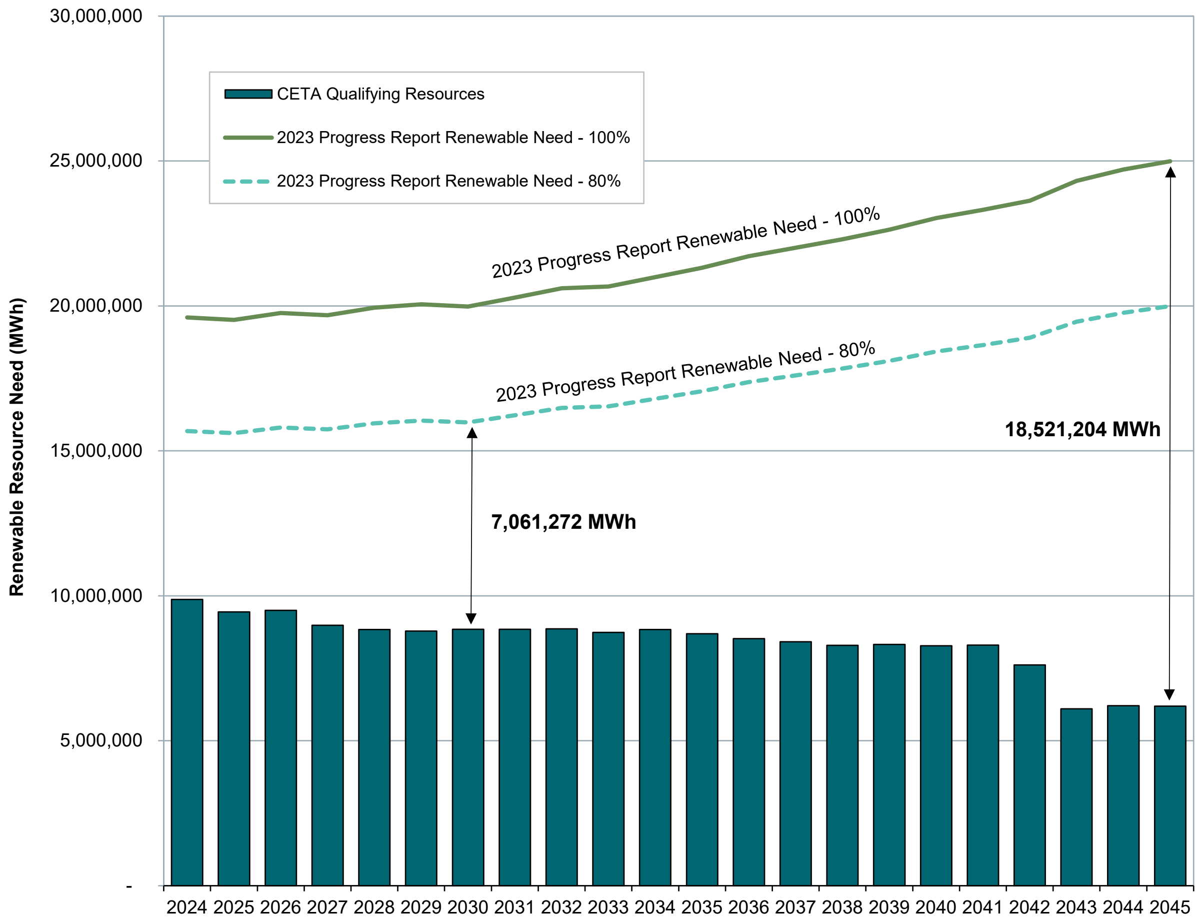
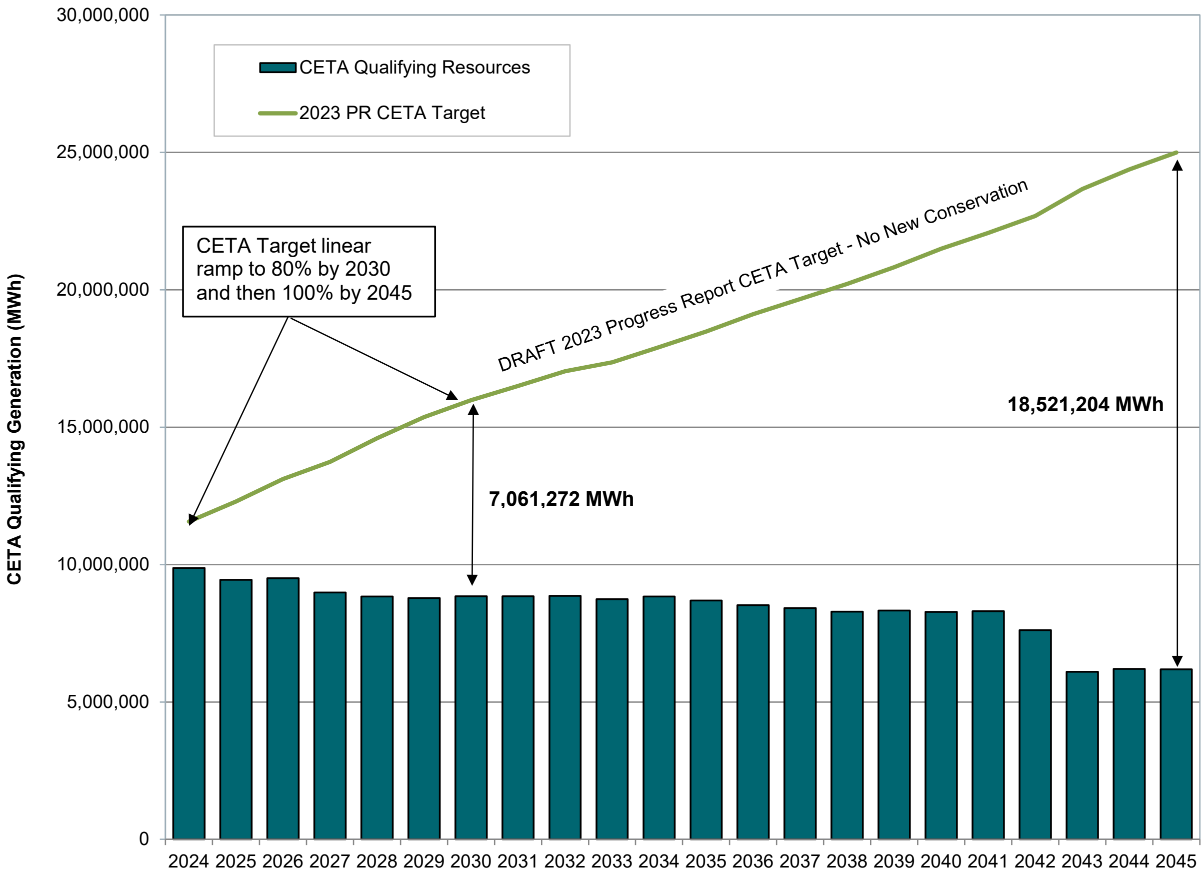


Figure 8.5 assumes a linear ramp to reach the 80 percent clean energy standard in 2030 and the 100 percent clean energy standard in 2045. We used the linear ramp to ensure the portfolio model gradually adds resources to meet clean energy standards rather than waiting until the goal's final target year to add them. The linear ramp starts in 2024, as the model assumes all new resources are self-builds, with most available to begin in 2024.

Figure 8.5: Renewable Need and Linear Ramp for CETA (Before Demand-side Resources)



4. Types of Analysis

We used deterministic optimization analysis to identify each portfolio's lowest reasonable cost. We then ran a stochastic risk analysis to test different resource strategies.[8] We used the portfolio benefit analysis to inform the equitable distribution of burdens and benefits in the resource planning process to ensure all customers benefit from the transition to clean energy.

4.1. Deterministic Portfolio Optimization Analysis

We subjected all the portfolios to deterministic analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio — the lowest-cost mix of demand-side and supply-side resources that will meet the need under the given static assumptions defined in the scenario or sensitivity. This stage helped us learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

[8] To screen some resources, we also used 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.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model used for portfolio modeling, only solves for the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable outcomes for customers while also considering cost.

The portfolio benefit analysis measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative CBIs and their metrics. Customer benefit indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources
- **Improved affordability of clean energy** — measured by the total portfolio cost
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio
- **Increased number of jobs** — measured by the number of estimated jobs generated for each portfolio
- **Increased participation in Energy Efficiency, Distributed Energy Resource, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq[9] generated per portfolio
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (excluding the portfolio cost) normalized to the reference portfolio, also known as the least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index is then compared to its total cost (direct and externality costs).

[9] CO_2-eq or CO_2-equivelant is a measure used to compare the emissions from various greenhouse gases on the basis of their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

➔ Appendix H: Electric Analysis and Portfolio Model includes a more detailed description of the methods used to conduct the portfolio benefits analysis.

4.3. Stochastic Risk Analysis

In this stage of the resource plan analysis, we examined how different resource strategies respond to the types of risk that reflect future uncertainty. We deliberately varied static inputs in the deterministic analysis to create simulations called draws, which we used to analyze the different portfolios.

With stochastic risk analysis, we tested the robustness of different portfolios to determine how well the portfolio might perform under various conditions. The goal is to understand the risks of varying candidate portfolios regarding costs. To assess those risks, we identified and characterized the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

To gain this understanding, we took some of the portfolios (drawn from the deterministic analysis of portfolios) and ran them through 310 draws[10] that modeled varying power prices, gas prices, hydroelectric generation, wind, and solar generation, load forecasts (energy and peak), and plant forced outages.

5. Reference Portfolio Analysis Results

The reference portfolio is the least-cost portfolio that meets CETA, energy, and reliability requirements. The reference portfolio sets the stage as the starting point that leads to an informed preferred portfolio. The reference case portfolio cost is $17.6 billion, and the social cost of greenhouse gases (SCGHG) is $3.2 billion, totaling $20.8 billion in total portfolio costs.

5.1. Reference Case Portfolio Builds

This section describes the resource additions needed for the reference portfolio to meet CETA requirements, reliability needs, and future energy growth.

5.1.1. Clean Energy Transformation Act

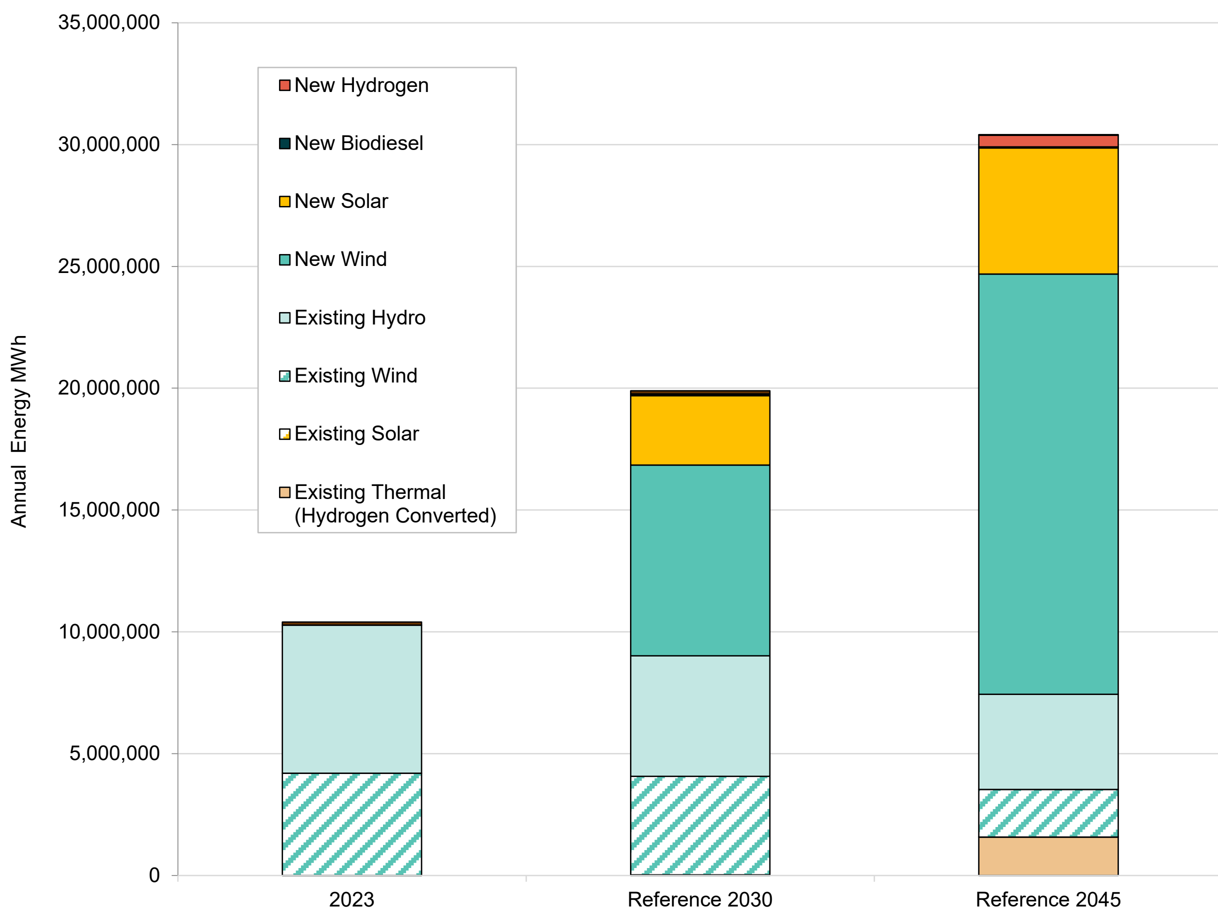
Figure 8.6 shows the energy breakdown from CETA-qualifying resources[11] for select years through 2045. Energy contribution from CETA-qualifying resources grows from over 10 million MWhs in 2023 to 20 million MWhs in 2030 and 30 million MWhs in 2045. New resources will be added to the portfolio starting in 2024, and by 2030 we will see a mix of hydroelectric, wind, solar, and hybrid resources (the renewable portion) eligible to meet CETA added to the portfolio. By 2045, energy from wind resources will make up most of the energy produced from CETA-qualifying

[10] Each of the 310 simulations is for the 22-year IRP forecasting period, 2024–2045.

[11] CETA-qualifying resources include all resources that qualify as renewable or non-emitting under CETA , which include renewables, hydrogen, biodiesel, and advanced nuclear as defined in RCW 19.405.020 (28) and (34)

resources. We also count energy from hydrogen and biodiesel peakers toward CETA achievement; however, those resources have a limited capacity factor and are mostly available to meet peak in high demand hours.

Figure 8.6: Energy for CETA-qualifying Resources — Reference Portfolio



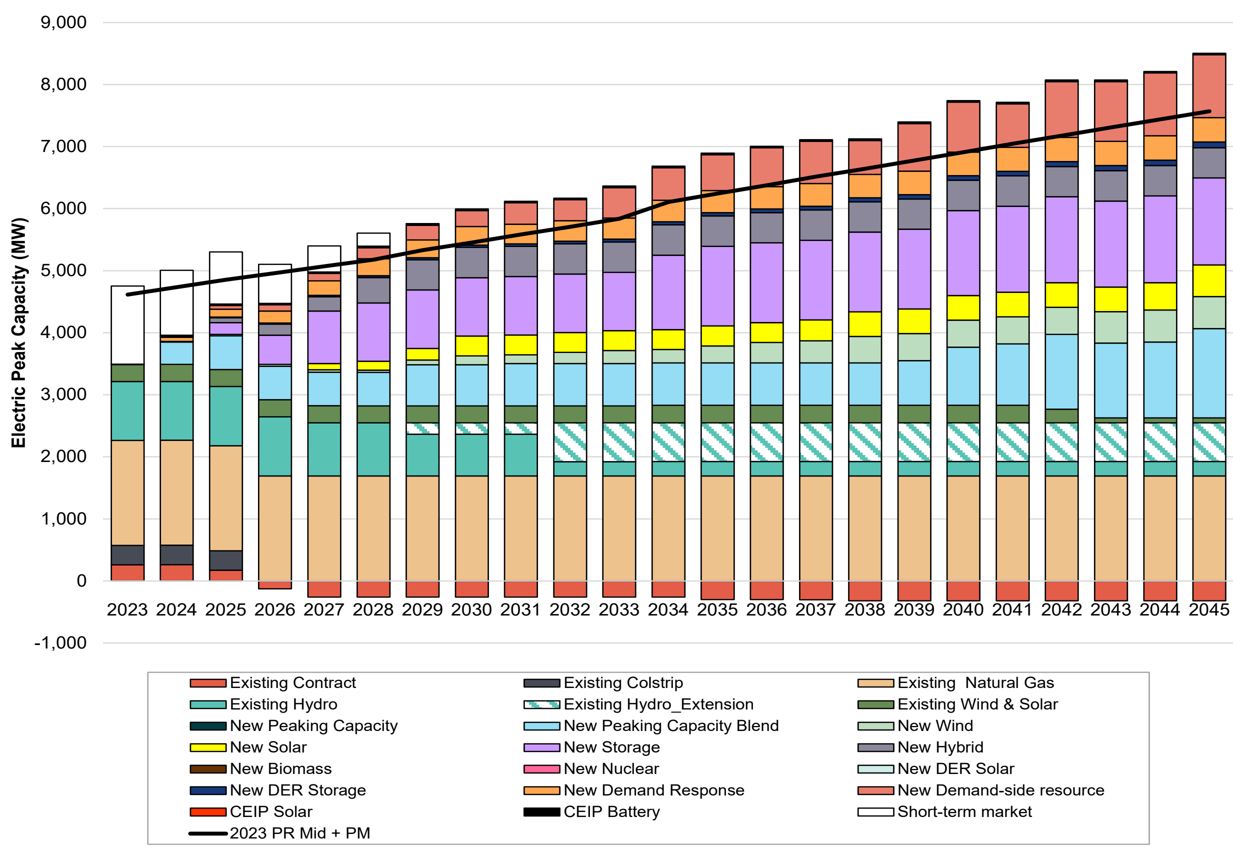
5.1.2. Meeting Reliability Needs

Many factors affect PSE's resource adequacy analysis, including climate change, electric vehicle forecast, and market reliance. Incorporating climate change data resulted in slightly lower normal winter peaks due to higher average temperatures in the winter, while the temperatures were higher on average for the summer leading to higher summer peaks. We also updated the electric vehicle forecast, which increased the winter peak demand. The increase from the electric vehicle forecast offset the decrease in normal winter peak from the climate change data.

Regarding market reliance, there is a concern about the availability of firm capacity in the short-term market. Puget Sound Energy currently has over 2,000 MW of available capacity to the Mid-Columbia (Mid-C) market, with a portion allocated to existing PSE-owned or contracted Mid-C resources, leaving PSE net about 1,400 MW to 1,500 MW of available Mid-C capacity for short term market purchases. This 1,500 MW of available Mid-C capacity was a firm resource in portfolio modeling for previous IRPs. For the 2023 Electric Report, we assumed that access to the short-term market would continue to be available but in decreasing amounts into the future. By 2029, we assumed that none of the transactions in the short-term market would be firm. The assumed reduction in market reliance increased PSE's peak needs. The winter peak need remains greater than the summer peak need through 2045.

Figure 8.7 provides a breakdown of peak capacity contribution by resource type for the summer. The solid black line in the chart represents the summer peak capacity. The combination of existing and new resource peak capacity for the reference portfolio in the summer is surplus of the summer target. Many of the resources we added to help meet CETA requirements, particularly solar resources, have a larger peak capacity contribution in the summer than in the winter. The peak contribution from energy storage resources is also larger in the summer than in the winter — PSE's system is built to meet winter peaking needs and is consequently surplus in the summer months.

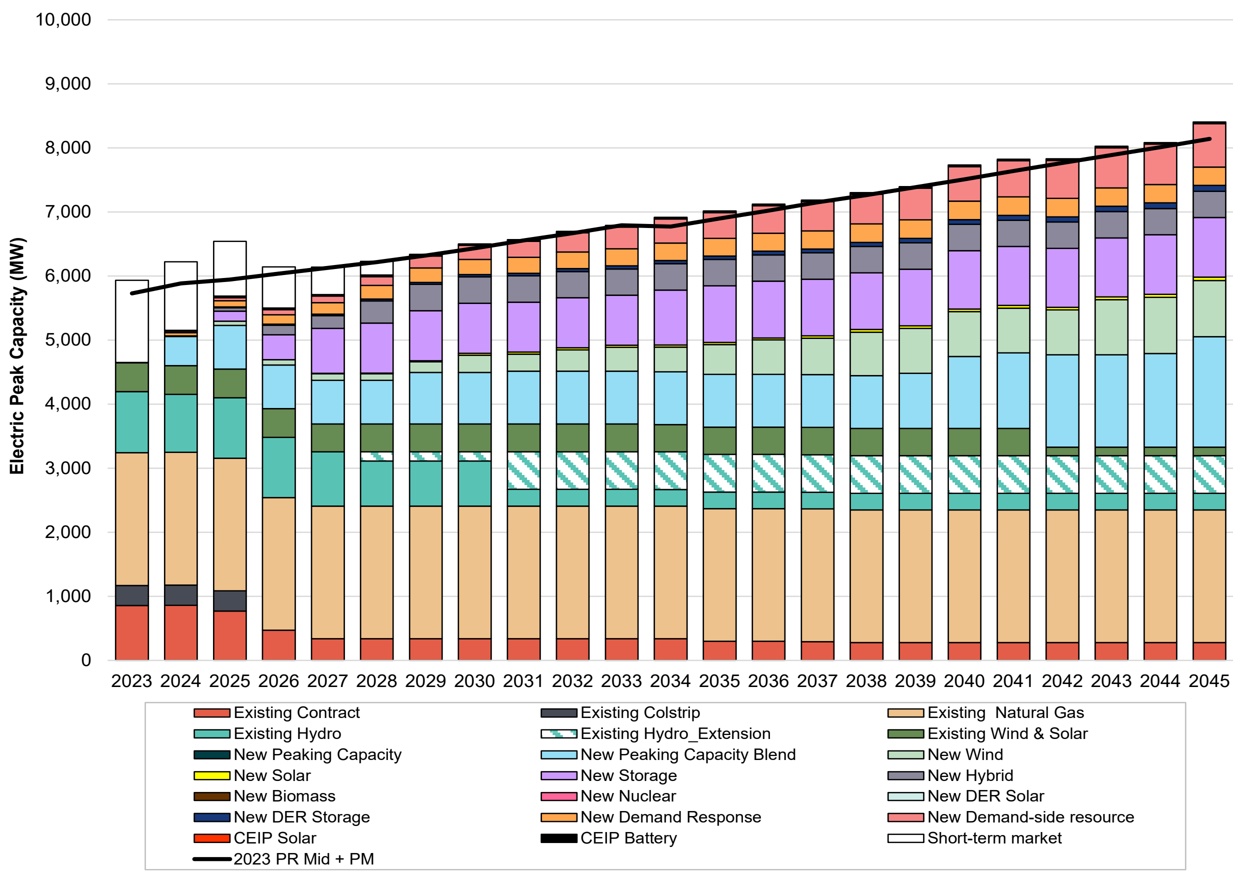
Figure 8.7: Effective Summer Peak Capacity by Resource Type – Reference Portfolio



➔ See Chapter Seven: Resource Adequacy Analysis for more details on resource adequacy.

However, new renewable resources' peak capacity is insufficient to meet winter peaks. We still need additional new peaking capacity to add to the reference portfolio. Looking at the same chart for the winter, we see the reference portfolio is no longer surplus but on target to meet the winter peak capacity. Figure 8.8 provides a breakdown of peak capacity by resource type for the winter. The solid black line in the chart represents the winter peak capacity plus the planning margin. Winter peak need drives new capacity resource builds for the reference portfolio.

Figure 8.8: Effective Winter Peak Capacity by Resource Type – Reference Portfolio



5.1.3. Meeting Future Growth

Puget Sound Energy meets our CETA, energy, and reliability requirements through a combination of conservation, demand response, distributed energy and clean energy resources, energy storage, and CETA-qualifying peaking new capacity resources. Overall cumulative capacity builds through 2045 is 14,287 MW. Table 8.1 summarizes the reference portfolio's incremental nameplate capacity for select years and the cumulative nameplate capacity.

Table 8.1: Incremental Resource Additions — Reference Portfolio (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand-side Resources	**184**	**369**	**553**	**547**	**1,100**
Conservation	51	175	226	469	695
Demand Response	133	194	327	78	405
Distributed Energy Resources	**182**	**252**	**434**	**1,177**	**1,612**
DER Solar	142	230	372	1,122	1,494
Net Metered Solar	59	225	284	1,109	1,393
CEIP Solar	79	-	79	0	79
New DER Solar	4	5	9	13	22
DER Storage	40	22	62	55	117
Supply-side Resources	**1,761**	**4,227**	**5988**	**5,587**	**11,575**
CETA Qualifying Peaking Capacity	711	128	839	949	1,788
Wind	600	800	1400	2,650	4,050
Solar	0	1,100	1100	1,290	2,390
Green Direct	0	100	100	0	100
Hybrid (Total Nameplate)	250	1,300	1550	0	1,550
Hybrid Wind	*100*	*800*	*900*	*0*	*900*
Hybrid Solar	*100*	*100*	*200*	*0*	*200*
Hybrid Storage	*50*	*400*	*450*	*0*	*450*
Biomass	0	0	0	0	0
Advanced Nuclear SMR	0	0	0	0	0
Standalone Storage	200	800	1000	700	1,700
Total	**2,127**	**4,849**	**6976**	**7,311**	**14,287**

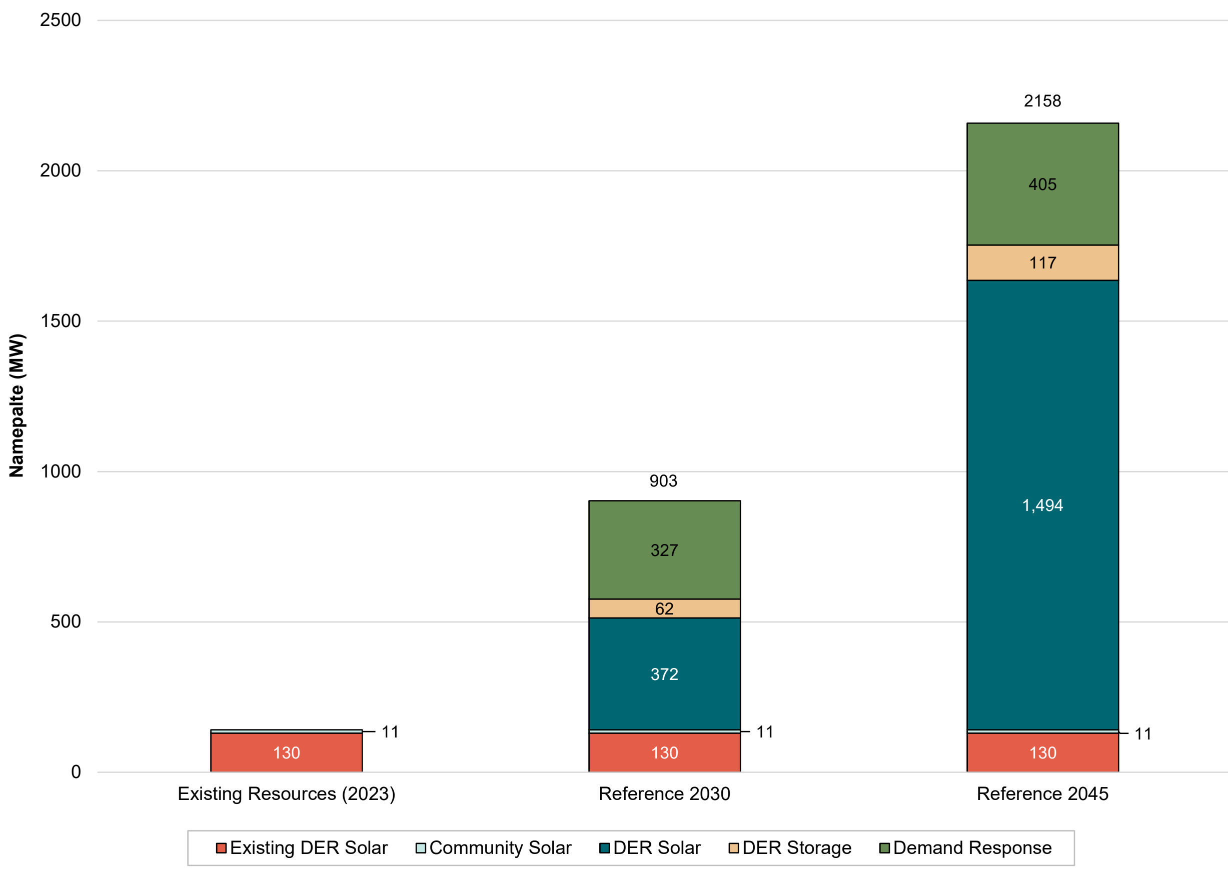
Demand-side Resources

In the AURORA model, conservation is consider a supply-side resource eligible to meet CETA requirements and competes with lower cost renewable resources during the resource selection. Conservation selected in the reference portfolio includes future effects of current Codes & Standards, Distribution Efficiency, and energy efficiency programs, with a total 695 MW added by 2045. A significant amount of demand response programs will be added to the reference portfolio for 405 MW by 2045, including a 12 MW demand response potential for interruptible customers. The high peak contribution and low program costs lead to increased amounts of demand response selected in the reference portfolio.

Distributed Energy Resources

Distributed energy resources for the reference portfolio combine net metering solar forecasts from Cadmus, PSE's forecast of DER solar additions, and DER solar targeted in the 2021 CEIP, totaling 1,494 MW by 2045. The total DER storage added to the portfolio by 2045 is 117 MW, a combination of PSE's forecast of DER storage projects and the DER storage targeted in the 2021 CEIP. Figure 8.9 shows the significant growth in distributed energy resources through 2045

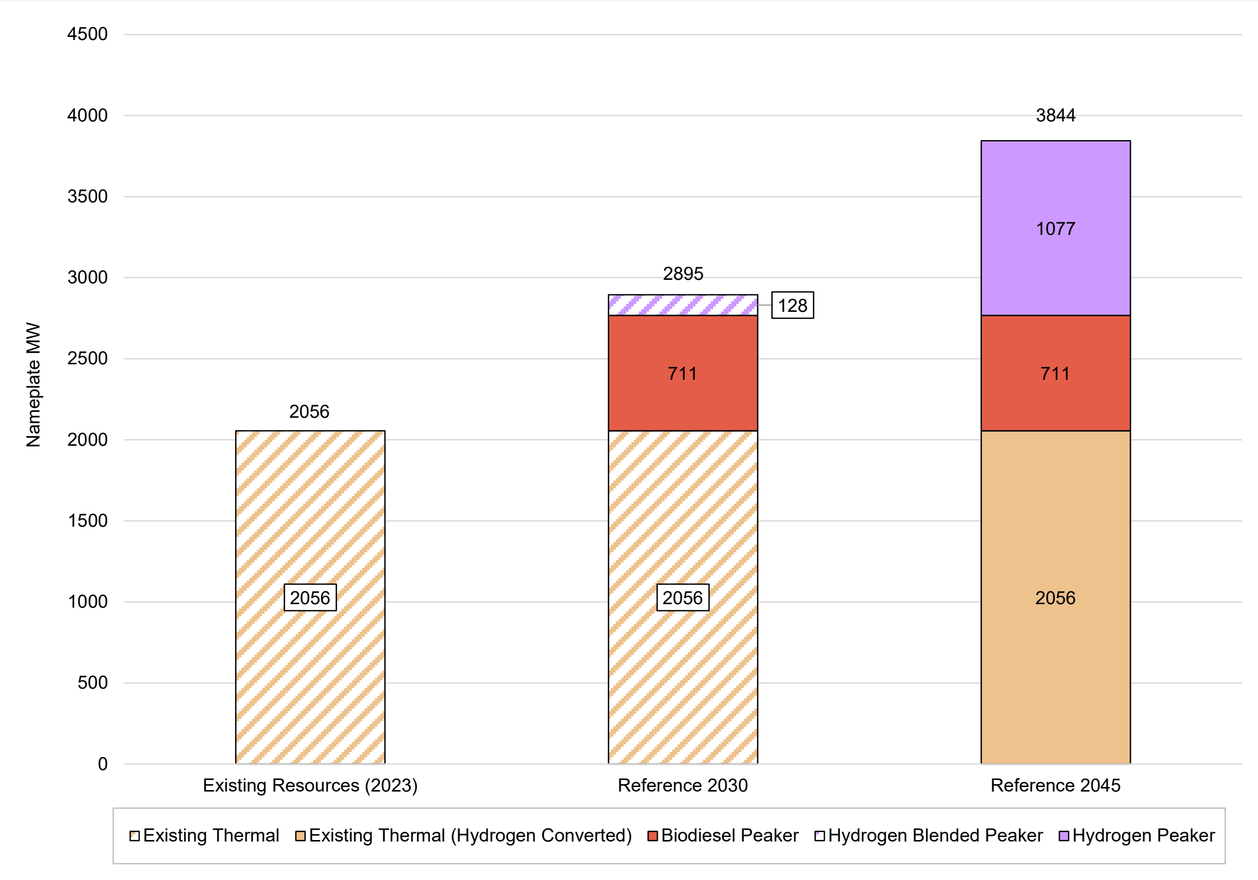
Figure 8.9: Cumulative Nameplate Capacity in MW for Distributed Energy Resources – Reference Portfolio Clean Energy Transformation Act Qualifying Peaking Capacity



CETA Qualifying Peaking Capacity Resources

By 2025, we will add 711 MW of frame peaker biodiesel plants in the reference portfolio to fill the peak need as we phase out our reliance on firm, short-term market purchases. These biodiesel peakers also help to counteract the anticipated retirement of Colstrip and Centralia power purchase agreements (PPA) by the end of 2025. By 2030, we see the addition of 128 MW of peakers using blended natural gas and hydrogen resources as firm short-term market purchases decline to zero MW. In 2031–2045, we see the addition of 711 MW of frame peaker blended natural gas and hydrogen resources and 238 MW of reciprocating peaker blended natural gas and hydrogen resources to help fill the peak needs for the portfolio in the later years. These natural gas/hydrogen blend peaking units can also have biodiesel backup capability if hydrogen is unavailable physically or economically. A discussion of the natural gas and hydrogen blending is in Appendix D: Generic Resource Alternatives. Figure 8.10 shows the cumulative additions of CETA-qualifying peaking capacity resources through 2045.

Figure 8.10: Cumulative Nameplate Capacity in MW for CETA-qualifying Peaking Capacity Resources — Reference Portfolio



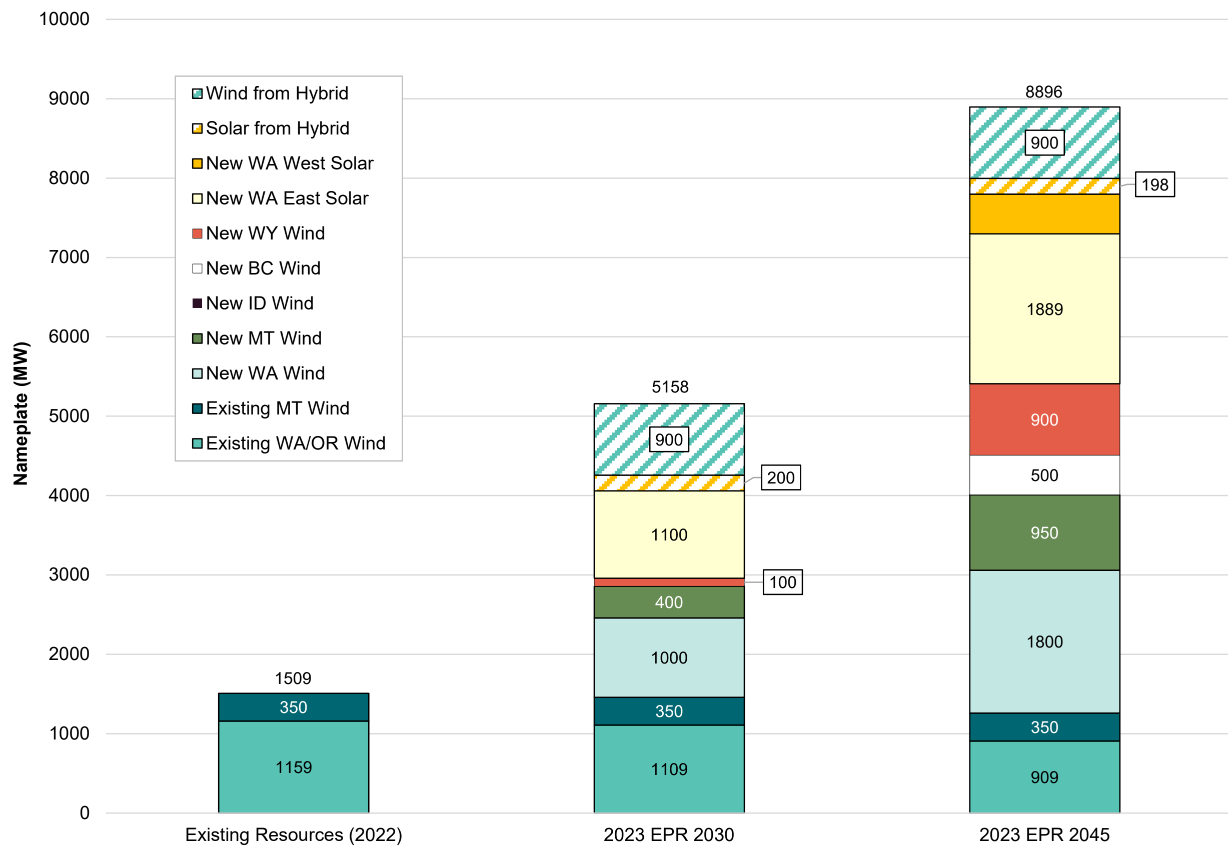
Wind and Solar Resources

We modeled multiple wind regions for this report, and we see this diversity reflected in the Reference portfolio, including Washington wind (WA), British Columbia wind (BC), Montana wind (MT), and Wyoming wind (WY) resources. Although we limited transmission for the wind resources in the near term, we assume unlimited transmission starting in 2035 for the various regions.

➔ A discussion of the transmission constraints is in Chapter Five: Key Analytical Assumptions.

By 2045, we added 5,050 MW of wind to the portfolio. This total includes a 100 MW Green Direct wind we added to the portfolio in 2026. Almost 2,100 MW of solar added to the reference portfolio comes from the WA East region and an additional 500 MW from the WA West region. We will add nearly 8,900 MW of wind and solar to the portfolio by 2045 to meet CETA requirements. Figure 8.11 shows wind and solar resources' significant growth and diversification through 2045.

Figure 8.11: Wind and Solar Resources Cumulative Nameplate Capacity – Reference Portfolio (MW)

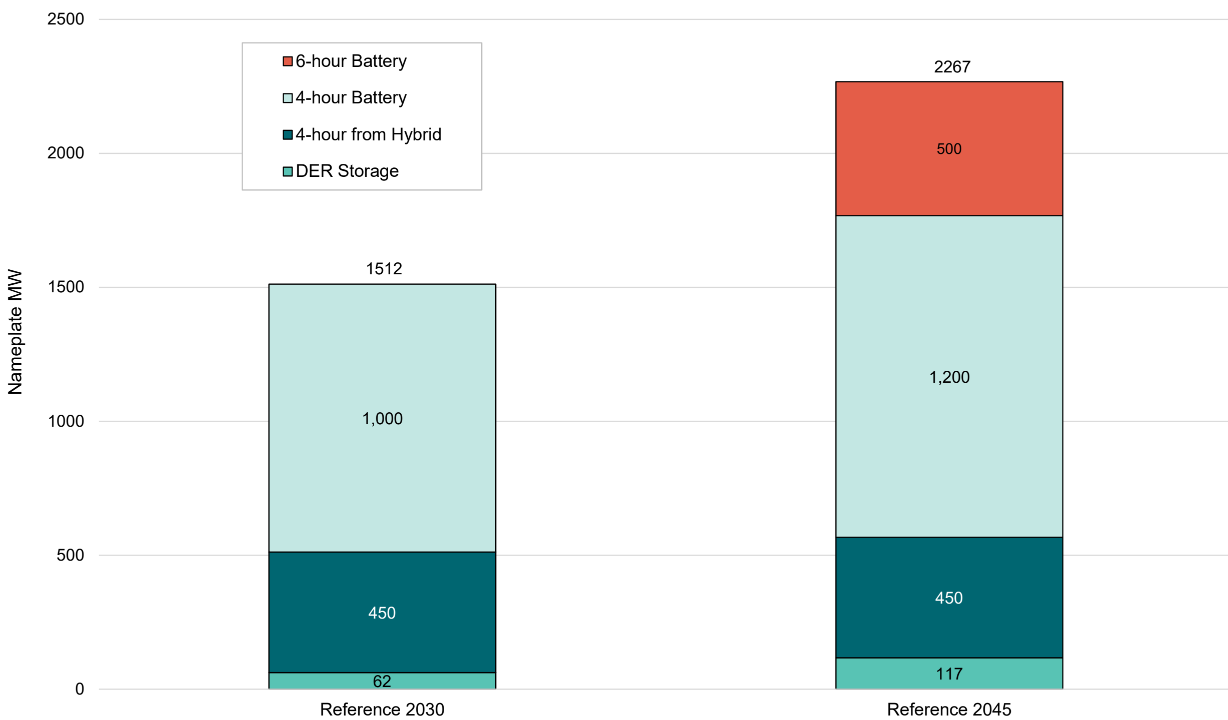


Energy Storage

Energy storage added to the portfolio comes from 1,200 MW of 4-hour batteries and 500 MW of 6-hour batteries. An additional 450 MW of 4-hour batteries are also added from the hybrid resources. Storage resources have a high effective load carrying capability (ELCC) for the first tranche of 1,000 MW, which is beneficial in meeting peak needs; however, the saturation effect can significantly impact the ELCCs. Figure 8.12 shows the storage additions through 2045.

➔ See Chapter Five: Key Analytical Assumptions for a detailed discussion of hybrid resources, and Chapter Seven: Resource Adequacy for ELCC energy storage and saturation effects.

Figure 8.12: Cumulative Nameplate Capacity in MW for Storage Resources — Reference Portfolio



Nuclear Small Modular Reactors and Biomass

Advanced nuclear small modular reactors (SMRs) and Biomass resources are CETA-qualifying resources; however, we did not add them to the reference portfolio due to higher costs than the resources.

➔ See Appendix I: Electric Analysis Inputs and Results for more detailed information on portfolio build results.

6. Sensitivity Analysis Results

Portfolio sensitivity analysis is an essential form of risk analysis that helps us understand how specific assumptions change the mix of resources in the portfolio and affect portfolio costs. Examples of a sensitivity include requiring the model to have 400 megawatts of energy storage in 2025 and 2026, relaxing transmission constraints between 2040 and 2045, or restricting any thermal resource additions during the entire planning period. This section provides the results and detailed analysis for each sensitivity.

More results, including year-by-year resource timelines, cost breakdowns, and emissions data, are in Appendix I: Electric Analysis Inputs and Results. Chapter Five: Key Analytical Assumptions includes 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. Appendix D: Generic Resource Alternatives discusses existing electric resources and resource alternatives. Appendix J: Economic, Health, and Environmental Benefits Assessment of Current Conditions details the CBIs we used in the customer benefits analysis.

6.1. Summary of Resource Modeling Assumptions

The resource alternative sensitivities schedule targeted and isolated resource additions to explore the effects on builds, cost, and emissions. Sensitivities 2–9 explore adding additional conservation, distributed resources, pumped heat electrical storage (PHES) resources, maximizing existing Montana transmission, and pursuing advanced nuclear SMR resources.

The diversified portfolio sensitivities 11 A1 and 11 B2 take what we learned from sensitivities 2–9 and combine them in a portfolio to identify an achievable portfolio of diverse resources that maximize equity-related benefits while maintaining reliability and affordability.

We modeled sensitivities 10 and 12 through 16 following requests from interested parties.

Table 8.2 describes the sensitivities we evaluated in this 2023 Electric Report.

➔ Additional details, including assumptions, are available in Chapter Five: Key Analytical Assumptions.

Table 8.2: 2023 Electric Progress Report Portfolios and Sensitivities

ID	Name	Type	Description
1	Reference	Portfolio	Least-cost and CETA-compliant
2	Conservation Bundle 10	Resource Alternative	Reference + Increase conservation to 486 aMW by 2045
3	Conservation Bundle 7	Resource Alternative	Reference + Increase conservation to 381 aMW by 2045
4	DER Solar	Resource Alternative	Reference Portfolio + 30 MW/year of DER rooftop solar from 2026–2045
5	DER Batteries	Resource Alternative	Reference + 25 MW/year of DER batteries (3-hour Li-ion) from 2026–2031
6	MT Wind PHES, All East Wind	Resource Alternative	Reference + 400 MW MT East Wind + 200 MW MT PHES in 2026
7	MT Wind PHES, Central & East Wind	Resource Alternative	Reference + 200 MW MT East Wind + 200 MW MT Central Wind + 200 MW MT PHES in 2026
8	PNW PHES	Resource Alternative	Reference + 200 MW of PNW PHES in 2026
9	Advanced Nuclear SMRs	Resource Alternative	Reference + 250 MW of advanced nuclear SMRs in 2032
11 A1	Least Diversified Sensitivity w/ Advanced Nuclear SMRs	Diversified portfolio	Reference + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT

ID	Name	Type	Description
			PHES in 2026 + 250 MW advanced nuclear SMRs in 2032
11 A2	Diversified + PNW PHES	Diversified portfolio	Diversified Portfolio 11 A1 + 200 MW PNW PHES in 2026
11 A3	Diversified + DER Solar	Diversified portfolio	Diversified Portfolio 11 A2 + 30 MW per year of DER rooftop solar from 2026–2045
11 A4	Diversified + DER Batteries	Diversified portfolio	Diversified Portfolio 11 A3 + 25 MW per year of DER batteries (3hr Li-ion) from 2026–2031
11 A5	Diversified + All DR Programs	Diversified portfolio	Diversified Portfolio 11 A4 + All DR Programs
11 B1	Least Diversified w/o Advanced Nuclear SMRs (11 A1 – Adv. Nuclear SMRs)	Diversified portfolio	Reference portfolio + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT PHES in 2026 Similar to Diversified Portfolio A1, without Adv. Nuclear SMRs
11 B2	Most Diversified w/o Advanced Nuclear SMRs (11 A5 – Adv. Nuclear SMRs)	Diversified portfolio	Diversified Portfolio 11 A5 less 250 MW Advanced Nuclear SMRs in 2032
10	Thermal builds prohibited before 2030	Requested Sensitivity	Reference + Peaker plants use biodiesel as an alternative fuel.
12	100% Renewable/Non-Emitting by 2030	Requested Sensitivity	Reference + Existing thermal retired by 2030; no new thermal allowed
13	High Carbon Price	Requested Sensitivity	Reference + CCA ceiling price used for all carbon allowances
14	No Hydrogen Fuel Available	Requested Sensitivity	Reference + Natural gas and biodiesel fuel are available, but not hydrogen fuel
15	SGHG in Dispatch	Requested Sensitivity	Reference + Model SCGHG costs as dispatch cost in the long-term capacity (LTCE) expansion model
16	WRAP Adjustment	Requested Sensitivity	Reference + Adjust PRM and ELCCs using information from WRAP

6.2. Key Findings

This section briefly summarizes the results of each sensitivity analyzed in this report.

6.2.1. Resource Alternative Sensitivities

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7

More expensive conservation measures led to a slightly lower selection of renewable resources and increased the overall portfolio costs. Increased additions of conservation measures provided near-term benefits in greenhouse gas emission reductions. However, the impact of emission reduction in the long-term, particularly in 2045, when almost all the resources in the portfolio are considered CETA-qualifying, is less significant. A further discussion of energy efficiency measures modeled can be found in Appendix E: Conservation Potential Assessment.

Sensitivity 4 DER Solar: Scheduling in additions of DER Solar at a rate of 30MW per year did not produce a substantially different portfolio but accounted for a notable increase in solar capacity and moderate change in total portfolio cost.

Sensitivity 5 DER Storage: Significant resource movement occurred due to a relatively small incremental increase in DER storage, such as 500 MW less utility-scale solar, added to the portfolio compared to the reference portfolio. This sensitivity decreased portfolio cost by $0.14 billion and decreased the total portfolio cost with SCGHG by $0.08 billion.

Sensitivity 6 MT Wind and Pumped Hydroelectric Energy Storage (PHES), All MT East Wind: Scheduled additions of eastern Montana wind and Montana pumped hydroelectric storage delay the addition of CETA qualifying peak resources, resulting in an accelerated reduction of GHG emissions but at an overall higher portfolio cost. Compared to sensitivity 7, which adds both eastern and central Montana wind and Montana PHES, sensitivity 6 provides fewer greenhouse gas reductions but significantly lower total portfolio cost. Therefore, sensitivity 6 is a more cost-effective strategy to lower greenhouse gas emissions and diversify energy storage resources.

Sensitivity 7 MT Wind and PHES, Central and East Wind: Scheduled additions of Montana east and central wind and Montana PHES slightly accelerate the reduction of greenhouse gases compared to the reference portfolio but at a higher overall portfolio cost. Compared to sensitivity 6, which adds only eastern Montana wind and Montana PHES (no central Montana wind), the greenhouse gas emission reductions for sensitivity 7 are greater, but the overall portfolio cost is also higher. Therefore, it is not a cost-effective strategy to overbuild the capacity of Montana transmission to reduce greenhouse gas emissions and diversify the energy storage resources.

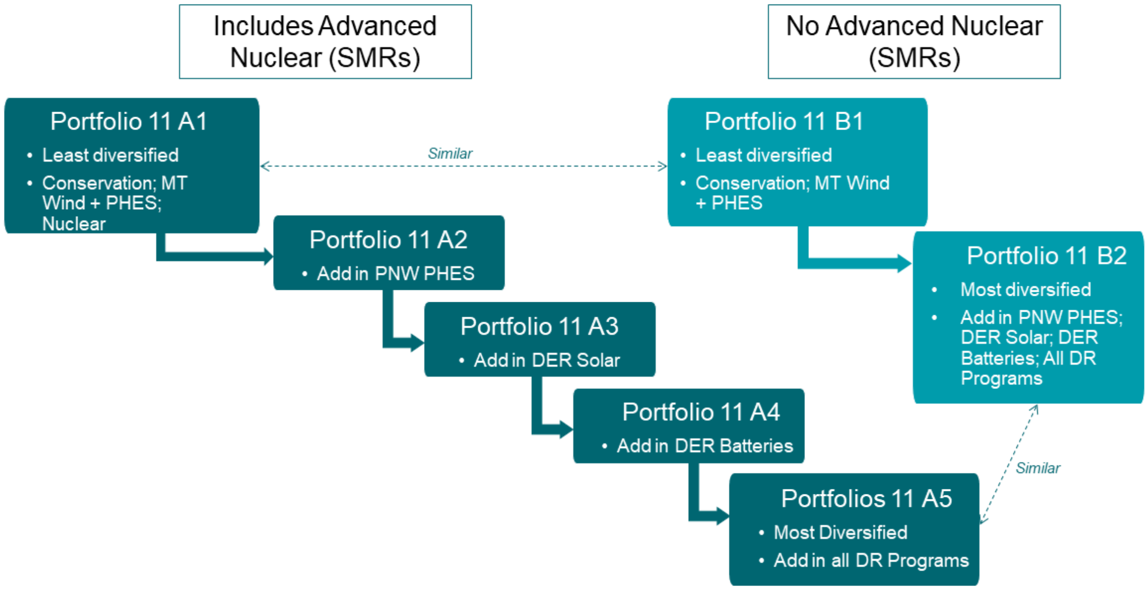
Sensitivity 8 PNW PHES: There is little difference between sensitivity 8 and the reference portfolio. Adding PNW PHES increases portfolio cost but results in little change to the overall outcome of the portfolio in terms of resource additions and greenhouse gas emissions, suggesting there is little benefit in adding PNW PHES as a means to diversify away from battery energy storage systems in the preferred portfolio.

Sensitivity 9 Advanced Nuclear Small Modular Reactors (SMRs): The ability of advanced nuclear SMRs to provide reliability and flexibility benefits for peak events while also providing the added benefit of emission-free production for meeting the CETA clean energy standards lead to the displacement of some renewable and peaking capacity resources. Overall, we see slightly lower portfolio additions by 2045 due to the addition of 250 MW of SMR; however, these advanced nuclear SMRs are more expensive and raise the portfolio costs by $1.47 billion.

6.2.2. Diversified Portfolio Sensitivities

The diversified portfolio sensitivities broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. Figure 8.13 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 8.13 Diversified Portfolio Sensitives Map



Sensitivity 11 A1–A5 Diversified: All diversified 11 A sensitivities have higher costs than the reference portfolio. As expected, each sequential resource addition correspondingly increases the sensitivity cost: of the diversified 11 A sensitivities, 11 A1 has the least cost and 11 A5 the highest. Adding advanced nuclear SMR resources will cause an additional cost spike in 2032.

Resource additions are relatively similar across the 11 A sensitivities by 2030, with expected variation in DER resources as these are added in 11 A3 and beyond. Notably, CETA qualifying peaking capacity in 2030 is equivalent across all sensitivities, including the reference, indicating a need for dispatchable energy soon. In the longer term, the wind, solar, and hybrid resource mix becomes slightly more pronounced across the diversified 11 A sensitivities, while CETA-qualifying peaking capacity, demand-side resources, and stand-alone storage resources are relatively similar. All diversified 11 A sensitivities reduce GHG emissions compared to the reference portfolio. This reduction is greatest in sensitivity 11 A5, which produces 7 million short tons fewer emissions than the reference portfolio.

Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMR: Sensitivity 11 B1 provides a little diversification relative to the reference portfolio by adding PHES and increasing energy efficiency measures. These scheduled additions result in a markedly different overall portfolio with fewer nameplate additions, made possible by selecting resources with higher peak capacities contributions, such as hybrid resources instead of stand-alone wind and solar resources. Despite adding fewer resources overall, the early addition of hybrid and storage resources inflated the portfolio cost above the reference portfolio. Greenhouse gas emission reductions are accelerated before 2030 but align with the reference portfolio 2030–2045.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Sensitivity 11 B2 provides diversification relative to the reference portfolio by adding distributed energy resources, PHES, and additional DSR. This diversification shifts the resource mix away from utility-scale resources toward distributed energy resources and DSR. Early additions of Montana wind and distributed solar reduce existing thermal resources dispatch and accelerate the reduction of greenhouse gases before 2030. Fewer new thermal peaking capacity resources are required in sensitivity 11 B2 due to increased additions of stand-alone storage and hybrid resources. We selected this portfolio as the preferred portfolio and explained its benefits in Chapter Three: Resource Plan of the 2023 Electric Report.

6.2.3. Requested Sensitivities

Sensitivity 10 No New Thermal before 2030 and Biodiesel as the Alternative Fuel: Delaying the availability of thermal peaking capacity resources until 2030 results in an additional 3,700 MW of battery storage and 900 MW of hybrid resources before 2030, displacing 839 MW of thermal plants built during that time. Adding over 5.0 GW of batteries in six years would be challenging to accomplish, given the magnitude. As of October 2022, only 7.8 GW of utility-scale batteries are operating nationwide.[12] After we lifted the thermal restriction in the model, it added minimal batteries due to the over-saturation of batteries in meeting peak. This sensitivity is $0.91 billion more expensive than the reference portfolio.

Sensitivity 12 100 Percent Renewable/Non-Emitting by 2030: Implementing the necessary changes for this sensitivity created substantial issues for the model. The short-term resource need became too large due to mass retirements of firm capacity, and the model could not make up for this with available new resources and transmission constraints as defined in the reference case. This sensitivity did not produce a solution, which speaks to the challenges of quickly retiring large amounts of thermal capacity.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The resource mix between the reference portfolio and sensitivity 13 is very similar, indicating that increased carbon costs do not significantly impact build decisions. This sensitivity costs less than the reference, driven primarily by a lower SCGHG. These results indicate a decrease in emitting resource dispatch, as we may expect with higher market prices for carbon allowances.

Sensitivity 14 No Hydrogen Fuel Available: There is a significant difference between sensitivity 14 and the reference portfolio. Without access to hydrogen fuel, we no longer see an accelerated reduction in GHG emissions, and portfolio costs are significantly higher, suggesting a notable benefit to hydrogen fuel as an alternative fuel option. Therefore, we should continue exploring blending hydrogen with natural gas fuel.

Sensitivity 15 SCGHG in Dispatch: Including the SCGHG in the dispatch cost for the long-term capacity expansion model adversely decreases the capacity factor of PSE's thermal plants, resulting in 2,000 MW of renewable resource additions by 2025, more than the energy needed for the year. This scenario also doubles PSE's existing renewable resources of 1,700 MW in three years. The CETA requirement is the driving factor for the resource build decisions by 2045.

Sensitivity 16 WRAP Adjustment: We cannot run the long-term capacity expansion model to evaluate sensitivity 16 due to incomplete information regarding ELCC saturation curves for renewable and storage resources from the Western Resource Adequacy Program (WRAP). We also understand that the WRAP data is not intended for long-term resource planning. Our best estimate using the WRAP PRM shows a decrease in the winter peak capacity need

[12] https://www.eia.gov/todayinenergy/detail.php?id=54939

by 300 MW and a reduction in the summer peak need by 1,200 MW in 2029. We need further study to incorporate WRAP in long-term resource planning. The WRAP estimated seasonal PRMs are in Table 8.3.

Table 8.3 PRM and Peak Capacity Needs

Sensitivity Year/Season	1 Reference 2029 Winter	1 Reference 2029 Summer	16 WRAP Adjustment 2029 Winter	16 WRAP Adjustment 2029 Summer
Peak Load (MW)	5,104	4,300	4,570	3,447
PRM (MW)	1,215	1,029	956	470
PRM%	24%	24%	21%	14%
Existing Resources Peak Capacity (MW)	3,607	2,493	3,120	2,343
Additional perfect capacity for 5% LOLP (MW)	2,712	2,837	2,406	1,574

6.3. Portfolio Costs

This section describes the changes in portfolio costs for the sensitivities evaluated in the 2023 Electric Progress Report. The portfolio cost in dollars is the levelized, net present value of the annual cost impacts for 22 years excluding SCGHG costs. This includes:

- Alternative compliance costs
- CCA costs
- Decommissioning costs as part of the economic decision of plant retirements
- Fixed and variable costs of existing resources and new resources
- Fuel costs
- Net market purchases and sales

We report the SCGHG as an externality cost separately. The sum of the portfolio costs and the SCGHG costs is what we refer to as total portfolio costs in this chapter.

6.3.1. Resource Alternative Sensitivities

Table 8.4 and Figure 8.14 show the costs associated with the Resource Alternative sensitivities 2–9 described in this section.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: As expected, increased distribution and energy efficiency additions led to higher portfolio costs. The portfolio cost of sensitivity 2 is $0.97 billion higher than the reference portfolio. However, the SCGHG of sensitivity 2 is $0.17 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.81 billion for sensitivity 2 compared to the reference portfolio. For sensitivity 3, the portfolio cost is $0.35 billion higher than the reference portfolio. Similar to sensitivity 2, the SCGHG of sensitivity 3 is also lower than the reference portfolio by $0.34 billion. This results in a net increase in total portfolio cost of $0.01 billion for sensitivity 3 compared to the reference portfolio.

Sensitivity 4 DER Solar: The total portfolio cost of sensitivity 4 is higher than the reference as expected by the substantial increase in DER solar resources shown to be relatively high cost by the reference case. The difference in portfolio cost between the two is significant at $0.45 billion, but with the inclusion of the social cost of greenhouse gases (SCGHG), the total portfolio cost difference is more moderate at $0.23 billion.

Sensitivity 5 DER Storage: The total portfolio costs between sensitivity 5 and the reference case were reasonably consistent. The total portfolio cost changes slightly, making sensitivity 5 $0.08 billion less over its lifetime. There is a bigger difference between the two in portfolio cost, but some of this is offset by small changes in SCGHG costs. Emissions are similar enough in both cases that the portfolio cost comparison with and without SCGHG does not vary dramatically, and the two portfolios follow similar cost trends in both instances.

Sensitivity 6 MT Wind and PHES, All MT East Wind: The portfolio cost of sensitivity 6 is $0.2 billion higher than the reference portfolio. However, the SCGHG of sensitivity 6 is $0.18 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 6, which is just $0.02 billion higher than the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana east wind and Montana PHES delay the addition of 474 MW of CETA-qualifying peaking resources from 2025–2029 and offsets dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 7 MT Wind and PHES, Central and East Wind: The portfolio cost of sensitivity 7 is $0.7 billion higher than the reference portfolio. However, the SCGHG of sensitivity 7 is $0.37 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.33 billion for sensitivity 7 compared to the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana wind and Montana PHES delays the addition of 474 MW of CETA-qualifying peaking resources from 2025 to 2027 and offsets the dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 8 PNW PHES: The portfolio cost of sensitivity 8 is $0.55 billion higher than the reference portfolio. However, the SCGHG of sensitivity 8 is $0.12 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.43 billion for sensitivity 8 compared to the reference portfolio.

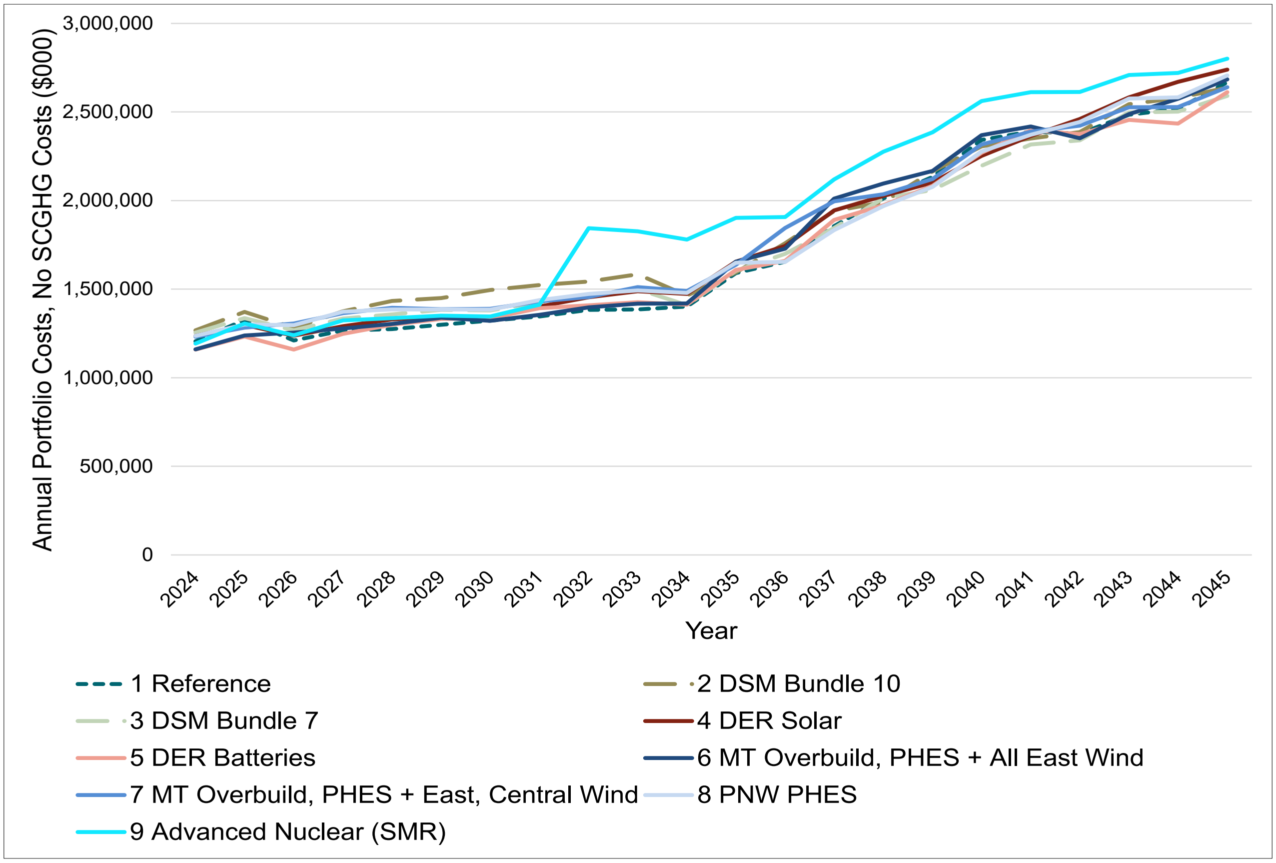
Sensitivity 9 Advanced Nuclear SMRs: Sensitivity 9 is a higher cost overall than the reference portfolio, and costs begin to diverge at a greater pace as the model added advanced nuclear SMR resources to the portfolio in 2032. This results in a net increase in total portfolio cost of $1.47 billion for sensitivity 9 compared to the reference portfolio.

Table 8.4 Resource Alternatives Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
2 DSM Bundle 10	18.58	3.07	21.65	0.81	4
3 DSM Bundle 7	17.96	2.90	20.86	0.01	0
4 DER Solar	18.06	3.02	21.08	0.23	1
5 DER Batteries	17.47	3.30	20.77	-0.08	0

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
6 MT Overbuild, PHES + All East Wind	17.81	3.06	20.87	0.03	0
7 MT Overbuild, PHES + East, Central Wind	18.31	2.87	21.18	0.34	2
8 PNW PHES	18.16	3.12	21.28	0.44	2
9 Advanced Nuclear SMRs	19.34	2.98	22.32	1.47	7

Figure 8.14: Annual Portfolio Costs — Resource Alternatives



6.3.2. Diversified Portfolio Sensitivities

The costs associated with the diversified portfolio sensitivities 11 A1-A5 and 11 B1-B2 are described in this section and summarized in Table 8.5 and Figure 8.15.

Sensitivity 11 A1 – A5 Diversified: All diversified 11 A sensitivities cost substantially more than the least-cost reference portfolio (Table 8.5). The least-diversified sensitivity, 11 A1, adds conservation, an advanced nuclear SMR power plant, and maximizes existing Montana transmission. These resource additions cost $2 billion (10 percent) more than the reference portfolio. Each subsequent resource addition, as observed in sensitivities 11 A2 through 11 A5, increases the total cost compared to the sensitivity proceeding it. However, adding DER solar and demand response programs cost approximately $0.02 billion each, whereas adding the Pacific Northwest PHES and DER batteries cost nearly twenty times this amount, approximately $0.4 billion each.

Generally, the diversified 11 A sensitivity costs are similar year to year through the 22-year planning period. Though costlier, they follow the reference portfolio trend through 2045 (Figure 8.15). Adding 250 MW of advanced nuclear SMRs is the notable exception: the spike above the reference portfolio in 2032 reflected the costs of this technology when we added this resource to the 11 A sensitivities.

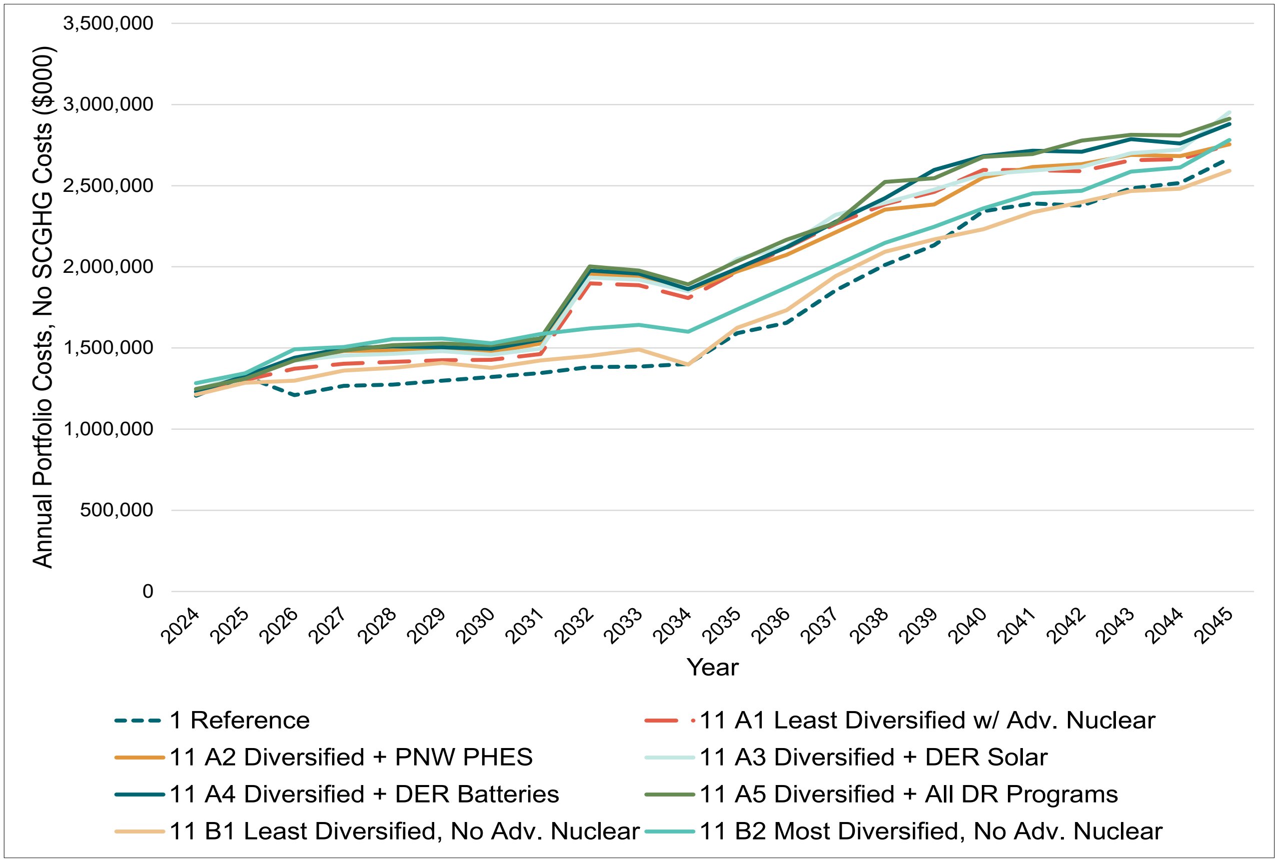
Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: The cost of sensitivity 11 B1 is $0.48 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B1 is $0.24 billion lower than the reference portfolio. This results in a net increase in the total cost of $0.24 billion for sensitivity 11 B1 compared to the reference portfolio. Early additions of hybrid and storage resources resulted in increased capital spending on resources in the years before 2030. Despite fewer nameplate additions overall, sensitivity 11 B1 results in a higher cost due to generally higher cost resources added earlier in the modeling horizon.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: The portfolio cost of sensitivity 11 B2 is $1.95 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B2 is $0.29 billion lower than the reference portfolio. This results in a net increase in the total cost of $1.66 billion for sensitivity 11 B2 compared to the reference portfolio.

Table 8.5: 11 A Diversified Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	0
11 A1 Least Diversified w/ Adv. Nuclear SMRs	20.01	2.82	22.83	1.99	10
11 A2 Diversified + PNW PHES	20.32	2.93	23.25	2.40	12
11 A3 Diversified + DER Solar	20.44	2.83	23.27	2.42	12
11 A4 Diversified + DER Batteries	20.74	2.90	23.64	2.80	13
11 A5 Diversified + All DR Programs	20.89	2.78	23.67	2.82	14
11 B1 Least Diversified w/o Advanced Nuclear SMRs	18.09	3.00	21.09	0.24	1
11 B2 Most Diversified w/o Advanced Nuclear SMRs	19.56	2.95	22.51	1.66	8

Figure 8.15: Annual Portfolio Costs — Diversified Portfolios



6.3.3. Requested Sensitivities

The costs associated with sensitivities 10 and 12-16 are described in this section and summarized in Table 8.6 and Figure 8.16.

Sensitivity 10 No New Thermal before 2030 and Biodiesel is the Alternative Fuel: The portfolio cost of sensitivity 10 is $1.67 billion higher than the reference portfolio. However, the SCGHG of sensitivity 10 is $0.77 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 10, which is just $0.91 billion higher than the reference portfolio. The restriction on thermal additions before 2030 results in the addition of more expensive stand-alone storage and hybrid resources in the near term and offsets dispatch of existing thermal resources resulting in reduced GHG emissions but at a higher overall cost.

Sensitivity 12 100 percent Renewable/Non-Emitting: This sensitivity did not solve due to the issues we discussed in the Key Findings section and consequently did not produce any portfolio cost metrics.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The portfolio cost without the SCGHG adder for this sensitivity is $0.50 billion higher than the reference case, likely driven by higher market prices. However, the SCGHG adder is $0.52 billion less than the reference case, resulting in an overall portfolio cost of $0.02

billion less than the reference case. This sensitivity illustrates that the higher market prices for carbon allowances result in decreased emitting resource dispatch, as shown by the lower SCGHG.

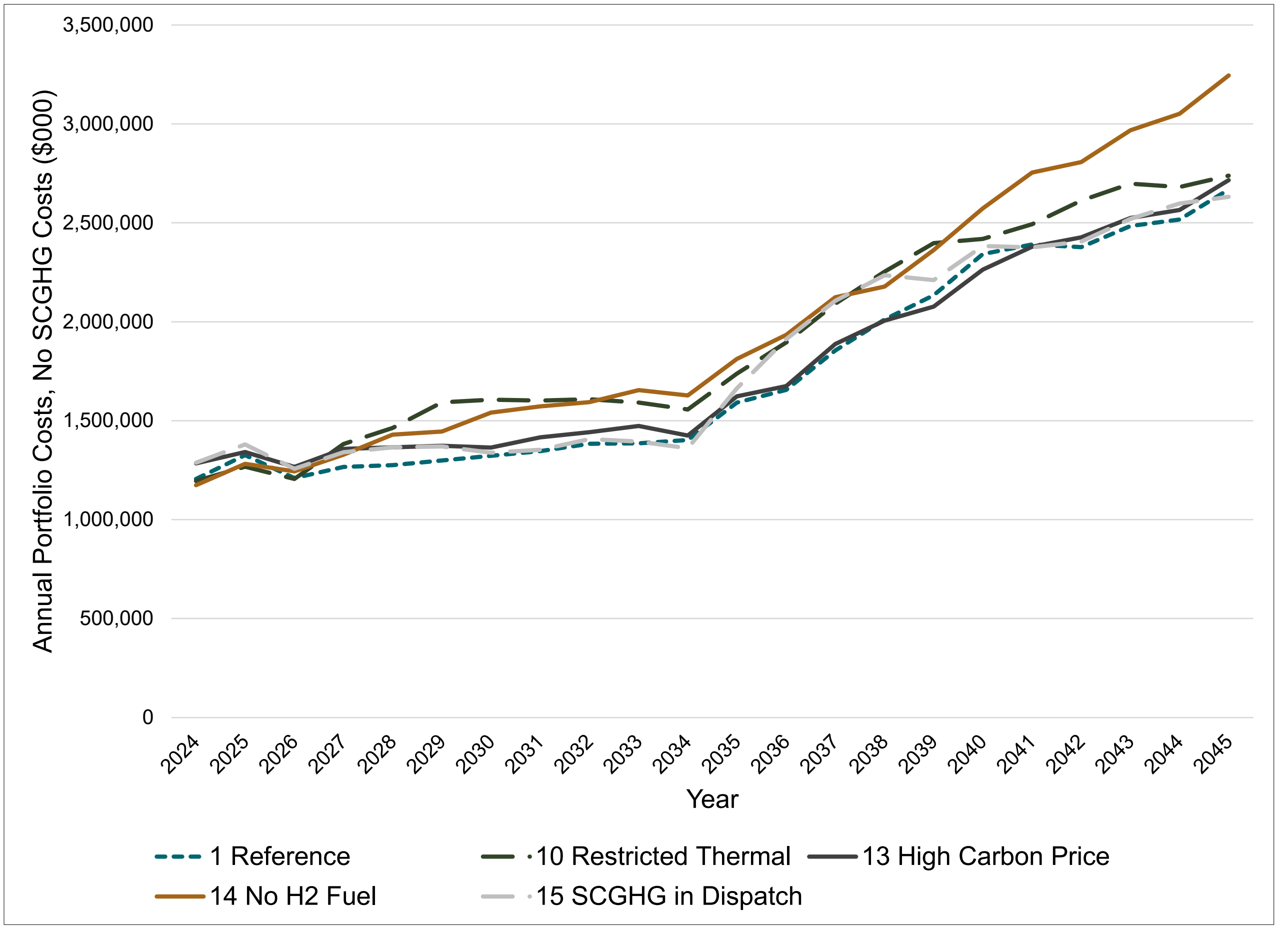
Sensitivity 14 No Hydrogen Fuel Available: The portfolio cost of sensitivity 14 is $2.03 billion higher than the reference portfolio. We also see an increase in SCGHG costs for sensitivity 14, which is $2.19 billion higher than the reference portfolio. This results in a net increase in total portfolio cost of $4.23 billion for sensitivity 14 compared to the reference portfolio.

Sensitivity 15 SCGHG in Dispatch: The portfolio costs are higher for sensitivity 15, with a portfolio cost of $18.34 billion. Though the sensitivity 15 portfolio cost is $0.73 billion higher than the reference portfolio, it greatly decreases the emission costs to $2.47 billion. The total cost of sensitivity 15 ($20.81 billion) is 0.04 billion lower than the reference portfolio total cost ($20.85 billion).

Table 8.6: Other Requested Sensitivities Portfolio Costs, 2024–2045 NPV (Billions)

Sensitivity	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
10 Restricted Thermal	19.28	2.47	21.75	0.91	4
13 High Carbon Price	18.11	2.72	20.83	-0.01	-0.1
14 No H2 Fuel	19.64	5.43	25.07	4.23	20
15 SCGHG in Dispatch	18.34	2.47	20.81	-0.04	0.2

Figure 8.26: Annual Portfolio Costs — Other Requested Sensitivities



6.4. Modeling Builds

This section describes the changes in resource builds for the sensitivities evaluated in this 2023 Electric Report.

6.4.1. Resource Alternative Sensitivities

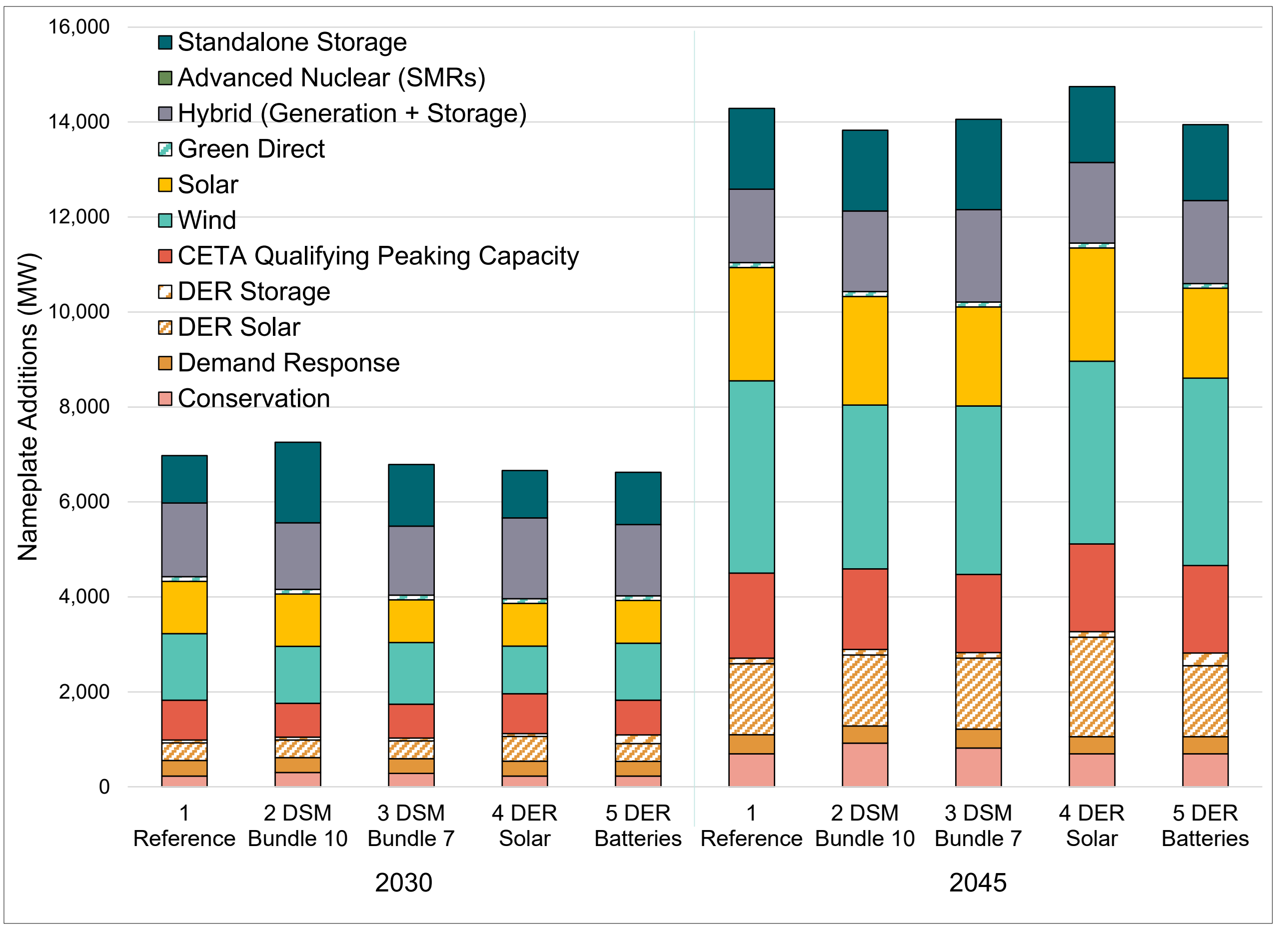
In this section, we described the resources added in the Resource Alternative sensitivities 2–9 and summarized them in Figures 8.17 and 8.18.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: Overall builds are similar, except for the increased addition of distributed and energy efficiency measures and slightly fewer renewable resources needed to meet CETA requirements in sensitivity 2 and sensitivity 3.

Sensitivity 4 DER Solar: Aside from the increase in DER solar capacity for sensitivity 4, it adds a similar mix of capacity by 2045 compared to the reference portfolio, although the timing of resource additions is quite different. Notable differences include a 450MW reduction in CETA-qualifying peaking capacity and a 400MW increase in utility-scale solar before 2025 for sensitivity 4. However, these resource groups end up in almost identical places at the end of the planning horizon. One consistent difference is that sensitivity 4 picks up less demand response than the reference portfolio, totaling a 41MW winter peak difference by 2045. At a coarser level, all capacity addition resource groups in sensitivity 4 are within 200 MW of their analogous group in the reference case.

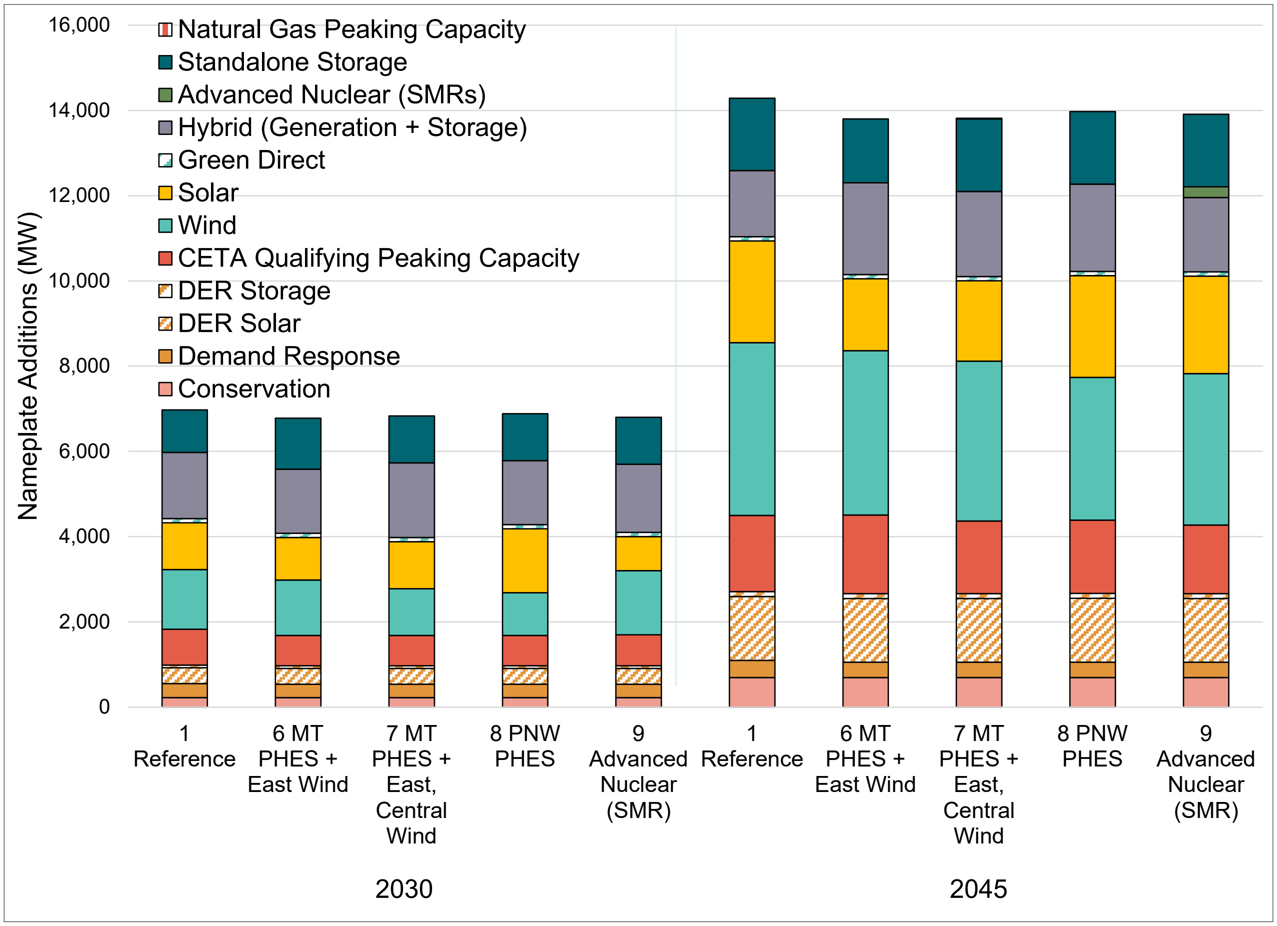
Sensitivity 5 DER Storage: A comparison between sensitivity 5 and the reference portfolio in terms of resource additions shows significant movement in certain resource groups. Most notably, by 2045, it will pick up 500 MW less solar than the reference portfolio. Other observed changes besides the prescribed DER storage increase (150 MW) include roughly 200 MW more hybrid capacity, 45 MW less demand response, a 55 MW increase in CETA-qualifying peaking capacity, and 100 MW less stand-alone storage — all by 2045. The reference portfolio builds resources earlier than sensitivity 5, building 500 MW more capacity by 2025, which lessens to a 341 MW capacity difference in 2045 at the end of the planning period.

Figure 8.37: Resource Additions — Resource Alternatives Part 1



Sensitivity 6–9: Overall builds are similar for each sensitivity and the reference portfolio, except for the scheduled addition of the resource we tested for the sensitivity.

Figure 8.48: Resource Additions — Resource Alternatives Part 2



6.4.2. Diversified Portfolio Sensitivities

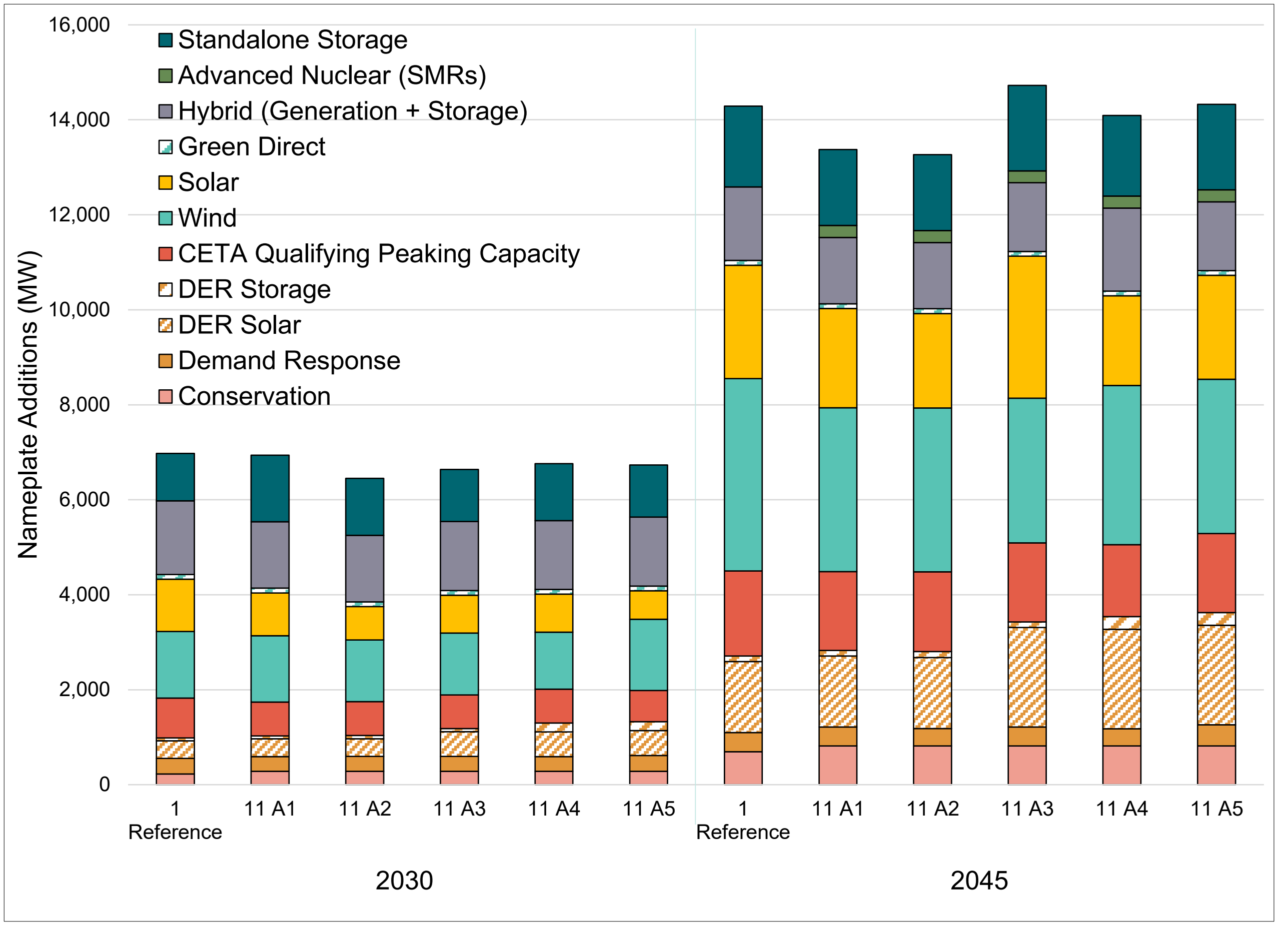
The resources added in the diversified portfolio sensitivities 11 A1–11 A5, and 11 B1–11 B2 are described in this section and summarized in Figures 8.19 and 8.20.

Sensitivity 11 A1– A5 Diversified: In the first two years of the planning period, between 2024 and 2025, the demand-side and distributed resource additions in the diversified 11 A sensitivities mirror the reference portfolio. However, this very near-term look highlights several strategies for meeting energy needs. Sensitivities 11 A1 and 11 A2 displace all three early CETA-qualifying peaking plants built in the reference portfolio with various combinations of renewable and storage resources (wind, solar, stand-alone storage, and hybrid). Peaking capacity is reduced but not replaced entirely in sensitivities 11 A3, 11 A4, and 11 A5, to 237, 474, and 18 MW, respectively. However, by 2030, CETA-qualifying peaking capacity will be equivalent across all diversified 11 A sensitivities at 711 MW, except for 11 A5, which builds slightly less at 657 MW. This indicates a constant need for dispatchable energy in the near-term planning horizon.

In the longer term, between 2031 and 2045, the resource mix becomes slightly more pronounced between the diversified sensitivities. Distributed solar and battery additions increase as expected in sensitivities 11 A3, 11 A4, and

11 A5, where we required the model to select these resource additions. Wind, solar, and hybrid resources are added in varying amounts across the 11 A sensitivities but generally sum to similar quantities by 2045. CETA-qualifying peaking capacity is a stable addition across all sensitivities, even with 250 MW of advanced nuclear SMRs, which diversifies dispatchable resources but does not displace the equivalent peaking capacity from the 11 A sensitivities. Battery storage and DSR are relatively constant across sensitivities by 2045, but both peak in 11 A5.

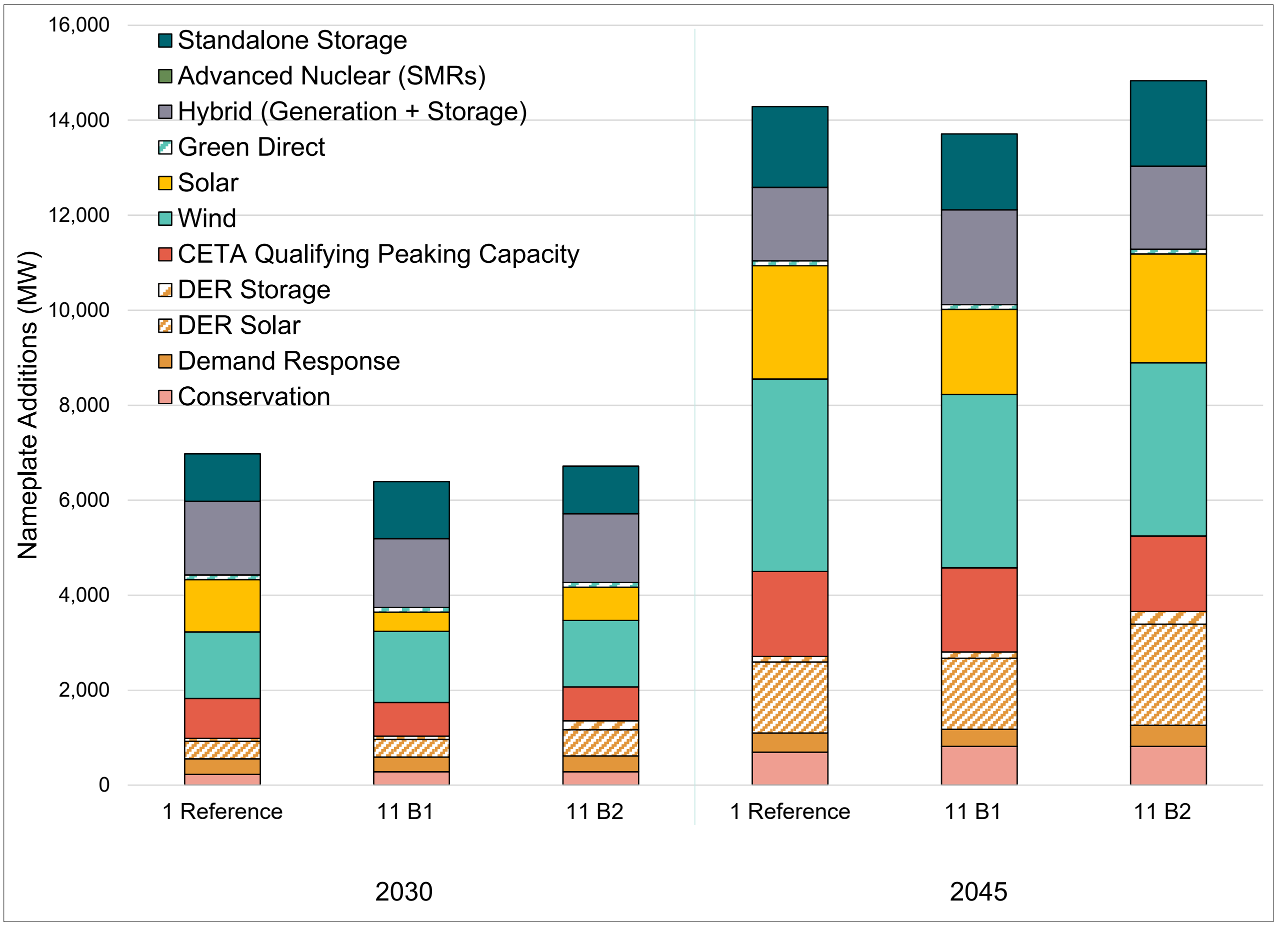
Figure 8.19: Resource Additions — Diversified Portfolio Sensitives Part 1



Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and sensitivity 11 B1 but with a few notable differences. Sensitivity 11 B1 results in nearly 600 MW fewer nameplate capacity additions by favoring resources with a greater peak capacity contribution, such as energy efficiency measures and shifting from stand-alone wind and solar to hybrid resources. Sensitivity 11 B1 defers the addition of thermal peaking capacity resources through the earlier addition of hybrid and storage resources compared to the reference portfolio.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and 11 B2 sensitivities. Sensitivity 11 B2 incorporates 780 MW more distributed solar and storage resources through scheduled resource additions than the reference case. The distributed energy resource additions in sensitivity 11 B2 reduce the capacity of stand-alone, utility-scale wind and solar resources added to the sensitivity. The percentage of demand-side and distributed resources in the sensitivity portfolio resource mix increases from 19 percent in the reference portfolio to 25 percent in sensitivity 11 B2. Increased addition of resources with high peak capacity contributions, including stand-alone storage, hybrid resources, and energy efficiency measures, reduce the total thermal peaking capacity added to sensitivity 11 B2 by 200 MW compared to the reference portfolio.

Figure 8.20: Resource Additions — Diversified Portfolio Sensitivities Part 2



6.4.3. Requested Sensitivities

We described the resources added in sensitivities 10 and 13–16 in this section and summarized in Figure 8.21.

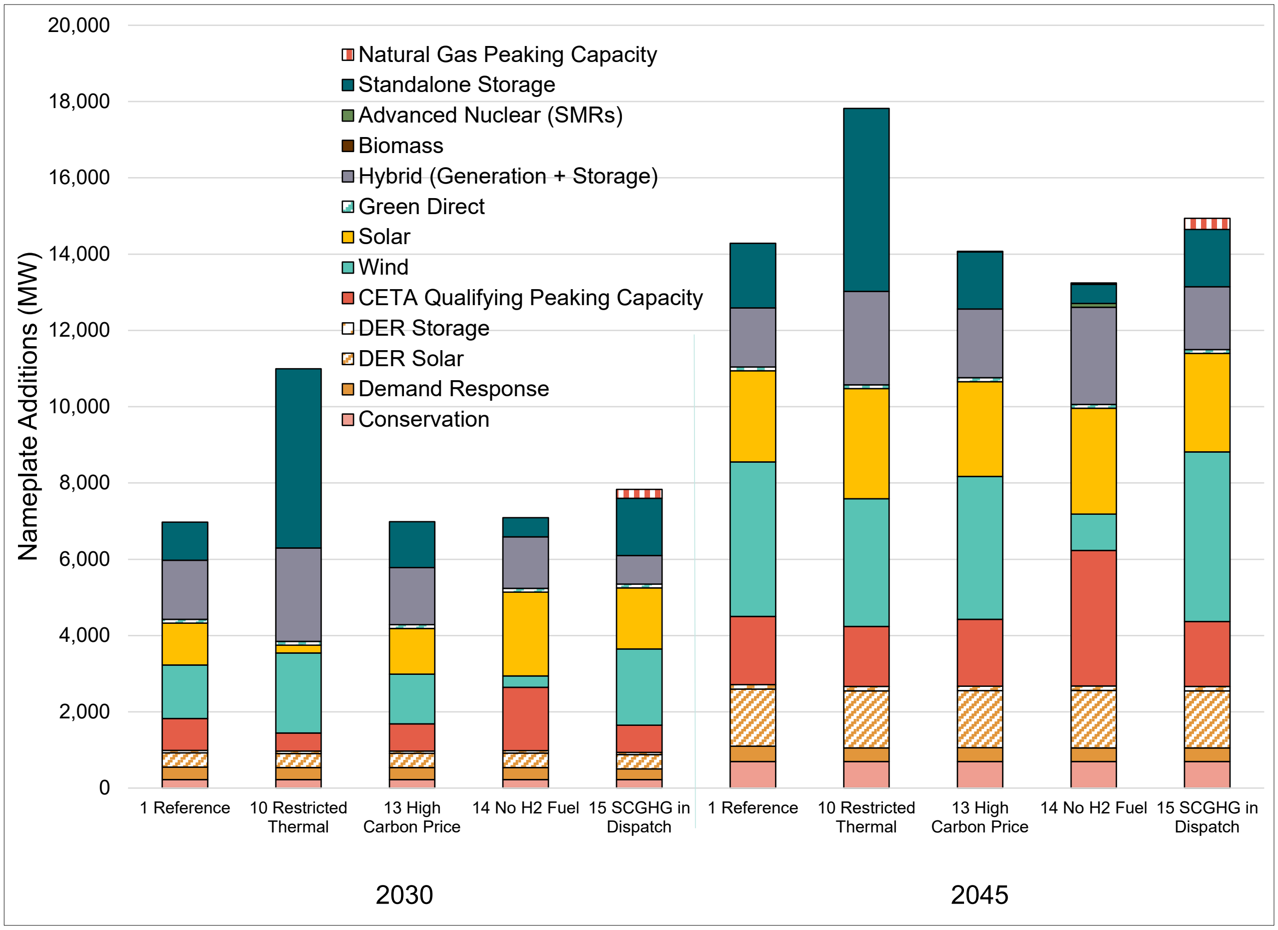
Sensitivity 10 No New Thermal before 2030, and Biodiesel as the Alternative Fuel: Sensitivity 10 adds 4,700 MW of storage to the portfolio through 2030. Once we removed the thermal restriction, an additional 1,569 MW of CETA-qualifying peaking resources were added to the portfolio, while only 100 MW of storage was added to the portfolio. The major difference between sensitivity 10 and the reference portfolio is an additional 4,000 MW of storage and hybrid resources and 200 MW less of CETA-qualifying peaking resources. We can explain this difference because as the portfolio becomes saturated with storage, the ELCC decreases.

Sensitivity 13 High Carbon Price based on the Ceiling Price Assumption: Overall builds are similar for sensitivity 13 and the reference portfolio. By 2045, sensitivity 13 has 100 MW less wind and solar resources, 50 MW less storage resources, 41 MW less of demand response, and nearly identical CETA-qualifying resources.

Sensitivity 14 No Hydrogen Fuel available: Without access to hydrogen fuel, sensitivity 14 incorporates 3,555 MW of frame peaker biodiesel resources. Interestingly, the increase in frame peaker biodiesel resources reduces the total capacity of stand-alone storage and utility-scale wind resources added to the portfolio. To meet the CETA requirement, we see a shift to increased utility-scale solar resources added in sensitivity 14. We also see the addition of 100 MW of advanced nuclear SMR resources in 2045.

Sensitivity 15 SCGHG in dispatch: Overall, we see more renewable resources added to the portfolio in the near term and a total of 8,400 MW of renewable resources added by 2045. Though surprising, we see one natural gas frame peaker and two hydrogen blend peakers added in 2024 in sensitivity 15 compared to one biodiesel peaker in the reference portfolio for the same year. These peakers are added to meet the peak capacity needs and resource adequacy requirements. The levelized cost of the capacity of the natural gas frame peaker plant with the SCGHG as an externality cost is $114/kw-yr, whereas the levelized cost of capacity with the SCGHG in dispatch is $104/kw-yr. When modeling SCGHG in dispatch, there are adverse effects on the cost of capacity of peaking resources which, in this case, led to increased resource additions earlier in the time horizon.

Figure 8.21: Resource Additions — Requested Sensitivities



7. Portfolio Benefit Analysis Results

This section describes the results of the portfolio benefit analysis.

➔ Appendix I: Electric Analysis Inputs and Results provides all underlying data, calculations, and a summary of the results in an Excel spreadsheet and may be a useful reference while reading this section.

7.1. Reference Portfolio

All results from the portfolio benefit analysis are relative to the reference portfolio. We used relative measures in this analysis because prescriptive guidelines on creating an equitable energy portfolio are currently unavailable. Relative measures provide us with an understanding of how one portfolio may enable more equitable outcomes than another.

The reference portfolio includes many aspects of an equity-enabling portfolio. The reference portfolio is the least-cost solution[13] identified by the AURORA long-term capacity expansion model: because electricity affordability is essential in enabling equitable outcomes, a low-cost portfolio is desirable. The reference portfolio produces more greenhouse gas emissions than most other portfolios analyzed but reaches zero greenhouse emissions by 2045. Similarly, the reference portfolio has higher outdoor air quality emissions (SO_2, NO_x, and PM) than most other portfolios but sees significant reductions by the end of the planning horizon.

The reference portfolio adds an estimated 45,736 jobs from new resource additions, more than many other portfolios analyzed. The reference portfolio is in the top third of portfolios for demand response peak capacity and demand response customer participation metrics. However, the reference portfolio lacks customer participation in distributed energy resources for both solar and storage. While the reference portfolio may have a CBI index of zero, it provides various customer benefits and represents a strong starting point for other portfolios.

Table 8.7 presents the reference portfolio CBI metrics against which we compared all other portfolios.

Table 8.7: Reference Portfolio CBI Metrics

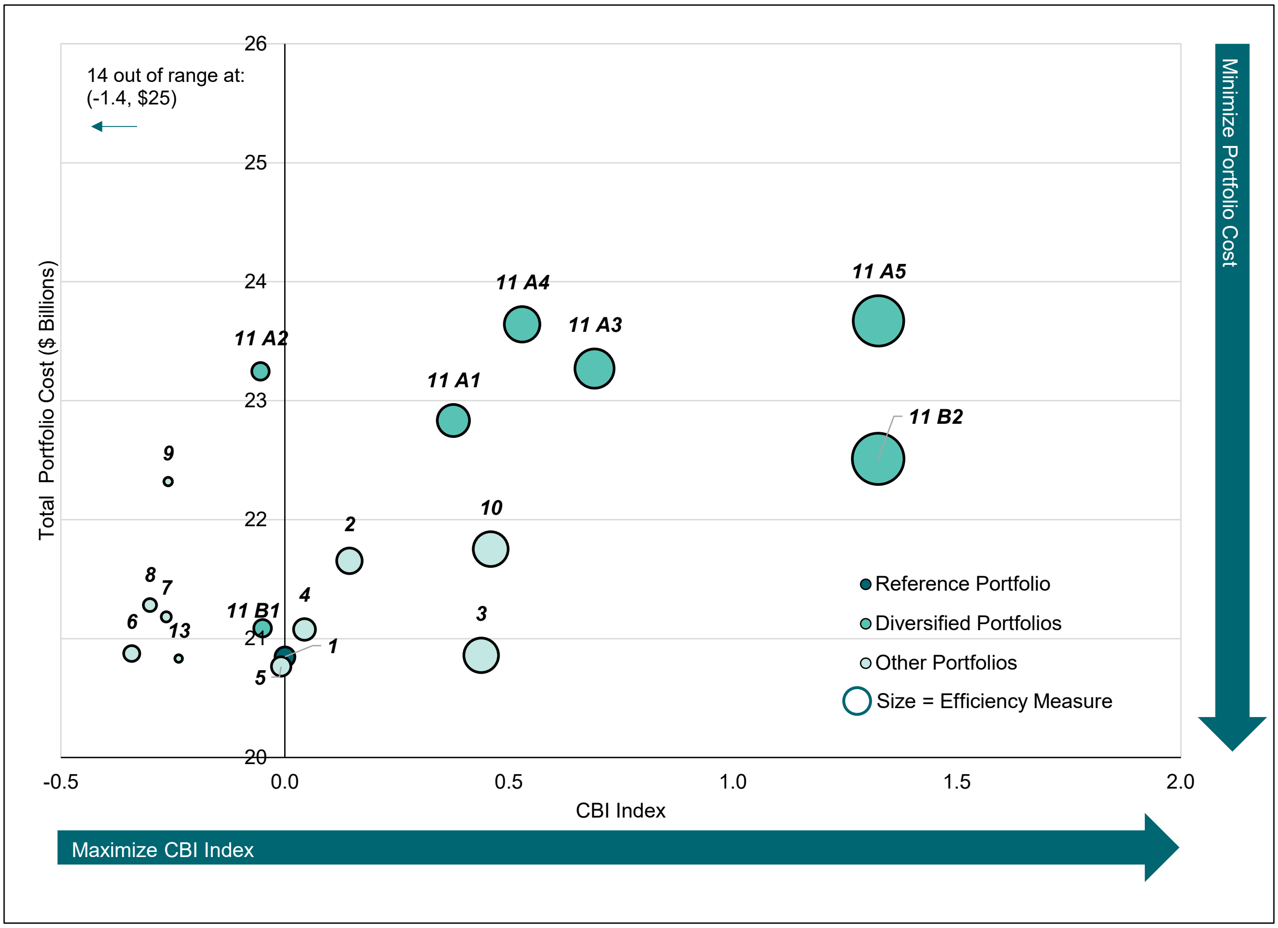
CBI Metric	Reference Portfolio
Cost (, Billions)	20.85
GHG Emissions (Short Tons)	48,824,734
SO_2 Emissions (Short Tons)	28,841
NO_x Emissions (Short Tons)	11,426
PM Emissions (Short Tons)	9,036
Jobs (Total)	45,736
Energy Efficiency Added (MW)	695
DR Peak Capacity (MW)	291
DER Solar Participation (Total New Participants)	12,115
DR Participation (Total New Participants)	513,238
DER Storage Participation (Total New Participants)	8,125

Figure 8.22 shows the results of the portfolio benefit analysis for all portfolios. Each portfolio is plotted with its CBI index value on the x-axis and total portfolio cost on the y-axis to show the tradeoff between equity enabling value and cost. The most desirable portfolios appear in the lower right corner of the plot, where cost is minimized and the CBI index is maximized. The point size estimates the CBI index per dollar spent on the portfolio, where larger points represent greater value per cost.

We plotted the reference portfolio at the CBI index equals zero line. We plotted portfolios containing elements that improve upon the reference portfolio's ability to enable equitable outcomes to the right of this line and those which may detract from equitable outcomes to the left of this line.

[13] Portfolios 5 and 13 are slightly lower cost than the reference portfolio by $80 million and $10 million, respectively. These small decreases in cost are within the 1 percent study precision tolerance of the AURORA long-term capacity expansion model.

Figure 8.22: Portfolio Benefit Analysis Results



7.1.1. Energy Efficiency

Our analysis shows portfolios that include increased energy efficiency measures tend to enable more equitable outcomes than the reference portfolio, as observed by the relationship between portfolios 2, 3, the diversified portfolios, and the reference portfolio. Portfolios 2, 3, and the diversified portfolios include increased energy efficiency measures. The reference case economically selected up to 695 aMW of conservation by 2045. We tested a large increase in energy efficiency by adding 923 aMW of conservation by 2045 in portfolio 2. This resulted in a relatively small increase in the CBI index, +0.14, but a much higher cost, +810 million. Understanding that increasing conservation results in diminishing returns, we tested slightly less conservation in portfolio 3 by adding 818 aMW and observed a larger increase in CBI index, +0.44, and a smaller increase in cost, +10 million.

The relationship between portfolios 2 and 3 illustrate the complexity of interaction between individual CBI metrics, the overall CBI index, and cost. Energy efficiency is one of the metrics used in this CBI index calculation, so intuitively, increasing its value should increase the overall CBI index. However, by reducing the amount of energy efficiency from 923 aMW to 818 aMW, portfolio 3 added other resources, which improved the CBI index for other metrics resulting in a higher overall CBI index at a lower cost.

As we developed the diversified portfolios, we incorporated 818 aMW of conservation, given the large increase in the CBI index for the relatively small increase in total portfolio cost.

7.1.2. Pumped Hydroelectric Storage

Portfolios that include PHES tend to have a lower CBI index than the reference portfolio. Portfolios 6, 7, 8, and the diversified portfolio include PHES. PHES is a costly resource and was not selected economically by any portfolios, so we tested scheduled additions of PHES to understand any benefit in diversifying energy storage away from solely battery energy storage.

We found that PHES delays the need to add thermal peaking capacity and reduces the dispatch of existing thermal resources when added to a portfolio resulting in fewer greenhouse gas emissions. Unfortunately, adding PHES tends to reduce the number of jobs expected from portfolios and reduces the amount of demand response selected by the portfolio resulting in an overall CBI index of less than zero or worse than the reference portfolio and portfolios 6, 7, and 8. Given the reduction of greenhouse gas emissions and diversification benefits of PHES, we decided to add PHES to the diversified portfolios. In portfolios 11 A5 and 11 B2, we controlled for the negative CBI index impacts of PHES by scheduling distributed solar and battery resources, discussed in Section 7.1.3, and maximizing demand response programs, resulting in portfolios with the highest overall CBI indices.

7.1.3. Distributed Energy Resources

We tested portfolios 4 and 5, which scheduled additions of distributed energy resources, solar, and storage, respectively, to understand how adding these resources would impact the cost. Distributed energy resources tend to cost more than their utility-scale counterparts and, therefore not selected in the reference portfolio. However, we created customer benefit indicators precisely to monitor customer participation in distributed solar and distributed storage technologies. We thought adding these resources to the portfolio would significantly increase the overall CBI index. However, portfolio 4, which adds distributed solar, only scores marginally better than the reference portfolio, and portfolio 5 scores worse. Adding distributed energy resources tends to reduce the number of jobs associated with the portfolio, and the amount of demand response added. These changes result in little net benefit for the increased DER participation metrics.

However, when we added DERs in coordination with other resources, the benefit became much stronger, as demonstrated in diversified portfolios 11 A3, 11 A4, 11 A5, and 11 B2, which have overall CBI indices much greater than the reference portfolio.

7.1.4. Diversified Portfolios

Diversified portfolios include several scheduled resource additions to create a diverse mix of resources within the portfolio. Increased diversification enables more equitable outcomes through greater participation in DER, more demand response programs, and lower greenhouse gas and outdoor air quality emissions. Portfolios 11 A5 and 11 B2, the most diversified portfolios, tie for the highest overall CBI index at +1.32 from the reference portfolio. Considering the tradeoff between the CBI index and cost, 11 B2 provides the better value, given that it is 1.16 billion less expensive than 11 A5.

8. Stochastic Portfolio Analysis Summary

We test the robustness of different portfolios with stochastic risk analysis to learn how well the portfolio might perform under various conditions. In this analysis, we run select portfolios through 310 simulations or draws[14] that vary power prices, gas prices, hydroelectric generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can quantify the risk of each portfolio. We tested two different portfolios in the stochastic portfolio analysis, as and described in Table 8.8.

Table 8.8: Portfolios Tested for Stochastic Analysis

ID	Name	Description
1	Reference Portfolio	The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios.
11 B2	Preferred Portfolio	This sensitivity is the most diversified portfolio we developed in this report, but without adding advanced nuclear SMR technology to the portfolio. We built this portfolio on the least-cost reference portfolio; it increases conservation and adds pumped hydroelectric storage, distributed energy, and demand response.

8.1. Risk Measures

The results of the risk simulation allow us to calculate portfolio risk. We calculated risk as the average value of the worst 10 percent of outcomes (TailVar90). This risk measure is the same one the Northwest Power and Conservation Council (NPCC) uses in its power plans.

8.2. Stochastic Results

Our electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. These resource forecasts are a guide. We will make resource acquisition decisions based on the latest information from the 2021 All-Source RFP[15] and other acquisition processes. The risk simulation results, however, indicate the portfolio costs risk range under varying input assumptions. Table 8.9 compares the portfolio costs for the deterministic run; the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for the two portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model runs for the reference and preferred portfolios.

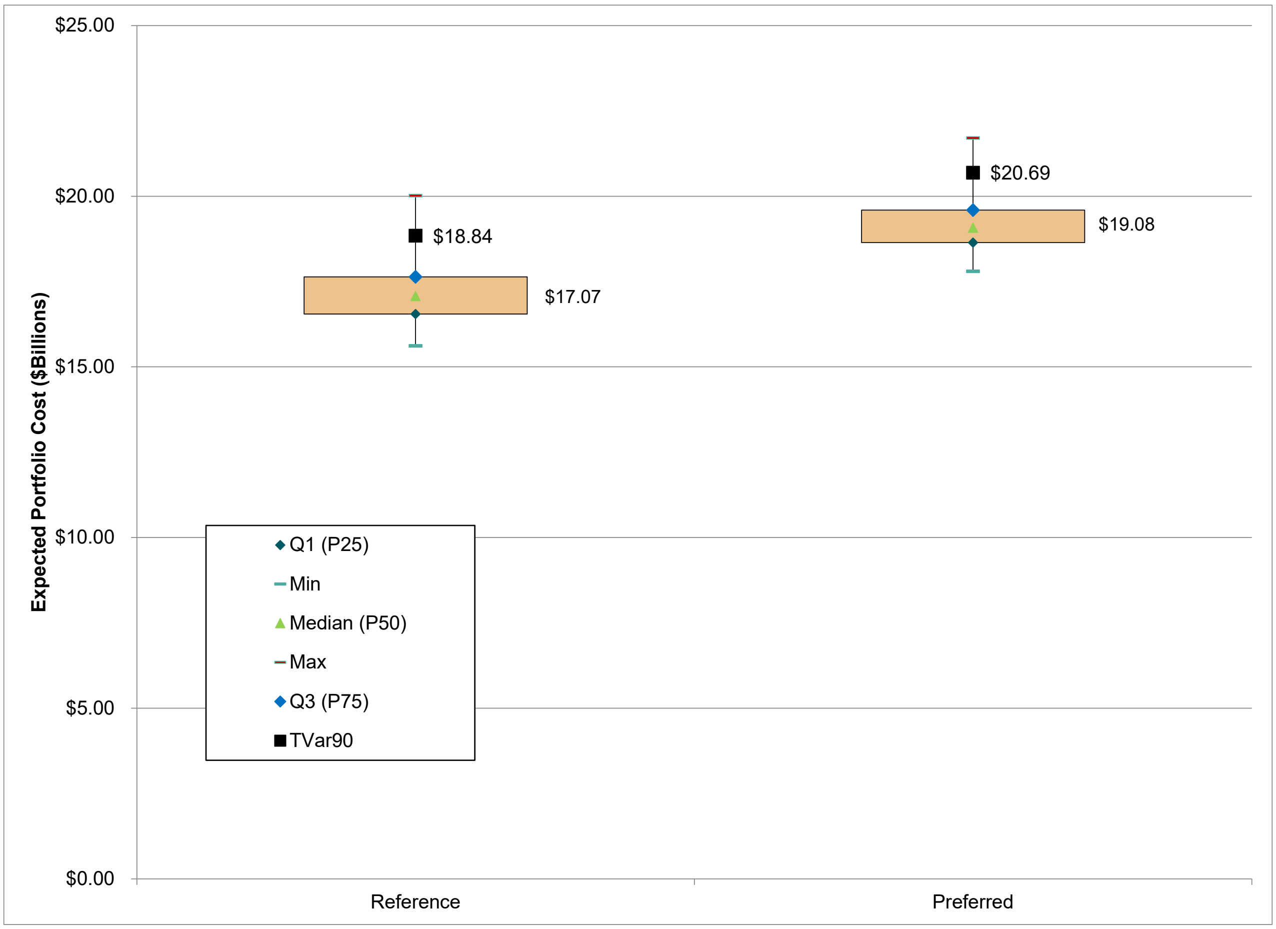
[14] Each of the 310 simulations is for the 24-year IRP forecasting period, 2022-2045.
[15] https://www.pse.com/en/pages/energy-supply/acquiring-energy

Table 8.9: Portfolio Costs Across 310 Simulations (Billion$)

Revenue Requirement	Portfolio	Deterministic ($)	Difference from Reference ($)	Mean ($)	Difference from Reference ($)	TVar90 ($)	Difference from Reference ($)
1	Reference	17.60	--	17.20	--	18.80	--
11 B2	Preferred	19.60	2.00	19.20	2.00	20.70	1.90

Figure 8.23 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 box represents the median for that portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the portfolio's minimum and maximum data values. The black square represents the TailVar90, the average value for the highest 10 percent outcomes.

Figure 8.23: Range of Portfolio Costs across 310 Simulations



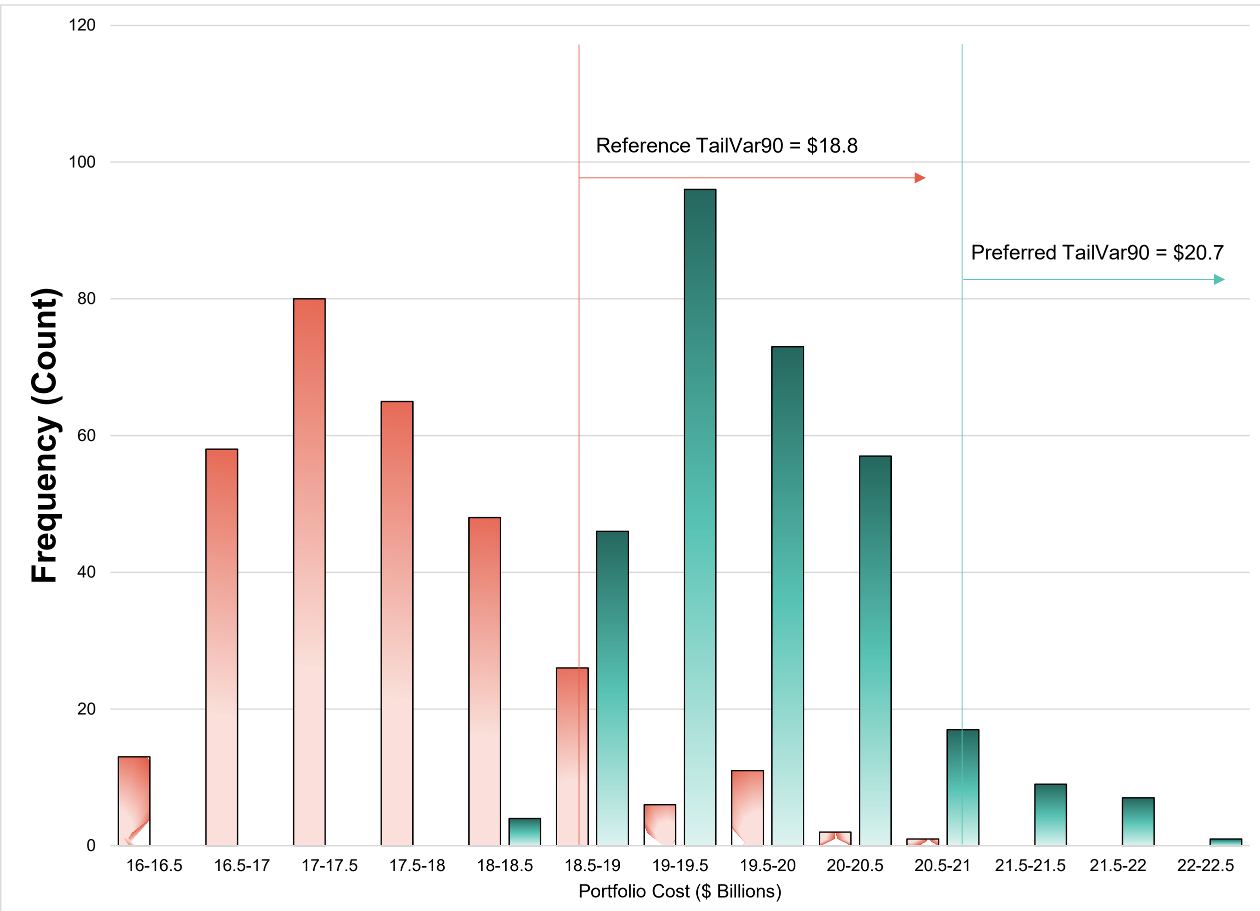
Key results of the analysis include:

- The mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix results in higher portfolio costs.

- The range for sensitivity 11 B2 is narrower than the reference portfolio, indicating that the varied inputs have less of an impact on the overall portfolio costs.
- While the interquartile range for sensitivity 11 B2 portfolio is comparatively narrower than the reference portfolio, suggesting that the expected portfolio costs are less variable and higher, TailVar90, at 20.7 billion, indicates a risk of higher costs for this portfolio.

Figure 8.24 compares the reference to sensitivity 11 B2. We sorted each simulation's portfolio cost results into bins containing a narrow range of expected portfolio costs. The shorter right-hand tail and lower TailVar90 value of sensitivity 11 B2 indicate less risk associated with sensitivity 11 B2 than the reference portfolio, despite the higher average portfolio cost.

Figure 8.24: Frequency Histogram of Expected Portfolio Cost ($ Billions) — Reference vs. Sensitivity 11 B2



In addition to the expected portfolio costs, we evaluated the expected SCGHG. Table 8.10 and Figure 8.25 compare the SCGHG costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of the two portfolios.

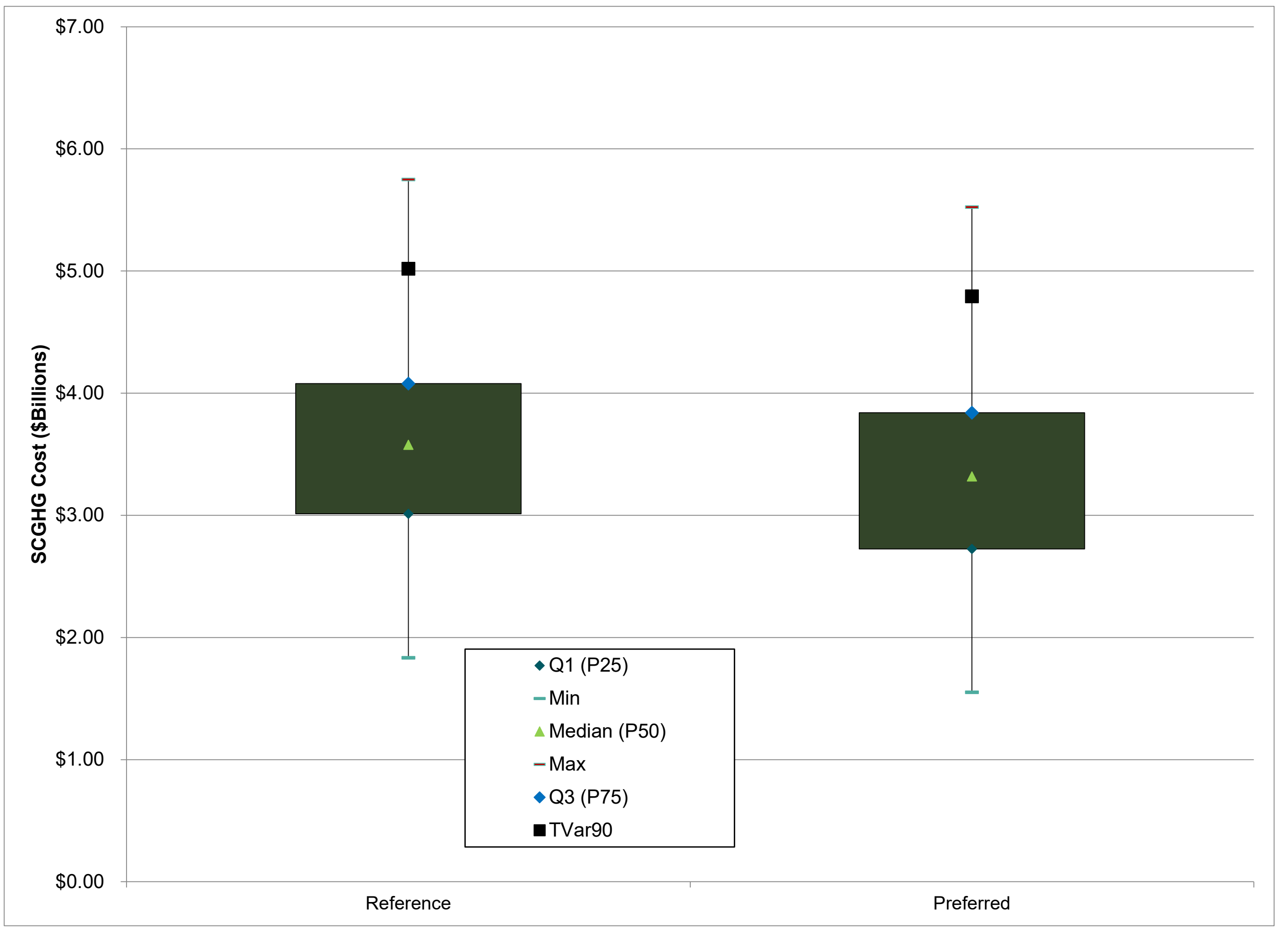
Key results of the analysis include:

- In contrast, the mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix to include more conservation and distributed energy resources results in lower average emissions.
- The range for sensitivity 11 B2 is more comprehensive than the reference portfolio, indicating the inputs were varied have a bigger impact on the overall SCGHG costs.

Table 8.10: SCGHG across 310 Simulations ($ Billions)

SCGHG	Portfolio	Emissions ($)	Difference from Mid ($)	Mean ($)	Difference from Mid ($)	TVar90 ($)	Difference from Mid ($)
1	Reference	3.24	--	3.59	--	5.02	--
11 B2	Preferred	3.33	0.09	3.33	(0.26)	4.79	(0.23)

Figure 8.25: Range of SCGHG Costs across 310 Simulations



2023 ELECTRIC PROGRESS REPORT

APPENDICES A–L

PUGET SOUND ENERGY

2023 ELECTRIC PROGRESS REPORT

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PUGET SOUND ENERGY

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PUBLIC PARTICIPATION
APPENDIX A

Contents

1. Introduction

Public participation is required and essential to developing Puget Sound Energy's 2023 Electric Progress Report (2023 Electric Report) for the 2021 Integrated Resource Plan (IRP). Puget Sound Energy (PSE) continues to expand and evolve the ways we engage with the public using a structured approach that aims to increase accountability and demonstrate how we incorporate feedback across our work products.

The activities described in this document resulted in valuable feedback, suggestions, and practical information from the organizations and individuals that helped guide the public participation process and informed key components of the 2023 Electric Report analysis. We thank those who participated in and supported this process for the time and energy they invested, and we encourage their continued participation.

Puget Sound Energy held eleven public meetings in 2022 before filing the 2023 Electric Report with the Washington Utilities and Transportation Commission (Commission) by April 1, 2023.

All materials related to the 2023 public participation process are available at pse.com/irp. The public participation materials include meeting agendas, presentations and datasets, meeting recordings, participant logs, chat transcripts, feedback reports, and meeting summaries.

Puget Sound Energy contracted public participation specialists from Maul Foster & Alongi (MFA) and Triangle Associates to help develop a public engagement strategy, provide independent meeting facilitation, develop meeting and public comment guidelines, assist with meeting documentation, and recommend approaches to promote transparent and timely communication and public engagement.

2. Public Participation Approach

Public participation for the 2023 Electric Report is built on the foundations set and lessons learned through past IRP and other PSE processes. We formally adopted the International Association of Public Participation (IAP2) framework for the 2021 IRP and subsequent 2023 Electric Report. The IAP2 framework, and various public participation techniques, helped PSE design and implement an effective public participation process that allowed interested parties to clearly understand how they could influence components of key inputs, assumptions, and decisions throughout the process and provide valuable feedback to PSE.

For the 2023 Electric Report, all meetings were open to the public, and we encouraged all attendees to participate actively. We observed safety measures for COVID-19 and held all public engagement virtually, using various online platforms, including PSE's IRP website, Zoom, and online feedback forms.

We are committed to reducing barriers to participation, communicating, and engaging with members of the public in various ways, such as recording meetings and making them available online, being transparent in sharing information and work products, and producing accessible documents.

2.1. Techniques and Objectives

Puget Sound Energy employed participation techniques designed to achieve specific meeting objectives. Our goal was to align participation objectives and techniques, clearly communicate when and how members of the public could provide input and feedback on particular report topics, offer straightforward and diverse methods for engagement, and indicate how we used feedback.

2.1.1. Transparency and Accessibility

To support and align key project milestones and decision points, PSE conducted brainstorming sessions weeks before every public meeting to develop clear objectives.

PSE's public participation practices prioritize transparency and accessibility. These practices include:

- Making comments from members of the public about the 2023 Electric Report and its development, including responses addressing how the input was considered or used, available on the PSE website
- Making data inputs and files used to develop the 2023 Electric Report available
- Making meeting summaries and materials from 2023 Electric Report public meetings publicly available on the PSE website
- Making presentation materials available to the public at least three business days before each meeting
- Outlining the schedule of report public meetings and significant topics to be covered on the PSE website (pse.com/irp)
- Providing transcripts of the chat log from public meetings and enable live closed captioning

2.1.2. Public Webinars

We continued to practice safety measures to prevent the spread of COVID-19. As a result, we hosted all public engagement activities via webinars. We designed these webinars to engage the public about critical milestones and topics in developing the 2023 Electric Report. During each webinar, those who participated could ask questions and provide feedback verbally or through the online chat feature. Triangle Associates facilitated participation to allow PSE staff to focus on the technical content of the presentations. If we could not answer a question during the meeting, we added it to the meeting feedback report, and PSE responded in writing. We mailed meeting reminders one week before each webinar to alert interested parties that we had posted the meeting materials at pse.com/irp and that feedback forms were open. PSE posted the webinar recordings and chat transcripts two days after each meeting to pse.com/irp.

2.1.3. Webinar Recordings

All webinars were recorded and posted online two days after the meeting. The recordings included a voice recording, thumbnail versions of the slides we used to support the meeting discussion, and a written transcript for easy searching. We also included the speakers' names in the transcript. We used the webinar recordings to promote participation by those who could not attend but wanted to stay involved and provide feedback. We accepted all input, whether the participant attended the webinar or not.

2.1.4. Webinar Chat Log

PSE conducted all webinars via Zoom. All comments and questions received through the online chat feature were documented in the webinar chat log and posted online two days after each meeting. The chat log documentation includes a list of all attendees along with a name, timestamp, and the comment made by each participant. We answered participant questions verbally and from the written chat. We captured these answers in each webinar recording. We added any questions not addressed during the webinar to the feedback report and answered by PSE in writing.

2.1.5. Feedback Forms

PSE designed an online feedback form and posted it at pse.com/irp/get-involved/give-feedback to promote topic-specific suggestions and questions related to each public webinar. The feedback form was opened one week before the webinar and closed one week after the meeting. Members of the public used the online feedback form to submit questions regarding the webinar presentation in advance of the meeting, and we typically answered those questions during the webinar. Following the webinar, members of the public used the feedback form to provide specific input regarding the report analysis and materials presented. Members of the public could also submit questions and comments at any time at pse.com/irp through a general comment form.

2.1.6. Feedback Reports

We prepared and posted feedback reports to pse.com/irp four weeks after each meeting. These reports included input, questions, and comments received from members of the public and written responses to feedback. The goal was to promote accountability and foster two-way communication. When we did not have sufficient time to respond to all participant feedback during a meeting, and if follow-up meetings were necessary to clarify input, the team provided a written response in the feedback report.

2.1.7. Meeting Summaries

PSE prepared and posted summaries of public meetings to pse.com/irp four weeks after each meeting, along with the feedback report. These summaries documented the major feedback themes we identified along with the feedback we received, reported on how we responded to feedback, and documented how we incorporated the feedback into the 2023 Electric Report.

2.1.8. Other Communication Tools

In addition to the techniques described, PSE also used the following communications tools:

- Triangle Associates conducted phone interviews with interested members of the public before public engagement meetings to discuss key concerns and explore process improvements.
- PSE sent email reminders about upcoming deadlines, webinars and registration information, and invitations to submit feedback forms and participate in surveys.
- PSE sent periodic email newsletters to reminded interested parties about upcoming webinars and deadlines, and included summaries of public feedback and updates on the status of the report's development.

3. Participants

One hundred and thirty-five organizations and 251 unique individuals participated in the development of the 2023 Electric Report. The participating organizations are listed below.

1099 Energy

1890 & Co

Absaroka Energy LLC

Armada Power

Atlas Renewable Power

Auto Grid

Avangrid Renewables

Avista

BayWa r.e.

Beacon Energy

Bonneville Power Administration

Brightnight Power

Broad Reach Power

BV Power

C Power Energy Management

Cadmus Group

Capital Power

Cascade Natural Gas

Chelan PUD

City of Des Moines

City of Enumclaw

City of Issaquah

City of Kenmore

City of Lake Forest Park

City of Mercer Island

City of Olympia

City of Puolsbo

City of Redmond

City of Seattle

City of Tacoma

Clear Energy Brokerage

Climate Solutions

Con Edison Clean Energy Business

Convergent Energy + Power

Creative Renewable Solutions

DNV

Ease Engineers

Ecoplexus

Elemental Energy

Enel

Energy Analytics

Energy GPS

Energy Solutions

Eolian Energy

esVolta

Flex Charging

Fortis

Franklin Energy

Frontier

General Electric

Generac Power Systems

Glarus Group

Guidehouse Consulting

Hardy Energy Consulting

Hecate Energy

Hull Street Energy

IATC

IBEW

IBV Energy

Illume Advising

Innergex

Invenergy

Jera Americas

King County

KL Gates

Laborers Local 252

Lakeridge Resources

Lightsource BP

Lloyd Reed Consulting

Matrixes Corp.

Monolith Energy Consulting

Mitsubishi Power Americas

Monolith Energy

Nationwide Energy Partners

NextEra Energy Resources

Northwest Power and Conservation Council

Northwest Power and Conservation Council

Novis Renewables

NW Energy Coalition (NWEC)

NWGA

NW Natural

Obsidian Renewables, LLC

One Energy Renewables

Optimum Building Consultants

Oracle

Pacific Architects and Engineers (PAE)

Pacific Northwest Utilities Conference Committee (PNUCC)

Pasco Energy

PGN

Phil Jones Consulting

Pierce County

Plus Power

Potelco

Power Ex

Q Cells

R Plus Energy

Renewable Northwest

Rye Development

Sageston Ventures

Sapere Consulting

SBW Consulting

Scout Clean Energy

Sierra Club

Snohomish County

Solar Horizon

SPI

Storage Alliance

Strata Clean Energy

Stratagen Consulting

Sun2oPartners

Sunenergy Systems Inc

Tenaska

The Masthead Group

TransAlta

Triangle Associates

Tuusso Energy LLC

UA Local 32

Wartsila

Washington Solar Energy Industries Association (WASEIA)

Wattbridge

West Rock

Western Energy Board

Washington Power Pool

Washington Environmental Council

Washington State Department of Commerce

Washington State Office of the Attorney General, Office of the Attorney General Public Counsel Unit

Washington Utilities and Transportation Commission (UTC)

Western Power Pool

Western Solar

Williams Companies

WRSI

Zipcon

4. Feedback Themes

The following section summarizes feedback themes from webinar meeting summaries and feedback reports during the 2023 Electric Report public participation process. We incorporated feedback into the 2023 Electric Progress Report where it was feasible and cataloged some feedback to incorporate into the 2025 IRP cycle.

4.1. Resource Alternatives and Emerging Technologies

Throughout the reporting process, interested parties expressed a desire to see PSE model alternative energy and energy storage solutions. For this report, PSE modeled several of these technologies, including:

- Advanced nuclear (SMR)
- Biodiesel
- Green hydrogen
- Hybrid renewables and diverse energy storage

Many interested parties expressed their concerns with SMR inclusion in the draft portfolio, so PSE removed SMR modeling for the final 2023 Electric Report.

➔ Please see Appendix D: Generic Resource Alternatives and Chapter Eight: Electric Analysis for additional information about how PSE modeled resource alternatives.

4.2. Impacts of the Inflation Reduction Act

Interested parties asked PSE to take into full consideration the impacts of the Inflation Reduction Act (IRA) in the 2023 Electric Report. PSE included the IRA provision for distributed solar investment tax credits (ITC) in the 2023 Electric Report because these are clear provisions that PSE has used in the past. However, the rulemaking process for energy efficiency is largely incomplete and we do not expect to understand the nuances of those results until mid-2023. PSE is working to stay informed about the IRA rulemaking process and will incorporate those provisions in future IRP cycles.

➔ Please see Chapter Four: Legislative and Policy Change for additional information about how PSE incorporated impacts of the IRA into this report.

4.3. Clean Energy Transformation Act Compliance

Interested parties expressed concern about PSE's commitment to compliance with the Clean Energy Transformation Act (CETA), which requires 100 percent GHG neutrality by 2030. PSE is pursuing cost-effective, reliable, and available conservation through renewable and non-emitting resources and we are committed to achieving the 2030 CETA requirements, as outlined in our 2021 Clean Energy Implementation Plan (CEIP). For the 2023 report, we focused on unbundled renewable energy credits (RECs) and carbon offsets to work toward meeting 100 percent GHG neutrality.

➔ Please see Chapter Eight: Electric Analysis and Chapter Two: Clean Energy Action Plan for additional information about CETA compliance in this report

4.4. Climate Change Considerations

Before and during this IRP cycle, members of the public encouraged PSE to incorporate climate change data into the planning process. We recognized the importance of climate change in past cycles but needed additional data to ensure that any analysis that reflected climate change was accurate. We began incorporating forward-looking climate change assumptions rather than historical climate data into load forecasting in the 2023 Electric Report.

➔ Please see Appendix F: Demand Forecasting Models for additional information about how PSE incorporated climate change data into their planning process.

4.5. Public Participation Process

Participants involved in public meetings for the 2023 Electric Report gave us valuable feedback on improving the public participation and feedback process. We implemented real-time improvements during this cycle and are assessing the public participation process for the next IRP cycle. For additional details see Section 2.2 of this document.

5. Timeline, Meetings, and Topics

We conducted all public meetings for the 2023 Electric Report remotely to help prevent the spread of COVID-19 while improving access for members of the public. Each meeting began with an orientation that explained how to participate using the electronic platform. The Meeting Documentation section of this appendix provides links to documentation for each of the 11 webinars.

5.1. January 2022

Date	Description
January 10	Invitation for January 20, 2022, *Energy planning process and next steps for 2022* webinar emailed to an expanded list of approximately 1,500 individuals with topics including updates on the Clean Energy Implementation Plan (CEIP), work plan for the 2023 Electric Progress Report, incorporating climate change data into the demand forecast, and Conservation

Date	Description
	Potential Assessment (CPA). The invitation provided a registration link to the first meeting and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted on the PSE IRP page online.
January 13	Meeting materials for the January 20 webinar were posted to pse.com/irp, and a feedback form was opened for public input.
January 20	**Energy Planning Process and Next Steps for 2022 Webinar** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 135 participants Puget Sound Energy provided updates on the CEIP, and work plan for the 2023 report, explained climate change in load forecasting, and explained how the Conservation Potential Assessment (CPA) fits into the IRP. Participants shared their feedback on climate change models and CPA.
January 24	A recording of the January 20 webinar and the transcript of the meeting chat was posted to pse.com/irp.
January 27	Feedback forms due for January 20 webinar, Energy Planning Process and Next Steps for 2022; 5 individuals responded.

5.2. February 2022

Date	Description
February 18	Invitation emailed to an expanded list of approximately 1,500 individuals for the March 22, 2022, Climate Commitment Act and assumptions for the 2023 Electric Progress Report webinar.
February 25	A feedback report of comments collected from the feedback form for the January 20 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.

5.3. March 2022

Date	Description
March 4	Invitation for March 22 Climate Commitment Act and assumptions for the 2023 Electric Progress Report webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including Climate Commitment Act, carbon prices and social cost of greenhouse gases, alternative electric supply-side resources and cost, and regional assumptions for electric price forecasts. Registration link to the webinar was included, and a sign-up or opt-out option for notifications concerning the process. Registration links and webinar information were also posted online.
March 15	Meeting materials for March 22 webinar were posted to pse.com/irp, and a feedback form was opened.
March 22	**Climate Commitment Act and Assumptions for the 2023 Electric Progress Report Webinar** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 68 participants

Date	Description
	Puget Sound Energy presented information on the Climate Commitment Act, carbon prices and social Cost of Greenhouse Gases, alternative electric supply-side resources and cost, and regional assumptions for electric price forecasts.
March 24	A recording of the March 22 webinar and the chat transcript was posted to pse.com/irp.
March 31	Feedback forms were due for March 22 webinar; eight individuals responded.

5.4. April 2022

Date	Description
April 22	A feedback report of comments collected from the feedback form for the March 22 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.

5.5. May 2022

Date	Description
May 5	Invitation for June 6 Electric and gas delivery system planning webinar emailed to an expanded list of 1,500 individuals with listed topics including Delivery System Planning (DSP) overview, modernization investments, DSP advancements, and distribution and transmission interconnection cost. It also includes saving the dates for all upcoming 2022 IRP meeting dates and legislative updates. A registration link to the webinar was included, along with a sign-up or opt-out option for notifications. Registration links and information were also posted online.
May 27	Meeting materials for June 6 webinar were posted to pse.com/irp, and the feedback form was opened.

5.6. June 2022

Date	Description
June 2	The second reminder was emailed to interested parties for the Electric and Gas Delivery System Planning (DSP) Webinar.
June 6	**Electric and Gas Delivery System Planning (DSP) Webinar** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 77 participants The Transmission team presented on Delivery System Planning ongoing work, Delivery System Planning — Integrating different voices, and Resource Interconnection Costs.
June 13	Feedback forms were due for June 6 webinar; four individuals responded.
June 17	Invitation for July 12 *Electric and gas demand forecast* webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including the demand forecast assumptions, electric and gas forecast results, and electric vehicle forecast. Registration link to the webinar was included along with a sign-up or opt-out option for notifications. Registration links and information were also posted online.

5.7. July 2022

Date	Description
July 1	A report of comments collected from the feedback form for the June 6 webinar, PSE's responses, and a meeting summary were posted to pse.com/irp.
July 5	Meeting materials for July 12 webinar were posted to pse.com/irp, and a feedback form was opened.
July 12	**Electric and Gas Demand Forecast Webinar** **Public role:** Inform and Consult **Meeting platform**: Zoom **Attendance:** 64 participants Puget Sound Energy presented natural gas results, electric results, demand forecast assumptions, and the electric vehicle forecast.
July 14	July 12 webinar recording and chat posted to pse.com/irp.
July 20	Invitation for the August 24 *resource adequacy information session* webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including overview and results to the Western Resource Adequacy Program (WRAP), 2022 Regional Forecast from Pacific Northwest Utilities Conference Committee (PNUCC), a summary of resource adequacy modeling results from E3, and PSE resource needs and market reliance. Registration link to the webinar is included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.
July 22	Feedback forms were due for July 12 webinar; one individual responded.

5.8. August 2022

Date	Description
Aug. 12	A feedback report of comments collected from the feedback form for the July 12 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
Aug. 17	Meeting materials for the August 24 webinar were posted to pse.com/irp, and a feedback form was opened.
Aug. 24	**Resource Adequacy Information Session Webinar** **Public role:** Inform **Meeting platform:** Zoom **Attendance**: 60 participants Representatives from the Western Resource Adequacy Program (WRAP) provided an overview of their program and metrics, the Pacific Northwest Utilities Conference Committee (PNUCC) provided a 2022 Regional Forecast, E3 shared a summary of resource adequacy modeling results, and PSE presented on resource needs and market reliance.
Aug. 26	August 24 webinar recording and chat posted to pse.com/irp.
Aug. 29	Invitation for September 13 webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including final resource need, Conservation Potential Assessment results, and final gas scenarios and gas alternatives. Registration link to Webinar was included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.

5.9. September 2022

Date	Description
Sept. 2	Feedback forms are due for the August 24 webinar; four individuals responded.
Sept. 6	Meeting materials for September 13 webinar were posted to pse.com/irp, and a feedback form was opened.
Sept. 13	**Conservation Potential Assessment (CPA) and assumptions for the 2023 Electric Progress Report** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 67 participants Puget Sound Energy presented Inflation Reduction Act impacts on the Electric Progress Report, resource alternatives, and how PSE is working towards 100 percent greenhouse gas neutrality by 2030, and Cadmus Group presented Conservation Potential Assessment results.
Sept. 15	September 13 webinar recording and chat posted to pse.com/irp.
Sept. 23	Feedback forms were due for September 13 webinar; four individuals responded
Sept. 28	**Portfolio Benefits Analysis Drop-In Session** **Public role:** Consult **Meeting platform:** Zoom **Attendance:** 19 participants Puget Sound Energy presented potential methodology for utilizing customer benefits in portfolio analysis, discussed potential methodology and ways to improve or evolve it, and discussed next steps for use of the analysis.
Sept. 30	**Portfolio Benefits Analysis Drop-In Session** **Public role:** Consult **Meeting platform:** Zoom **Attendance:** 16 participants Puget Sound Energy presented potential methodology for utilizing customer benefits in portfolio analysis, discussed potential methodology and ways to improve or evolve it, and discussed next steps for use of the analysis.

5.10. October 2022

Date	Description
Oct. 14	A feedback report of comments collected from the feedback form for the September 13 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
Oct. 20	A feedback report of comments collected from the feedback form for the September 22 webinar, along with PSE's responses and a meeting summary posted to pse.com/irp.
Oct. 20	Date change announcement for December 12 webinar, originally scheduled for November 17, was emailed to an expanded list of approximately 1,500 individuals with listed topics including draft portfolio results for the 2023 Electric Progress Report and Gas Utility IRP. Registration link to Webinar was included, and a sign-up or opt-out option for notifications concerning the process.
Oct. 25	**Portfolio Benefits Analysis Drop-In Session** **Public role:** Consult

Date	Description
	Meeting platform: Zoom **Attendance:** 14 participants Puget Sound Energy presented potential methodology for utilizing customer benefits in portfolio analysis, discussed potential methodology and ways to improve or evolve it, and discussed next steps for use of the analysis.

5.11. November 2022

Date	Description
	Feedback forms were due for September 28, 30, and October 25 drop-in sessions; 4 individuals responded.
Nov. 16	Invitation for December 12 *Updates and feedback on draft results of electric and gas portfolio* webinar emailed to an expanded list of 1,500 individuals with listed topics, including final draft results for electric and gas portfolio. Registration link to the webinar is included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.
Nov. 22	A feedback report of comments collected from the feedback form for the September 28 and 30, and October 25 drop-in sessions, along with PSE's responses and a meeting summary posted to pse.com/irp.

5.12. December 2022

Date	Description
Dec. 5	Meeting materials for December 12 webinar were posted to pse.com/irp, and a feedback form was opened.
Dec. 12	**Draft results of electric portfolios webinar** **Public role**: Consult, Involve and Inform **Attendance:** 92 participants Puget Sound Energy delivered an overview of the 2023 Electric Progress Report modeling process and timeline; discussed PSE's distributed energy resources and customer renewable programs; presented resource plan modeling results; and facilitated a discussion of the candidate portfolios.
Dec. 14	December 12 webinar recording and chat posted to pse.com/irp.
Dec. 19	Feedback forms were due for the December 12 webinar; 4 individuals responded.

5.13. January 2023

Date	Description
Jan. 9	A meeting summary for the December 12 meeting posted to pse.com/irp.
Jan. 24	Draft Chapter 3: Resource Plan of the Electric Progress Report published at pse.com/irp. A feedback form was opened.

5.14. February 2023

Date	Description
Feb. 7	Feedback forms due for the Draft Chapter 3: Resource Plan of the Electric Progress Report published at pse.com/irp.
Feb. 27	Invitation for March 14 *Final portfolio results of 2023 Electric Progress Report and Gas Utility IRP* webinar emailed to the expanded list of approximately 1,500 individuals with listed topics, including final results for electric and gas portfolio. Registration links to both Webinars are included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.

5.15. March 2023

Date	Description
March 7	Meeting materials for March 14 webinar were posted to pse.com/irp.
March 14	**Final Portfolio results of the 2023 Electric Progress Report and Gas Utility IRP Webinar** **Public role:** Inform and Consult **Attendance:** TBD In this webinar, PSE explained the market risk assessment and results of the stochastic analysis. The preferred portfolio and background concerning the approach and methodology was presented.
March 16	March 14 webinar recording and chat posted to pse.com/irp.
March 24	March 14 webinar meeting summary posted to pse.com/irp.

6. Meeting Documentation

Links to materials for each 2023 report webinar are included below and posted on pse.com/irp.

6.1. January 20, 2022 Webinar

Topic: Energy planning process and next steps for 2022

- Agenda
- Presentation
- 2022 Climate Change Data Calculation [Excel]
- Chat log
- Meeting recording
- Meeting summary

6.2. March 22, 2022 Webinar

Topic: Climate Commitment Act and assumptions for the 2023 Electric Progress Report

- Hot Sheet

- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report
- Meeting Files
  - 2023 Electric Progress Report – Generic Resource Cost Adjustments (Excel)
  - 2023 Electric Progress Report – Generic Resource Cost Breakdown (Excel)
  - 2023 Electric Progress Report – Regional New Builds and Retirements (Excel)
  - 2019 HDR Generic Resource Assumptions report

6.3. June 6, 2022 Webinar

Topic: Electric and gas delivery system planning

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report

6.4. July 12, 2022 Webinar

Topic: Electric and gas demand forecast

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report

6.5. August 24, 2022 Webinar

Topic: Resource adequacy information session

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording

- Meeting summary and feedback report
- Meeting files:
  - August 2021 Effective Load Carrying Capability (ELCC) Workshop Recording
  - Presentation from the 2021 ELCC Workshop
  - Resource Adequacy Primer (2021)
  - Review of Puget Sound Energy ELCC Methodology (2021)
  - Response to Public Comments on ELCC Calculations and Use (2021)
  - Market Reliance Workshop presentation (2021)
  - Market Reliance Workshop video recording (2021)
  - Market Reliance Workshop Q&A (2021)

6.6. September 13, 2022 Webinar

Topic: Electric Progress Report: Final resource need and Conservation Potential Assessment (CPA) results

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report
- Meeting files:
  - Electric Price Forecast for the 2023 Electric Progress Report
  - 2023 Electric Progress Report Electric Price Forecast [Excel]
  - Generic Resources Capital Costs and Operating Assumptions
    2023 Electric Progress Report Updated Generic Resources Cost Assumptions [Excel]

6.7. September 28 and 30, and October 25, 2022 Webinars

Topic: Portfolio Benefits Analysis Drop-in Sessions

- Presentation
- Customer Benefit Indicator Calculator [Excel]
- Meeting summary and feedback report

6.8. December 12, 2022 Webinar

Topic: Draft portfolio results of 2023 Electric Progress Report

- Hot sheet
- Agenda
- Presentation

- Chat log
- Meeting recording
- Meeting summary

6.9. March 14, 2023 Webinar

Topic: Final portfolio results of the 2023 Electric Progress Report and Gas Utility IRP

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary

LEGAL REQUIREMENT
APPENDIX B

PSE PUGET SOUND ENERGY

Contents

1. Regulatory Requirements

This document outlines PSE's regulatory requirements for the 2023 Electric Progress Report (2023 Electric Report). Figure B.1 lists the regulatory requirements for electric utilities codified Washington Administrative Code (WAC) 480-100-620, 480-100-625 and 480-100-630. Figure B.2 lists requirements in the Revised Code of Washington (RCW) 19.280.030. Figure B.3 lists the requirements in RCW 19.280.100.

Table B.1: Electric Progress Report Regulatory Requirements Codified in WAC 480-100-620, 480-100-625, and 480-100-630

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620(3)(a) Assessments of a variety of distributed energy resources. These assessments must incorporate nonenergy costs and benefits.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan Decisions • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix K: Delivery Systems Planning
WAC 480-100-620(3)(b)(i) An assessment of currently employed and potential policies and programs needed to obtain all cost-effective conservation, efficiency and load management improvements.	• Chapter Eight: Electric Analysis • Appendix E: Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-620(3)(b)(ii) Assess currently employed and new policies and programs needed to obtain all cost-effective demand response.	• Chapter Three: Resource Plan Decisions • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix K: Delivery Systems Planning • Appendix E: Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-620(3)(b)(iii) Include distributed energy programs and mechanisms identified pertaining to energy assistance.	PSE provided an assessment to the Department of Commerce of mechanisms pertaining to energy assistance, as well as progress toward meeting customer energy assistance need. Existing PSE programs include bill assistance and weatherization services. Currently, PSE does not have any distributed energy resource (DER) programs as part of its energy assistance strategy. However, in future years, there may be programs and mechanisms that could be used to meet customer energy assistance need, and those programs will be considered and incorporated into the IRP as indicated in draft WAC 480-100-610(3).
WAC 480-100-620(3)(b)(iv)	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan

Statutory or Regulatory Requirement	Chapter and/or Appendix
Assess other distributed energy resources that may be installed by the utility or the utility's customers including energy storage, electric vehicles, and PV.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix K: Delivery Systems Planning
WAC 480-100-620(4) An assessment of a wide range of commercially available generating and nonconventional technologies.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(5) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources and addressing overgeneration events, if applicable to the utility's resource portfolio.	• Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(6) An assessment of regional generation and transmission capacity. Must include the utility's existing transmission capabilities, and future resource needs. Must identify the general location and extent of transfer capability limitations on its transmission network.	• Appendix K: Delivery Systems Planning
WAC 480-100-620(7) A comparative evaluation of all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost.	• Chapter Three: Resource Plan • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix E: Conservation Potential Assessment and Demand Response Assessment • Appendix H: Electric Analysis and Portfolio Model • Appendix K: Delivery Systems Planning
WAC 480-100-620(8) An assessment and determination of resource adequacy metrics and an appropriate resource adequacy requirement and measurement metrics consistent with CETA.	• Chapter Seven: Resource Adequacy
WAC 480-100-620(9) An assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk, informed by the cumulative impact analysis conducted by the department of health.	• Appendix J: Economic, Health and Environmental Assessment of Current Conditions
WAC 480-100-620(10)(a) At least one scenario must describe the lowest reasonable cost and reasonably available portfolio that the utility would	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model

Statutory or Regulatory Requirement	Chapter and/or Appendix
have implemented if not for CETA requirements in RCW 19.405.040 and 19.405.050.	
WAC 480-100-620(10)(b) At least one scenario must be a future climate change scenario.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(10)(c) At least one sensitivity must be a maximum customer benefit scenario. The sensitivity should model the maximum amount of customer benefits described in RCW 19.405.040(8).	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(11) Integration of the demand forecasts and resource evaluations into a long-range integrated resource plan describing the mix of resources that meet current and projected resource needs.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Six: Demand Forecasts • Appendix F: Demand Forecasting Models
WAC 480-100-620(11)(a) A narrative description of decisions made including how the IRP expects to achieve the clean energy transformation standards at lowest cost.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan
WAC 480-100-620(11)(b) A narrative description of decisions made including how the IRP expects to serve utility load, based on hourly data with the output of the utility's owned resources, market purchases, and power purchase agreements net of any off-system sales.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(c) A narrative description of decisions made including how the IRP expects to include all cost-effective, reliable and feasible conservation and efficiency and demand response resources.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(d) A narrative description of decisions made including how the IRP expects to consider acquisition of existing renewable resources.	• Chapter Two: Clean Energy Action Plan Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(e) A narrative description of decisions made including how the IRP expects in the acquisition of new resources, to rely on renewable resources and energy storage in so far as doing so is at the lowest reasonable cost.	• Chapter Two: Clean Energy Action Plan Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(f) A narrative description of decisions made including how the IRP expects to maintain and protect the safety, reliable operation, and balancing of the utility's electric system.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(g)	• Chapter Two: Clean Energy Action Plan

Statutory or Regulatory Requirement	Chapter and/or Appendix
A narrative description of decisions made including how the IRP expects to achieve the requirements in WAC 480-100-610 (4) (c) including the long-term strategy and interim steps the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations; and the estimated degree to which benefits will be equitably distributed and burdens reduced over the planning horizon.	
WAC 480-100-620(11)(h) A narrative description of decisions made including how the IRP expects to assess the environmental health impacts to highly impacted communities.	• Appendix J: Economic, Health and Environmental Assessment of Current Conditions
WAC 480-100-620(11)(i) A narrative description of decisions made including how the IRP expects to analyze and consider combinations of distributed energy resource costs, benefits, and operational characteristics to meet system needs.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(j) A narrative description of decisions made including how the IRP expects to incorporate the social cost of greenhouse gas emissions as a cost adder.	• Appendix G: Electric Price Models Chapter Five: Key Analytical Assumptions
WAC 480-100-620(12) A ten-year clean energy action plan for implementing the clean energy standards at the lowest reasonable cost; informed by the utility's ten year cost-effective conservation potential assessment; identifies how the utility will meet the requirements in WAC 480-100-610 (4) (c); establishes a resource adequacy requirement; identifies cost-effective demand response and load management programs; identifies renewable resources, nonemitting electric generation and distributed energy resources; identifies any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities; identifies the nature and possible extent to which the utility will rely on alternative compliance options; and incorporates the social cost of greenhouse gas emissions as a cost adder.	• Chapter Two: Clean Energy Action Plan
WAC 480-100-620(13) Include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. Must list nonenergy costs and benefits addressed in the IRP and specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities or the general public.	• Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(14) Data input files made available to the Commission in native format as an appendix to the IRP.	• Appendix H: Electric Analysis and Portfolio Model

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620(15) Information and analysis that will be used to inform annual filings under Chapter 480-106 WAC related to qualifying facilities.	• Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(16) A summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the previous IRP.	• Chapter Five: Key Analytical Assumptions
WAC 480-100-620(17) A summary of public comments received during IRP development and utility responses.	• Appendix A: Public Participation
WAC 480-100-625(4)(a)(i) In this report, the utility must update its load forecast.	• Chapter Six: Demand Forecast
WAC 480-100-625(4)(a)(ii) In this report, the utility must update its demand-side resource assessment, including a new conservation potential assessment.	• Appendix E: Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-625(4)(a)(iii) In this report, the utility must update its resource costs.	• Chapter Five: Key assumptions • Appendix D: Generic Resource Alternatives
WAC 480-100-625(4)(a)(iv) In this report, the utility must update its portfolio analysis and preferred portfolio.	• Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Models
WAC 480-100-625(4)(b)(v) The progress report must include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces.	• Chapter Four: Legislative and Policy Change
WAC 480-100-625(4)(c) The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.	• Chapter 4: Legislative and Policy Change • Chapter 8: Electric Analysis
WAC 480-100-630(1) The utility must demonstrate and document how it considered input from advisory group members in the development of its IRP and two-year progress report. Examples of how the utility may incorporate advisory group input including using modeling scenarios, sensitivities, and assumptions advisory group members proposed and using data and information supplied by advisory group members as inputs to plan development.	• Chapter One: Executive Summary • Appendix A: Public Participation

Table B.2: Electric Utility Integrated Resource Plan Regulatory Requirements Codified in RCW 19.280.030

Statutory or Regulatory Requirement	**Chapter and/or Appendix**
RCW 19.280.030(1)(b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as	• Chapter Eight: Electric Analysis

Statutory or Regulatory Requirement	Chapter and/or Appendix
appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources.	• Appendix E: Conservation Potential Assessment and Demand Response Assessment • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources.	• Chapter Four: Legislative and Policy Change • Chapter Seven: Resource Adequacy • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion.	• Chapter Three: Resource Plan • Chapter Five: Key Assumptions • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix E: Conservation Potential Assessment and Demand Response Assessment • Appendix H: Electric Analysis and Portfolio Model Appendix K: Delivery System Planning
RCW 19.280.030(1)(e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(f) An assessment and ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers.	• Chapter Three: Resource Plan • Chapter Five: Key Assumptions • Chapter Seven: Resource Adequacy • Chapter Eight: Electric Analysis
RCW 19.280.030(1)(g) A determination of resource adequacy metrics for the resource plan consistent with the forecasts.	• Chapter One: Executive Summary • Chapter Seven: Resource Adequacy • Chapter Eight: Electric Analysis • Appendix G: Electric Price Models • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(h) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations.	• Chapter Five: Key Analytical Assumptions • Appendix E: Conservation Potential Assessment and Demand Response Assessment
RCW 19.280.030(1)(i)	• Chapter Seven: Resource Adequacy

Statutory or Regulatory Requirement	Chapter and/or Appendix
An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing sections 3 through 5 of CETA.	• Chapter Eight: Electric Analysis • Appendix G: Electric Price Models
RCW 19.280.030(1)(j) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing sections 3 through 5 of CETA, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliability operation, and balancing of its electric system.	• Chapter One: Executive Summary • Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions
RCW 19.280.030(1)(k) An assessment, informed by the cumulative impact analysis conducted under section 24 of CETA of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks, and energy security and risk.	• Chapter Two: Clean Energy Action Plan • Appendix J: Economic, Health and Environmental Assessment of Current Conditions
RCW 19.280.030 (1) (l) A ten-year clean energy action plan for implementing sections 3 through 5 of CETA at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan.	• Chapter Two: Clean Energy Action Plan
RCW 19.208.030(3)(a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities, pursuant to section 15 of CETA when developing integrated resource plans and clean energy action plans.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model

Table B.3: Distributed Energy Resources Planning Requirements Codified in RCW 19.280.100

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.100(2)(a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery Systems Planning
RCW 19.280.100(2)(b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery Systems Planning
RCW 19.280.100(2)(c)	• Chapter Five: Key Analytical Assumptions

Statutory or Regulatory Requirement	Chapter and/or Appendix
Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	• Appendix E: Conservation Potential and Demand Response Assessments • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.100(2)(d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	• Appendix E: Conservation Potential Assessment and Demand Response Assessment
RCW 19.280.100(2)(e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	• Chapter Four: Legislative and Policy Change • Appendix A: Public Participation • Appendix K: Delivery System Planning
RCW 19.280.100(2)(f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources	• Chapter Two: Clean Energy Action Plan • Chapter Five: Key Analytical Assumptions • Appendix K: Delivery System Planning

Statutory or Regulatory Requirement	Chapter and/or Appendix
to displace or delay system resources in the integrated resource plan;	
RCW 19.280.100(2)(g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery System Planning
RCW 19.280.100(2)(a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	• Chapter Two: Clean Energy Action Plan
RCW 19.280.100(2)(b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	• Chapter Two: Clean Energy Action Plan
RCW 19.280.100(2)(c) Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	Programs will be identified through the CEIP process and through engagement with the Equity Advisory Group. PSE is pursuing an Alternative Pricing pilot.
RCW 19.280.100(2)(d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	• Appendix E: Conservation Potential Assessment and Demand Response Assessment
RCW 19.280.100(2)(e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires	• Chapter Four: Legislative and Policy Change • Appendix A: Public Participation

Statutory or Regulatory Requirement	Chapter and/or Appendix
alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	
RCW 19.280.100(2)(f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources to displace or delay system resources in the integrated resource plan;	• Chapter Two: Clean Energy Action Plan • Chapter Five: Key Analytical Assumptions • Appendix K: Delivery System Planning
RCW 19.280.100(2)(g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery System Planning
RCW 19.280.100(2)(h) Include a discussion of lessons learned from the planning cycle and identify process and data improvements planned for the next cycle.	• Appendix K: Delivery System Planning

2. Report on Previous Action Plans

Per WAC 480-100-238(3)(h),[1] each item from the 2021 IRP electric resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

[1] WAC 480-100-238

2.1. 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.

Progress: Through the end of 2022, PSE acquired 243.22 MWh of conservation, equal to 27.8 aMW or 48.8 percent of the target.

2.2. Equity Advisory Group

Convene and engage an Equity Advisory Group (EAG) 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.

Progress: PSE formed the EAG in April 2021, meeting 19 times between April 2021 and December 2022. The EAG has informed our work on a wide range of topics, including those listed above.

2.3. 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.

Progress: For the 2023 Electric Report, PSE assumed that access to the short-term market would continue to be available but in decreasing amounts into the future. By 2029, we assumed that none of the transactions in the short-term market would be firm

2.4. 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.

Progress: On June 30, 2021, Puget Sound Energy (PSE) filed with the Washington Utilities and Transportation Commission (Commission) the final Request for Proposals for All Resources (the All-Source RFP) in docket UE-210220.

A draft All Source RFP was filed on April 1, 2020. After a 45-day public comment period, on June 1, 2021, PSE filed responses to all public comments and a revised RFP for Commission approval. Following an open meeting on June 11, 2021, the Commission issued Order #1 on June 14, 2021 approving with conditions PSE's draft All Source RFP. The Commission order approving PSE's All Source RFP may found in Commission's web site in the All-Source RFP docket UE-210220. Information about the Commission's approval process and how interested parties can participate can be found in the All-Source RFP Schedule and Public Participation sections below.

The All-Source RFP seeks bids from qualified respondents to supply up to 1,669 GWh of Clean Energy Transformation Act ("CETA") eligible resources and up to 1,506 MW of capacity resources to PSE. It is an All-Source RFP, meaning that PSE will consider any electric resource or energy storage resource that can meet all or part of the company's resource need, consistent with the requirements described in the RFP.

2.5. 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

Progress: After filing a draft with the Washington Utilities and Transportation Commission ("WUTC") on April 1, 2021, and a subsequent public comment period, on May 14, 2021, PSE issued a RFI for DERs. The DER RFI enhanced PSE's understanding of DER options available in its service territory and informed the development of a well-designed targeted DER RFP. In 2021, PSE also developed the requirements for a virtual power plant ("VPP") platform that will be used to dispatch DERs, including demand response. PSE expects that a common VPP platform will provide additional value to PSE customers and clarity to DER bidders by identifying specific integration and operational requirements.

Using the knowledge gained through the RFI process, PSE filed the draft targeted DER RFP with the WUTC on November 15, 2021, in docket UE-210878, which incorporates the technical and operational requirements of the VPP platform. A revised DER RFP was filed on January 14, 2022, incorporating public comments, with the WUTC approving the updated filing on January 27, 2022. The final DER RFP was filed February 7, 2022. PSE accepted proposals for the DER RFP from February 7, 2022 till 11:59 PM PST on March 21, 2022.

2.6. 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.

Progress: Puget Sound Energy continues to improve the process between the electric and gas utility modeling. For this progress report, we included modeling of hydrogen and natural gas blending starting in 2030 and increasing to 100 percent hydrogen by 2045. This fuel blending was modeled as options for new peaker plants along with the existing thermal plants. The 2023 Gas Utility IRP includes analysis for electrification and is located here.

➔ A full discussion of the hydrogen modeling is included in Chapter Five: Key Analytical Assumptions.

EXISTING RESOURCE INVENTORY

APPENDIX C

Contents

1. Introduction

Puget Sound Energy (PSE) uses supply-side and demand-side resources to meet customer loads. Supply-side resources provide electricity to meet the load; these resources originate on the utility side of the meter. Demand-side resources contribute to meeting the need by reducing demand. An integrated resource plan includes both supply- and demand-side resources. This appendix describes PSE's existing electric supply- and demand-side resources.

1.1. Capacity Values

We describe PSE's existing electric resources using the net maximum capacity of each generation facility in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period — in this case, 60 minutes — when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads, and before the losses incurred in transmitting energy over transmission and distribution lines. This explanation is consistent with how we described capacities in the annual 10K report[1] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

We referenced different capacity values in other PSE publications because output varies depending on a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades, and expansions. Selecting a single reference point based on a consistent set of assumptions is necessary to describe the relative size of resources. Depending on the nature and timing of the discussion, these assumptions, and therefore the expected capacity value, may vary.

1.2. CETA-qualifying Capacity

The Clean Energy Transformation Act (CETA) requires PSE to supply electricity free of greenhouse gas emissions by 2045; we must generate all electricity from renewable or non-emitting resources. PSE's total existing CETA-qualifying capacity is 2,969 MW, which includes 1,020 MW of PSE-owned and 1,465 MW of contracted resources. The final 483 MW of CETA-qualifying capacity are load-reducing contracted resources.

The following tables summarize PSE's existing supply-side resources, in MW of net maximum capacity, that meet CETA's renewable or non-emitting requirements. Additional details on these resources are in subsequent sections of this appendix.

Table C.1 presents all CETA-qualifying PSE-owned resources.

Table C.1: Existing PSE-owned CETA-qualifying Electric Generating Resources

Resource	Type	Net Maximum Capacity (MW)
Upper Baker River	Hydroelectric	91
Lower Baker River	Hydroelectric	105

[1] PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in February 2022 for the year ending December 31, 2021. See http://www.pugetenergy.com/pages/filings.html.

Resource	Type	Net Maximum Capacity (MW)
Snoqualmie Falls	Hydroelectric	48
Hopkins Ridge	Wind	157
Wild Horse	Wind	343
Lower Snake River	Wind	273
Wild Horse	Solar	0.5
Glacier Battery Demonstration Project	Storage	2
Total Capacity, PSE-owned	**All**	**1,020**

The majority of our CETA-qualifying energy is generated from contracted hydroelectric and wind resources. These are presented in Table C.2.

Table C.2: Existing Contracted CETA-qualifying Electric Generating Resources

Resource	Type	Net Maximum Capacity (MW)
Priest Rapids	Hydroelectric	6
Rock Island I & II	Hydroelectric	156
Rocky Reach	Hydroelectric	325
Wanapum	Hydroelectric	7
Wells	Hydroelectric	228
Canadian Entitlement Return	Hydroelectric	-33
Baker Replacement	Hydroelectric	7
Energy Keepers	Hydroelectric	40
BPA Capacity Product	Hydroelectric	100
Klondike III	Wind	50
Golden Hills	Wind	200
Clearwater	Wind	350
SPI Biomass	Biofuel/Biogas	17
Farm Power Rexville	Biofuel/Biogas	0.75
Rainier Biogas	Biofuel/Biogas	1
Vander Haak Dairy	Biofuel/Biogas	0.60
Edaleen Dairy	Biofuel/Biogas	0.75
Blocks Evergreen Dairy	Biofuel/Biogas	0.19
Emerald City Renewables	Biofuel/Biogas	4.5
Emerald City Renewables 2	Biofuel/Biogas	4.5
Total Capacity, Contracted Resources	**All**	**1,465**

Table C.3 details the existing resources allocated to serving PSE's customer renewable energy programs. We describe these programs in Section 3.2 of this appendix.

Table C.3: Existing CETA-qualifying Load Reducing Customer Program Electric Resources

Resource	Customer Program[2]	Type	Net Maximum Capacity (MW)
City of Bonney Lake	Community Solar	Solar	0.45
Olympia High School	Community Solar	Solar	0.2
Pine Lake Middle School	Community Solar	Solar	0.175
Urtica Solar	Community Solar	Solar	5
Penstemon Solar	Community Solar	Solar	5
Lund Hill	Green Direct	Solar	150
Skookumchuck	Green Direct	Wind	137
Camas Solar	Green Power/PURPA QFs	Solar	5
Koma Kulshan	PURPA QFs	Hydroelectric	13
Twin Falls	PURPA QFs	Hydroelectric	20
Weeks Falls	PURPA QFs	Hydroelectric	4.6
Cascade Community Solar #1 and #2 (combined)	PURPA QFs	Solar	0.03
Finn Hill (Lake Wash SD)	PURPA QFs	Solar	0.36
IKEA	PURPA QFs	Solar	0.83
Port of Coupeville	PURPA QFs	Solar	0.08
3 Bar-G Wind	PURPA QFs	Wind	0.12
Knudson Wind	PURPA QFs	Wind	0.11
Swauk Wind	PURPA QFs	Wind	4.3
Net Metering[1]	Net Metering	--	137
Total Capacity, Load Reducing Resources		**All**	**483**

Notes:

1. Existing net metered customers are captured in the base demand forecast. Therefore we do not include this as a resource in our IRP or progress report modeling.
2. PURPA QFs are Public Utility Regulatory Policies Act of 1978 Qualifying Facilities; Community Solar, Green Direct, Green Power, and Net Metering customer programs are described in section 4.7 of this appendix.

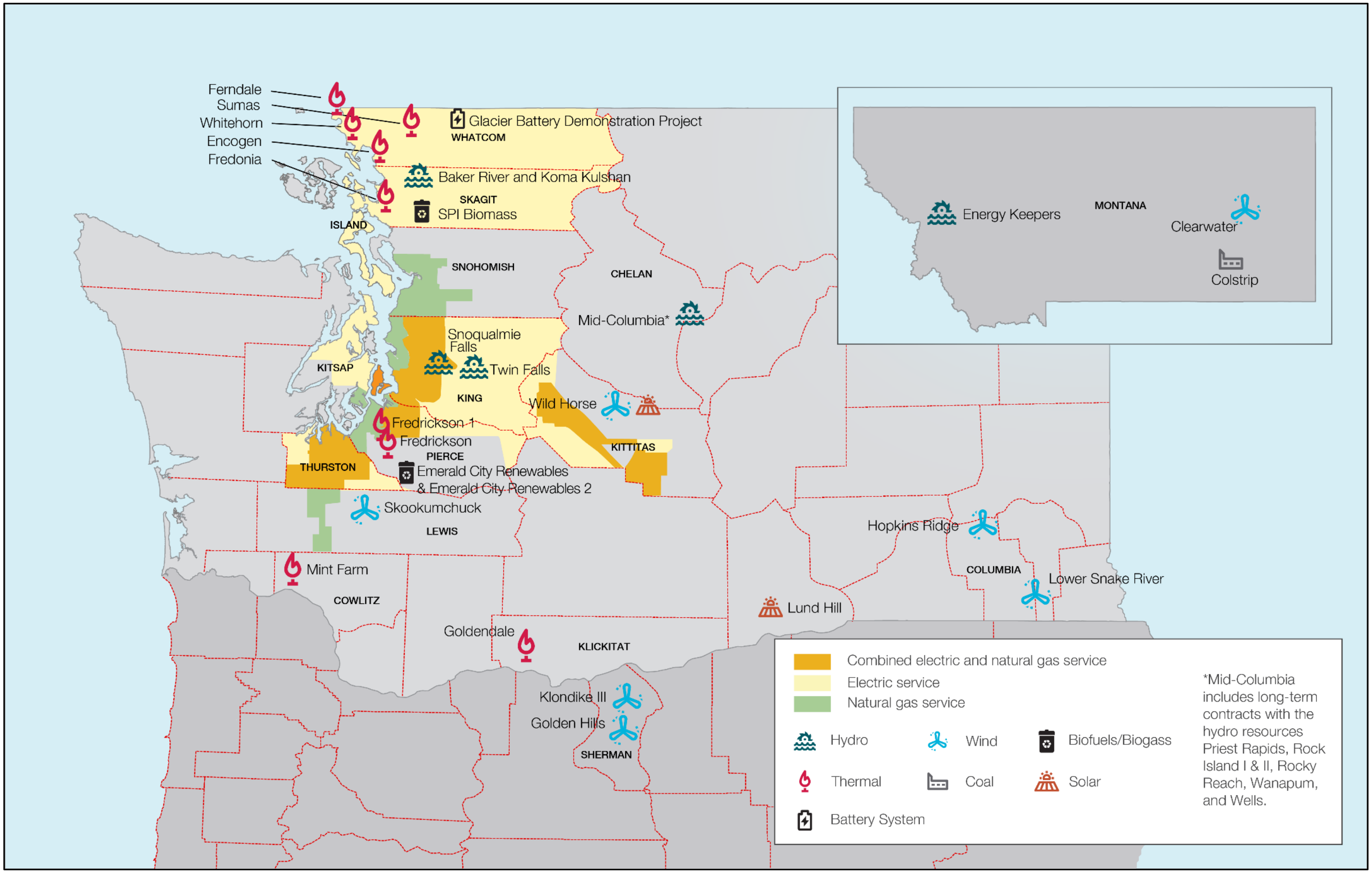
2. Supply-side Resources

We primarily use supply-side resources to meet customer load. We describe PSE's existing supply-side resources in the following sections and explain:

- **Generating and storage resources**: Hydroelectric, wind, solar, battery, coal, and combustion turbines (baseload and peakers)
- **Long-term contracts:** Negotiated with independent producers to supply electricity from various fuel sources
- **Transmission contracts:** Negotiated with Bonneville Power Administration (BPA) to carry electricity from the short-term wholesale market purchases to our service territory

Figure C.1 displays electricity-generating resources that PSE owns or contracts with independent energy producers. In this figure, we included only contracted projects with a maximum capacity greater than 5 MW. We show all PSE-owned facilities regardless of capacity.

Figure C.1: PSE's Existing Resources Inventory



2.1. Renewable Resources

Renewable resources use renewable fuels such as water, wind, sunlight, and biomass to generate electricity. Hydroelectricity generation provides flexible baseload energy production, which means it produces energy at a constant rate over long periods and is used to meet some or all a region's continuous energy demand. Hydroelectricity can also perform peaking functions when needed. Alternatively, wind and solar are intermittent resources – also known as variable energy resources – because their generating patterns vary due to uncontrollable environmental factors. These resources cannot consistently deliver energy when customers need it, such as when the wind dies down or clouds cover the sun, so we need additional energy sources to back up intermittent resources.

Hydroelectricity and wind generation are PSE's primary renewable resources. Utility-scale wind and solar are PSE's largest intermittent resources. Other intermittent resources include small-scale power production generated by customers, including rooftop solar.

Energy storage has the potential to provide multiple services to the PSE system, including backup power for intermittent renewable generation, efficiency, reliability, and ancillary services. Storage can benefit the entire system — generation, transmission, distribution, and customers. However, these benefits vary by location and how we apply the technology or resource. For instance, storage in one place could relieve transmission congestion and thereby defer the cost of transmission upgrades, while storage at another location might back up intermittent wind generation and reduce integration costs.

Puget Sound Energy's energy storage resources include hydroelectric reservoirs behind dams and oil backup for peaking facilities and batteries. Battery and pumped hydroelectric energy storage (PHES) operate for a limited time and require energy from other sources.

Table C.4 summarizes PSE's total renewable resources, and the subsections describe PSE's existing hydroelectricity, wind, and solar generating resources and PSE's storage facilities.

Table C.4: Total Renewable Resources

Type	Net Maximum Capacity (MW)
Hydroelectric — owned	244
Hydroelectric — contracted	722
Wind	773
Solar	0.5
Battery Storage	2.0
Total	1,742

2.1.1. Hydroelectricity

Puget Sound Energy's hydroelectric resources are precious clean energy sources that provide a net maximum capacity of 966 MW (Table C.3). These resources can instantly respond to customer load and have relatively low operating costs. Hydroelectric resources are limited operationally by protections for endangered species and environmental conditions. High precipitation and snowpack levels generally allow us to generate more hydroelectricity, and low-water years produce less hydroelectricity. During low-water years, we must rely on other, more expensive, self-generated power or market resources to meet the load. Our analysis for this 2023 Electric Progress Report (2023 Electric Report) accounts for both seasonality and year-to-year variations in hydroelectric generation. Puget Sound Energy owns hydroelectric projects in western Washington and has long-term power purchase contracts with three public utility districts (PUDs) that own and operate extensive hydroelectric facilities on the Columbia River in central Washington. These resources are described in this section and summarized in Table C.5.

Table C.5: PSE-owned and Contracted Hydroelectric Resources

Plant	Owner	PSE Ownership (%)	NET Maximum Capacity (MW)[1]	Contract Expiration Date
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	105	None
Snoqualmie Falls[2]	PSE	100	48	None
Wells[3]	Douglas Co. PUD	27.1	228	9/30/28
Rocky Reach[4]	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II[4]	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.6	7	03/31/52
Priest Rapids	Grant Co. PUD	0.6	6	03/31/52
Total Owned	-	-	244	-
Total Contracted	-	-	722	-
Total All	-	-	966	-

Notes:

1. Net maximum capacity reflects PSE's share only.
2. The FERC license authorizes the full 54.4 MW. However, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 square cubic feet and, therefore, output to 47.7 MW.
3. In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that began on August 31, 2018, and continues through September 30, 2028. PSE also agreed in June 2018 to purchase an additional 5.5 percent of the Wells project through September 2021. This agreement for the additional 5.5 percent from the Wells project was extended through September 2025.
4. In 2021, PSE purchased an additional 5 percent share from 2022 through 2025.

Puget Sound Energy also contracts smaller hydroelectric generators in PSE's service territory. We discuss these hydroelectric resources in the Long-term Contracts section and provide summaries in Tables C.12 and C.13.

Baker River Hydroelectric Project

Baker River Hydroelectric project is in Washington's north Cascade Mountains. The facility comprises two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems, including a floating surface collector (FSC) to safely capture juvenile salmon in Baker Lake and transport them downstream around both dams. There is a second, newer FSC on Lake Shannon to move young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access to recreation and significant flood-control storage for people and property in the Skagit Valley.

Hydroelectric projects require a license from FERC for construction and operation. These licenses typically are for 30 to 50 years, and after that initial period, they must be renewed to continue operations. After a lengthy renewal process, FERC issued a 50-year license in October 2008, allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. Puget Sound Energy also completed a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The replacement unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.[2]

Snoqualmie Falls Hydroelectric Project

Located east of Seattle on the western slope of the Cascade Mountains, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, encased in bedrock 270 feet beneath the surface, was the world's first underground power plant. Built in 1898–99, Snoqualmie Falls Hydroelectric Project was also the Northwest's first large hydroelectric power plant.

The FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility underwent a significant redevelopment project between 2010 and 2015, which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment increased annual output by more than 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.[2]

Mid-Columbia Long-term Purchased Power Contracts

Under long-term power purchase agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects on the Columbia River in central Washington. Puget Sound Energy pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. In March 2017, PSE entered into a new power sales agreement with Douglas County PUD that began on August 31, 2018, and continues through September 30, 2028.

Under this new agreement, PSE will continue to take a percentage of the output from the Wells project. The actual rate available to PSE will be calculated annually and based primarily on Douglas PUD's retail load requirements. As Douglas PUD's retail load grows or declines, they will reserve a greater or lesser share of Wells project output for their customers, and the percentage we purchase will decrease or increase. Puget Sound Energy has a 20-year agreement with Chelan County PUD to purchase 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. Puget Sound Energy also has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD continues through the term of the project's FERC license, which ends on March 31, 2052.

[2] RCW 19.285

2.1.2. Wind Energy

Puget Sound Energy is the largest utility owner and operator of wind power facilities in the Pacific Northwest. The maximum capacity of the company's three wind farms is 773 MW (Table C.6). The farms produce more than 2 million MWh of power per year on average, which is about eight percent of PSE's energy needs. These resources are integral to meeting renewable resource commitments.

- **Hopkins Ridge** in Columbia County, Washington, with an approximate maximum capacity of 157 MW, began commercial operation in November 2005.
- **Lower Snake River** in Garfield County, Washington, with an approximate maximum capacity of 343 MW, began operation in February 2012 and is PSE's third and largest wind farm.
- **Wild Horse** in Kittitas County near Ellensburg, Washington, with an approximate maximum capacity of 273 MW, began commercial operation in December 2006 at 229 MW and was expanded by 44 MW in 2010.

Table C.6: PSE-owned Wind Resources

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Hopkins Ridge	100	157
Lower Snake River, Phase 1	100	343
Wild Horse	100	273
Total	100	773

2.1.3. Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[3] The array can produce up to 0.5 MW of electricity with full sun (Table C.6). Panels can also produce power under cloudy skies — 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine yearly, roughly the same as Houston, Texas. On average, this site generates 780 MWh of power per year.

In addition to the Wild Horse solar facility, we own three small solar facilities that provide energy for our Community Solar program, which is a customer renewable energy program described in Section 4.2. These facilities are located in western Washington on the roofs of public buildings, including schools and a municipal water storage facility. The first facility opened in November 2021.

Table C.7: PSE's Owned Solar Resources

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Wild Horse Solar Demonstration Project	100	0.50
City of Bonney Lake	100	0.45
Olympia High School	100	0.20

[3] Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility and used 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Pine Lake Middle School	100	0.18
Total	100	1.33

2.1.4. Battery Energy Storage System

Puget Sound Energy's only battery energy storage system, the Glacier Battery Demonstration Project, was installed in early 2017 (Table C.8). The 2 MW / 4.4 MWh lithium-ion battery storage system is adjacent to the existing Glacier, Washington substation in Whatcom County. The Glacier project serves as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core island of businesses and residences during outages, reduces system load during periods of high demand, and helps balance energy supply and demand.

The project was partly funded by a $3.8 million Smart Grid Grant from the Washington State Department of Commerce. Between January and June of 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward successfully responding to unplanned outages.

We have two additional battery projects in the planning phases. The first project plans to install a 3.3 MW utility-scale battery as part of a larger project to improve reliability and modernize the grid on Bainbridge Island. The battery system will serve electricity during peak periods when customer demand is high (e.g., cold winter mornings), and we expect it to be online by the end of 2023. The second project plans to install a 1 MW lithium-ion battery at PSE's Blumaer substation and a solar array on adjacent land. Both installations will complement existing solar panels at nearby Tenino High School. The combined system will form a microgrid capable of providing temporary backup power to the school during an outage. Performance testing by PSE and PNNL is planned through 2024.

Table C.8: PSE-owned Battery Storage Resources

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Glacier Battery Demonstration Project	100	2.0
Total	100	2.0

2.2. Thermal Resources

Thermal resources use fossil fuels (natural gas, oil, coal) or alternative fuels (biodiesel, hydrogen, renewable natural gas) to generate electricity. Puget Sound Energy's existing thermal resources include combustion turbines and coal-fired generating facilities, which serve as baseload or peaking resources.

Baseload resources produce energy at a constant rate over long periods at a lower cost than other production facilities available to the system. They are typically used to meet some or all a region's continuous energy demand. Baseload resources usually have a high fixed cost, but low marginal cost and are the most efficient thermal units PSE operates.

Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Peaking resources are quick-starting units that can ramp up and down quickly to meet short-term spikes in need. They also provide flexibility for load following wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload resources. Historically, peaking units have low-capacity factors because they are often not economical compared to market purchases.

Table C.9 summarizes, and the following subsections describe, PSE's thermal resources, which include combined-cycle combustion turbines (CCCTs), coal, and simple-cycle combustion turbines (CT peakers).

Table C.9: Total Thermal Resources

Type	Use	Net Maximum Capacity (MW)
CCCT	Baseload	1,293
Coal	Baseload	370
CT	Peaker	612
Total baseload thermal resources	-	1,663
Total CT peaking resources	-	612
Total thermal resources	-	2,275

2.2.1. Combined-cycle Combustion Turbines

Puget Sound Energy's six baseload CCCT plants have a combined net maximum capacity of 1,293 MW and are summarized in Table C.10. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy, making it more efficient than the CT peakers. Puget Sound Energy's baseload CCCTs include:

- **Encogen, Ferndale, and Sumas** in Whatcom County, Washington
- **Frederickson 1** in Pierce County, Washington. Puget Sound Energy owns 49.85 percent of this plant; Atlantic Power Corporation owns the remainder
- **Goldendale** in Klickitat County, Washington
- **Mint Farm** in Cowlitz County, Washington.

Table C.10: CCCT Resources by Facility

Name	PSE Ownership (%)	Net Maximum Capacity (MW)[1]
Encogen	100	165
Ferndale[2]	100	253
Frederickson 1[2,3]	49.85	136
Goldendale[2]	100	315
Mint Farm[2]	100	297
Sumas	100	127
Total	**-**	**1,293**

Notes:
1. Net maximum capacity reflects PSE's share only.
2. Maximum capacity of Ferndale, Frederickson 1, Goldendale, and Mint Farm includes duct firing capacity.

3. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation, USA.

The Colstrip Generating Plant Retirement and Shutdown Plan

After a request in June 2019 by PSE's Unit 1 and 2 co-owner and plant operator, Talen Montana LLC, PSE agreed to retire the units. We based our decision on economic considerations. In January 2020, the facility ceased to generate electricity and work commenced to place it in a secure and safe condition. We are currently overseeing environmental remediation of the impacted water and will continue, in compliance with all local, state, and federal regulations, as we retire the physical structures.

Units 3 and 4 are owned by six separate entities with different interests. Puget Sound Energy is limited in its ability to act unilaterally since operational decisions are dictated by the rules governing the ownership agreement. After 2025, CETA restricts PSE from serving load from Colstrip without penalty. As a result this EPR only includes generation from Colstrip 3 and 4 through 2025.

2.2.2. Coal

The Colstrip Generating Plant in eastern Montana, about 120 miles southeast of Billings, consists of four coal-fired steam electric plant units. Puget Sound Energy owns 25 percent each of Units 3 and 4 (Table C.11). Puget Sound Energy's ownership in Colstrip contributes 370 MW net maximum capacity to our existing portfolio.

Table C.11: Coal Resources by Facility

Name	PSE Ownership (%)	Net Maximum Capacity (MW)[1]
Colstrip 3 & 4	25	370
Total	**-**	**370**

Note: Net maximum capacity reflects PSE's share only.

2.2.3. Combustion Turbine Peakers

Combustion Turbine (CT) peakers provide important peaking capability and help PSE meet operating reserve requirements. We displace these resources when their energy is not needed to serve load or we can purchase lower-cost energy. Puget Sound Energy's three peaker plants (eight total units) contribute a net maximum capacity of 612 MW (Table C.12). When pipeline capacity is unavailable to supply them with natural gas fuel, these units can operate on distillate fuel oil.

- **Frederickson Units 1 and 2** are south of Seattle in east Pierce County, Washington.
- **Fredonia Units 1, 2, 3, and 4** are near Mount Vernon, Washington, in Skagit County.
- **Whitehorn Units 2 and 3** are in northwestern Whatcom County, Washington.

Table C.12: CT Peaking Resources

Name	PSE Ownership (%)	Net Maximum Capacity (MW)
Fredonia 1 & 2	100	207
Fredonia 3 & 4	100	107
Whitehorn 2 & 3	100	149
Frederickson 1 & 2	100	149
Total CT Peakers	**-**	**612**

2.3. Long-term Contracts

Long-term contracts include agreements with independent producers and utilities to supply electricity to PSE. Fuel sources for those contracts include hydropower, wind, solar, natural gas, coal, waste products, and system deliveries without a designated supply resource. We contract 1,882 MW of electric capacity, of which 58 percent (1,094 MW) is CETA-compliant. We did not include short-term wholesale market purchases negotiated by our energy trading group in this list.

2.3.1. Power Purchase Agreements

Most of PSE's long-term contracts are Power Purchase Agreements (PPAs) with independent power producers. This section provides a brief description of each PPA. Schedule 91 contracts define PPAs from small producers whose total capacity is 5 MW or less. We summarize these contracts in Table C.13 and Table C.14.

Table C.13: Power Purchase Agreements for Electric Power Generation

Name	Type	Contract Start	Contract Expiration	Contract Capacity (MW)
BPA Capacity Product	Hydroelectric	1/1/2022	12/31/2026	100
Energy Keepers	Hydroelectric	3/1/2020	7/31/2035	40
Clearwater Wind	Wind	11/30/2022	11/29/2042	350
Golden Hills Wind	Wind	4/29/2022	4/28/2042	200
Klondike III	Wind	12/1/2007	11/30/2027	50
Skookumchuck Wind [1]	Wind	6/30/2020	12/31/2045	137
Lund Hill Solar [1]	Solar	12/1/2022	11/30/2042	150
SPI Biomass	Biomass	1/1/2021	12/31/2037	17
MSCG System	System	1/3/2022	12/31/2026	100
Pt. Roberts[2]	System	10/1/2022	9/30/2025	8
Coal Transition [3]	Coal	12/1/2014	12/31/2025	380
Total, CETA-compliant	-	-	-	**1,044**
Total	-	-	-	**1,532**

Notes:

1. Output from this resource serves subscribers to PSE's Green Direct program (Schedule 139 Contracts).
2. Point Roberts is not physically connected to PSE's system and relies on power from a single intertie point on BC Hydro's distribution grid.

3. The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from Dec. 1, 2015, to Nov. 30, 2016, 380 MW from Dec. 1, 2016, to Dec. 31, 2024, and 300 MW from Jan. 1, 2025, to Dec. 31, 2025.

Table C.14: Schedule 91 Power Purchase Agreements for Electric Power Generation

Name	Type	Contract Start	Contract Expiration	Contract Capacity (MW)
Black Creek	Hydroelectric	3/26/2021	12/31/2032	4.2
Koma Kulshan	Hydroelectric	12/1/1990	3/31/2037	13.3
Nooksack Hydro	Hydroelectric	1/1/2014	12/31/2023	3.5
Skookumchuck Hydro	Hydroelectric	2/25/2011	12/31/2025	1
Smith Creek	Hydroelectric	1/12/2011	12/31/2025	0.12
Sygitowicz – Kingdom Energy [1]	Hydroelectric	3/25/2016	12/31/2030	0.448
Twin Falls	Hydroelectric	12/1/1989	3/18/2025	20
Weeks Falls	Hydroelectric	12/1/1987	12/31/2023	4.6
3 Bar-G Wind [2]	Wind	8/31/2011	12/31/2029	0.12
Knudson Wind	Wind	6/16/2011	12/31/2029	0.108
Swauk Wind	Wind	12/14/2012	12/31/2023	4.25
Cascade Community Solar #1 and #2 (combined)	Solar	9/28/2012	12/31/2024	0.026
Finn Hill Solar (Lake Wash SD)	Solar	7/16/2012	12/31/2032	0.355
IKEA	Solar	1/1/2017	12/31/2031	0.828
Port of Coupeville [3]	Solar	1/1/2022	12/31/2023	0.075
Camas Solar	Solar	8/1/2018	12/31/2036	4.99
Penstemon Solar	Solar	1/1/2020	12/31/2036	4.99
Urtica Solar	Solar	8/1/2018	12/31/2036	4.99
Blocks Evergreen Dairy	Biogas	6/1/2017	12/31/2031	0.19
Edaleen Dairy	Biogas	8/21/2012	12/31/2023	0.75
Emerald City Renewables [4]	Biogas	11/6/2013	12/31/2029	4.5
Emerald City Renewables 2	Biogas	11/6/2013	12/31/2029	4.5
Farm Power Rexville	Biogas	8/28/2009	12/31/2032	0.75
Rainier Biogas	Biogas	11/30/2012	12/31/2032	1
VanderHaak Dairy [5]	Biogas	11/5/2004	12/31/2023	0.6
Total, CETA-compliant	-	-	-	**80**
Total	-	-	-	**80**

Notes:

1. The site was purchased by Hillside Clean Energy on May 1, 2020, with PSE's consent.
2. The agreement was initially for 1.395 MW, but only 0.120 MW was constructed; the contract was amended to reflect this change.

3. Formerly Island Solar, ownership was transferred to the Port of Coupeville on July 1, 2020, with PSE's consent.
4. Emerald City Renewables was formerly known as BioFuels Washington.
5. VanderHaak has two generators with a combined capacity of 0.60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of 0.45 MW.

Energy Keepers Hydroelectric

Puget Sound Energy contracted with Energy Keepers, Inc., a corporation owned by the Confederated Salish and Kootenai Tribes, to purchase 40 MW of zero-carbon energy produced by the Selis Ksanka Qlispe hydroelectric project through July of 2035.

Bonneville Power Administration Capacity Product Hydroelectric

Under a five-year agreement beginning in January 2022, the Bonneville Power Administration (BPA) will offer to sell PSE up to 100 MW of surplus power generated from the Federal Columbia River Power System. Hydroelectricity can quickly increase and decrease to meet power demand and help the region achieve its renewable goals by dovetailing with more variable output resources such as wind and solar.

Run-of-River Hydroelectric

Among our power purchase agreements are several long-term contracts for production output from hydroelectric projects within our balancing area. These contracts include Twin Falls, Koma Kulshan, and Weeks Falls. We show the contracts in Table C.13. The projects are run-of-river, meaning they do not hold back, store water, or provide flexible capacity.

Klondike III Wind

Puget Sound Energy's wind portfolio includes a power purchase agreement with Avangrid Renewables for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Oregon. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2027.

Golden Hills Wind

Puget Sound Energy executed a 20-year power purchase agreement with Avangrid Renewables for the output of a 200 MW wind farm they will build in Sherman County, Oregon. Avangrid expects to complete the project by mid-2022. The project will help us meet our goals to reduce greenhouse gas emissions and provide additional capacity to serve customers, particularly during winter periods of high electricity demand.

Clearwater Wind

Puget Sound Energy executed a 20-year power purchase agreement in early 2021 with NextEra Energy Resources to buy the output of 350 MW of wind-generated power. The wind farm is in Rosebud, Custer, and Garfield Counties, Montana, and began operation in November 2022. The project will allow PSE to use existing transmission lines from Colstrip, Montana, to bring energy to our customers in western Washington. This project also supports our environmental and deep decarbonization commitment by investing in more wind energy.

Skookumchuck Wind

Puget Sound Energy executed a 20-year power purchase agreement with Southern Power Company to purchase the output from the Skookumchuck Wind Project. The wind project is in Thurston and Lewis counties and became operational in November 2020. Along with the production from the Lund Hill Solar facility, the Skookumchuck facility output serves subscribers to our Green Direct program (Schedule 139), described in the Demand-side Resources section of this appendix.

Lund Hill Solar

Puget Sound Energy executed a 20-year power purchase agreement with Avangrid Renewables (through the project company Lund Hill Solar, LLC) to purchase the output from the Lund Hill Solar Project, located in Klickitat County, Washington. We expect the project to come online in late 2022. We will use the output from the facility to serve subscribers to PSE's new Green Direct program (Schedule 139), described in the Demand-Side Resources section of this appendix.

Sierra Pacific Industries Biomass

Puget Sound Energy has a 17-year contract with Sierra Pacific Industries (SPI) to purchase 17 MW of renewable energy from SPI's Mt. Vernon Mill; deliveries began in 2021. The cogeneration facility is an operational plant that uses wood byproducts from its manufacturing process to generate steam that makes electricity and heat kilns to dry lumber. An air pollution control device filters fine particles and other emissions from the burning wood.

Point Roberts System

This contract provides power deliveries to PSE's Point Roberts, Washington, retail customers. The Point Roberts load, physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. We pay a fixed price for each MWh of energy delivered during the contract term.

Morgan Stanley Commodities Group System

Puget Sound Energy is in the Western System Power Pool (WSPP) agreement with the Morgan Stanley Commodities Group (MSCG) for a system PPA to deliver 100 MW of firm heavy load hour energy in the first and fourth quarters only, commencing in January 2022.

Coal Transition

Puget Sound Energy began purchasing 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024, the contract is for 380 MW; in the last year of the contract, 2025, the volume drops to 300 MW. This contract conforms to a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025.

In 2011, the State Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmental advocacy groups, and labor representatives. The timelines agreed to by the parties enable the state to transition to cleaner fuels while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington's only coal-fired plant.

Schedule 91 Contracts

Puget Sound Energy's portfolio includes several electric power contracts with small power producers in our electric service area (see Table C.14). These qualifying facilities offer output pursuant to WAC chapter 480-106.[4] WAC 480-106-020 states: "A utility must purchase, in accordance with WAC 480-106-050 Rates for purchases from qualifying facilities, any energy and capacity that is made available from a qualifying facility: (a) Directly to the utility; or (b) Indirectly to the utility in accordance with subsection (4) of this section."[5] A qualifying facility is defined in WAC 480-106-007 as a "cogeneration facility or small power production facility that is a qualifying facility under 18 C.F.R. Part 292 Subpart B."[6]

2.3.2. Other Contract Agreements

In addition to PPAs, PSE has a long-term agreement with the U.S. Army Corps of Engineers (USACE), a treaty agreement between the U.S. and Canada, and a power exchange with Pacific Gas & Electric (PG&E). We describe these contracts in Table C.15 and the next section.

Table C.15: Other Contract Agreements for Electric Power Generation

Name	Type	Contract Start	Contract Expiration	Contract Capacity (MW)
Baker Replacement	Hydro	10/1/2019	9/30/2029	7
Canadian Entitlement Return	Hydro	1/1/2004	9/15/2024	-32.5
PG&E Seasonal Exchange — PSE	System	10/11/1991	Ongoing	300
Total, CETA-compliant	-	-	-	**-26**
Total	-	-	-	**275**

Baker Replacement

Under a 20-year agreement signed with the USACE, PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Upper Baker Reservoir at the request of the USACE. Then, during high precipitation and runoff between October 15 and March 1, PSE stores water in the Upper Baker Reservoir and controls its release to reduce downstream flooding. In return, PSE receives a total of 7,000 MWh of energy and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

4 WAC 480-106
5 WAC 480-106-020
6 WAC 480-106-007

Canadian Entitlement Return

Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. We see benefits and obligations from this storage based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's obligation to return our share of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number. Puget Sound Energy's share of energy returned during 2021 was approximately 23 aMW, with a peak capacity return of 42.5 MW. The Columbia River Treaty has no end date but can be terminated after 2024 with 10 years' notice. The United States and Canada recently concluded the ninth round of negotiations to modernize the treaty to ensure effective flood risk management, provide a reliable and economical power supply, and improve the ecosystem.

Pacific Gas and Electric Seasonal Exchange

Under this system-delivery power exchange contract, PSE exchanges 300 MW of seasonal capacity and 413,000 MWh of energy with PG&E on a one-for-one basis each calendar year. Puget Sound Energy has historically been a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

2.4. Transmission Contracts

In addition to owning and purchasing power from electric generating resources, PSE fulfills loads by buying electricity from the short-term wholesale market. Puget Sound Energy participates in two markets. The first is the Mid-Columbia (Mid-C) market hub, the principal electricity market hub in the Northwest and one of the major trading hubs in the Western Electricity Coordinating Council (WECC). The Mid-C market hub is also the central market for northwest hydroelectric generation. The second is the Western Energy Imbalance Market (EIM), which allows participants to trade electricity in real-time across neighboring grids throughout the western United States. To carry this electricity to PSE's service territory, PSE has negotiated transmission contracts with BPA. This section describes these transmission contracts.

2.4.1. Mid-C Transmission

Puget Sound Energy has 2,481 MW of transmission capacity to the Mid-C market; of that, we contract 2,031 MW from BPA (Table C.16) long-term and own 450 MW (Table C.16).[7] Puget Sound Energy Merchant owns the BPA transmission rights. PSE Transmission sells 450 MW of transmission as the transmission provider. Currently, our 449 customers hold the rights to the 450 MW of transmission; however, when the 449 customers do not entirely utilize these rights, the rights are allocated to PSE Merchant or sold on the open access same-time information system

[7] PSE also owns transmission and transmission contracts to markets in addition to the Mid-C market transmission detailed here.

(OASIS). We use approximately 1,500 MW of this transmission capacity to the Mid-C wholesale market for short-term market purchases to meet our peak need.[8]

Table C.16: BPA Mid-C Hub Transmission Resources

Name	Effective Date	Termination Date	Transmission Demand (MW)
Midway	11/1/2017	11/1/2027	100
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach[1]	11/1/2017	11/1/2027	100
Rocky Reach	11/1/2017	11/1/2027	100
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	5
Rocky Reach	11/1/2019	11/1/2024	55
Rocky Reach	9/1/2014	11/1/2031	160
Vantage	11/1/2017	11/1/2027	100
Vantage	12/1/2019	12/1/2024	169
Vantage	10/1/2013	3/1/2025	3
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	3
Vantage	11/1/2019	11/1/2024	36
Vantage	11/1/2019	11/1/2024	5
Wells	9/1/2018	9/1/2023	266
Vantage	3/1/2017	2/28/2026	23
Midway	10/1/2018	10/1/2023	115
Midway	3/1/2019	3/1/2024	35
Wells/Sickler	11/1/2018	11/1/2023	50
Vantage	11/1/2018	11/1/2023	50
Vantage	12/1/2019	11/1/2027	50
Total BPA Mid-C Transmission	**-**	**-**	**2,031**

Note: Contract split between Mid-C and EIM Imports below.

We own two transmission resources, described in Table C.17.

[8] See Chapter Eight: Electric Analysis, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Table C.17: PSE-Owned Mid-C Hub Transmission Resources

Name	Transmission Demand (MW)
McKenzie to Beverly	50
Rocky Reach to White River	400
Total PSE Mid-C Transmission	**450**

2.4.2. Energy Imbalance Market Transmission

When PSE joined the Energy Imbalance Market (EIM) in October 2016, we redirected 300 MW of Mid-C transmission capacity contracted from BPA annually for EIM imports. Starting in June 2020, Mid-C transmission shifted for EIM imports was reduced to 150 MW to align with PSE's market-based rate authority. This amount is required to maintain market-based authority and allows PSE to redirect beyond this amount for use in the EIM. Although these redirects reduce the transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. We will need to renew the amount of redirected Mid-C transmission on an ongoing basis, allowing us to reevaluate our EIM transfer capacity needs considering future winter peak needs. Table C.18 details the transmission capacity currently redirected for EIM.

We redirect an additional 300 MW, reserved under the PG&E Seasonal Exchange contract, for EIM exports during certain months of the year on an as-feasible basis. When our obligations to PG&E during summer months prevent this redirect, we instead redirect our existing Mid-C transmission, bringing the total redirected Mid-C transmission for EIM during summer months up to 450 MW.

Table C.18: Mid-C Hub Transmission Resources Redirected for EIM Imports as of 1/1/2023

Name	Effective Date	Termination Date	Transmission Demand (MW)
Rocky Reach	11/1/2017	11/1/2027	150
Total[1]	-	-	150

Note: Total BPA Mid-C Transmission Redirected for EIM Imports

3. Demand-side Resources

This section describes PSE's existing demand-side resources (DSR), which we implement on the customer side of the meter. The DSR programs include energy efficiency and demand response (DR) programs. We also describe the customer renewable energy programs PSE offers. In this 2023 Electric Report analysis, we account for the electricity contribution from DSR programs as a reduction in demand.

3.1. Demand-side Resource Programs

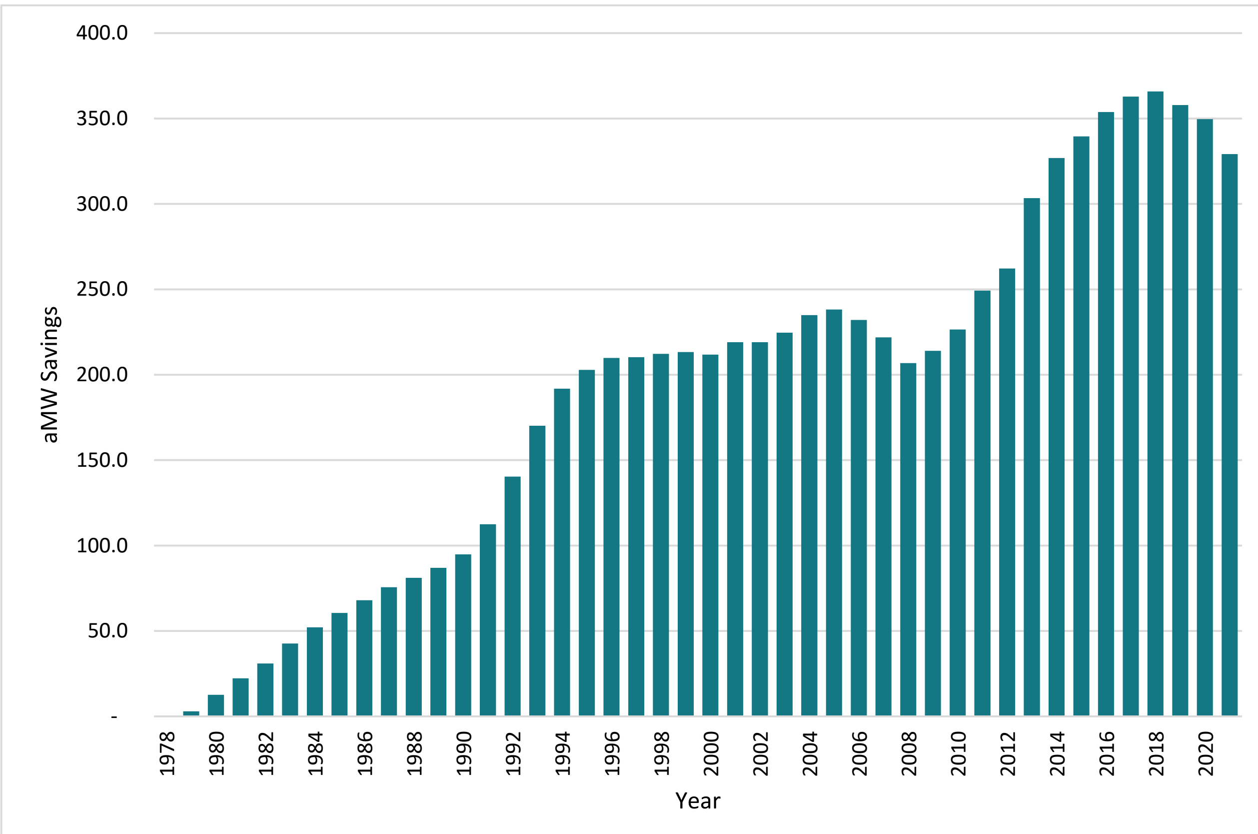
Puget Sound Energy's currently available DSR programs include the following:

- Demand Response
- Distributed Generation
- Distribution Efficiency

- Energy Efficiency
- Generation Efficiency

Puget Sound Energy has led the Pacific Northwest in implementing demand-side resource programs. Since 1978, our annual first-year savings (as reported at the customer meter) have grown by more than 200 percent, from 9 aMW in 1978 to 19.4 aMW in 2021 (Figure C.2). On a cumulative basis, these savings reached 329 aMW by 2021[9]. To achieve these savings, the company spent approximately $1.77 billion in incentives to customers and for program administration from 1978 to 2021.

Figure C.2: Cumulative Electric Energy Efficiency Savings from DSR, 1978–2021



3.1.1. Energy Efficiency

Energy efficiency is by far PSE's largest electric demand-side resource. Energy efficiency consists of measures and programs that replace existing building components and systems, such as lighting, heating, water heating, insulation, and appliances, with more energy-efficient versions. There are two types of measures: retrofit measures (when

[9] Savings are adjusted for measure life and then retired so they no longer count towards the cumulative savings. For the purposes of the PR analysis, measure life is assumed to be 10 years.

replacement is cost-effective before the equipment reaches its end of life); and lost opportunity measures (when replacement is not cost-effective until the existing equipment burns out).

Puget Sound Energy's energy efficiency programs serve all customers — residential (including low-income), commercial, and industrial. We establish program savings targets every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and the Integrated Resource Plan (IRP) public participation process. We fund most electric energy efficiency programs with electric conservation rider funds collected from all customer classes.[10]

In the most recently completed program cycle, the 2020–2021 tariff period, energy efficiency saved 44.3 aMW. The target for the current 2022–2023 program cycle is 61.3 aMW.

We made the following changes in the 2022–2023 program cycle:[11]

- Added 85,000 home energy reports to participating gas-only customers
- Added a new industrial pay-for-performance option for industrial systems optimization participants to encourage bundling of capital and O&M measures
- Added a new residential midstream heating ventilation and cooling (HVAC) and water heat program with a focus on engaging distributors to increase sales by reducing first costs and increasing stock
- Added the lean buildings accelerator program to help building owners comply with the new clean buildings requirement
- Increased equipment and weatherization incentives and customized home energy reports for manufactured home customers
- Increased natural gas targets leading to a focus on residential space heat programs, home energy reports, and commercial/industrial retrofit natural gas programs
- Raised the income threshold for the low-income weatherization program from 60 to 80 percent of the area median income (AMI) or 200 percent of the federal poverty level (FPL), whichever is higher
- Reintroduced the lodging rebates program for hotel and motel customers

We anticipate PSE's 2022–2023 electric energy efficiency programs will cost just over $240 million and save 61.3 aMW of electricity.

3.1.2. Distribution Efficiency

The production and distribution efficiency program includes implementing energy conservation measures that prove cost-effective, reliable, and feasible within our distribution facilities.

We implement improvements at PSE's electric substations for efficiency in transmission and distribution (T&D). These improvements focus on phase balancing and conservation voltage reduction (CVR). The methodology used to

[10] See Electric Schedule 120, Electricity Conservation Service Rider, for more information.

[11] See 2020-21 Biennium Conservation Plan Overview for more details on efficiency programs, especially low-income weatherization programs.

determine CVR savings is the Simplified Voltage Optimization Measurement and Verification Protocol provided by the Northwest Power and Conservation Council Regional Technical Forum.[12]

Table C.19 below lists the CVR-related projects completed to date. Going forward, we plan to significantly expand CVR projects tied to implementing the Advanced Metering Infrastructure (AMI) and substation automation projects. These two projects will enable Volt-Var optimization (VVO), an improved CVR method that allows for deeper savings compared to PSE's current CVR implementation method of line drop compensation (LDC).

Savings associated with CVR are affected by several variables, including but not limited to the increasing penetration of distributed energy resources (DERs) we expect in the future. Therefore, the savings from these projects can vary significantly. We are investigating the need for a study that provides an updated energy savings methodology for Volt-Var CVR projects.

Table C.19: Energy Savings from Conservation Voltage Reduction, Cumulative Savings to Date, kWh

Substation	Year Savings Claimed	Date of Implementation	kWh Savings / Year	Savings as (%) of Baseline kWh
South Mercer	2013	11/1/2013	607,569	1.3
Mercerwood	2013	12/8/2013	357,240	0.9
Mercer Island	2014	8/8/2014	859,586	1.3
Britton	2014	12/5/2014	636,197	5.6
Panther Lake	2016	8/27/2015	804,326	1.3
Hazelwood	2016	9/18/2015	1,352,149	1.4
Pine Lakes	2016	9/17/2015	1,163,150	1.3
Fairwood	2018	5/1/2018	768,367	1.2
Rhode Lakes	2018	5/23/2018	1,639,803	1.6
Rolling Hills	2018	5/24/2018	1,359,515	1.5
Phantom Lake	2019	12/19/2018	343,748	0.8
Overlake	2019	12/6/2019	326,644	1.0
Lake McDonald	2020	5/26/2020	404,699	1.0
Maplewood	2021	7/28/2021	911,874	0.9
Marine View	2021	12/2/2021	742,569	1.0
Cambridge	2021	12/13/2021	597,420	1.0
Avondale	2022	12/2/2021	995,168	1.1
Lake Hills	2022	11/15/2021	671,548	1.2
Wayne	2022	12/3/2021	505,679	0.8
Wilkeson	2022	7/28/2021	232,538	0.9
North Bothell	2022	12/2/2021	576,033	1.0

12 rtf.nwcouncil.org.

Substation	Year Savings Claimed	Date of Implementation	kWh Savings / Year	Savings as (%) of Baseline kWh
Average to Date	**-**	**-**	**755,039**	**1.3**
Total to Date	**-**	**-**	**15,855,822**	**-**

3.1.3. Generation Efficiency

In 2014, PSE worked with the Conservation Resource Advisory Group (CRAG) to refine the boundaries of what to include as savings under generation efficiency. We determined we would include only parasitic loads[13] served directly by a generator in the savings calculations available for generation efficiency upgrades; we would not include generators that serve parasitic loads from the grid. Using this definition, we completed site assessments in 2015. The assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and meager operating hours made these opportunities not cost-effective.

Puget Sound Energy staff will continue to study efficiency opportunities in these facilities and report on cost-effective savings we identify and implement in the 2022 and 2023 Annual Conservation Reports.

3.1.4. Distributed Generation

Puget Sound Energy offers cogeneration and combined heat and power incentives in our commercial and industrial programs. However, to date, we have not implemented any projects.

We discuss renewable distributed generation programs in this appendix's Customer Renewable Energy Programs section.

3.1.5. Demand Response

To meet PSE's Clean Energy Implementation Plan (CEIP) target of 23.7 MW of DR capacity reduction by 2025, we issued a distributed energy resource (DER) request for proposals (RFP) on February 7, 2022. Puget Sound Energy received responses from nine unique bidders proposing DR programs utilizing various technologies, including HVAC, water heat, battery energy storage, electric vehicle, sighting, building automation systems, and behavioral. The proposals total 161 MW of winter capacity. Puget Sound Energy plans to evaluate all proposals and implement the DR program(s) in 2023.

In the meantime, PSE's Customer Energy Management group plans to operate geographically targeted pilots in both a natural gas (Duvall) and an electric (Bainbridge Island) program. We implemented these programs in late 2022, following some initial contracting delays.

[13] Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the parasitic load.

3.2. Customer Renewable Energy Programs

This section describes PSE's customer renewable energy programs. We divide these programs into two general categories. The voluntary subscription products serve customers who want additional renewable energy, including Green Power, Solar Choice, Community Solar, and Green Direct programs. The Customer Connected Solar products include Net Metering and Local Energy Development, which serve customers who generate distributed renewable energy on a small scale.

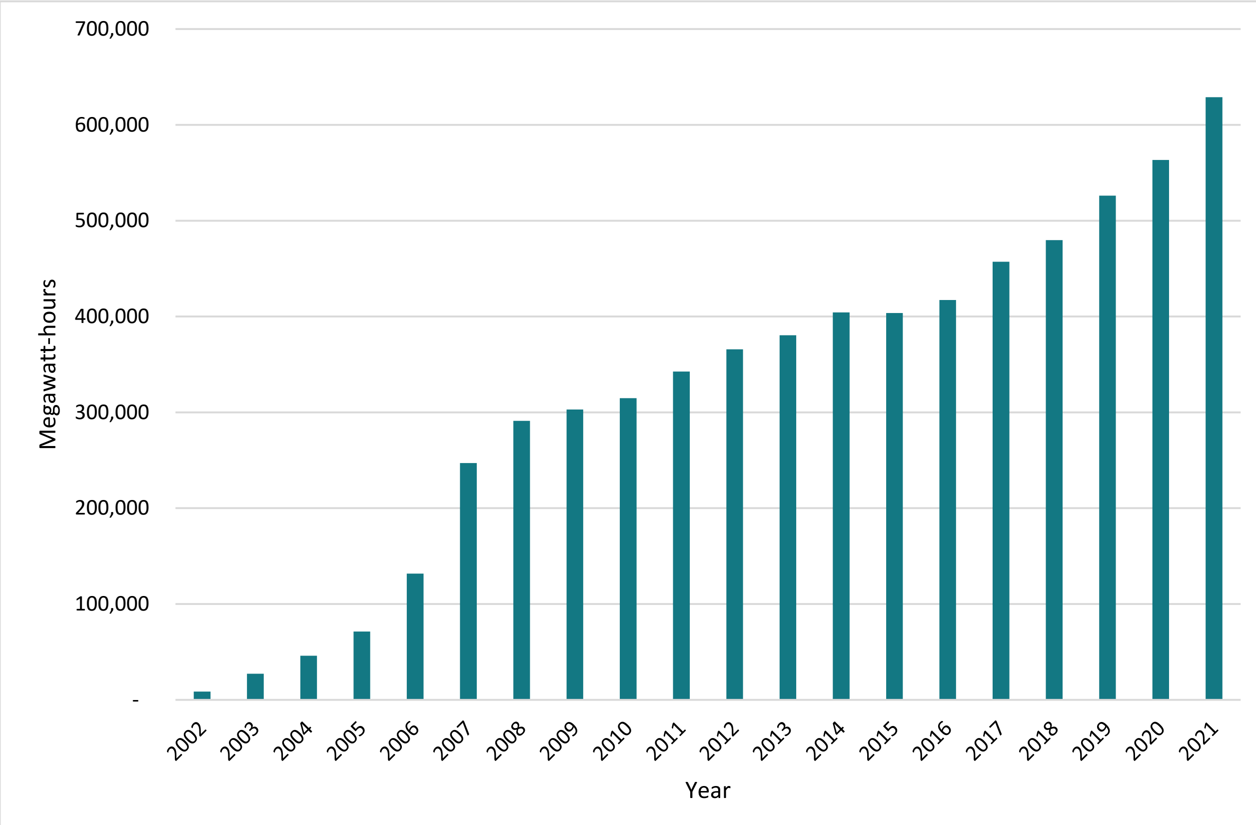
3.2.1. Renewable Power Purchasing Programs

In the following sections, we describe the voluntary subscription products for customers interested in purchasing additional renewable energy.

Green Power Program

We launched the Green Power Program in 2001. This program allows customers to voluntarily purchase Renewable Energy Credits (RECs) from qualified renewable energy resources. The program has grown to include more than 66,000 participants at the end of 2021. Customers purchased an additional approximately 19.5 percent of MWh during 2019–2021, ending the period with sales of 628,945 MWh in 2021 (Figure C.3).

Figure C.3: Green Power MWh Sold 2002–2021



The Green Power Program built a portfolio of RECs from various renewable energy technologies and projects in the Pacific Northwest. In mid-2020, we requested a quote (RFQ) seeking RECs to supply the Green Power program for 2021–2023. The Green Power Program also purchased RECs from small, local, and regional producers to support small-scale renewable resources. These small producers included:

- FPE Renewables
- Farm Power Rexville
- Edaleen Cow Power
- Van Dyk-S Holsteins
- Rainier Biogas
- 3Bar G Community Wind
- First Up! Knudson Community Wind
- Ellensburg Community Solar
- Swauk Wind
- LRI Landfill Gas

Many of these entities also provide power to PSE under the Schedule 91 contracts discussed in the Long-Term Contracts section of this appendix.

Increasing the number of utility-scale solar projects in Idaho and Oregon allowed us to grow the number of RECs sourced from solar projects. We would prefer to source RECs first from projects in Washington and then from Oregon and Idaho. However, the supply of Pacific Northwest RECs continues to tighten as voluntary program sales have grown and we dedicate more resources to serving compliance targets. This constricted market has made it more difficult to source all our supplies from the region. To maintain current program pricing, we have begun sourcing from other locations in the WECC, including Montana, Utah, Colorado, California, British Columbia, and partly from national REC sources for the Large Volume Green Power product. We believe this trend will continue as CETA compliance increases the demand for renewable energy in the region.

Green Power Community Grants

Over the past 15 years, the Green Power program has also committed more than $3,700,000 in grant funding to 15 cities and 45 local organizations in our electric service area to install solar projects to support low-income or Black, Indigenous, and People of Color (BIPOC) communities and the organizations that serve them. For example, in late 2020, PSE awarded solar grants to 14 organizations in six counties to be installed in 2021. The following organizations received more than $1,000,000 to install more than 500 new kW of solar:

- Boys and Girls Clubs of Skagit County
- Boys and Girls Club of South Puget Sound
- Camp Korey
- Friends of the Manchester Library
- Helping Hands Food Bank
- Hopelink, Institute for Washington's Future
- King County Housing Authority – Vantage Point
- Lummi Nation School
- Nisqually Indian Tribe
- Skagit Valley Hospitality House Association
- South Whidbey Good Cheer Food Bank
- Sustainable Connections
- YWCA

In 2021, PSE issued another solicitation and awarded over $900,000 in grant funding to 11 organizations for solar installations to non-profits, public housing authorities, or tribal entities serving low-income or BIPOC community members in PSE's electric service area. We expect most projects to be installed by early 2023. We issued another solicitation in mid-2022 for $750,000 for solar projects installed in 2023.

Green Power Rates

Puget Sound Energy provides two rate schedules in the Green Power program. The first, under Schedule 135, serves residential and commercial Green Power customers and was launched in 2001. The current rate for green power is $0.01 per kWh. Customers can purchase 200 kWh blocks for $2.00 per block with a two-block minimum or participate in the 100 percent Green Power Option. We introduced this program option in 2007; it adjusts the customer's monthly green power purchase amount to match their monthly electric usage. In 2021, the average residential customer purchase was 708 kWh per month, and the average commercial customer purchase was 1530 kWh. There are more than 80,000 subscribers to the Green Power and Solar Choice programs.

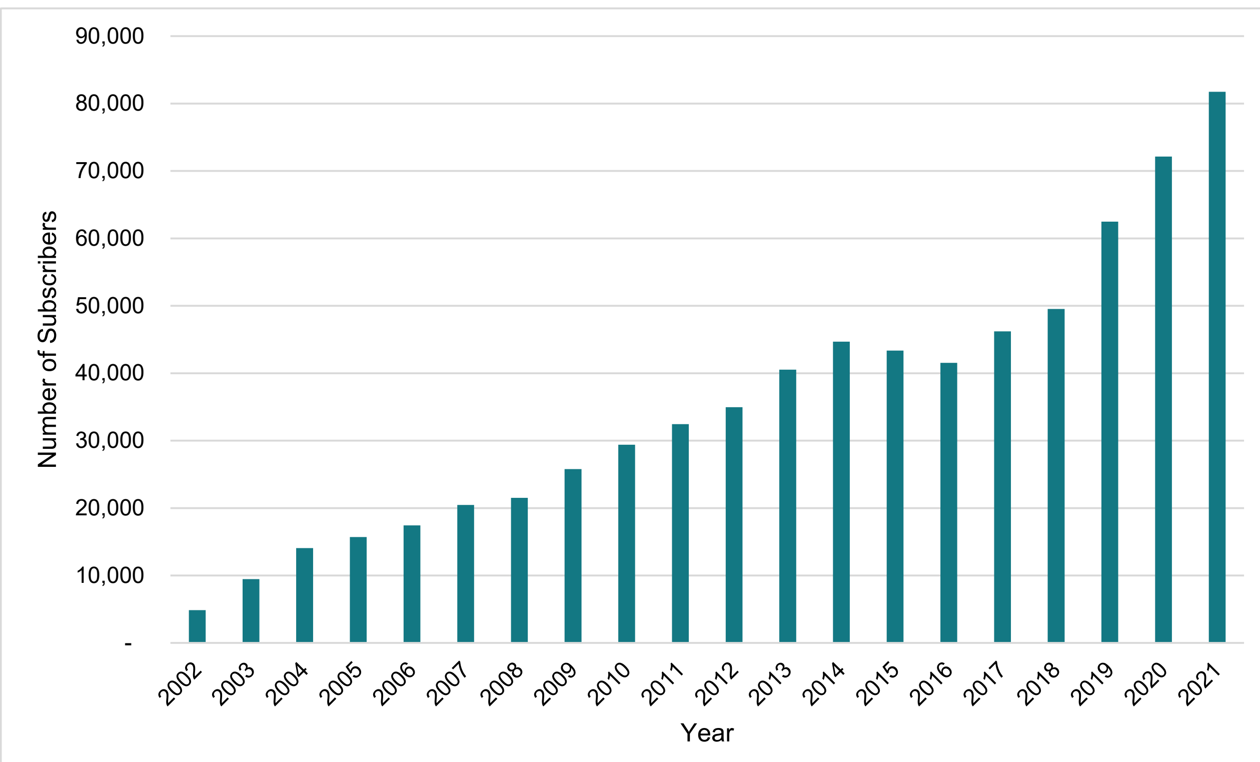
The second schedule is for customers who purchase more than one million kWh annually from the Green Power program and is detailed under Schedule 136. In 2022, PSE received approval from the Commission to increase the large-volume green power rate from $0.0035 per kWh to $0.006 per kWh. We made this latest change to better align the large volume rate with regional and national REC pricing. We will work to balance pricing with a mix of national and regionally produced RECs. The average 2021 large-volume purchase under Schedule 136 was 43,617 kWh per month. This product has attracted approximately 35 customers since we introduced it in 2005.

Solar Choice

In September 2016, the Commission approved PSE's Solar Choice program, a renewable energy product for residential and small to mid-size commercial customers. Like the Green Power program, Solar Choice allows customers to purchase retail electric energy from qualified renewable energy resources voluntarily; in this case, all the resources are solar energy facilities in Washington, Oregon, and Idaho. Customers can elect to purchase solar in $5.00 blocks for 150 kilowatt-hours. We add the purchases to their monthly bill. We officially launched the program in April 2017. As of December 2021, the program had 15,612 participants. These customers purchased 42,526 megawatt-hours of solar energy in 2021, a 37 percent increase from 2020 to 2021.

Figure C.4 illustrates the number of subscribers in our Green Power and Solar Choice offerings, by year. Of our 81,739 Green Power and Solar Choice subscribers at the end of 2021, 80,514 were residential customers, 1,115 were commercial accounts, and 110 accounts were under a large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 7,350, Olympia with 6,909, and Kirkland with 4,564.

Figure C.4: Green Power and Solar Choice Subscribers, 2002–2021



Community Solar

The Commission approved the PSE Community Solar Program for up to 20 MW in January 2021. Community Solar allows PSE electric customers to share the benefits of 100 percent local solar power. By subscribing to shares of a local solar array of their choice, PSE electric customers can replace some or all of their regular electricity use from solar energy projects located in western and central Washington and interconnected to PSE's distribution system. Each Community Solar share is $20 per month; however, PSE dedicates 20 percent of the available program shares to serving income-eligible customers at no cost. All Community Solar participants receive a monthly bill credit of $0.045 per kWh generated by the customer's solar energy share(s). Monthly energy credits vary based on the real-time production of the solar energy sites. One share is equal to 1.46 kW. Customers must commit to an initial one-year term and can cancel their subscription any time after that year.

The first Community Solar site opened in November 2021 on the roof of Olympia High School. Another site started operating in March 2022 at Pine Lake Middle School in Sammamish. A third site in Bonney Lake was completed in October 2022. We additionally contract power from Penstemon and Urtica solar sites, both located in Kittitas County. These sites opened in January and November of 2022, respectively. As we put additional Community Solar sites in service, subscriptions will become available for restricted shares per site. When a solar site is fully subscribed, we add customers to a waitlist for future availability at that site, or they may choose to subscribe to a different site if one is available.

Green Direct

We launched the Green Direct program on September 30, 2016, after the Commission approved it. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A,[14] Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large commercial (10,000 MWh per year or more of load in PSE's service area) and government customers from specified wind and solar resources.

For Phase I, PSE signed a 20-year PPA for the output from the 137 MW Skookumchuck Wind project in Lewis County. Customers could elect to enroll for 10, 15, or 20 years. The customer continues to receive and pay for all the standard utility services for safety and reliability. We charge customers for the total energy cost from the new plant, but they receive a credit for the energy-related power costs from the company.

Phase I of Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. By the end of June 2017, less than two months later, the wind facility was fully subscribed to 21 customers. Enrollees include companies like Starbucks, Target Corporation, REI, and government entities like King County and the City of Olympia. The Skookumchuck Wind project reached commercial operation in November 2020.

For Phase II, PSE issued an RFP to identify a new resource (or resources) in August 2017. In early 2018, PSE selected a 120 MW solar project in south-central Washington that we expected to achieve full commercial operation in 2022. Following selection, we proposed a blended rate of the Phase I wind and Phase II solar projects, which the

[14] RCW 19.29A

Commission approved in July 2018. Phase II enrollment opened on August 31, 2018, and was entirely subscribed by 16 customers; four were wait-listed. We subsequently requested to expand the project size from 120 MW to 150 MW, which the Commission approved. The expansion allowed all 20 customers to participate. Phase II customers include the following:

- Amazon
- Bellevue College
- Kaiser Permanente
- Port of Bellingham
- Providence Health & Services
- Several customers from Phase I requesting additional supply
- Six Washington State agencies
- The cities of Kent and Redmond
- The Issaquah School District
- T-Mobile
- UW Bothell
- Walmart

3.2.2. Customer Connected Renewables Programs

Puget Sound Energy offers two customer programs for customers who install small-scale generation: a net metering program and the Washington State Renewable Energy Production Incentive Program. These are not mutually exclusive, and most customer-generators were enrolled in both programs until the Production Incentive Program closed to new participants in 2019.

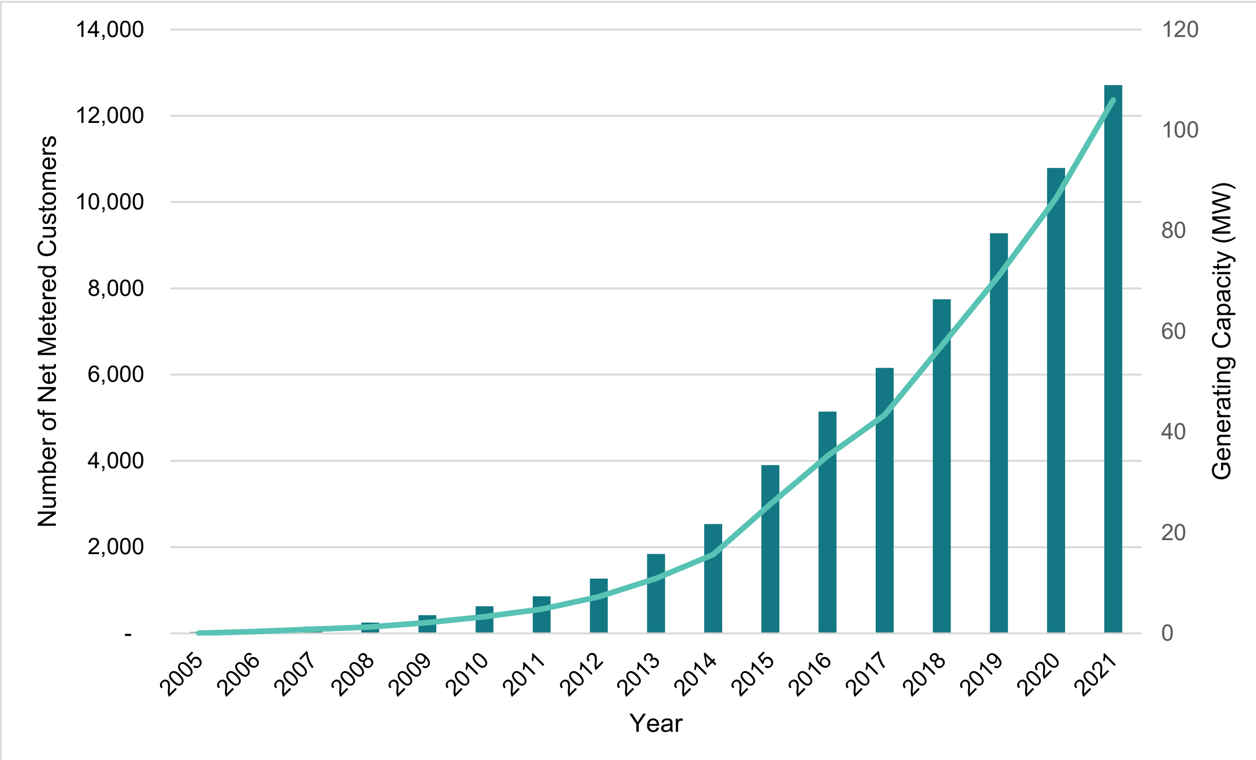
Net Metering Program

The Net Metering Program is defined in Rate Schedule 150 and governed by RCW 80.60.[15] This program began in 1999 and was most recently updated by the Washington State Legislature in Engrossed Substitute Senate Bill 5223 on July 28, 2019. Net metering allows customers who generate renewable electricity to offset the electricity provided by PSE. We subtract the amount of electricity the customer generates and sends back to the grid from the amount provided by PSE, and the net difference is what the customer pays monthly. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over a month. According to state law, customers can carry over the banked energy until March 31 each year, when we reset the account to zero. The interconnection capacity allowed under net metering is 100 kW alternating current (AC).

Customer interest in small-scale renewables has increased significantly over the past 20 years, as shown. The program has more than doubled the number of participating customers in the last five years, with strong growth continuing even after the closure of the State Production Incentive Program. As of May 1, 2022, the program has more than 13,500 participants (Figure C.5).

[15] RCW 80.60

Figure C.5: Net Metered Customers, 1999–2021



Most customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 8 kW, but there are also small-scale hydroelectric generators and wind turbines (Table C.20). By mid-2022, PSE was net metering more than 113 MW (AC) of generating capacity.

Table C.20: Interconnected System Capacity by Type of System, as of Q2 2022

System Type	Number of Systems	Average Capacity per System Type (kW [MW])	Sum of All Systems by Type (kW [MW])
Hybrid: solar/wind	16	9.3 [0.0093]	184 [0.184]
Micro hydro	6	15.7 [0.0177]	101 [0.101]
Solar array	13,546	8.37 [0.008]	113,422 [113]
Wind turbine	28	2.7 [0.0027]	80 [0.08]
Total	**13,597**	**8.0 [0.008]**	**113,82 [113.827]**

These small-scale renewable systems are distributed over a wide area of PSE's service territory (Table C.21).

Table C.21: Net Metered Systems by County

County	Number of Net Meters
Whatcom	2,744
King	4,362
Skagit	1,230
Island	646
Kitsap	1,308
Thurston	1,775
Kittitas	681
Pierce	851
Total	**13,597**

Customer preference, declining prices, and federal tax incentives drive customer solar PV adoption. Residential customers were 92 percent of all solar PV by number and 83 percent by nameplate capacity. In 2021, we engaged in a project to link our Interconnection portal with our customer billing system, Systems Applications, and Products in Data Processing (SAP) and attach system information to the customer premise. This upgrade allows for a smoother interconnection process, greater visibility of customer generation on our distribution system, and a streamlined move-in and move-out process for customers with solar. We continue to examine our processes to scale up customer generation.

Renewable Energy Production Incentive Payment Program

The Washington State Renewable Energy Production Incentive Program is a production-based financial incentive for solar, wind, and bio-digester-generating systems customers. Puget Sound Energy has voluntarily administered this state incentive to qualified customers under Schedule 151 since 2005. For a PSE customer-generator to participate in Schedule 151, they must:

- Be a PSE customer with a valid interconnection agreement with PSE to operate their grid-connected renewable energy system.
- Be certified (as named on the PSE account) by the Washington State Program Administrator as eligible for annual incentive payments.
- Have a system that includes production metering capable of measuring the energy output of the renewable energy system.

In June 2019, the Washington State Program Administrator issued a notice that this program's budget was fully obligated, and we formally withdrew our voluntary participation effective December 12, 2019. We continue to administer annual incentive payments to all certified program participants, but customers installing new solar systems after December 12, 2019, are not eligible to participate in this program. Thus, the State Production Incentive Program is no longer a driver of solar energy adoption.

Annual Production Reporting and Payments

Puget Sound Energy measures and reports the kilowatt hours generated by participants' renewable energy systems annually and makes incentive payments to eligible customers as determined by the Washington State Program Administrator. Legacy participants (those certified to participate by the Department of Revenue before October 1, 2017) with valid certifications received payments of up to $5,000 per year for electricity produced through June 30, 2020, at rates ranging from $0.14 to $0.504 per kWh. The year 2020 was the final payment year for 5,300 legacy program participants.

Participants who obtained state certification on or after October 1, 2017, and who maintain ongoing eligibility requirements are eligible for up to eight years of annual incentive payments on kilowatt-hours generated from July 1, 2017, through June 30, 2029. The incentive rate for these participants ranges from $0.02 to $0.21 per kWh based on system size, technology, and certification date. The Washington State Program Administrator determines participant eligibility, rates, terms, payment limits, and incentive payment amounts.

Puget Sound Energy has administered more than $95 million to our customers in production incentive payments through 2021. We recover these payments through state tax credits.

GENERIC RESOURCE ALTERNATIVES

APPENDIX D

PSE PUGET SOUND ENERGY

Contents

1. Introduction

Generic resources are theoretical electric generating resources used to develop Puget Sound Energy's (PSE) long-term capacity expansion planning model. As electric generating and storage technologies evolve, assumptions change. We update generic resource assumptions, including cost, operating, and availability, to align with the most recent and industry-reliable data for each Integrated Resource Plan (IRP). This appendix is a catalog of the supply-side — before the meter — generic resource alternatives we considered in the 2023 Electric Progress Report (2023 Electric Report).

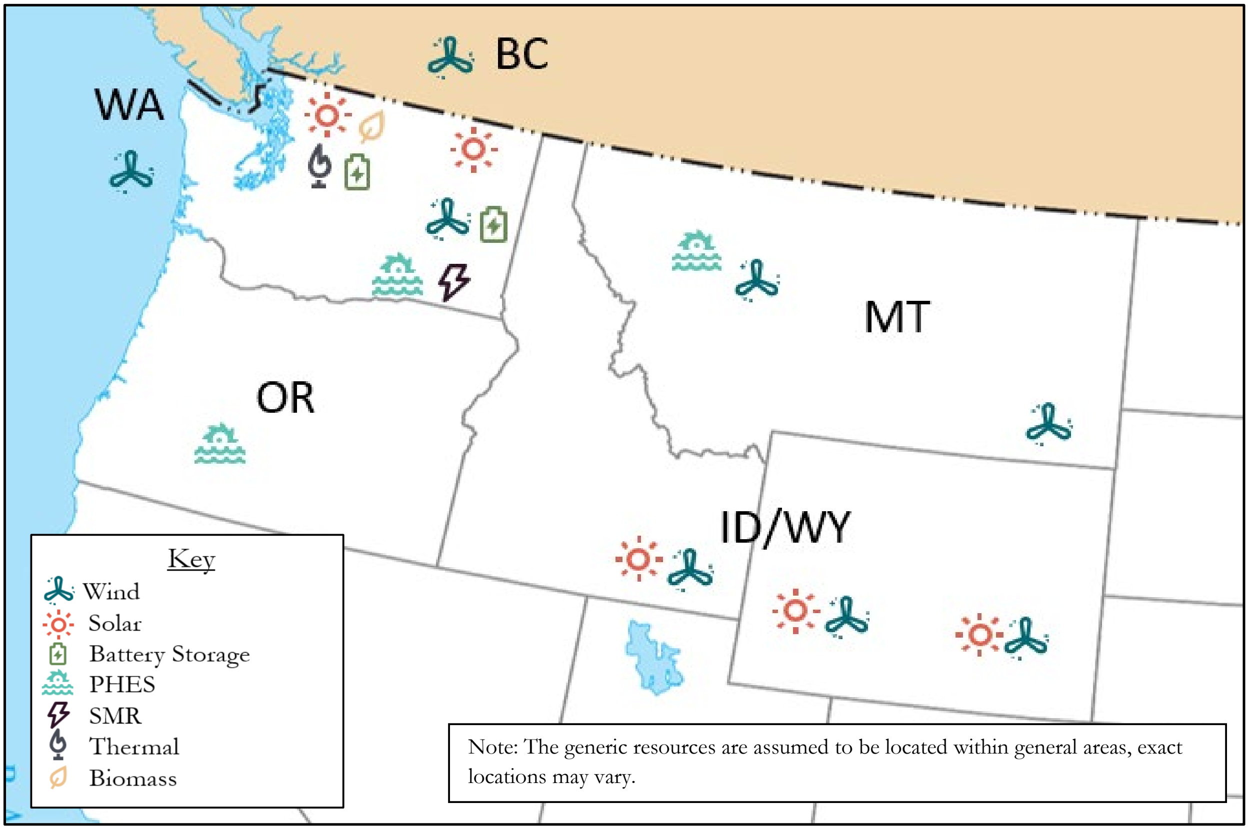
➔ We describe our planning models in Appendix G: Electric Price Models.

Here we describe mature technologies and new ways to generate power, including those commercially viable in the near- and mid-term. We explain the technologies available and the corresponding assumptions we adopted in our long-term capacity expansion model for each resource type. We primarily focused on updating cost assumptions in this report. Conversely, operating assumptions are generally consistent with the 2021 IRP, with some notable exceptions, such as operating life and reliable capacity assumptions. We present the data sources we consulted in Sections 1.1 and 1.2.

Although generic resources are not associated with a specific location, geography can heavily influence assumptions. Therefore, each of our generic resources is region-specific (we modeled Washington wind and Montana wind as separate generic resources) to best capture realistic future costs and operating characteristics in the modeling process. Figure D.1 presents the assumed geographic locations of the various generic resource alternatives we analyzed for this report.

➔ We also analyzed demand-side — after the meter — resources to help meet resource needs and discussed these in Appendix E: Conservation Potential Assessment.

Figure D.1: Generic Resource Alternatives Locations



1.1. Cost Assumptions

We sourced the generic resource costs for renewable, energy storage, and thermal resources described in the following pages primarily from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB). We also used input from publicly available data sources, including the U.S. Energy Information Administration (US EIA), Lazard, the Northwest Power and Conservation Council (NPCC), other national laboratories, and other regional IRPs. All cost assumptions are in 2020 dollars, with a 2.5 percent inflation applied through the planning horizon.

➔ Generic resource cost assumptions, including all data sources and averaging assumptions, are available in Appendix H: Electric Analysis and Portfolio Model.

1.2. Operating Characteristics

The following sources informed our generic resource operating characteristics:

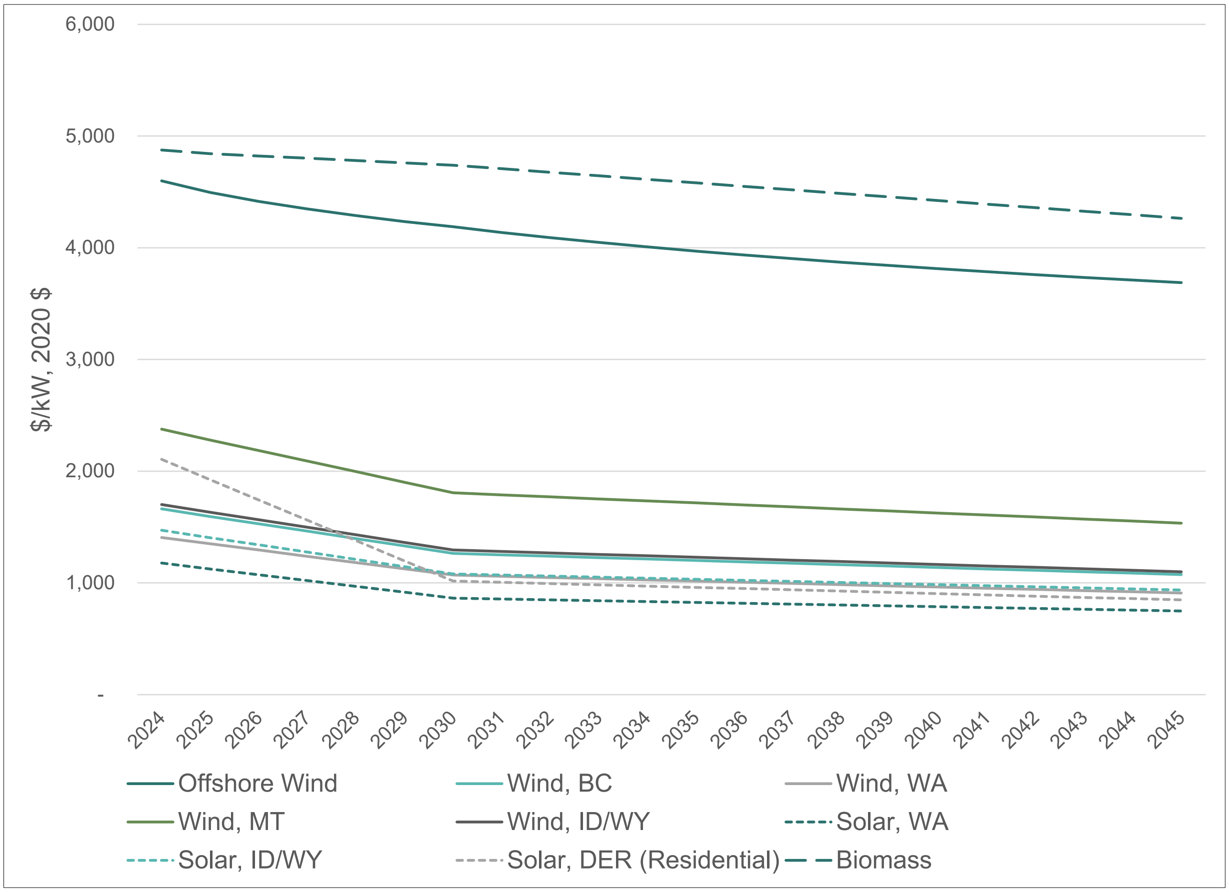
- NREL's 2022 ATB[1]
- PSE's experience in owning, operating, and developing electric-generating resources
- Solar and wind data provided by the consulting firm DNV
- 2019 HDR Generic Resource Costs for Integrated Resource Planning report[2]

2. Renewable and Storage Resource Technologies and Assumptions

We modeled five types of renewable energy resources in this report: biomass, wind, solar, storage, and hybrid technologies. We described these technologies in the following sections and include cost assumptions and commercial availability. Table D.1 through Table D.5 further summarize the technology parameters we modeled. Figure D.2 shows the capital cost curves for each renewable technology through the planning horizon.

1 https://atb.nrel.gov/electricity/2022/index.
2 https://www.pse.com/-/media/PDFs/IRP/2022/03222022/2019_HDR_GenericResourceAssumptionsReport_rev4.pdf?sc_lang=en&modified=20220506194408&hash=E6B1FDDF642DABBE25C1A42AFAB595D2.

Figure D.2: Capital Cost Curves for Renewable Energy Resources



2.1. Biomass

Biomass, in this context, refers to burning woody biomass in boilers. Most existing biomass in the Northwest works with steam hosts, also known as cogeneration or combined heat and power. Biomass is found mainly in the timber, pulp, and paper industries. That dynamic has limited the amount of biomass energy available to date. The typical biomass plant size is 10–50 MW. One significant advantage of biomass plants is they can operate as a baseload resource since they are not variable, unlike wind and solar. Biomass is considered separately from waste-to-energy technologies, including municipal solid waste, landfill, and wastewater treatment plant gas, which are discussed in Section 5.1: Renewable Resources Not Modeled.

We modeled biomass as a 15 MW, wood-fired facility with a heat rate of 14,599 BTU per kWh. These parameters reflect a cogeneration facility near a timber mill and are the same parameters presented in our 2021 with updates to cost data (e.g., capital costs, operations and maintenance, transmission). We show the operating assumptions for the 2021 IRP and this report in Table D.1.

Biomass technology is commercially available. Greenfield development of a new biomass facility — designing, permitting, and constructing a completely new, previously unplanned facility — requires approximately three years.

2.2. Wind

Wind energy is the dominant renewable technology used in the Pacific Northwest region to meet Washington State's Renewable Portfolio Standards (RPS) and Clean Energy Transformation Act (CETA) requirements. Wind technology is mature, is cost effective, is acceptable in various regulatory jurisdictions, and has a large utility-scale compared to other renewable energy technologies. However, wind also poses challenges. Wind power generation does not correlate with customer demand because the availability of wind is variable. Therefore, we must have other, more flexible resources ready to respond when wind is unavailable. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a power system that is already congested.

2.2.1. Land-based Wind Technology

Land-based wind turbine generator technology is mature. Although the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding higher towers, wider rotor diameters, greater nameplate capacity, and increased wind capture (efficiency). Commercially available turbines range in capacity from 2-4 MW, with an average of 2.55 MW per turbine. Hub heights and blade diameters average 90 meters and 121 meters, respectively[3]. The primary factor driving changes in wind technology is the need to site new development in less energetic wind sites because premium high-wind spots are already developed. This technology will likely continue to advance and become more accessible as the current generation of turbines pushes the physical limits of existing transportation infrastructure. The U.S. Department of Energy is researching potential solutions, including designing more slender, flexible blades and developing towers that crews can assemble on-site.[4]

The cost of installing a wind turbine includes the turbine, foundation, roads, and electrical infrastructure. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $28.36 to $55.37 per MWh (in 2021 U.S. dollars) for new wind resources entering service in 2024. This cost depends heavily on the capacity factor of wind at the location and federal tax credits, which, even with the extension under the Inflation Reduction Act (IRA), will likely decline or expire during the planning horizon.[5] Greenfield development of a new wind facility requires approximately two to three years and consists of the following activities at a minimum: one to two years for development, permitting, major equipment lead time, and one year for construction.

2.2.2. Offshore Wind Technology

Offshore winds blow at higher speeds and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can make significantly more electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and an average wind speed of 14 mph.

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[3] Lawrence Berkeley National Laboratory, Wind Energy Technology Update: 2020 Edition: https://emp.lbl.gov/sites/default/files/2020_wind_energy_technology_data_update.pdf

[4] https://www.energy.gov/eere/articles/wind-turbines-bigger-better

[5] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2022, March 2022: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

However, offshore wind installations have higher capital and operational costs than land-based installations per unit of generating capacity, mainly because of turbine upgrades required for operation at sea and increased expenses related to turbine foundations, the balance of system infrastructure, interconnection, and installation, and the difficulty of maintenance access. In addition, developing infrastructure incurs one-time costs to support offshore construction, such as vessels to erect foundations and install turbines and related port facilities.

Wind turbine generators used in offshore environments require durability modifications to prevent corrosion and to operate reliably in harsh marine environments. Their foundations must be designed to withstand storm waves, hurricane-force winds, and even ice floes. The engineering and design of offshore wind facilities depend on site-specific conditions, particularly water depth, the geology of the seabed, and expected wind and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with various styles for each category. The fixed foundation is a proven technology used throughout Europe. Monopiles, the most prevalent foundation type, are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters. However, roughly 90 percent of the offshore U.S. wind resource occurs in waters too deep for a fixed foundation, particularly on the West Coast. The wind industry is developing new technologies, such as floating wind turbines, but this technology is not commercially mature.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. A power cable connects each turbine to an electric service platform (ESP). High voltage cables, typically buried beneath the seabed, transmit the power collected from wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

In Europe, offshore wind is a proven technology in shallow coastal waters. As of 2020, Europe's total installed capacity was 25 GW, with turbines spanning 12 countries[6]. The United States currently has two operational offshore wind projects — the 30 MW Block Island Wind Farm off the coast of Rhode Island, which began operation in December 2016, and the two-turbine 12 MW Coastal Virginia Offshore Wind pilot project, completed in June 2020. As a result of this dearth of data, reliable capital cost estimates for large-scale U.S. installations are unavailable.

However, this will change during the planning horizon for the 2023 Electric Report, as the Biden administration has set a goal of achieving 30 GW of offshore wind by 2030 and has subsequently approved the first two commercial-scale projects in the nation, Vineyard Wind and South Fork Wind projects, which are currently under construction. Additionally, in June of 2022, the administration launched the Federal-State Offshore Wind Implementation Partnership, intended to accelerate the offshore wind progress[7]. According to The American Clean Power Association, project developers expect 12 offshore wind projects totaling 10,300 MW to be operational by 2026[8]. As the market develops, costs should decrease as we all gain experience. Based on the current design trajectory of wind turbine development, bigger units will be able to capture more wind and achieve more significant economies of scale in the years ahead.[9]

[6] https://windeurope.org/intelligence-platform/product/offshore-wind-in-europe-key-trends-and-statistics-2020
[7] https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/23/fact-sheet-biden-administration-launches-new-federal-state-offshore-wind-partnership-to-grow-american-made-clean-energy
[8] https://cleanpower.org/facts/offshore-wind
[9] https://www.energy.gov/eere/wind/offshore-wind-research-and-development

2.2.3. Modeling Assumptions

We modeled wind in the following locations for this report: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho, and Washington offshore. Table D.2 summarizes the wind resources we modeled in the 2023 Electric Report and those we modeled in the 2021 IRP for reference. We held operating assumptions consistent with the 2021 IRP values, except for capacity factors, ELCC calculations, and cost assumptions.

Generic Wind Locations

Eastern Washington wind is in Bonneville Power Administration's (BPA) balancing authority, so this wind requires only one transmission wheel – transfer from one transmission provider to another – through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require three transmission wheels to deliver the power to PSE's service territory. Similarly, the Wyoming and Idaho wind sites are well outside PSE's service territory and will require three transmission wheels to deliver power in 2024-2030. From 2031 through the end of the planning horizon in 2045, we assumed the Gateway West[10] transmission projects would be complete. Once constructed, we assume two wheels will deliver power from Wyoming and Idaho: from Aeolus, Wyoming, to Hemmingway, Idaho, then from Hemmingway, Idaho, to Longhorn, Washington.

We modeled offshore wind located 16 miles off Grays Harbor County, Washington coast. Offshore wind requires a marine cable to interconnect the turbines and bring the power back to land. Once on land, a transmission wheel through BPA to PSE would be necessary.

Generate Wind Shapes

A wind (or solar) shape is the net capacity factor of a wind turbine (or solar array) at a specific location over time. A wind shape provides data on how well a given wind resource will perform. Puget Sound Energy engaged the consulting company DNV to generate wind shapes for each generic wind resource. Using a consulting firm was a departure from the 2021 IRP when we used the NREL Wind Toolkit database[11] to derive wind shapes. This 2023 Electric Report presents wind shapes as a net capacity factor for every hour within one calendar year. Figure D.3 shows the wind shapes for the generic wind resources we analyzed for this report.

DNV used an internal wind mapping system to generate hourly shapes at a 5-kilometer resolution for each potential wind site. This modeling process involves conducting dynamical downscaling to generate high-resolution mesoscale wind maps. Inputs include soil and sea surface temperatures, moisture levels, and NASA's MERRA-2 reanalysis dataset, which contains data obtained from various sources, including rawinsondes, radar, land-based stations, aircraft, ships, scatterometer wind readings, and NASA's EOS satellites. Outputs from this modeling include an hourly time series of wind speed, temperature, pressure, and direction at hub heights.

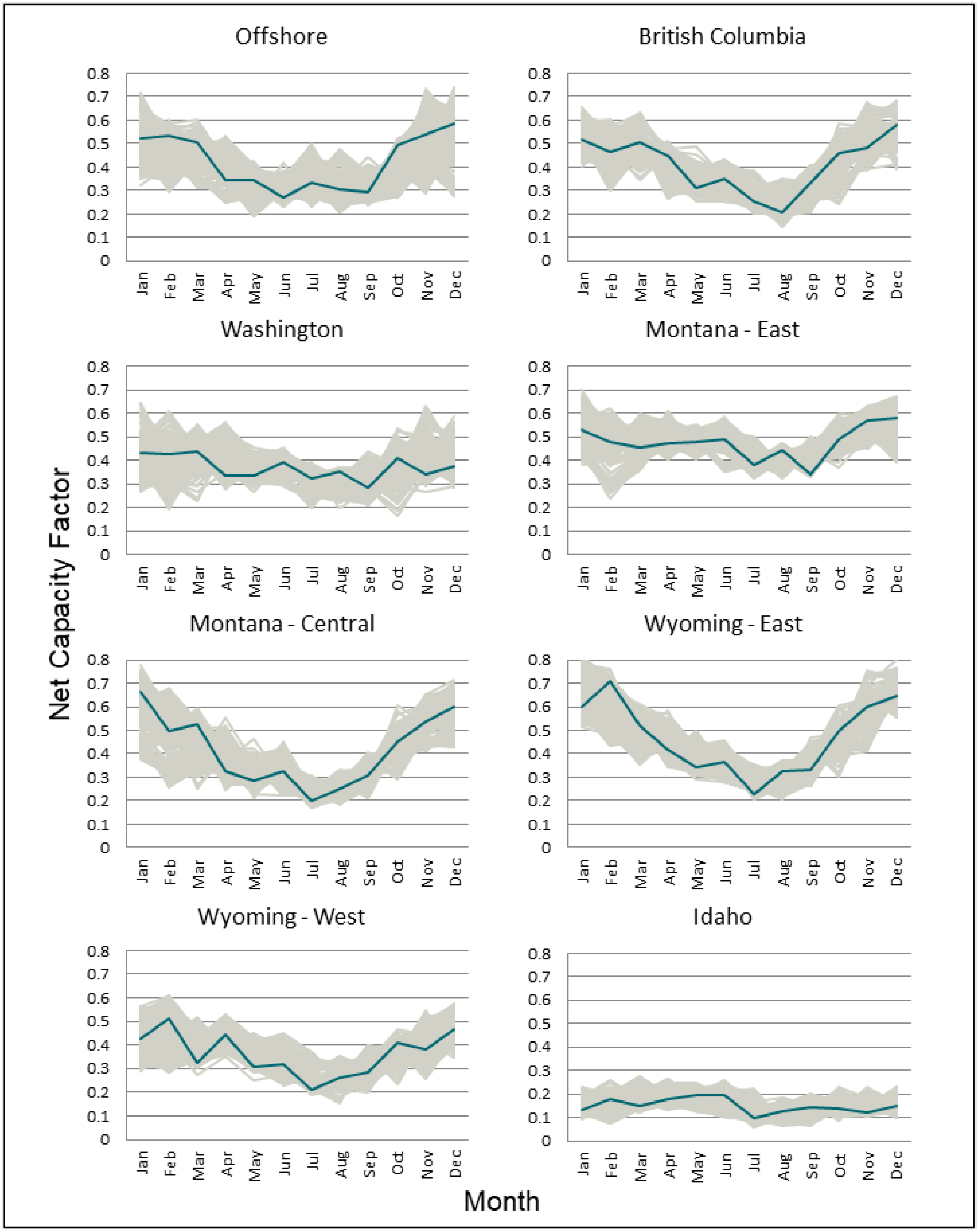
DNV subsequently used this output, in conjunction with turbine model and power data, as inputs to a stochastic model. The stochastic model generated 1,000 stochastic time series to represent the net capacity factor of a wind

10 http://www.gatewaywestproject.com
11 https://www.nrel.gov/grid/wind-toolkit.html

turbine for each site over the 22-year planning period. This methodology maintained daily, seasonal, and annual cycles from the original data. The stochastic model also maintained spatial coherency of weather, generation, and system load to preserve the relationships of projects across a region. DNV then randomly selected a sample of 250 annual hourly draws for each site, verified the data were representative of the total distribution, and provided the data to PSE for modeling purposes.

These updated wind shapes from DNV are generally consistent across sites with the wind shapes provided in the 2021 IRP, except for the existing Skookumchuck wind resource and the generic Idaho wind resource. Upon examining these resources further, we determined that the NREL wind toolkit database lacked wind speed data near the sites, so it did not adequately represent the Skookumchuck and Idaho wind sites. Therefore, we determined the DNV shapes provided a more accurate representation of wind conditions at these sites and adopted those shapes for this 2023 Electric Report.

Figure D.3: Seasonal Wind Shapes for Generic Wind Resources



2.3. Solar

Renewable portfolio standards (RPSs), falling prices, and tax incentives drive most utility-scale solar development in the United States, with solar installations accounting for 50 percent of total capacity additions across the U.S. in Q1

2022.[12] With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic growth has been relatively slow in the Northwest. However, since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably, and solar remains an appealing renewable technology for us to procure to meet RPS and CETA requirements. Like wind technology, solar resources pose challenges that include daily and hourly variability in power generation, the misalignment with generation and customer demand, and the need for the long-haul transmission to bring solar power generated in sunnier locations into PSE's system.

2.3.1. Solar Technologies

Photovoltaic (PV) technology, semiconductors that generate direct electric currents, uses solar radiation to generate electricity directly. The current typically runs through an inverter to create alternating current, which ties into the grid. Most PV solar cells are silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film PVs, have gained substantial market share. Significant ongoing research efforts continue for all PV technologies and have helped increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays ranging from a few watts for sensor or communication applications to hundreds of megawatts for utility-scale power generation. Photovoltaic systems can be installed on a stationary frame at a tilt to capture the sun (fixed-tilt) best or on a frame than can track the sun from sunrise to sunset.

Concentrating and bifacial PVs are high-efficiency technologies. Concentrating photovoltaics use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems. Bifacial photovoltaic modules collect light on both sides of the panel, instead of just on the side facing the sun (as in typical PV installations). Bifacial modules can achieve greater efficiencies per unit of land, reducing the land use requirements. Efficiency gains made by bifacial module are highly dependent on the amount of light reflected by the ground surface, or albedo.

Distributed solar uses similar technologies to utility-scale PV systems but at a smaller scale. The defining characteristic of distributed solar systems is that the power is generated at, or near, the point where the power will be used. This scenario means that distributed solar systems do not have the same costly transmission requirements as utility-scale systems. Distributed solar may include rooftop or ground-mounted systems, such as parking lot canopies.

The Solar Electric Industries Association (SEIA) reports that as of Q1 2022, the U.S. has installed over 121 GW of total solar capacity, with an average annual growth rate of 33 percent over the last ten years. Solar has ranked first or second in new electric capacity additions every year for the last nine years. Through early 2022, 46 percent of all new electric capacity added to the grid came from solar.[13] According to SEIA's U.S. Solar Market Insight report for Q4 2021, modeled U.S. national average costs for utility fixed-tilt and tracking projects averaged $0.82 and $0.95 per

[12] Solar Electric Industries Association (SEIA), Solar Industry Research Data: https://www.seia.org/solar-industry-research-data. Accessed 6/24/2022.

[13] Solar Electric Industries Association (SEIA), Solar Industry Research Data: https://www.seia.org/solar-industry-research-data. Accessed 6/24/2022.

$Watt_{dc}$, respectively; costs for residential systems had reached approximately $3.06 per $Watt_{dc}$; and costs for commercial systems had reached $1.45 per $Watt_{dc}$.[14]

2.3.2. Modeling Assumptions

We modeled two solar PV applications for this report: a utility-scale, single-axis tracking PV technology, and a residential-scale fixed-tilt, rooftop, or ground-mounted PV technology. We modeled six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho, and residential-scale rooftop or ground-mounted PV solar in western Washington. Table D.3 summarizes the solar resources modeled in the 2023 Electric Report and those modeled in the 2021 IRP for reference. We held operating assumptions consistent with the 2021 IRP values, except for capacity factors, ELCC calculations, and cost assumptions.

Generic Solar Locations

Washington solar resources are located either within PSE's service territory or in BPA's balancing authority, which would require one transmission wheel to PSE. However, Wyoming and Idaho solar resources are outside BPA's balancing authority and will need three transmission wheels to deliver the power to PSE's service territory from 2024–2030. From 2031 through the end of the planning horizon in 2045, we assumed the Gateway West[15] transmission project would be complete. Once constructed, we assumed two wheels to deliver power from Wyoming and Idaho: from Aeolus, Wyoming, to Hemmingway, Idaho, then from Hemmingway, Idaho, to Longhorn, Washington.

Solar Shape Generation

We used specific solar generation profiles or shapes provided by DNV. Using a consulting firm was a departure from the 2021 IRP when we used the shapes derived using irradiance data queries from the NREL's National Solar Radiation Database (NSRDB)[16] and then modeled using NREL's System Advisor Model (SAM) to create realistic generation profiles for each location. For this report, DNV generated 1,000 stochastic series to represent each site over a 22-year window for a total of 22,000 simulated years.

This method relied on inputs that included 22-year hourly solar power time series based on historical irradiance data and load and temperature inputs provided by PSE. Irradiance data was sourced from NASA's Geostationary Operational Environmental Satellites and processed by DNV to account for regional loss factors for each site. Loss factors include temperature, shading, soiling, availability, electric, inverter, and transformer losses.

All resources were modeled with a DC (direct current) to AC (alternating current) ratio of 1.3, and azimuth angles were assumed to be south facing. Utility-scale resources were modeled as ground mounted with single-axis tracking panels, whereas residential-scale resources were modeled as fixed-tilt for rooftop and ground-mounted units.

This methodology maintained daily, seasonal, and annual cycles from the original data and spatial coherency of weather, generation, and system load to preserve how projects are related across a region. A sample of 250 annual

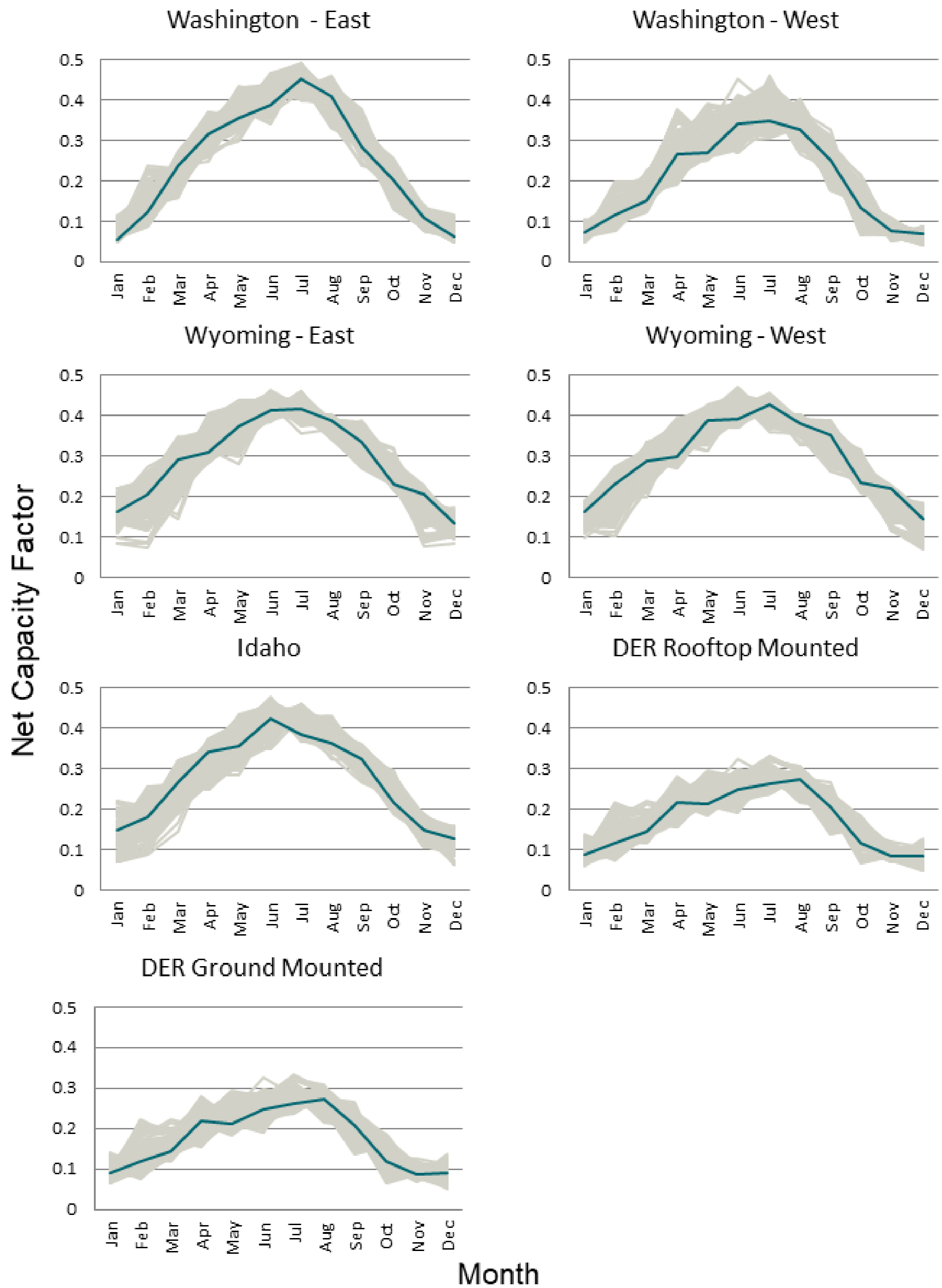
[14] SEIA, Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2021-q4.
[15] http://www.gatewaywestproject.com
[16] https://nsrdb.nrel.gov

hourly draws was then randomly selected for each site and, after being statistically verified to be representative of the total distribution of 22,000 annual draws for a site, provided to us for modeling.

All capacity factors are provided as AC, where the capacity of the inverter is taken as the nameplate of the solar facility. This differs from the DC capacity, which measures the capacity based on the capacity of the solar modules installed. The AC capacity is typically higher, because most solar facilities undersize the inverter as defined by the DC to AC ratio; in the case of PSE generic resources, the DC to AC ratio is 1.3.

We found these updated solar shapes were generally consistent across sites with the solar shapes we used in the 2021 IRP. Finally, a single, most-representative draw is selected from the 250 draws based on nearness to the annual average production of all 250 provided solar profiles. Figure D.4 summarizes the seasonal solar shapes used in the 2023 Electric Report. The grey lines represent the 250 stochastic draws, and the blue line represents the draw selected.

Figure D.4: Seasonal Solar Shapes for Generic Solar Resources



2.4. Energy Storage

Energy storage encompasses a wide range of technologies capable of shifting energy usage from one period to another. These technologies could deliver essential benefits to electric utilities and their customers since the electric system currently operates on just-in-time delivery. PSE must perfectly balance generation and load to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, balance supply and demand, provide backup power when primary sources are interrupted, and help integrate intermittent renewable generation. Energy storage technologies are rapidly improving and can benefit all parts of the system – generation, transmission, distribution, and customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

2.4.1. Battery Storage Technologies

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable, and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for an extensive storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its performance characteristics, commercial availability, and costs. We chose to model lithium-ion as the generic battery resource in this report because the technology is commercially available, successful projects are operating, and cost estimates and data are available on a spectrum of system configurations and sizes. We received the most energy storage bids for 4-hour lithium-ion battery arrays[17] in response to our 2021 All Source RFPs.[18]

Lithium-ion batteries have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell memory, and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability, and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (e.g., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

At the end of 2019, the U.S. had 1,022 MW of large-scale battery energy storage resources in operation. Lithium-ion batteries continued to dominate the energy storage market, representing more than 90 percent of operating large-scale battery storage capacity. In 2019, U.S. utilities also reported 402 MW of existing small-scale storage capacity. [19] Forty-

[17] In an actual RFP solicitation, we would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees, and counterparty credit.

[18] In an actual RFP solicitation, we would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees, and counterparty credit.

[19] U.S. Energy Information Administration, Battery Storage in the United States: An Update on Market Trends, August 2021: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

one percent of this capacity was installed in the commercial sector, 41 percent in the residential sector, 14 percent in the industrial sector, and the remaining 4 percent connected directly to the distribution grid.

2.4.2. Pumped Hydroelectric Energy Storage Technology

Pumped hydroelectric energy storage (PHES, pumped hydro storage, pumped storage, pumped hydro, or PHS) facilities provide the bulk of utility-scale energy storage in the United States. These 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. Load shifting over several hours requires a large energy storage capacity, and a device like PHES is well suited for this application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are traditionally large, at 300 MW or more. Due to environmental impacts, permitting these projects can take many years. Pumped storage can be designed to provide 6–20 hours of storage with 80 percent roundtrip efficiency.

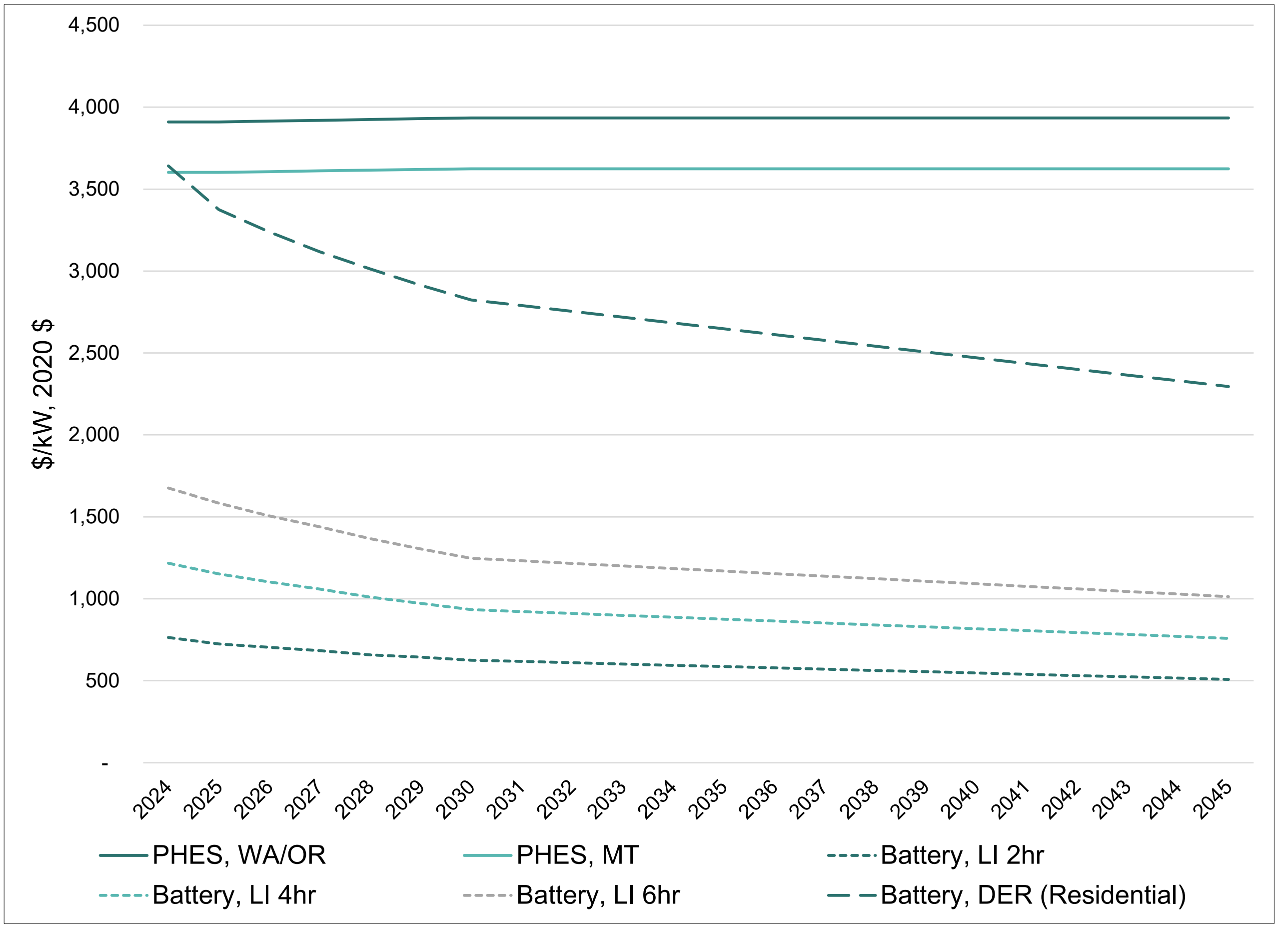
According to the U.S. Department of Energy's most recent *Hydropower Market Report*, there are 43 plants with a capacity of 21.9 GW, which represent 93 percent of utility-scale electrical energy storage in the U.S. Most of this capacity was installed between 1960 and 1990, and almost 94 percent of these storage facilities are larger than 500 MW. No new pumped storage projects have come online in the United States since 2012.[20] At the end of 2019, there were 67 pumped storage projects with a potential capacity of 52.48 GW in the development pipeline. The median project size in the development pipeline is 480 MW, but projects span a wide range of sizes from large projects greater than 3,000 MW to small closed-loop systems of less than 100 MW.[21]

2.4.3. Modeling Assumptions

We modeled six energy storage resources in this report: 100 MW lithium-ion batteries in 2-, 4-, and 6-hour sizes; a smaller 3-hour lithium-ion battery as a distributed energy resource; and two PHES systems, one located in Montana and the other in either Washington or Oregon. Table D.4 summarizes the generic cost assumptions used in the energy storage resource analysis and assumptions used in the 2021 IRP for comparison. Figure D.5 shows the capital cost curves for each energy storage technology through the planning horizon. All costs are in 2020 dollars.

[20] U.S. Energy Information Agency, Annual Electric Generator Report: https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf.
[21] Ibid.

Figure D.5: Capital Cost Curves for Generic Energy Storage Resources



2.5. Hybrid Technologies

Hybrid resources combine two or more resources at one location to take advantage of synergies created through the co-location of the resources. Hybrid resources may combine two generating resources, such as solar and wind, or one generating and one storage resource, such as solar and a battery energy storage system. Benefits of hybrid resources include reduced land use needs, shared interconnection and transmission costs, improved frequency regulation, backup power potential, and operational balancing potential, among others. From 2017 to 2020, the number of installed hybrid systems in the U.S. doubled from less than 30 to 80 facilities.[22] Furthermore, 73 percent of the battery storage power planned to come online between 2021 and 2024 will be co-located with solar or wind power plants.[33]

2.5.1. Modeling Assumptions

We are evaluating three hybrid systems, each of which pairs a generating resource with a storage resource. These hybrid resources include Washington wind plus 4-hour battery storage and Washington utility solar plus 4-hour battery storage. Additionally, we are evaluating a hybrid configuration of wind and solar generation plus a 4-hour battery storage resource, located in eastern Washington. We configured the hybrid resources in the model so the storage resource can charge using either energy from the generating resource to which it is connected from the market.

Table D.5 presents the operating assumptions for the hybrid systems modeled in this 2023 Electric Report and those modeled in the 2021 IRP for comparison.

3. Thermal Resource Technologies and Assumptions

Combustion turbines (CT) play an essential role in the portfolio, given their versatility and reliability. The following characteristics make combustion turbines a critical tool.

- Proximity: Combustion turbines located within or adjacent to PSE's service area avoid costly transmission investments required for long-distance resources like wind.
- Timeliness: Combustion turbines are dispatchable; we can turn them on to meet loads, unlike intermittent resources that generate power sporadically, such as wind, solar, and run-of-the-river hydropower.
- Versatility: Combustion turbine generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.

This section describes the thermal resources modeled in this report.

[22] https://www.eia.gov/todayinenergy/detail.php?id=43775.

3.1. Baseload Combustion Turbine Technologies

Baseload combustion turbine plants (combined-cycle combustion turbines or CCCTs) produce energy at a constant rate over long periods at a lower cost than other production facilities available to the system. Baseload combustion turbine plants are typically used to meet some or all of a region's continuous energy demand.

These baseload plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. The baseload heat rate for the CCCTs modeled for the 2023 Electric Report is 6,624 BTU per kWh. Many plants also feature duct firing. Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. Combined-cycle combustion turbines have been a popular source of baseload electric power and process steam generation since the 1960s because of their high thermal efficiency and reliability, relatively low initial cost, and relatively low air emissions. This technology is commercially available. Greenfield development requires approximately three years.

3.2. Peaker Technologies

Peakers are quick-starting single-cycle combustion turbines that can ramp up and down rapidly to meet spikes in need. They also provide the flexibility needed for load following, wind integration, and spinning reserves. We modeled two types of peakers; each brings strengths to the overall portfolio.

3.2.1. Frame Peakers

Frame CT peakers are also known as industrial or heavy-duty CTs and are sometimes referred to as simple cycle combustion turbines (SCCT); these are generally larger in capacity and feature frames, bearings, and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil, or a combination of fuels (dual fuel). The turndown capability of the units is 30 percent. This report's assumed heat rate for frame peakers is 9,904 BTU per kWh. Frame peakers also have slower ramp rates than other peakers at 40 MW per minute for 237 MW facilities. Some can achieve a full load in 21 minutes. Frame CT peakers are commercially available. Greenfield development requires approximately two years.

3.2.2. Reciprocating Peakers

Reciprocating internal combustion engines (recip peakers or RICE) use a reciprocating engine technology evaluated based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher oxygen ratio to fuel, allowing the reciprocating engine to generate power more efficiently. Ramp rates are 16 MW per minute for an 18 MW facility. The heat rate is 8,445 BTU per kWh. However, reciprocating engines are constrained by their size.

The largest commercially available reciprocating engine for electric power generation produces 18 MW, less than the typical frame peaker. Larger-sized generation projects would require more reciprocating units than an equivalent-sized project implementing a frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and minimizes the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers. This technology is commercially available. Greenfield development requires approximately three years.

3.3. Modeling Assumptions

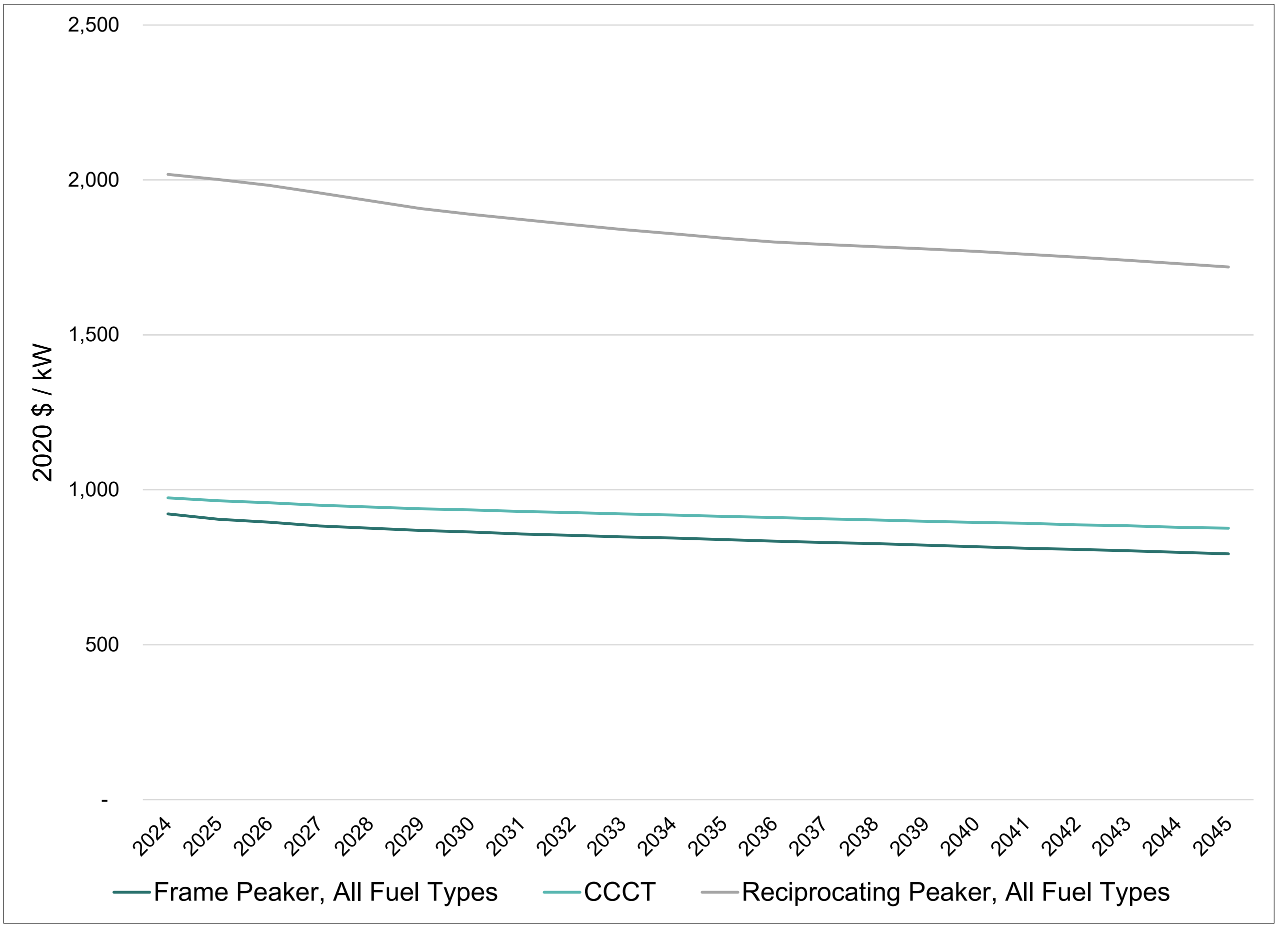
PSE modeled two general types of thermal resources in this 2023 Electric Report: baseload combustion turbine plants (CCCTs), and peaking capacity plants. As PSE moves towards CETA goals, we explored fuel alternatives to natural gas to operate thermal resources and provide non-emitting dispatchable power. Alternative fuels modeled in this 2023 Electric Report include hydrogen and biodiesel.

We modeled a single natural gas-powered CCCT in this report. We modeled three frame-peaking capacity plants: one fueled with natural gas, one with a hydrogen blend, and another with biodiesel. Finally, we modeled two types of reciprocating peaking capacity plants, one fueled with natural gas and the other with a hydrogen blend.

For natural gas-powered CCCT units, we assumed the natural gas supply would be firm year-round at projected incremental gas pipeline firm rates. We assumed natural gas-powered frame peaking units have oil backup, and natural gas supply is available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. We assumed that 20 percent of gas storage is available to baseload CCCT plants and peaking plants and modeled it to accommodate mid-day start-ups or shutdowns. Regardless of fuel type, all thermal units are assumed to be connected to the PSE transmission system and therefore do not incur any direct transmission cost.

The following subsections describe these technologies, including cost assumptions and commercial availability. Figure D.6 presents the capital cost curves for each thermal technology through the planning horizon. Because the fuel type does not affect the overall capital cost of the units, Figure D.6 includes the three different thermal technologies modeled. Table D.6 summarizes the cost and operating assumptions used in the analysis for thermal resources. We also presented assumptions from the 2021 IRP for comparison. All costs are in 2020 dollars.

Figure D.6: Capital Cost Curves for Generic Thermal Resources



3.3.1. Natural Gas Transportation Modeled Costs

Fixed and variable natural gas transportation costs for the combustion turbine plants assumed that natural gas is purchased at the Sumas Hub. Natural gas transportation costs for resources without oil backup assumed the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 20 percent of the plant's complete fuel requirements. This scenario applies to the baseload CCCT and reciprocating engine without oil.

The analysis assumed that we would meet the gas transportation needs for these resources with 100 percent firm gas transportation on a Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on the Westcoast Pipeline expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential gain between Sumas and Station 2 mitigates the gas transportation costs. We assume oil backup with no firm gas transportation for the natural gas frame peaker resources. Table D.7 shows the natural gas transport assumptions for resources without oil backup, and Table D.8 shows natural gas transport assumptions for frame peakers with oil backup.

3.3.2. Green Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and could become an essential energy carrier in the power sector.[23] Hydrogen is abundant in several feedstocks, including water, biomass, fossil fuels, and waste products, but it requires a significant amount of energy to produce elemental hydrogen from these feedstocks. It is common practice to classify hydrogen with color to describe the feedstock and energy source used to produce the hydrogen. Green hydrogen is the most attractive variety of hydrogen in the context of a clean energy transformation. Green hydrogen is typically made from water electrolysis using low- or non-emitting energy sources to power the process.

Green hydrogen has the potential to act as a useful energy carrier to store and deliver low- or no-carbon energy where and when it is needed. When wind and solar generation is plentiful, we can turn on electrolyzers to produce and store hydrogen. When demand is high and renewable generation is unavailable, the stored hydrogen may be combusted in a turbine or electrochemically reacted in a fuel cell to produce electricity. A key advantage green hydrogen has over other storage technologies (e.g., battery energy storage systems or pumped hydroelectric storage) is that hydrogen is stable over long periods, meaning we can store energy monthly instead of hour-to-hour as in other storage systems. This long storage period allows hydrogen to store excess energy in spring and autumn for use in the peak summer and winter seasons.

Despite its potential usefulness, the green hydrogen industry must overcome several obstacles before it can play a significant role in the power sector. Large-scale electrolyzers are an emerging technology with relatively few installations scattered across the globe. Research and development into scaling up production and reducing the costs of electrolyzers are necessary to produce the quantities of hydrogen needed to support the power sector. Powering large installations of electrolyzes will also require a large amount of low- or no-carbon electricity. It is necessary to develop adequate quantities of wind, solar, or other non-emitting generation and the transmission to move the power to the electrolyzers.

After production, hydrogen must be stored and transported. Pipelines are the obvious choice for storage and transportation, but utilities will need dedicated pipelines for high-purity hydrogen storage and transport. Finally, to access the energy stored in hydrogen, existing combustion turbines will require modifications to accommodate the new fuel, or new technologies, such as fuel cells, will need to be researched and developed. These infrastructure-related hurdles add cost and require detailed long-term planning to incorporate green hydrogen into the power system successfully.

The enactment of the 2022 Inflation Reduction Act provides incentives that dramatically reduce the cost barriers to establishing the infrastructure required to make green hydrogen an economically viable energy carrier for the power system. Production Tax Credits (PTCs) from the Inflation Reduction Act could reduce hydrogen prices by up to $3 per kilogram[24], putting green hydrogen price forecasts on par with natural gas prices by the mid-2030s.

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[23] https://www.nrel.gov/docs/fy21osti/77610.pdf
[24] https://www.congress.gov/bill/117th-congress/house-bill/5376/text

This development and additional momentum behind green hydrogen from the Department of Energy's Regional Clean Hydrogen Hubs[25] spurred us to include green hydrogen as a fuel source in the 2023 Electric Report. We will likely obtain green hydrogen as part of an offtake agreement from an independent fuel supplier; therefore, hydrogen is modeled simply as a fuel source in the AURORA model.

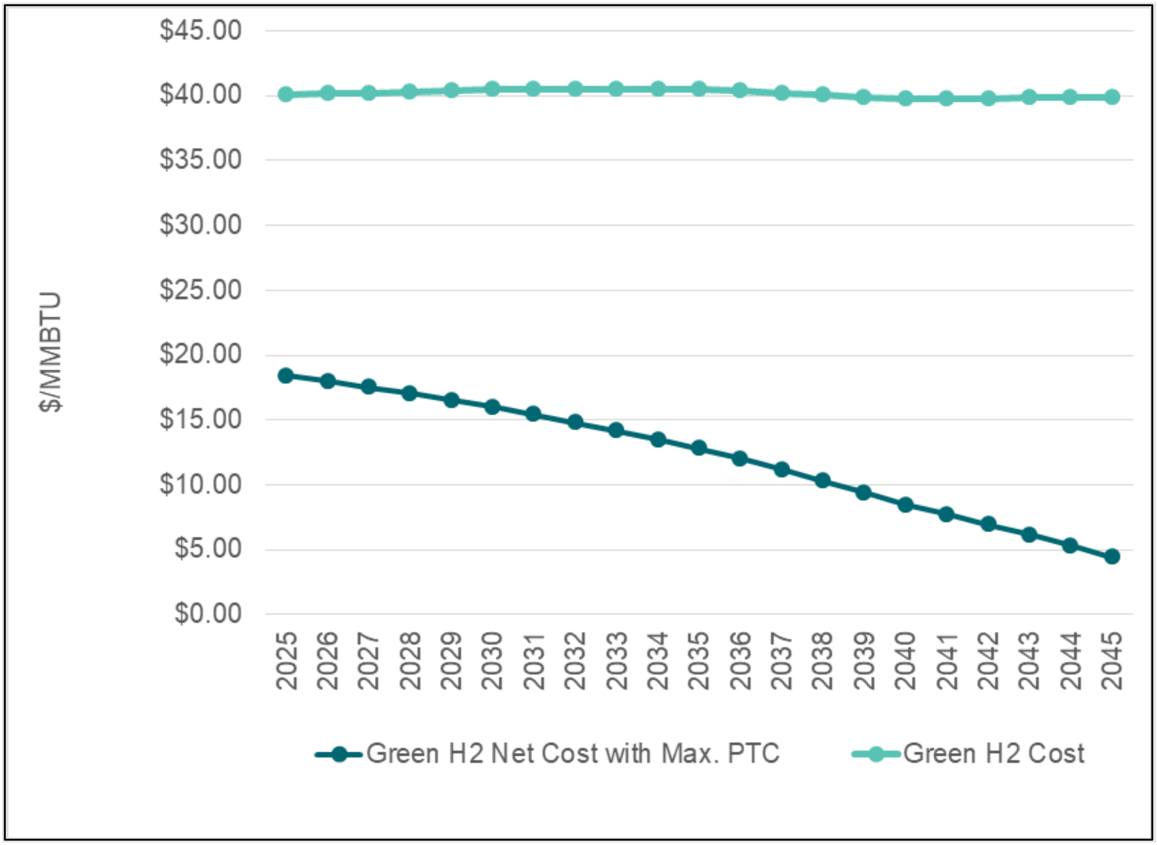
We assumed several resources are eligible to combust green hydrogen, including a generic frame peaker, a generic reciprocating peaker, and PSE's existing thermal generation fleet. Supply is essential in modeling green hydrogen as a fuel source because it will take time to establish the required infrastructure. Based on our understanding and engagement in the nascent green hydrogen industry, it seems likely the first year significant quantities of hydrogen will become available is 2030. From 2030 forward, we forecast a growing green hydrogen supply in the Pacific Northwest large enough to supply PSE's existing thermal generation fleet. Table D.9 illustrates a trajectory of hydrogen supply using a blend rate with natural gas.

Developing a hydrogen pipeline to the regions of PSE's generation fleet will also constrain green hydrogen fuel supply. To reflect this constraint in the model, we limited access to green hydrogen for PSE's existing thermal fleet to a schedule based on our estimate of probable hydrogen production regions and subsequent expansion of pipelines from those regions. Table D.10 reflects the timeline we forecast a hydrogen pipeline may be available at new and existing thermal resources.

Price is the final consideration required to model green hydrogen. We developed a hydrogen price forecast based on assumptions from the E3 Pacific Northwest report[26] and industry consultations. We also applied the maximum PTC benefit to the green hydrogen price, reflecting the incentives expected for green hydrogen development in the Pacific Northwest. Figure D.7 illustrates the price forecast for green hydrogen in the AURORA model.

[25] https://www.energy.gov/oced/regional-clean-hydrogen-hubs
[26] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Figure D.7: Green Hydrogen Price Forecast



3.3.3. Biodiesel

Washington State defines biodiesel 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 like petroleum diesel but is derived from waste cooking oil or dedicated crops. According to the U.S. Energy Information Administration, two facilities in Washington State make biodiesel, which together can manufacture upward of 100 million gallons of biodiesel a year.

Biodiesel may become a viable fuel supply for combustion turbines to provide peak capacity in the future. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At total 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 fire for a 48-hour peak event continuously. The existing Washington State biodiesel production capacity of 107 million gallons per year in 2022[27] could plausibly supply several combustion turbines intended to supply reliable power during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low-hydroelectric conditions.

We explored biodiesel used in simple-cycle combustion turbines in this 2023 Electric Report. We included a generic frame peaker with biodiesel as the primary fuel in the AURORA long-term capacity expansion analysis. We

[27] https://www.eia.gov/biofuels/biodiesel/capacity/

configured this biodiesel peaker to purchase a fixed seven-day biodiesel supply during critical peak hours each year. This limited fuel supply equals an approximate 2 percent capacity factor for the biodiesel peaker. We estimated biodiesel prices at $33.13/MMBTU based on the Department of Energy Alternative Fuel Price Report, January 2022.[28]

4. New Resource Technologies and Assumptions

Puget Sound Energy considered modeling several emerging technologies, particularly energy storage technologies. However, due to accurate and reliable data availability, advanced nuclear small modular reactors (SMRs) are the only new technology considered in this 2023 Electric Report. Advanced nuclear SMR resource technology, cost, and operating assumptions are provided below. Other emerging technologies are discussed further in the following section, Resource Technologies Not Modeled.

4.1. Advanced Nuclear Small Modular Reactors

Nuclear power is considered a source of non-emitting electric generation under section 2 (28) of CETA [RCW 19.405.020.[29] This configuration has the distinct advantage over traditional nuclear resources of being far more flexible in terms of scaling energy output and therefore has the potential for use as a dispatchable resource rather than being utilized strictly as baseload capacity. In practice, this resource could be either entirely dispatchable or have a portion dedicated to baseload and a part held in reserve to cover peak events. In addition to the flexibility benefits, this resource is a non-variable resource making it highly reliable and non-emitting. This combination of dispatchability, reliability, and emission-free production could make this a very attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

An advanced nuclear SMR plant consists of a cluster of nuclear reactors that share land and infrastructure while retaining the ability to activate and deactivate independently. Each module consists of a single reactor, similar in size and technology to the units employed on nuclear submarines, with an output ranging from 40 to 80 MWs. An entire SMR plant may consist of four to twelve modules. Advances in nuclear engineering in fuel containment and cooling systems, including the ability to dry cool a system even in total water loss, make SMR systems much safer than traditional large-scale nuclear plants.

An SMR plant is far more cost-effective than a traditional nuclear plant because they require a fraction of the land footprint, and the modules are small and can be prefabricated off-site and shipped to the desired location. Although SMR plants are a relatively new application of nuclear technology in utility-scale electric generation, this application appears to be entering commercial availability, with several companies bringing this application to market. Those companies include X-energy, which currently has a contract to install an SMR facility at the Hanford Nuclear site for Energy Northwest, and NuScale, also constructing an SMR facility in Idaho Falls in partnership with the Idaho National Laboratory.

[28] https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_january_2022.pdf
[29] RCW 19.405.020

There is not a significant amount of literature on SMR waste disposal. However, one influential study whose authors include a former chairperson of the U.S. Nuclear Regulatory Commission[30] suggests that although SMRs use less fuel than traditional nuclear plants, they could generate significantly more waste due to increased irradiation of specific reactor components. Although the current practice for existing nuclear facilities is to store waste on-site in casks built to contain the waste material, the cited paper recommends that a portion of waste material would ideally be treated before disposal in a geologic repository with engineered barriers for shielding material from the environment. It suggests this could significantly raise disposal-related costs.

Greenfield development of a new SMR facility requires approximately four years.

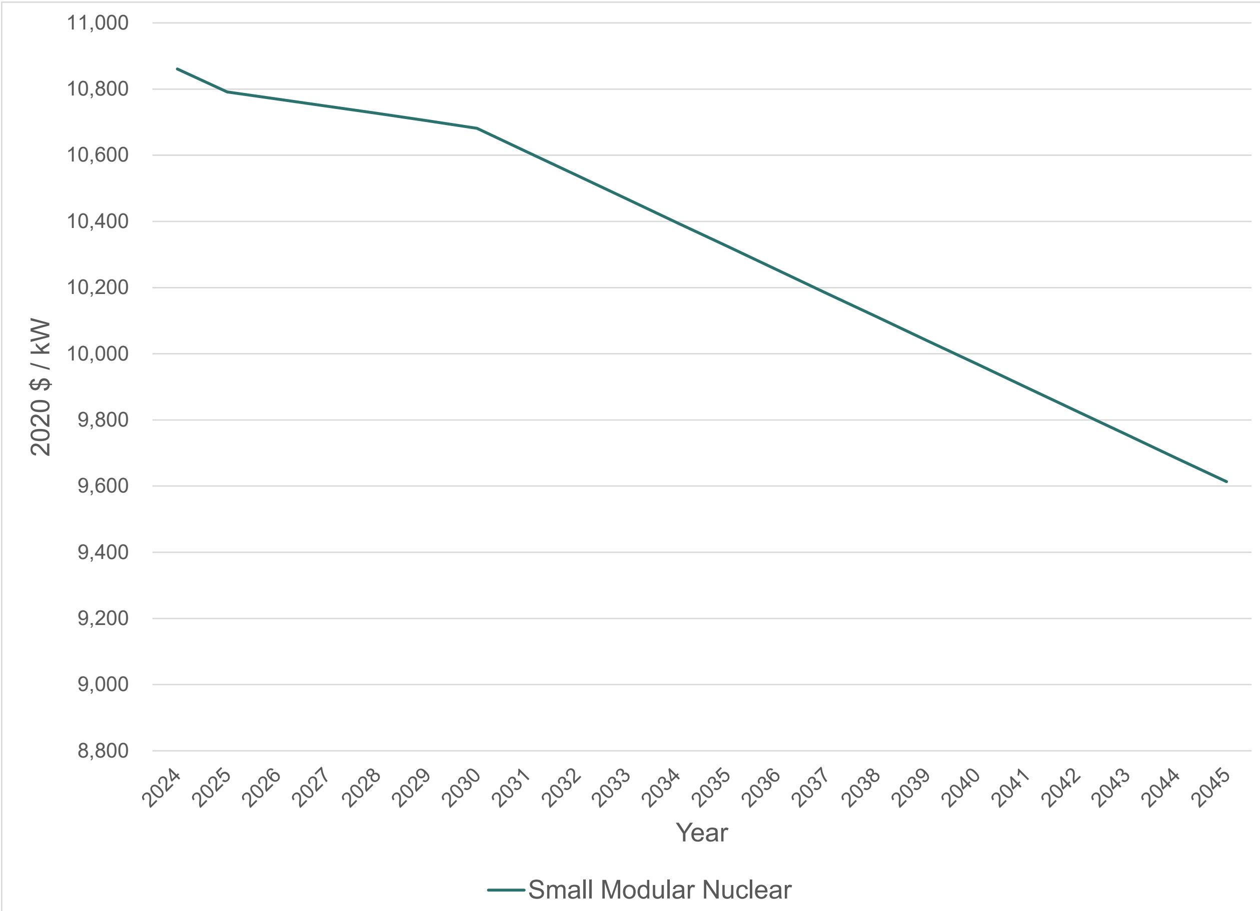
4.1.1. Modeling Assumptions

For the first time, we modeled an SMR plant in this report. We modeled an SMR configuration consisting of 12 modules with an output of 50 MWs each, totaling 600 MWs of capacity and a heat rate of 10046 BTU per kWh. This configuration is consistent with information provided by the EIA's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies.[31]

Figure D.8 presents the capital cost curves for SMR plants through the planning horizon. Table D.11 summarizes the cost and operating assumptions used in the analysis for SMR resources. All costs are in 2020 dollars. Because this technology is not commercially available at the time of this analysis, we constrained the model to allow the first year of SMR resource builds in 2030.

[30] https://www.pnas.org/doi/10.1073/pnas.2111833119
[31] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Figure D.8: Capital Cost Curve for Advanced Nuclear Small Modular Reactors



5. Resource Technologies Not Modeled

This section discusses the resource technologies PSE considered but did not model in this 2023 Electric Report. Some technologies, such as coal, are becoming obsolete in a clean energy landscape; others PSE determined to be either geographically or technologically infeasible for PSE's system at this time.

5.1. Renewable Resources Not Modeled

Several renewable resource technologies were not modeled in this 2023 Electric Report because 1) the technologies are in the early development stages and cost and operational data is lacking; 2) the technology is not feasible within geographic proximity to PSE; and/or 3) the technology has not been built to operate on a large, utility scale. Several of these technologies are summarized in this section.

5.1.1. Solar Thermal Plants

Solar thermal plants focus the direct irradiance of the sun to generate heat that produces steam, which in turn drives a conventional turbine generator. Two general types are used or in development today, trough-based and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun on a horizontal pipe carrying water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A transfer fluid collects and transfers the heat to make steam. Thermal solar plants have been operating successfully in California since the 1980s.[32]

5.1.2. Fuel Cells

Fuel cells combine fuel and oxygen to create electricity, heat, water, and other by-products through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, and larger ones can power equipment, buildings, or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures, and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. Fuel cell systems must be cost-competitive with and perform as well as traditional power technologies over the system's life[33] to be economical.

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the U.S. Department of Energy's report *State of the States: Fuel Cells in America 2017*,[34] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that California remains the leader with the greatest number of stationary fuel cells. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington State offers no incentives specific to stationary fuel cells. The EIA, estimates fuel cell capital costs to be approximately $7,224 per kW.[35]

5.1.3. Geothermal

Geothermal generation technologies use the natural heat under the earth's surface to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

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32 SEIA, Solar Spotlight – California for Q3 2018, December 2018: https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_California_1.pdf.
33 U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.
34 U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2017," dated January 2018, https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf.
35 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

- Dry steam plants use hydrothermal steam from the earth to power turbines directly. Dry steam plants were the first type of geothermal power generation technology developed.[36]
- Flash steam plants operate similarly to dry steam plants but use low-pressure tanks to vaporize hydrothermal liquids into steam. This technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius) like dry steam plants.[37]
- Binary-cycle power plants can use lower-temperature hydrothermal fluids to transfer energy through a heat exchanger to a liquid with a lower boiling point. This system is an entirely closed loop; no steam emissions from the hydrothermal fluids are released. Most new geothermal installations will likely be binary-cycle systems due to the limited emissions and greater potential sites with lower temperatures.[38]
- Enhanced geothermal or hot dry rock (HDR) technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[39]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower-than-anticipated production from the geothermal resource. In 2021, geothermal power plants in seven states produced about 16 GWh, equal to 0.4 percent of total U.S. utility-scale electricity generation.[40] As of November 2019, 2.5 GW of geothermal generating capacity was online in the United States.[41] Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and Idaho's 15.8 MW Raft River plant.

The EIA estimates capital costs for geothermal resources are approximately $2,521/MW.[42] Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that can be built in the Northwest Power Pool region, where most of the proposed sites are located. Site-specific factors, including resource size, depth, and temperature, can significantly affect costs.

5.1.4. Waste-to-energy Technologies

Converting wastes to energy is a way to capture the inherent energy locked in wastes. Generally, these plants take one of the following forms.

- Waste combustion facilities: These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. Waste combustion is a well-established technology, with 75 plants operating in the United States, representing 2,534 MW in generating capacity. According to the U.S. EPA's website, only one new facility has opened since 1995. However, some existing facilities have expanded their capacity to convert more waste into electricity.[43]

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[36] http://energy.gov/eere/geothermal/electricity-generation
[37] Ibid
[38] Ibid
[39] http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
[40] U.S. Energy Information Administration, https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php.
[41] U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=42036.
[42] U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020.
[43] U.S. Environmental Protection Agency website. http://energyrecoverycouncil.org/wp-content/uploads/2019/10/ERC-2018-directory.pdf.

- Waste thermal processing facilities include gasification, pyrolysis, and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, the facility generates syngas, which can be combusted for heat or to produce electricity. Several pilot facilities once operated in the United States, but only a few remain.
- Landfill gas and municipal wastewater treatment facilities: Most landfills in the United States collect methane from decomposing landfill waste. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both processes produce low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then fuel a boiler for heat recovery or a turbine or reciprocating engine to generate electricity. According to the U.S. EPA's website, as of June 2022, there are 541 operational landfill gas energy projects in the United States.[44]

Washington's RPS initially included landfill gas as a qualifying renewable energy resource but excluded municipal solid waste. The passage of Washington State Senate Bill (ESSB) 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

Several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities — the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant, and the Emerald City facility — use landfill gas for electric generation in Washington State; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and can produce a maximum capacity of 36.5 MW.[45] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and can produce up to 22 MW of electric capacity.[46] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.8 MW of electricity. The facility became commercially operational in December 2013.[47] Puget Sound Energy purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which we discuss in Appendix C. The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies gas to meet pipeline natural gas quality; the gas is sold to PSE rather than used to generate electricity.

Few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2018* estimates municipal solid waste-to-energy costs to be approximately $8,742 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience for more than 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion

[44] U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/lmop/basic-information-about-landfill-gas, June 2022.

[45] Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10 MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, January 2019.

[46] Spokane Waste to Energy website. Retrieved from https://my.spokanecity.org/solidwaste/waste-to-energy, January 2019.

[47] BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC and renamed Emerald LFGTE Facility). Retrieved from https://energyneeringsolutions.com/wp-content/uploads/2018/02/ESI_CaseStudy_Emerald.pdf, January 2019.

facilities, the output is typically more stable because we can more easily control the amount of input waste and heat content.

5.1.5. Wave and Tidal

We can use the natural movement of water to generate energy through the flow of tides or the rise and fall of waves.

Tidal generation technology uses tidal flow to spin rotors that turn a generator. Two significant plant layouts exist: barrages, which use artificial or natural dam structures to accelerate the flow through a small area, and in-stream turbines, placed in natural channels. France's Rance Tidal Power barrage system was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. The 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada, is the world's next-largest operating tidal generation facility. China, Russia, and South Korea have smaller tidal power installations.[48] Also worth noting is the planned 398 MW MeyGen Tidal Energy Project in Scotland, which, if completed, would be the largest tidal generation facility in the world. The project's first phase, a 6 MW demonstration array, began operating in April 2018.[49] The project is designed to be constructed in multiple phases, with phase 2B completed in September 2020.[50]

Wave generation technology uses the rise and fall of waves to drive hydraulic systems and fueling generators. Technologies tested include floating devices and bottom-mounted devices. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[51] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's website, the 20 kW Azura device, developed by EHL Group and Northwest Energy Innovations, is the nation's first grid-connected wave energy converter device.[52]

Since mid-2013, several significant wave and tidal projects and programs have slowed, stalled, or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting, and the early stage of the technology's development. The FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After operators obtain permits, they must conduct studies of the site's water resources and aquatic habitat before they install test equipment.

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[48] U.S. Energy Information Administration website. Retrieved from https://www.eia.gov/energyexplained/index.php?page=hydropower_tidal, January 2019.
[49] https://tethys.pnnl.gov/project-sites/meygen-tidal-energy-project-phase-i
[50] Ibid
[51] CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
[52] The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

There are three tidal demonstration projects in various stages of development in the United States located on Roosevelt Island (New York), Western Passage (Maine), and Cobscook Bay (Maine). Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[53] Several years ago, Tacoma Power considered and abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years, and their production volumes are limited, so costs remain high, and the durability of the equipment over time is uncertain.

5.2. Energy Storage Not Modeled

Several energy storage technologies are still in development, or are still new enough that reliable cost and operational data are not yet available. Some of these technologies are described in this section.

5.2.1. Flow Batteries

Flow batteries are rechargeable batteries that are charged by two chemical components dissolved in liquids contained within the system. A membrane separates the two components, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can offer the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time.

In 2016, Avista Utilities installed the first large-scale[54] U.S. flow battery storage system in Washington; in 2017, utilities in Washington and California installed two additional flow battery facilities. Approximately 70 MW and 250 MWh of flow batteries have been deployed worldwide, almost all in medium- to large-scale projects.[55] Flow batteries have limited market penetration at this time.

5.2.2. Liquid Air Energy Storage

Liquid Air Energy Storage (LAES) technology involves supercooling air into a liquid state for storage in insulated tanks. As the air is reheated and expands back into a gaseous state, the pressure created moves a turbine. The LAES technology utilizes a relatively small footprint and has no other special siting requirements, giving the technology geographical flexibility and the potential to be deployed as a distributed resource. This technology can store energy for long periods with little degradation and provide long-duration discharge to the grid. Finally, additional insulated tanks are the main component required to scale up the size and capacity of a LAES system, making this technology modular, flexible, and inexpensive compared to other storage alternatives.

[53] The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project, October 2014.
[54] Large-scale refers to a facility that is typically grid connected and greater than 1 MW in capacity. Small-scale refers to systems typically connected to a distribution system that are less than 1 MW in power capacity.
[55] IDTechEx Research, Batteries for Stationary Energy Storage 2019-2029.

The LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage, and expansion of pressurized gasses. Although the components are based on proven technology currently used in industrial processes and available from large Original Equipment Manufacturers (OEMs), no commercial LAES systems are currently in operation in the U.S. However, in June 2018, Highview Power Storage, a small U.K. company partnering with GE to develop utility-scale LAES systems, launched the world's first grid-scale LAES plant at a landfill gas site near Manchester, England. The pilot plant can produce 5 MW/15MWh of storage capacity. Furthermore, the company is constructing a 50 MW LAES resource in Vermont and up to 2 GWh storage in Spain. According to Highview Power Storage, the technology can be scaled up to hundreds of megawatts to better align with the needs of cities and towns.[56]

5.2.3. Hydrogen Energy Storage

Hydrogen energy storage systems use surplus renewable electricity to power a process of electrolysis, passing a current through a chemical solution to separate and create hydrogen. This renewable hydrogen is then stored for later conversion back into electricity and for other applications such as fuel for transport. Hydrogen does not degrade over time and can be stored for long periods in large quantities, most notably in underground salt caverns. This pure hydrogen can be used for re-electrification in a fuel cell or combusted in a gas turbine.

In 2018, Enbridge Gas Distribution and Hydrogenics opened North America's first multi-megawatt power-to-gas facility using renewably sourced hydrogen, the 2.5 MW Markham Energy Storage Facility in Ontario, Canada. In the United States, SoCalGas has partnered with the National Fuel Cell Research Center to install an electrolyzer demonstration project, powered by the University of California at Irvine on-campus solar electric system. SoCalGas also partnered with NREL to install the nation's first biomethanation reactor system located at their Energy Systems Integration Facility (ESIF) in Golden, Colo. Full-scale hydrogen energy projects are also in development, most notably a 1,000 MW Advanced Clean Energy Storage (ACES) facility in Utah through a partnership of Mitsubishi Hitachi Power Systems and Magnum Development, which owns large salt caverns to store the hydrogen. Xcel Energy is partnering with the NREL to create a 110 kW wind-to-hydrogen project using the site's hydrogen fueling station for storage, to be converted back to electricity and fed to the grid during peak demand hours.[57]

5.2.4. Solid Gravity Storage

Solid gravity storage is an emerging alternative to PHES. Several companies are pioneering different forms of solid gravity storage technology, which can involve raising and lowering large bricks using a crane or elevator system or moving a rail car loaded with weight along an inclined rail track.

Only a handful of prototypes or demonstration projects are in operation now. The company Energy Vault has constructed a modular crane kinetic storage demonstration unit in Switzerland, storing 20-80 MWh of energy and delivering 4–8 MW of continuous power to the grid.[58] The European company, Gravitricity, has built an above-

[56] Forbes website. Retrieved from https://www.forbes.com/sites/mikescott/2018/06/08/liquid-air-technology-offers-prospect-of-storing-energy-for-the-long-term/#3137f759622f, January, 2019.
[57] Sources: Fuel Cell & Hydrogen Energy Association, Energy Storage Association, Utility Dive.
[58] Energy Vault website: https://www.energyvault.com/gravity.

ground prototype of their underground kinetic storage technology, which is currently operating in Scotland.[59] The rail kinetic storage company, Advanced Rail Energy Storage, has been contracted to build a facility in Nevada which will supplement the CAISO grid but is still in the planning phase.[60] However, these technologies are still emerging, and publicly available and reliable data on operating parameters are costs are unavailable at this time.

5.3. Thermal Resources Not Modeled

Laws, practical obstacles, and cost constrain other potential thermal resource alternatives. Long-term coal-fired generation is not a resource alternative because RCW 80.80[61] precludes utilities in Washington from entering into new long-term agreements for coal. The Clean Energy Transformation Act (CETA) also requires utilities to eliminate coal-fired generation from their state portfolios by 2025. New traditional nuclear generation is neither practical nor feasible.

5.3.1. Coal

Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

New coal-fired generation is not a resource alternative for PSE because RCW 80.80[61] 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.[62] With current technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard. Carbon capture and sequestration technology are not yet effective or affordable enough to significantly reduce those levels. Furthermore, CETA passed on May 7, 2019, explicitly requires Washington state utilities to eliminate coal-fired electricity generation from their state portfolios by 2025.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

5.3.2. Traditional Nuclear

Capital and operating costs for large-scale nuclear power plants are significantly higher than most conventional and renewable technologies such that only a handful of the largest capitalized utilities can consider this option. In addition, nuclear power carries significant technology, credit, permitting, policy, and waste disposal risks over other baseload resources.

[59] Gravitricity website: https://gravitricity.com.
[60] S&P Global IQ Pro Platform. Available at: https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home.
[61] RCW 80.80
[62] To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

There is little reliable data on recent U.S. nuclear developments from which we can make reasonable and supportable cost estimates. The construction cost and schedule track record for nuclear plants built in the U.S. in the 1980s, 1990s, and 2000s have been poor at best. Actual costs have been far higher than projected, construction schedules have been subject to lengthy delays, and interest rate increases have resulted in high financing charges. The Fukushima disaster in 2011 also motivated changes to technical and regulatory requirements and contributed to project cost increases.

With many other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution, and the bankruptcy of a major nuclear supplier all lead to significant uncertainty. These factors make a full-scale nuclear plant an unwise and unnecessary risk for PSE.

5.3.3. Aeroderivative Peakers

Aeroderivative Combustion Turbines (Aero) combustion turbines are a mature technology. However, suppliers continually bring new aeroderivative features and designs to market. These turbines can be fueled by natural gas, oil, renewable natural gas, hydrogen, biodiesel, or a combination of fuels (dual fuel). A typical heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another critical difference between aero and frame units is size. Aero CTs are typically smaller, from 5 to 100 MW each. This small scale allows for modularity but also tends to reduce economies of scale.

The Aero peakers are higher cost than the Frame peakers and smaller and more modular than the frame peakers. We modeled the Aero peakers for several IRPs in a row but never selected them as a cost-effective resource given the higher cost than the frame peakers. Given that we are already modeling a large frame peaker and the smaller Recip Peaker to show how a smaller, more modular unit can benefit the portfolio, we felt there was enough diversity in the resource alternatives and removed the Aero peakers as an option.

This technology is commercially available. Greenfield development requires approximately three years.

6. Tables

Table D.1: Biomass Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Assumptions	2023 Electric Report Assumptions
Nameplate Capacity (MW)	15	15
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	--	--
Capacity Credit (ELCC), Summer (%)	--	--
Operating Reserves (%)	3	3
Capacity Factor (%)	85	85
Capital Cost ($/kW)	7,093	4,822
O&M Fixed ($/kW-yr)	207	151
O&M Variable ($/MWh)	6	6
Land Area (acres/MW)	6 – 8	6 - 8
Degradation (%/year)	--	--
Location	WA	WA
Fixed Transmission ($/kW-yr)	22.2	23
Variable Transmission ($/MWh)	0.00	0.26
Loss Factor to PSE (%)	1.9	1.9
Heat Rate – Baseload (HHV) (Btu/kWh)	14,599	14,599
NOx (lbs/MMBtu)	0.03	0.03
SO2 (lbs/MMBtu)	0.03	0.03
CO2 (lbs/MMBtu)	213	213
First Year Available	2024	2024[i]
Economic Life (Years)	30	30
Greenfield Dev. & Const. Lead-time (Years)	3.3	3.3

Notes:

i. Given the 2021 All Source RFP process, it is possible some of these resources will be in process of development before the beginning of this analysis, and will therefore be available as soon as 2024.

Table D.2: Wind Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values					2023 Electric Report Values					
	Offshore	WA	MT East / Central	ID	WY East / West	Offshore	BC	WA	MT East / Central	ID	WY East / West
Nameplate Capacity (MW)	100	100	200	400	400	100	100	100	100	100	100
Winter Peak Capacity (MW)	--	--	--	--	--	32	34	13	36	48	182
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	48	18	22 / 30	24	40 / 28	32	34	13	36	12	46
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	--	--	41	13	5	23	17	34
Operating Reserves (%)	3	3	3	3	3	3	3	3	3	3	3
Capacity Factor (%)	35	37	44 / 40	33	33	42	41	37	41 / 48	15	46 / 36
Capital Cost ($/kW)	5,609	1,806	1,806	1,806	1,806	4,728	1,730	1,464	2,472	1,772	1,772
O&M Fixed[ii] ($/kW-yr)	110	41	41	41	4	71	42	42	42	42	42
O&M Variable ($/MWh)	0	0	0	0	110 / 0	0	0	0	0	0	0
Land Area (acres/MW)	--	48.2	48.2	48.2	48.2	--	48.2	48.2	48.2	48.2	48.2
Degradation (%/year)	0	0	0	0	0	0	0	0	0	0	0
Fixed Transmission[iii] ($/kW-yr)	33	33	50	158	231 / 211	31	62	31	59	61	97
Variable Transmission ($/MWh)	10	10	10	10	10	0.26	0.26	0.26	0.26	0.26	0.26
Loss Factor to PSE (%)	1.9	1.9	4.6	4.6	4.6	1.9	1.9	1.9	4.6	6.9	6.9
First Year Available	2030	2024	2024	2026	2026	2030	2024[iv]	2024[iv]	2024[iv]	2026	2026

Parameter	2021 IRP Values					2023 Electric Report Values					
	Offshore	WA	MT East / Central	ID	WY East / West	Offshore	BC	WA	MT East / Central	ID	WY East / West
Economic Life (Years)	30	30	30	30	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time (Years)	3	2	3	2	2	3	2	2	2	2	2

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches, with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy.

ii. Fixed operations and maintenance for wind, solar, battery storage, and hybrid resources change over time. This table shows the 2023 value.

iii. The Wyoming wind and solar rates apply to 2024–2030 and assume the use of Idaho Power Company transmission infrastructure. Between 2031 and 2045, fixed transmission rates for wind and solar resources from Wyoming decreased to $67 and $64/kW-year, respectively, assuming the Gateway West transmission line is completed in 2030.

iv. Given the 2021 All Source RFP process, some of these resources may be in development before the beginning of this analysis and be available as soon as 2024.

Table D.3: Solar Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values				2023 Electric Report Values			
	WA (East / West)	ID	WY (East / West)	DER Rooftop / Ground-mounted WA West	WA (East / West)	ID	WY (East / West)	DER Rooftop & Ground-mounted WA West
Nameplate Capacity (MW)	100 / 50	400	400	300 / 50	100	100	100	5
Winter Peak Capacity (MW)	--	--	--	--	4	32	42	0
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	4 / 1	3	6	2 / 1	4	8	11	4
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	--	54	38	29	28
Operating Reserves (%)	3	3	3	3	3	3	3	--
Capacity Factor (%)	24 / 16	26	27 / 28	16	25 / 20	27	29 / 30	17
Capital Cost ($/kW)	1,675	1,675	1,675	4,389 / 3,568	1,230	1,537	1,537	2,287
O&M Fixed[ii] ($/kW-yr)	22	22	22	0	19	19	19	25
O&M Variable ($/MWh)	0	0	0	0	0	0	0	0
Land Area (acres/MW)	5 – 7	5 – 7	5 – 7	-- / 5 – 7	5 – 7	5 – 7	5 - 7	--
Degradation (%/year)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	--
Fixed Transmission[iii] ($/kW-yr)	30 / 8	155	228 / 208	0	28	58	94	5
Variable Transmission ($/MWh)	10	10	10	0	0.26	0.26	0.26	0.26
Loss Factor to PSE (%)	1.9 / --	4.6	4.6	--	1.9	6.9	6.9	--
First Year Available	2024	2026	2026	2024	2024[iv]	2026	2026	2024
Economic Life (Years)	30	30	30	30	30	30	30	30
Greenfield Lead-time (Years)	1	1	1	1	1	1	1	--

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy.
ii. Fixed operations and maintenance for wind, solar, battery storage, and hybrid resources change over time. The 2023 value is in this table.
iii. Rates for WY solar apply to 2024–2030 and assume the use of Idaho Power Company transmission infrastructure. Between 2031 and 2045, fixed transmission rates for solar from WY go down to $64/kW-year, assuming the Gateway West transmission line is completed in 2030.
iv. Given the 2021 All Source RFP process, it is possible that some of these resources will be in development before the beginning of this analysis and will be available as soon as 2024.

Table D.4: Generic Energy Storage Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Electric Report Values					
	PHES	BESS		PHES		BESS			
	Closed Loop (8-hour)	Li-Ion 2-hour	Li-Ion 4-hour	Closed Loop (8-hour) WA, OR	Closed Loop (8-hour) MT	Li-Ion 2-hour	Li-Ion 4-hour	Li-Ion 6-hour	DER Batteries (3-hour)
Nameplate Capacity (MW)	25	25	25	100	100	100	100	100	5
Winter Peak Capacity (MW)	--	--	--	99	99	85	96	98	--
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	37.2	12.4	24.8	99	99	85	96	98	--
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	99	99	90	97	98	--
Operating Reserves (%)	3	3	3	3	3	3	3	3	3
Capital Cost ($/kW)	2,656	1,172	2,074	3,910	3,602	805	1,310	1,819	3,923
O&M Fixed ($/kW-year)	16	23	32	18	18	20	33	45	98
O&M Variable ($/MWh)	0.00	0.00	0.00	0.51	0.51	0.00	0.00	0.00	0.00
Forced Outage Rate (%)	--	--	--	1	1	2	2	2	0.1
Degradation (%/year)	0	--	--	(ii)	(ii)	(iv)	(iv)	(iv)	2.2
Operating Range (%)	147-500[iii] MW	2	2	147-500[iii] MW	147-500[iii] MW	2	2	2	10
R/T Efficiency (%)	80	82	87	80	80	86	87	88	87
Discharge at Nominal Power (Hours)	8	2	4	8	8	2	4	6	3
Maximum Storage (MWh)	200	50	100	800	800	200	400	600	15
Fixed Transmission ($/kW-year)	22	0	0	23	50	0	0	0	0
Variable Transmission ($/MWh)	0.00	0.00	0.00	0.26	0.26	0.00	0.00	0.00	0.00
First Year Available	2028	2023	2023	2029	2029	2024[v]	2024[v]	2024[v]	2024
Economic Life2 (Years)	30	30	30	40	40	30	30	30	30
Greenfield Dev. & Const. Leadtime (years)	5–8	1	1	5–8	5–8	1	1	1	0.5

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy..

ii. PHES degradation is close to zero.

iii. The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).
iv. Fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life.
v. Given the 2021 All Source RFP process, it is possible that some of these resources will be in development before the beginning of this analysis and will be available as soon as 2024.

Table D.5: Hybrid Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Progress Report Values		
	MT Wind + PHES	Wind + Battery (WA)	Solar + Battery (WA)	Wind + Battery (WA)	Solar + Battery (WA)	Wind + Solar + Battery (WA)
Nameplate Capacity (MW)	300	125	125	150	150	250
Winter Peak Capacity (MW)	--	--	--	101	77	83
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	54	24	14	67	51	33
Capacity Credit (ELCC), Summer (%)	--	--	--	53	87	54
Operating Reserves (%)	3	3	3	3	3	3
Capacity Factor (%)	44	37	24	37	25	62
Capital Cost ($/kW)	4,016	2,680	2,563	(i)	(i)	(i)
O&M Fixed ($/kW-year)	57	64	46	(i)	(i)	(i)
O&M Variable ($/MWh)	0	0	0	0	0	0
Land Area (acres/MW)	48.2	48.2	5-7	48.2	48.2	48.2
Degradation (%/year)	0	0.5	0.5	(ii)	(iii)	(ii, iii)
Fixed Transmission ($/kW-year)	50	33	30	31	28	36
Variable Transmission ($/MWh)	10	10	10	0.26	0.26	0.26
Loss Factor to PSE (%)	4.6	1.9	1.9	1.9	1.9	1.9
First Year Available	2028	2024	2024	2024[iv]	2024[iv]	2024[iv]
Economic Life (Years)	30	30	30	30	30	30
Greenfield Dev. & Const. Lead time (years)	5 – 8	2	1	2	1	2
Operating Range (%)	147-500 MW	2	2	2	2	2
R/T Efficiency (%)	80	82	82	87	87	87
Discharge at Nominal Power (Hours)	8	2	2	4	4	4

Notes:

i. We input individual capital costs and fixed operations and maintenance values for each element of the hybrid resource into the AURORA model. The individual hybrid component capital costs are adjusted (discounted) from stand-alone counterparts to account for savings in installation, grid connection, and system balance.

ii. Battery fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life; degradation for wind is 0 percent.

iii. Battery fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life; degradation for solar is 0.5 percent.

iv. Given the 2021 All Source RFP process, some of these resources may be in development before the beginning of this analysis and therefore be available as soon as 2024.

Table D.6: Generic Combustion Turbine Resource Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Electric Report Values					
	Frame Peaker	CCCT	Recip Peaker	Frame Peaker[1]	CCCT[i]	Recip Peaker[i]	Frame Peaker Blend H_2	Recip Peaker Blend H_2	Frame Peaker Biodiesel
Nameplate Capacity (MW)	225	336	219	225	336	219	225	219	225
Winter Capacity Primary (23º F) (MW)	237	348	219	237	348	219	237	219	237
Incremental Capacity DF (23º F) (MW)	--	19	--	--	19	--	--	--	--
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	--	--	--	96	96	84	96	84	96
Capacity Credit (ELCC), Summer (%)	--	--	--	98	96	92	98	92	98
Capital Cost ($/kW)	948	1,255	1,671	944	987	2,045	944	2,045	944
O&M Fixed ($/kW-year)	8	13	6	16	23	15	16	15	10
Flexibility ($/kW-year)	--	--	--	-10	-5	-28	-10	-5	-10
O&M Variable ($/MWh)	7.86	3.32	7.05	1.02	6.16	1.16	1.02	1.16	1.02
Start-up Costs ($/Start)	7.86	3.32	7.05	11,729[ii]	0	0	11,729[ii]	0	11,729[ii]
Operating Reserves (%)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Forced Outage Rate (%)	2.4	3.9	3.3	2.4	3.9	3.3	2.4	3.3	2.4
Heat Rate — Baseload (HHV) (Btu/kWh)	9,904	6,624	8,445	9,904	6,624	8,445	9,904	8,445	9,904
Heat Rate — Turndown (HHV) (Btu/kWh)	15,794	7,988	11,288	15,794	7,988	11,288	15,794	11,288	15,794
Heat Rate — DF (Btu/kWh)	--	8,867	--	--	8,867	--	--	--	--
Min Capacity (%)	30	38	30	30	38	30	30	30	30
Start Time (hot) (minutes)	21	45	5	21	45	5	21	5	21
Start Time (warm) (minutes)	21	60	5	21	60	5	21	5	21

Parameter	2021 IRP Values			2023 Electric Report Values					
	Frame Peaker	CCCT	Recip Peaker	Frame Peaker[1]	CCCT[i]	Recip Peaker[i]	Frame Peaker Blend H_2	Recip Peaker Blend H_2	Frame Peaker Biodiesel
Start Time (cold) (minutes)	21	150	5	21	150	5	21	5	21
Start-up fuel (hot) (MMBtu)	366	839	69	366	839	69	366	69	366
Start-0up fuel (warm) (MMBtu)	366	1,119	69	366	1,119	69	366	69	366
Start Fuel Amount (warm) (MMBtu/MW/Start)	1.544	3.214	0.317	1.54	3.21	0.32	1.54	0.32	1.54
Start-up fuel (cold) (MMBtu)	366	2,797	69	366	2,797	69	366	69	366
Ramp Rate (MW/minutes)	40	40	16	40	40	16	40	16	40
Fixed Ga Transport ($/Dth/Day)	0.00	0.25	0.25	0.00	0.27	0.27	0.00	0.00	0.00
Fixed Gas Transport ($/kW-year)	0.00	14.67	18.70	0.00	15.41	19.65	0.00	20	0.00
Variable Gas Transport ($/MMBtu)	0.04	0.06	0.06	0.04	0.06	0.06	0.04	0.06	0.06
Fixed Transmission ($/kW-year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable Transmission ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2 - Natural Gas (lbs./MMBtu)	118	118	118	118	118	118	118 declining to 0	118 declining to 0	0
NOx - Natural Gas (lbs./MMBtu)	0.004	0.008	0.029	0.004	0.008	0.029	0.004	0.029	0.004
First Year Available	2025	2025	2025	2024[iii]	2024[iii]	2024[iii]	2024[iii]	2024[iii]	2024[iii]
Economic Life (years)	30	30	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time (years)	1.8	2.7	2.3	1.8	2.7	2.3	1.8	2.3	1.8

Notes:

i. Technology assumptions: the frame peaker is a 1x0 F-Class Dual Fuel; the CCCT is a 1x1 F-Class; and the reciprocal peaker is a 12x0 18 MW class reciprocating internal combustion engine.
ii. The startup cost adder of $52.13/start/MW, from the 2020 CAISO default values, is applied to the frame peaker.
iii. Given the 2021 All Source RFP process, some frame peakers may be in development before the beginning of this analysis and therefore be available as soon as 2024.

Table D.7: Natural Gas Transportation Costs for Western Washington CCCT and Reciprocating Engine Peakers without Oil Backup — 100% Sumas on NWP + 100% Station 2 on West Coast

Pipeline/Resource	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion[i]	0.6900	0.0083	0.0013	1.41	3.85
Westcoast Expansion[ii]	0.7476	0.0551	--	--	--
Basis Gain[iii]	(0.8139)	--	--	2.71	3.85
Gas Storage[iv]	0.0767	--	--	2.00	3.85
Total	**0.7004**	**0.0634**	**0.0013**	**6.12**	**3.85**

Notes:

i. Estimated NWP Sumas to PSE Expansion.

ii. Estimated West coast Expansion Fixed Demand.

iii. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses, and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0551 per Dth per day, and fuel losses are 2.71 percent per Dth. A state utility tax of 3.852 percent applies to the natural gas price.

iv. We based storage requirements on current storage withdrawal capacity to peak plant demand for the natural gas for power portfolio (approximately 20 percent).

Table D.8: N Natural Gas Transportation Costs for Western Washington Frame Peakers with Oil Backup — No Firm Gas Pipeline

Pipeline / Resource	Fixed Demand ($/Dth/day)	Weighted Average Variable Demand ($/Dth)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Demand	0.0000	0.0300	0.0083	0.0013	1.41	3.82
Total	**0.0000**	**0.0300**	**0.0083**	**0.0013**	**1.41**	**3.82**

Table D.9: Green Hydrogen Blend Rate

Year	Green Hydrogen Blend Rate (%, H_2 energy / total energy)
2025	0
2030	30
2035	50

Year	Green Hydrogen Blend Rate (%, H_2 energy / total energy)
2040	70
2045	100

Table D.10: Resource Access to a Green Hydrogen Fuel Supply

Resource	Access Year
New generic resources	2030
Frederickson 1, 2, CC	2030
Whitehorn 1, 2	2030
Ferndale	2030
Encogen	2035
Fredonia 1,2,3,4	2035
Mint Farm	2035
Sumas	2040
Goldendale	2045

Table D.11: Advanced Nuclear Small Modular Reactor Resource Assumptions, 2020 $

Parameter	Assumptions
Nameplate Capacity (MW)	50
Capacity Credit, (Effective Load Carrying Capacity) (%)	100%
Operating Reserves (%)	3%
Capital Cost ($/KW)	$10,930
O&M Fixed ($/KW-yr)	$114
O&M Variable ($/MWh)	$3

Parameter	Assumptions
Forced Outage Rate (%)	10%
Heat Rate – Baseload (HHV) (Btu/KWh)	10,046
Heat Rate – Turndown (HHV) (Btu/KWh)	12,500
Min Capacity (%)	30%
Start Time (minutes)	60
Ramp Rate (MW/min)	30
Location	PSE
Fixed Transmission ($/KW-yr)	$0
Variable Transmission ($/MWh)	$0
First Year Available	2028
Economic Life (Years)	30
Greenfield Dev. & Const. Lead Time (years)	4

CONSERVATION POTENTIAL AND DEMAND RESPONSE ASSESSMENTS

APPENDIX E

PSE PUGET SOUND ENERGY

Contents

1. Introduction

We analyzed demand-side resource (DSR) alternatives in conservation potential and demand response assessments (CPA) to develop a supply curve as an input to the portfolio analysis. The portfolio analysis then determines the maximum energy savings we can capture without raising the overall electric or natural gas portfolio cost. This analysis identifies the cost-effective level of DSR to include in the portfolio.

We included the following demand-side resource alternatives in the CPA, which The Cadmus Group performed for this 2023 Electric Progress Report (2023 Electric Report) on behalf of PSE.

- **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. We included only those in place at the time of the CPA study.
- **Demand response (DR):** Demand response resources comprise flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
- **Distributed generation:** Distributed generation refers to small-scale electricity generators close to the source of the customer's load on the customer's side of the utility meter. This resource alternative includes combined heat and power (CHP) and rooftop solar.[1]
- **Distribution efficiency (DE):** Distribution efficiency involves conservation voltage reduction (CVR) and phase balancing. Voltage reduction reduces the voltage on distribution circuits to reduce energy consumption, so many appliances and motors can perform while consuming less energy. Phase balancing eliminates total current flow energy losses.
- **Energy efficiency measures:** We used this label for a wide variety of measures that result in a smaller amount of energy 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, and appliance upgrades.
- **Generation efficiency:**[2] This involves energy efficiency improvements at the facilities that house PSE generating plant equipment and where the loads that serve the facility are drawn directly from the generator, not the grid. These are parasitic loads — specific measures target HVAC, lighting, plug loads, and building envelope end-uses.

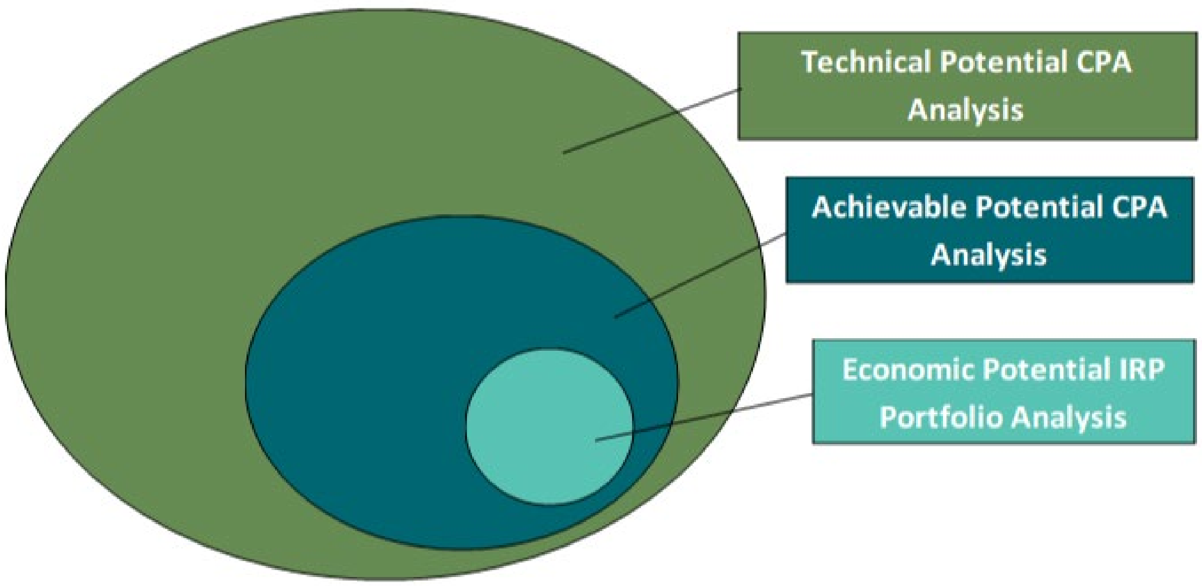
[1] In this report distributed solar photovoltaic (PV) is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the total resource cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

[2] Generation efficiency potential was studied in prior planning cycles, was relatively small and found to be not cost-effective and hence this resource is not included in this report.

2. Treatment of Demand-side Resource Alternatives

The CPA performed by the Cadmus Group on behalf of PSE develops two levels of demand-side resource conservation potential: technical potential and achievable technical potential. The 2023 Electric Report portfolio analysis then identifies the third level, economic potential. Figure E.1 shows the relationship between the technical, achievable, and economic conservation potentials.

Figure E.1: Relationship between Technical Achievable and Economic Potential

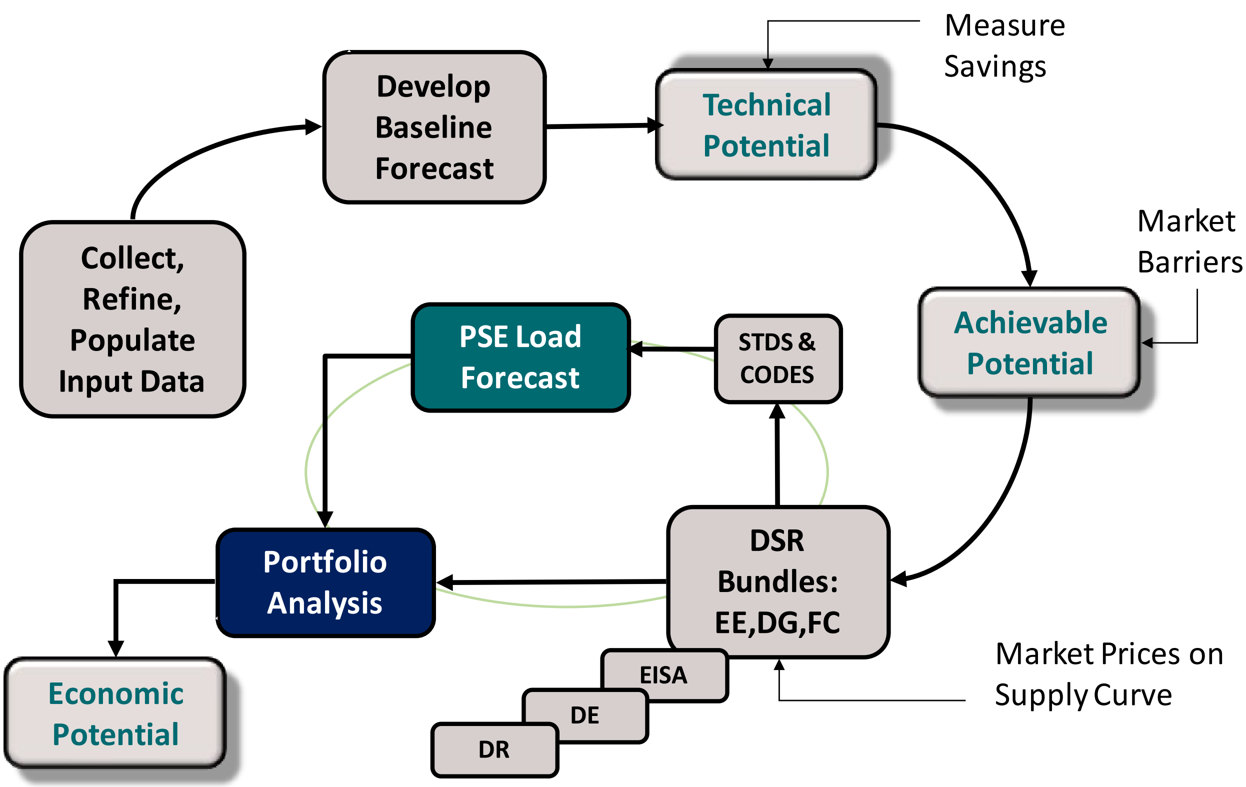


First, the CPA screened each measure for technical potential. This screen assumed we could capture all energy- and demand-saving opportunities regardless of cost or market barriers, which ensured the model surveyed the full spectrum of technologies, load impacts, and markets.

Second, we applied market constraints to estimate the achievable potential. Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment to gauge achievability. For this report, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

We combined the measures into bundles based on levelized cost in the third step. This step produced a conservation supply cost curve in the portfolio optimization analysis to identify the bundles' economic potential (cost-effectiveness).

Figure E.2 Methodology to Assess Demand-side Resource Potential in the 2023 Electric Progress Report



➔ For the results of the Cadmus study, please see the excel file posted under Appendix E: Conservation Potential Assessment and Demand Response Assessment.

This appendix contains the conservation potential assessment report for the 2023 Electric Progress Report. It includes a detailed discussion of all the demand-side resource types mentioned, except for distribution efficiency, which PSE developed and discussed here.

3. Distribution Efficiency

We updated plans for distribution efficiency in this report to reflect 1) changes in technology required to maintain power quality and stability as the role of distribution efficiency grows and 2) the increase in amounts of the distributed generation entering the delivery system.

The original conservation voltage reduction (CVR) program we implemented in 2012–2013 utilized advanced metering infrastructure (AMI) meters that are now outdated and incompatible with the company-wide rollout of upgraded AMI technology that began in 2018. We expect to complete the rollout in 2023. In the meantime, selected substations that received the AMI upgrade can participate in the current CVR program.

We also have a second technology upgrade planned. The current CVR program is a static form of CVR that cannot react to compensate for changes in the distribution system produced by distributed resources such as battery storage, solar generation, and day ahead (DA) schemes. Because the static system cannot react and adjust to changing conditions in the distribution system, we are investing in automated distribution management system (ADMS) technology that we can program to automatically detect and anticipate changing conditions on the system. This technology allows the system to react fast enough to prevent damaging customers' power quality.

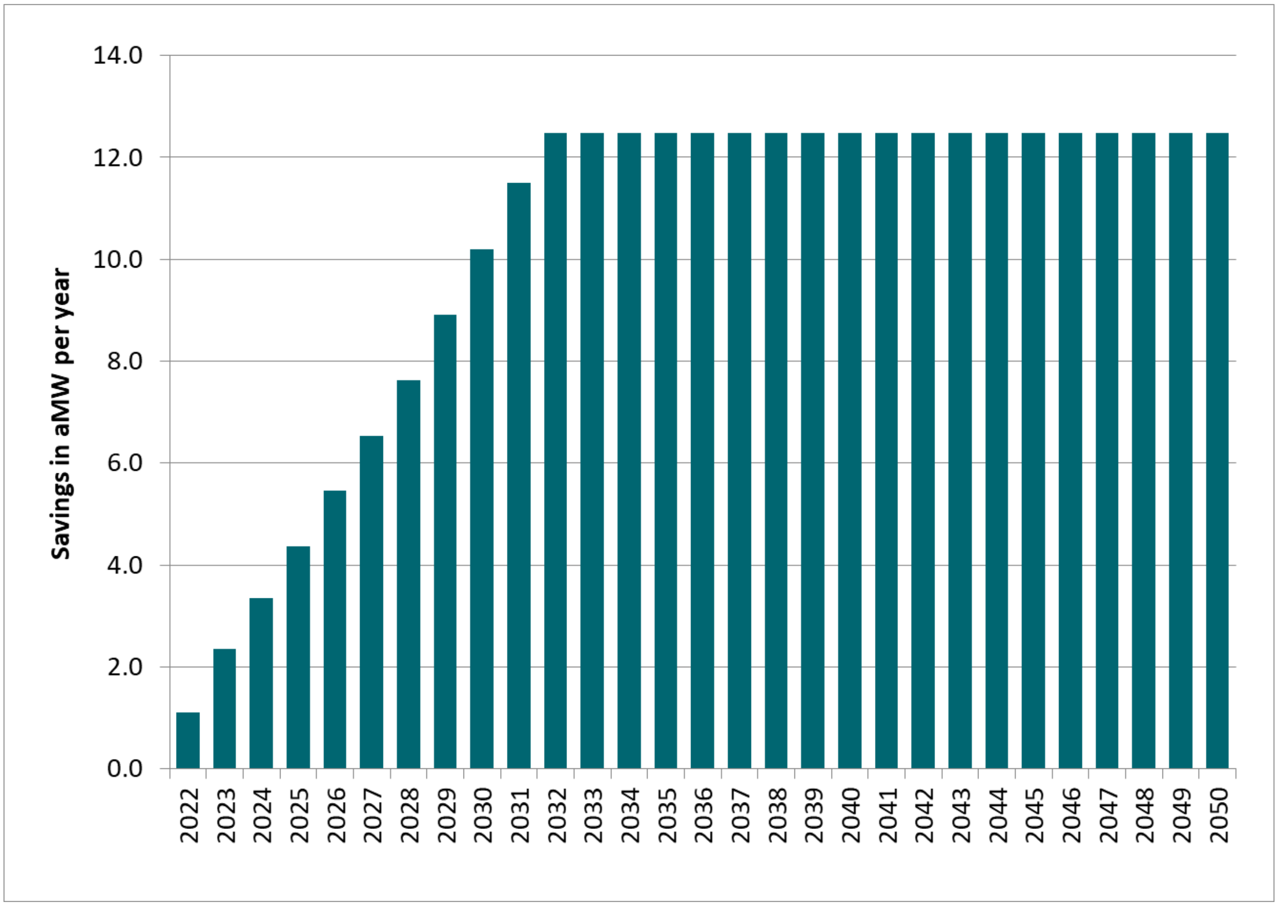
Once we implement the AMI and ADMS technologies, we will have the operational control system necessary to transition the CVR program to total Volt-Var Optimization (VVO). With its analytics and control intelligence, the ADMS will leverage AMI data at the end of line to dynamically optimize power delivery within the distribution network, minimize losses, and conserve energy. This system builds on dynamic voltage control by sensing and managing switched capacitors to optimize the power factor. VVO is a more sophisticated and extensive process than CVR but relies on similar principles.

We expect to complete the AMI rollout in 2023 and the ADMS software platform in 2026. We expect to begin piloting VVO in 2025. From 2023–2025, we will continue implementing the current static line drop compensation (LDC) CVR, but we may continue to encounter complications and risks due to changes in the distribution system that are already occurring.

Figure E.3 presents the expected cumulative savings throughout the 2023 Electric Progress Report planning horizon from CRV and VVO.

Eligible Substations: We started the current CVR program based on a study completed in 2007. That study identified approximately 160 substation banks with at least 50 percent residential customers as having the potential for energy savings using LDC CVR, based on typical customer usage patterns and the customer composition of the substations.

Figure E.3: Cumulative Savings in aMW from Distribution Efficiency (CVR+VVO)



DEMAND FORECAST
APPENDIX F

PUGET SOUND ENERGY

Contents

1. Introduction

We employed time series econometric methods to forecast monthly energy demand and peaks for Puget Sound Energy's (PSE) electric service area. We gathered sales, customer, demand, weather, economic, and demographic variables to model use per customer (UPC), customer counts, and peaks. Once we completed the modeling, we used internal and external forecasts of new major demand (block sales), retail rates, economic and demographic drivers, normal weather, and short-term demand-side resource (DSR) forecasts to create a long-term projection of monthly demand and peaks. Puget Sound Energy's 2023 Electric Progress Report (2023 Electric Report) base demand forecast for energy reflects short-term DSR via codes and standards impacts, and committed energy efficiency program targets through 2023. The 2023 Electric Report base demand net of DSR also reflects the optimal DSR we chose in the 2023 report analysis. Figure F.1 depicts the demand forecast development process.

Figure F.1: Demand Forecast Development Process

Model Estimation: Billed Sales, Customer Counts, Peak

- Billed sales volume, Effective Retail Rates
- Customer counts
- PSE System Load
- Economic and demographic observations
- Temperature observations at Sea-Tac Airport station

Forecast Models: Billed Sales, Customer Count, Peak

- Retail rate forecast
- Economic and demographic forecasts
- Normal temperatures using historic and forecast temperatures

Base Demand Forecasts, before additional DSR: Demand and Peak

- Major projects, EV forecast, System Additions and Departures
- Losses
- Billing cycles schedules
- 2022–2023 Short term demand side resources, code changes, and solar

Final Demand Forecast, after additional DSR: Demand and Peak

- 2023 IRP Demand Side Resources 2024–2050, including solar
- Effects of 70 percent more efficient building codes

2. Model Estimation

To capture incremental customer growth, temperature sensitivities, and economic sensitivities, we forecasted billed sales by estimating UPC and customer count models. Models are disaggregated into the following major classes and sub-classes, or sectors as determined by tariff rate schedule, to best estimate the underlying determinants of each class.

- Commercial — high-voltage interruptible, large, small/medium, lighting
- Industrial — high-voltage interruptible, large, small/medium
- Resale
- Residential
- Streetlights

Each class's historical sample period ranged from January 2003 to December 2021. Some class estimation periods start later than January 2003 or end earlier than December 2021 to isolate the impacts of the COVID-19 pandemic without impacting the long-term forecast levels and sensitivities.

➔ See Chapter Six: Demand Forecasts, for how we developed economic and demographic input variables.

2.1. Customer Counts

We estimated monthly customer counts by class and sub-class. These models use explanatory variables such as population, unemployment rate, and total and sector-specific employment. We estimated larger customer classes via first differences, with economic and demographic variables implemented in a lagged or polynomial distributed lag form to allow delayed variable impacts. Some smaller customer classes are held constant. The team also utilized autoregressive moving average (ARMA) (p,q) error structures, subject to model fit.

The equation we used to estimate customer counts is[1]:

$$CC_{C,t} = \boldsymbol{\beta_C}[\propto_C \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{ED}_{C,t}] + u_{C,t},$$

The details for the estimating equation components are:

$\boldsymbol{CC_{C,t}}$	=	Count of customers in Class/sub-class C and month t
C	=	Class/sub-class, as determined by tariff rate
t	=	Estimation time
$\boldsymbol{\beta_C}$	=	Vector of CC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
$\boldsymbol{\propto_C}$	=	Indicator variable for class constant (if applicable)
$\boldsymbol{D_{M,t}}$	=	Vector of month/date-specific indicator variables
$\boldsymbol{T_{C,t}}$	=	Trend variable (not included in most classes)
$\boldsymbol{ED_{C,t}}$	=	Vector of economic and/or demographic variables
$\boldsymbol{u_{C,t}}$	=	ARMA error term

[1] The term vector or boldface type denotes one or more variables in the matrix.

2.2. Use Per Customer

We estimated monthly use per customer (UPC) at the class and sub-class levels using multiple explanatory variables. Major drivers include heating degree days (HDD), cooling degree days (CDDs), seasonal effects, retail rates, and average billing cycle length. We also used economic and demographic variables such as income and employment levels. Finally, an ARMA(p,q) is added depending on the equation. The equation we used to estimate UPC is[2]:

$$\frac{UPC_{C,t}}{D_{c,t}} = \boldsymbol{\beta_C}\left[\propto_C \quad \frac{\boldsymbol{DD}_{C,t}}{D_{C,t}} \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{RR}_{C,t} \quad \boldsymbol{ED}_{C,t}\right] + u_{C,t}$$

The details for the estimating equation components are:

$\boldsymbol{UPC_{C,t}}$	=	Billed Sales ($\boldsymbol{Billed\ Sales_{C,t}}$) divided by Customer Count ($\boldsymbol{CC_{C,t}}$)
$\boldsymbol{D_{C,t}}$	=	Average of billed cycle days for billing month t in class C
$\boldsymbol{\beta_C}$	=	Vector of regression coefficients
$\propto_{\boldsymbol{C}}$	=	Indicator variable for class constant (if applicable)
$\boldsymbol{DD_{C,t}}$	=	Vector of weather variables ($\mathbf{HDD}_{\text{C,Base,t=45}}, \dots, \mathbf{HDD}_{\text{C,Base,t=65}}$ $\mathbf{CDD}_{\text{C,Base,t=55}}, \dots, \mathbf{CDD}_{\text{C,Base,t=70}}$). These are calculated values that drive monthly heating and cooling demand.
$\mathbf{HDD}_{\text{C,Base,t}}$	=	$\sum_{d=1}^{\text{Cycle}_t} \lvert\max(0, \text{Base Temp} - \text{Daily Avg Temp}_d)\rvert$
$\mathbf{CDD}_{\text{C,Base,t}}$	=	$\sum_{d=1}^{\text{Cycle}_t} \lvert\max(0, \text{Daily Avg Temp}_d - \text{Base Temp})\rvert * \text{BillingCycleWeight}_{\text{C,d,t}}$
$\boldsymbol{D_{M,t}}$	=	Vector of month/date-specific indicator variables
$\boldsymbol{T_{C,t}}$	=	Trend variable (not included in most classes)
$\boldsymbol{RR_{C,t}}$	=	The effective retail rate. The rate is smoothed, deflated by a Consumer Price Index, interacted with macroeconomic variables, and further transformed.
$\boldsymbol{ED_{C,t}}$	=	Vector of economic and/or demographic variables
$\boldsymbol{u_{C,t}}$	=	ARMA error term

2.3. Peak Electric Hour

The electric peak demand model relates observed monthly peak system demand to monthly weather-normalized demand. The model also controls for other factors, such as observed hourly temperature, holidays, the day of the week, and the time of day.

[2] The term vector or boldface type denotes one or more variables in the matrix.

The primary driver of a peak demand event is temperature. In winter, colder temperatures yield higher demand during peak hours, especially on evenings and weekdays. The peak demand equation uses the difference of observed peak temperatures from normal monthly peak temperature and month-specific variables, scaled by normalized average monthly delivered demand, to model the weather and non-weather sensitive components. In the long-term forecast, growth in monthly weather-normalized demand will drive growth in forecasted peak demand, given the relationships established by the estimated regression coefficients.

The equation we used to estimate electric peak hourly demand is:

$$\boldsymbol{max}(\boldsymbol{Hour}_{1,t} \ldots \boldsymbol{Hour}_{H_t,t}) =$$
$$\boldsymbol{\beta}\left[\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{M,t} \quad \Delta Temperature_{N,t}\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{S,t}\boldsymbol{D}_{PeakType,t} \quad \boldsymbol{D}_{DoW,t} \quad D_{LtHr,t} \quad D_{Hol,t} \quad T_{Hot,t}\right] + \varepsilon_t$$

$\boldsymbol{Hour}_{J,t}$	=	Hourly PSE system demand (MWs) for hour j=1 to H_(t,)
$\boldsymbol{H}_t$	=	Total number of hours in the month at time t
$\boldsymbol{\beta}$	=	Vector of electric peak hour regression coefficients
$\boldsymbol{Demand}_{N,t}$	=	Normalized total demand in a month at time t
$\Delta\boldsymbol{Temperature}_N$	=	Deviation of actual peak hour temperature from the hourly normal minimum peak temperature
$\boldsymbol{D}_{M,t}$	=	Vector of monthly date indicator variables
$\boldsymbol{D}_{S,t}$	=	Vector of seasonal date indicator variables
$\boldsymbol{D}_{PeakType,t}$	=	Vector of heating or cooling peak indicators
$\boldsymbol{D}_{DoW,t}$	=	Vector of Monday, Friday, and Mid-Week indicators
$\boldsymbol{D}_{LtHr,t}$	=	Indicator variable for evening winter peak
$\boldsymbol{D}_{Hol,t}$	=	Indicator variable for holiday effects
$\boldsymbol{T}_{Hot,t}$	=	Trend to account for summer air conditioning saturation
$\boldsymbol{\varepsilon}_t$	=	Error term

3. Base and Final Demand

The customer count, UPC, and peak models we described comprise the foundation of the base demand forecasts. We forecasted customer count, UPC, and peaks using model coefficient estimates and forecasted variable inputs as we described in Chapter Six: Demand Forecast. We then added various externally sourced forecasts to get the final demand forecasts. The following sections summarize the results of the component forecast models (customer counts and UPC by class) and detail how we formed the demand forecasts from their component parts.

3.1. Billed Sales Forecast

We formed the class total billed sales forecasts $\widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t}$)by multiplying forecasted UPC and customers ($Block\ Sales_{C,t}$, then adjusting for known future discrete additions and subtractions ("$Block\ Sales_{C,t}$").

We incorporated significant additional sales changes as additions or departures to the sales forecast as we did not reflect them in historical trends in the estimation sample period. Examples include emerging electric vehicle (EV) demand or other infrastructure projects. Finally, for the base demand forecast, we reduced the forecast of billed sales by short-term codes and standards, programmatic energy efficiency targets, and customer-owned solar ($DSR_{C,t}$) by class, using established targets in 2022–2023 and forecasts of codes and standards and customer-owned solar estimates for 2022 and 2023 from the 2021 IRP.

The total billed sales forecast equation by class and service is:

$$Billed\ Sales_{C,t} = \widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t} + Block\ Sales_{C,t} + EV_{C,t} - DSR_{C,t}$$

The details for the estimating equation components are:

t	=	Forecast time horizon
$\widehat{UPC}_{C,t}$	=	Forecast use per customer
$D_{C,t}$	=	Average of scheduled billed cycle days in class C
$\widehat{CC}_{C,t}$	=	Forecast count of customers
$DSR_{C,t}$	=	Base Forecast: codes and standards, programmatic energy efficiency targets, and customer-owned solar for 2022 and 2023
$EV_{C,t}$	=	Incremental EV sales
$Block\ Sales_{C,t}$	=	Expected entering or existing sales not captured as part of the customer count or UPC forecast

We calculated total billed sales in a month as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{C,t}$$

3.2. Demand

We formed total system demand by aggregating individual class sales, distributing forecasted monthly billed sales into calendar sales, then adjusting for electricity losses from transmission and distribution.

The electric demand forecast ($\widehat{Demand}_{N,t}$) is the 2023 report base electric demand forecast.

The final demand forecast net of DSR will include the optimal conservation bundle calculated in the 2023 report.

3.3. Peak Demand

We forecasted electric peak hourly demand with internal and external peak demand assumptions. We employ the estimated model coefficients, normal design temperatures, and forecasted normal total system energy demand ($\widehat{Demand}_t$) less forecasted EV energy demand and short-term demand-side resources ($EV_t + DSR$) to create a peak forecast before EVs and DSR. We then adjusted this forecast with short-term forecasted peak demand-side resources ($DSR_{Peak,t}$), and forecasted EV peak demand at hour ending 18 (EV_t), to forecast total peak demand.

We removed EV and short-term DSR forecast projections from forecast normal total system energy demand in the peak hour forecast for an important reason: Energy demand DSR and EV projected MWH are distinct from peak demand DSR and EV MW and do not necessarily have the same daily demand shape as current demand on PSE's system. Thus, using the same relationships between energy demand and peak demand as of 2021 is not a valid treatment for DSR and EVs in the forecast period: Different conservation measures may have larger or small impacts on peak when compared with energy.

Thus, the peak model reflects the peak DSR assumption from short-term codes and standards and energy efficiency programs and activities, as opposed to simple downstream calculations from demand reduction. We employed this same methodology to best capture EV peak demand. We deducted EV energy demand from the base demand forecast used for peak demand forecasting, then added as a separate MW impact calculated from EV demand load shapes provided by the energy consulting firm, Guidehouse. These calculations yield system hourly peak demand in the evening each month based on normal design temperatures.

$$Peak\ Demand_t = F\left(\widehat{Demand}_{t,}, \Delta Temperature_{N,Design,t}\right) + EV_{t,HE=18} - DSR_{Peak,t}$$

$\boldsymbol{Peak\ Demand_t}$	=	Forecasted maximum system demand for month t
t	=	Forecast time horizon
$\boldsymbol{\widehat{Demand}_t}$	=	Forecast of delivered demand for month t
$\boldsymbol{\Delta Temperature_{Normal,Design,}}$	=	Deviation of peak hour/day design temperature from the monthly normal peak temperature
$\boldsymbol{EV_t}$	=	Electric Vehicle Demand at peak
$\boldsymbol{DSR_{Peak,t}}$	=	Ramped/shaped peak DSR from programmatic energy efficiency targets and short-term codes and standards effects; IRP Optimal DSR

For the electric peak forecast, we based the normal design peak hour temperature on the median (1 in 2 or 50th percentile) of seasonal minimum temperatures. The data we used to determine seasonal temperatures to reflect climate change in our forecast is a mix of historical data and future forecasted hourly temperatures, as provided by the Northwest Power and Conservation Council (NWPCC).

We netted the effects of the 2022 and 2023 conservation programs, estimated codes and standards update impacts, and customer-owned solar from the peak demand forecast to account for DSR activities already underway to reach the 2023 report's base peak demand forecast. This approach allows us to choose optimal future resources to meet peak demand. Once we determined the optimal DSR in this report, we adjusted the peak demand forecast for the peak contribution of future demand-side resources.

➔ Results of this analysis are in Chapter Six: Demand Forecast.

3.4. Hourly Demand Forecast

The AURORA portfolio analysis utilizes monthly energy and peak demand forecasts and an hourly forecast of PSE's demand. The AURORA demand forecast starts with hourly profiles. We then calibrated and shaped it to the forecasted monthly and peak demand forecasts we described. The hourly (8,760 hours + 10 days) profile starts with day one of the hourly shape as a Monday, day two as a Tuesday, and so on, with the AURORA model adjusting the first day to line up January 1 with the correct day of the week. We estimated the hourly demand shape with regression models relating observed temperatures and calendar effects to historical hourly demand data. We controlled for pandemic effects in the estimation period and suppressed them in the forecast period. We estimated demand for each hour, day of the week type (weekday, weekend/holiday), and daily average temperature type (heating, mild, cooling), yielding 24x2x3 sets of regression coefficients.

The statistical hourly regression equation summarizes the estimated demand relationships:

$$Demand_{h,d,s,t} =$$

$$\boldsymbol{\zeta_h}\left[Demand_{h-1,d,t} \quad \boldsymbol{D_{M,t}} \quad D_{Hol,d,t} \quad D_{Covid,d,t} \quad \boldsymbol{D}_{DoW,d,t} \quad \boldsymbol{T}_{h,d,t}\right] + u_{i,d,t}$$

$$\boldsymbol{T}_{h,d,t} =$$

$$\left[max(55 - T_{h,d,t}, 0) \quad max(T_{h,d,t} - 55,0) \quad max(55 - T_{h,d,t}, 0)^2 \quad D_{h=1}\, max(40 - DAvg_{t-1}, 0) \quad D_{h=1}\, max(DAvg_{t-1} - 70,0)\right]$$

$\boldsymbol{Demand_{h,d,t}}$	=	PSE hourly demand
h	=	Hour of day {1–24}
d	=	Day grouping {Weekday, Weekend/Holiday}
t	=	Date
s	=	Daily temperature grouping (heating, cooling, mild)
$\boldsymbol{\zeta_h}$	=	Vector of regression coefficients
$\boldsymbol{T_{h,d,t}}$	=	Hourly temperature at SeaTac Weather Station (KSEA)
$\boldsymbol{DAvg_{t-1}}$	=	Previous daily average temperature
$\boldsymbol{D_{M,t}}$	=	Vector of monthly date indicator variables

We forecasted an annual hourly demand profile with a future calendar of months, weekends, weekdays, and holidays and an annual 8,760-hour profile of typical normal temperatures sourced from the climate change temperature datasets described here and in Chapter Six: Demand Forecast. After we forecasted the standard demand shape, we augmented it with projected demand growth due to customer growth and increased air conditioning saturation and an hourly profile of forecasted EV demand, sourced from the consulting firm, Guidehouse.

We created the final hourly shape in the AURORA software by fully calibrating and shaping the forecasted hourly demand to forecasted monthly delivered demand ($\widehat{Demand}_{N,t}$) and monthly peak demand, as forecasted for the 2023 report base demand forecast. We used AURORA's option for Pivot High Hours, which scaled the hourly demand forecasts based on ranking and preserved low demand hours to calibrate and shape the final output.

4. Stochastic Demand Forecasts

Demand forecasts are inherently uncertain. Acknowledging this uncertainty, we considered distributions of stochastic demand forecasts in this report's models. We created two sets of stochastic demand forecasts to model these uncertainties for analyses. These energy and peak demand forecast sets are:

- The 310 electric stochastic monthly energy and peak demand forecasts that we developed for AURORA modeling
- The 90 stochastic monthly energy demand, seasonal peak demand, and hourly demand forecasts for years 2028–2029 and 2033–2034 that we used to model resource adequacy.

➔ Please see Chapter Seven: Resource Adequacy for E3's description of the methodology used to develop resource adequacy load forecasts used in the RA analysis.

Variability in the energy and peak demand forecast originates from underlying customer growth and usage uncertainty. We forecasted customer growth and usage with varying underlying driver assumptions, principally economic and demographic indicators, temperatures, EV growth, and regression model estimate uncertainty to create a distribution of potential energy and peak demand forecasts.

4.1. Economic and Demographic Assumptions

The econometric demand forecast equations depend on specific economic and demographic variables; these may vary depending on whether the equation is for customer counts or UPC and whether the equation is for a residential or non-residential customer class. In PSE's demand forecast models, the key service area economic and demographic inputs are population, employment, consumer price index (CPI), personal income, and manufacturing employment. These variables are inputs into one or more demand forecast equations.

We performed a stochastic simulation of PSE's economic and demographic model to produce the distribution of PSE's economic and demographic forecast variables to develop the stochastic simulations of demand. Since these variables are a function of key U.S. macroeconomic variables such as population, employment, unemployment rate, personal income, personal consumption expenditure index, and long-term mortgage rates, we utilized the stochastic simulation functions in EViews[3] by providing the standard errors for the quarterly growth of key U.S. macroeconomic inputs into PSE's economic and demographic models.

We based these standard errors on historical actuals from the last 30 years, ending in 2021. This created 1,000 stochastic simulation draws of PSE's economic and demographic models, which provided the basis for developing the distribution of the relevant economic and demographic inputs for the demand forecast models over the forecast period. We removed outliers from the 1,000 economic and demographic draws.

4.2. Temperature

We modeled uncertainty in the heating and cooling load levels by considering varying future years' degree days and temperatures. We randomly sourced annual normal weather scenarios from three climate models (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA). We used weather data from these climate models from 2020 to 2049 in the stochastic simulations.

4.3. Electric Vehicles

The team sourced high and low scenarios of EV energy and peak demand from Guidehouse in addition to the base EV demand forecast. We provide these forecasts in Chapter Six: Demand Forecast. Although the 310 stochastic demand forecasts evaluated in the AURORA modeling process include a proportional number of these high/low EV scenarios, the demand forecasts we developed for resource adequacy modeling did not.

4.4. Model Uncertainty

The stochastic demand forecasts introduce model uncertainty by adjusting customer growth and usage by normal random errors, consistent with the statistical properties of each class and sub-class regression model. These model adjustments are consistent with Monte-Carlo's methods of assessing regression models' uncertainty.

5. Climate Change Assumptions

Puget Sound Energy's demand forecasting models employ various thresholds of HDDs and CDDs, consistent with industry practices. Monthly degree days help estimate the service area's heating- and cooling-sensitive demand. Most PSE's customer classes are weather sensitive and require a degree day assumption. A degree day measures the heating or cooling severity, as defined by the distance between a base temperature and the average daily temperature. The UPC models we discussed use historical observations to derive UPC to degree day sensitivities, which we then forecasted forward with a monthly "normal" degree day assumption. To reflect climate change in the 2023 Electric Report, we employed historically observed temperatures and forecasted temperatures derived from climate change models provided by the NWPCC. Please see Chapter Six: Demand Forecast for details of the climate change models

[3] EViews is a popular econometric forecasting and simulation tool.

and results we incorporated. The following section discusses our methodology to create normal degree days from these various temperature sources.

5.1. Energy Forecast

We define monthly normal degree days as a rolling weighted average of the 15 years before and the 15 years after the forecast year, including the forecast year for the 2023 report. The years after historical actuals are three climate change models provided by the NWPCC. The new definition results in warmer winters, thereby decreasing total heating demand, and warmer summers, increasing cooling demand. The net effect of these assumptions for every year in the forecast is negative. What follows is how we calculated future degree days:

We defined Heating Degree Days $\boldsymbol{HDD}_{M,Base,t}$ and Cooling Degree Days $\boldsymbol{CDD}_{M,Base,t}$ for a scenario (M), Base temperature, and observation time (t) as:

$$\boldsymbol{HDD}_{M,Base,t} = \sum_{d=1}^{Days_t} max\left(0, Base\ Temp_t - Daily\ Avg\ Temp_{d,M}\right)$$

$$\boldsymbol{CDD}_{M,Base,t} = \sum_{d=1}^{Days_t} max\left(0, Daily\ Avg\ Temp_{d,M} - Base\ Temp_t\right)$$

To calculate normal heating or cooling degree days, we calculated historical actual degree days and weighted averages of the future degree day model for a time period t using the following data set:

$$\boldsymbol{DD}_{Base,t} = \begin{cases} \boldsymbol{DD}_{Actuals,Base,t}\ for\ t < Jan\ 2020 \\ \frac{\mathbf{1}}{\mathbf{3}}\left(\boldsymbol{DD}_{CanESM2,Base,t} + \boldsymbol{DD}_{CCSM4,Base,t} + \boldsymbol{DD}_{CNRM,Base,t}\right) for\ t > Dec\ 2019 \end{cases}$$

To calculate normal degree days, we calculated the average monthly degree days for the 15 years prior and 15 years forward from the given year in the forecast period, using actual temperature data through 2020 and forecasted climate projections after 2020.

$$\boldsymbol{DDN}_T = \frac{\mathbf{1}}{\mathbf{30}} \sum_{t=T-15}^{T+14} \boldsymbol{HDD}_{Base,t}\ , T = Jan\ 2024 - Dec\ 2050$$

5.2. Peak Forecast

Previous IRPs assumed an electric normal hourly peak temperature of 23 degrees, based on the 1-in-2 seasonal minimum temperatures during peak hours, hour ending (HE) 8 am–8 pm), for 30 years of history 1988–2017. To calculate the new peak temperature, we replicated and expanded the methodology used to calculate the previous peak temperature to incorporate multiple sets of climate model temperature projections and calculate peak temperatures under additional peak-specific conditions (evening-only specific peak).

5.2.1. Calculate Maximum and Minimum Temperatures in Season

For each model (M: CanESM2, CCSM4, CNRM), Year, Peak Period (All Hours: HE8–HE20 and Evening: HE17–HE19), and Season (Winter: Nov, Dec, Jan, Feb and Summer: June-September), calculate the minimum and maximum temperatures.

$$Min\ Temp_{Y,M,P=All} = \begin{cases} min\left(\boldsymbol{min(D_{H=8}\ T}_{Y,Actual}),\ldots,\boldsymbol{min(D_{H=20}\ T}_{Y,Actual})\right)\ Y < Aug\ 2021 \\ max\left(\boldsymbol{min(D_{H=8}\ T}_{Y,Ml}),\ldots,\boldsymbol{min(D_{H=20}\ T}_{Y,M})\right)\ Y > Aug\ 2021 \end{cases}$$

$$Min\ Temp_{Y,M,P=Evening} = \begin{cases} min\left(\boldsymbol{min(D_{H=17}\ T}_{Y,Actual}),\boldsymbol{min(D_{H=18}\ T}_{Y,Actual}),\boldsymbol{min(D_{H=19}\ T}_{Y,Actual})\right)\ Y < Aug\ 2021 \\ max\left(\boldsymbol{min(D_{H=17}\ T}_{Y,Ml}),\boldsymbol{min(D_{H=18}\ T}_{Y,M}),\boldsymbol{min(D_{H=19}\ T}_{Y,M})\right)\ Y > Aug\ 2021 \end{cases}$$

$$Max\ Temp_{Y,M,P=Evening} = \begin{cases} max\left(\boldsymbol{max(D_{H=17}\ T}_{Y,Actual}),\boldsymbol{max(D_{H=18}\ T}_{Y,Actual}),\boldsymbol{max(D_{H=19}\ T}_{Y,Actual})\right)\ Y < Aug\ 2021 \\ max\left(\boldsymbol{max(D_{H=17}\ T}_{Y,Ml}),\boldsymbol{max(D_{H=18}\ T}_{Y,M}),\boldsymbol{max(D_{H=19}\ T}_{Y,M})\right)\ Y > Aug\ 2021 \end{cases}$$

We extended the range of observed actuals for peak temperatures past calendar year-end into summer 2021 to reflect observations occurring during June 2021's Heat Dome event. We calculated additional peak temperature restrictions to reflect the time of day in which peak load typically occurs. The minimum daily temperature occurs almost exclusively during HE8 or HE9; thus, minimum temperatures calculated over all peak hours effectively represent morning peak conditions. We calculated the additional evening peak period to capture the expected peak temperature during evening peak load hours — the most common for December and summer peaks. The peak temperatures with these additional restrictions inform the evening peak demand forecast.

For each peak temperature type and period, the result will be four series (Actuals, CanESM2, CCSM4, CNRM) for each season, with observations of seasonal minimum and maximum for each year.

5.2.2. Create Samples of Minimum and Maximum Temperatures by Climate Period

Here we use the term climate period to refer to the 30-year rolling window of 15 years backward- and 15 years forward-looking data for projections. For example, in the forecast year 2024, the relevant climate period to create the sample of possible temperature outcomes is 2009 to 2038. The first forecast year that uses only climate change model projections is winter 2036.

For each peak temperature type (minimum or maximum), forecast year (T), and peak period (P), the sample population is used to determine a 1-in-2 temperature range below.

We define the sample set for each climate model by the 30 maximum and minimum temperatures by year and peak period:

$$\boldsymbol{Max\ Temp}_{T,M,P} = \{Max\ Temp_{Y=T-15,M,P}, \ldots, Max\ Temp_{Y=T+14,M,P}\}$$

$$\boldsymbol{Min\ Temp}_{T,M,P} = \{Min\ Temp_{Y=T-15,M,P}, \ldots, Min\ Temp_{Y=T+14,M,P}\}$$

The collection of sample sets defined, which span historical observations and climate models, forecast year, and peak period, defined the set we used for the distributions of peak temperature outcomes:

$$\boldsymbol{Max\ Temp}_{T,P} = \{\boldsymbol{Max\ Temp}_{T,Actual,P}, \boldsymbol{Max\ Temp}_{T,Actual,P}, \boldsymbol{Max\ Temp}_{T,Actual,P}, \boldsymbol{Max\ Temp}_{T,CANESM2,P},,, \boldsymbol{Max\ Temp}_{T,CCSM4,P}, \boldsymbol{Max\ Temp}_{T,CNRM,P}\}$$

$$\boldsymbol{Min\ Temp}_{T,P} = \{\boldsymbol{Min\ Temp}_{T,Actual,P}, \boldsymbol{Min\ Temp}_{T,Actual,P}, \boldsymbol{Min\ Temp}_{T,Actual,P}, \boldsymbol{Min\ Temp}_{T,CANESM2,P},,, \boldsymbol{Min\ Temp}_{T,CCSM4,P}, \boldsymbol{Min\ Temp}_{T,CNRM,P}\}$$

We repeated the actual observed temperature set to equally weight a year of historical observations with a year of the three future climate models because we did not aggregate the future climate models before we added them to the sample population. They have no averaging, nor did we take the minimum or maximum within individual climate model samples. This approach is the most straightforward way to not bias temperature observations towards the climate models and away from actual historical observations for appropriate climate periods. The sets $\mathbf{Max\ Temp}_{\mathrm{T,Actual}}$ and $\mathbf{Min\ Temp}_{\mathrm{T,P}}$ gradually shrink as the forecast year increases and is empty for T>2036.

5.2.3. Calculate 50th Percentile by Study Year

$$P\{Min\ Peak\ Temp_{T,P} < \boldsymbol{Min\ Temp}_{T,P}\} = 0.5$$

$$P\{Max\ Peak\ Temp_{T,P} < \boldsymbol{Max\ Temp}_{T,P}\} = 0.5$$

The resulting $Peak\ Temp_{T,P}$ for a given forecast year T (2024–2045), peak period P (all hours, evening hours), and type (minimum, maximum) is the expected temperature for which there is a 50 percent likelihood the actual peak seasonal minimum or maximum temperature will be higher or lower during the given peak period (all hours or just evening), based on the sample sets defined in the process above.

➔ Please see Chapter Six: Demand Forecast for a discussion of why climate change models are employed and why we must model an evening-specific peak event.

5.3. Hourly Forecast

We created the hourly temperature profiles by ranking days (24-hour temperature shapes) within a month by daily average temperature and then averaging the 24-hour temperature profile across relevant models. Depending on the year desired, the hourly average temperatures are an equal weighting of the 30-year rolling window of historical observations and the three climate change models. Once we created a set of typical monthly 24-hour profiles, we reordered days to typically observed monthly temperature patterns, with typical seasonal peak times (summer and winter) containing heating and cooling events consistent with the 1-in-2 peak temperature assumptions described Chapter Six: Demand Forecast.

5.3.1. Rank Monthly Temperature Observation by Daily Average Temperature

For each climate model and historical observation, rank days by daily average temperature within a month (M) and year (T), where:

$$\bar{t}_{T,M,(i)} = \sum_{h=1}^{24} Temp_{h,T,M}, i = 1 \ldots 28/30/31$$

Let (i) denote the order statistics of the daily temperature for the month:

$$\bar{\boldsymbol{t}}_{T,M} = \{\bar{t}_{T,M,(1)}, \ldots, \bar{t}_{T,M,(31)}\}$$

5.3.2. Average 24-hour Profiles by Daily Rank Across Appropriate Climate Period

As we discussed, the climate period for a forecast year is a 30-year rolling window of years, weighted appropriately to not bias against the historical period for appropriate years. For a given forecast year, in a month, the temperature profile (a 24-hour vector) for the ith ranked day is defined as:

$$\boldsymbol{t}_{T,(i)} = \frac{1}{2} * \frac{1}{30} * \left(\left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,CANESM2,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,CANESM2,R=i} \right] + \left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,CCSM4,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,CCSM4,R=i} \right] + \left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,CNRM-CM5MACA,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,CNRM-CM5MACA,R=i} \right] \right) + \frac{1}{2} \left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,Actual,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,Actual,R=i} \right]$$

5.3.3. Reorder the Daily Profile by Typical Daily Ranking

To reflect the typical progression of temperature patterns over a month, we reordered daily temperature profiles by a historical ranking of the coldest and warmest days in the month.

For a given year and month forecast year T, when n is the coldest day and 1 is the warmest day, and each $\boldsymbol{t}_{T,(i)}$ is a vector of 24 hours, an example of a typically ordered profile may be:

$$\boldsymbol{t}_T = \begin{bmatrix} \boldsymbol{t}_{T,(2)} \\ \boldsymbol{t}_{T,(4)} \\ \cdots \\ \boldsymbol{t}_{T,(n-2)} \\ \boldsymbol{t}_{T,(n-1)} \\ \boldsymbol{t}_{T,(n)} \\ \cdots \\ \boldsymbol{t}_{T,(10)} \\ \boldsymbol{t}_{T,(14)} \\ \boldsymbol{t}_{T,(15)} \end{bmatrix}$$

Because we expect the peak demand modeled to occur on a weekday and non-holiday, we adjusted the rankings by calendar year, so the most extreme days occur on the nearest non-holiday and mid-weekday to the warmest or coldest typical ranked day in a month.

ELECTRIC PRICE FORECAST
APPENDIX G

PUGET SOUND ENERGY

Contents

1. Introduction

This appendix summarizes the electric price forecast assumptions and results Puget Sound Energy (PSE) used as a basis for the company's 2023 Electric Progress Report (2023 Electric Report).

We developed this electric price forecast as part of our 2023 Electric Report. In this context, electric price is not the rate charged to customers but PSE's price to purchase or sell one megawatt (MW) of power on the wholesale market, given the prevailing economic conditions. Electric price is essential to our analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio.

We performed two Western Electricity Coordinating Council (WECC)-wide modeling runs using AURORA software, an hourly chronological price forecasting model based on market fundamentals, to create wholesale electric price assumptions.

- The first AURORA model run identifies the capacity expansion needed to meet regional loads. AURORA looks at loads, peak demand, and a planning margin and then identifies the lowest cost resource(s) to ensure all the modeled zones are balanced.
- The second AURORA model run produces hourly power prices. A complete simulation across the entire WECC region produces electric prices for all 34 zones shown in Figure G.1. The lines and arrows in the diagram indicate transmission links between zones and their transmission capacity noted in megawatts.

Figure G.1 illustrates the AURORA System Diagram, and Figure G.2 shows PSE's process to create wholesale market electric prices using AURORA, as described.

The AURORA model produces electric price forecasts for each zone included in the model's topology. We then calculate the Mid-Columbia Hub (Mid-C) electric prices in post-processing as the demand-weighted average of the zones which compose the Pacific Northwest. The Pacific Northwest zones are Avista, Bonneville Power Administration (BPA), Chelan County Public Utility District (PUD), Douglas County PUD, Grant County PUD, PacifCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure G.2: AURORA System Diagram

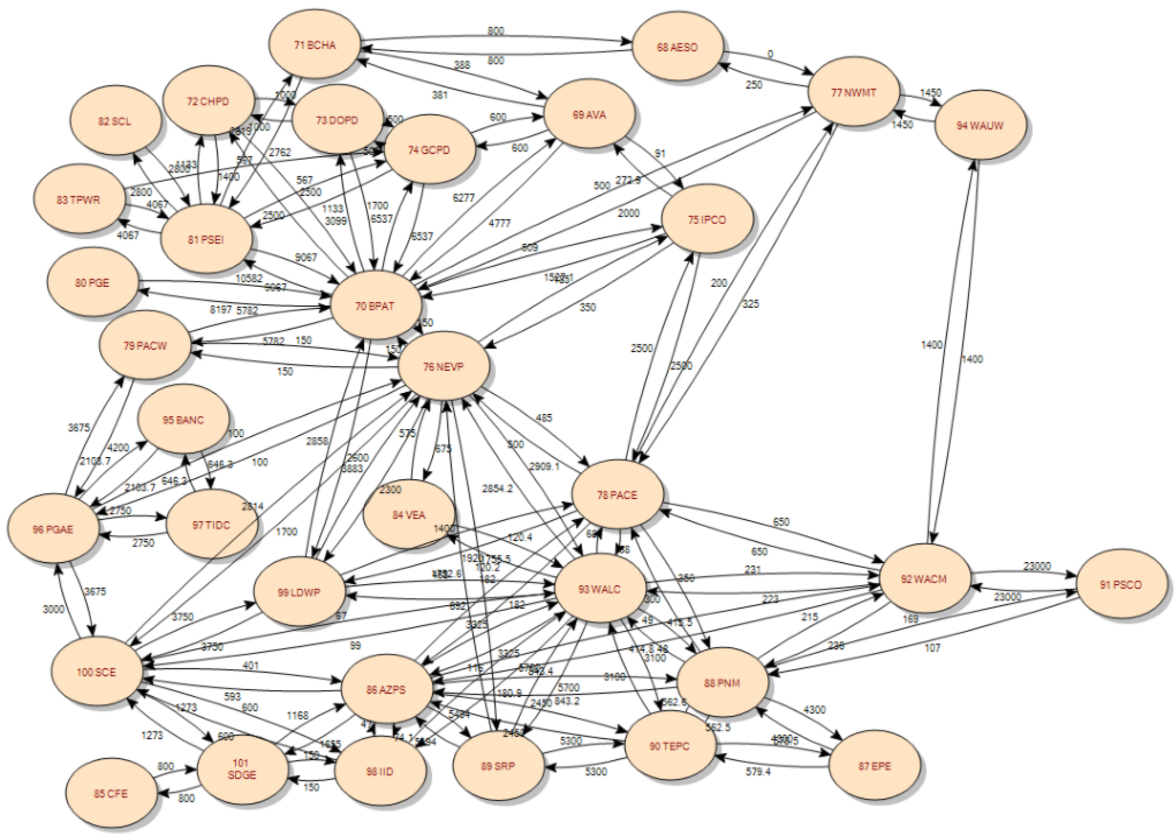
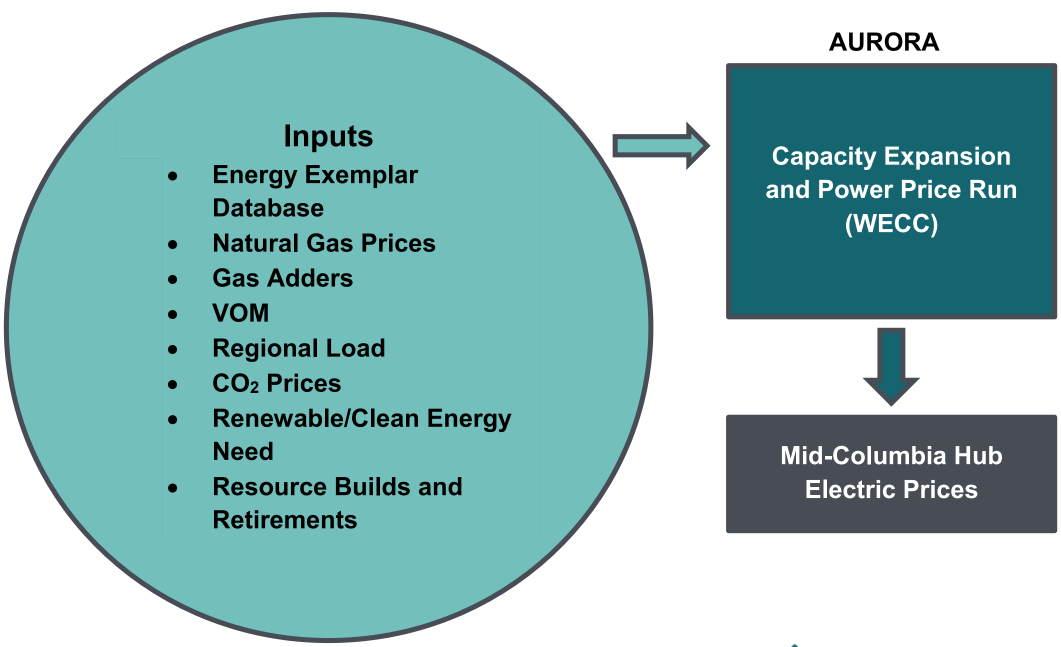


Figure G.1: PSE IRP Modeling Process for AURORA Wholesale Electric Price Forecast



2. 2021 Integrated Resource Plan

Puget Sound Energy filed the 2021 Integrated Resource Plan (IRP) in April 2021. We used inputs and assumptions from the Energy Exemplar 2018 database for AURORA price forecast modeling for the 2021 IRP. We then incorporated updates such as regional demand, natural gas prices, resource assumptions, renewable portfolio standard (RPS) needs, and resource retirements and builds. The 20-year levelized nominal power price in the Mid-C scenario for the 2021 IRP was $23.37/MWh. Details of the inputs and assumptions for the AURORA database are available for review in the 2021 IRP[1].

3. Modeling Power Prices

The electric price forecast for the 2023 Electric Report retains the fundamentals-based approach of forecasting wholesale electric prices while incorporating significant changes to some methodologies and input assumptions from the 2021 IRP process. Methodology changes include:

- Expand renewable portfolio and clean energy standards to include non-binding clean energy policies set by municipalities and utilities
- Include Washington State carbon pricing to reflect the impact of the Climate Commitment Act (CCA)
- Incorporate the impacts of climate change on demand and hydroelectric assumptions

This report documents all methodology and input assumption changes from the 2021 IRP.

3.1. Model Framework Updates

The electric price model for PSE's 2023 Electric Report includes two significant changes to the modeling framework from the 2021 IRP, updated AURORA software, and the WECC database updates.

3.1.1. AURORA Version 14.1

We updated the AURORA software from version 13.4, which we used for the 2021 IRP, to version 14.1 for the 2023 report. AURORA version 14.1 includes several changes that make it easier to use and allow greater modeling flexibility. AURORA enhancements include:

- New scripting functions
- Updates to the storage logic and limits on charging and generating in the same hour when a storage method has a minimum generation constraint

[1] PSE | 2021 IRP

3.1.2. Energy Exemplar WECC Zonal Database version 1.0.1

We updated the AURORA input database from the WECC 2018 database to the WECC 2020 database for the 2023 Electric Report. As a result of these changes, the WECC 2020 database:

- Introduces battery energy storage systems as a new resource option
- Limits the addition of new natural gas-fired power plants to years before 2030 across the WECC
- Modifies the structure of fuel price adders for increased flexibility
- Moves to a default 34-zone system topology that models each balancing authority in the WECC as a unique zone, a change from the 16-zone system topology previously used
- Updates generic resource costs
- Updates transmission assumptions

These changes result in a materially different starting point for the 2023 Electric Report and provide differing pathways for determining the solution in the long-term capacity expansion simulation from previous electric price models. We gained a more granular system topology by moving from a 16-zone to a 34-zone system that better represents the transmission constraints between balancing authorities across the WECC. Limitations on natural gas builds and adding storage as a new resource option provide more cost-effective decarbonization pathways to meet growing clean energy policy targets.

We made the following changes and updates to the WECC database:

- Adjusted clean energy policies
- Added climate change impacts
  - Updated the regional demand forecast based on climate change impacts
  - Updated the hydroelectric forecast based on climate change impacts
- Added Climate Commitment Act (CCA) impacts
- Updated natural gas prices

3.1.3. Clean Energy Policies

Clean energy policies are shaping the resource generation landscape of the WECC. For this electric price forecast, clean energy policies include a range of different targets, such as:

- Municipal clean energy goals and mandates
- Renewable portfolio standards
- Statewide clean energy goals
- Utility-set clean energy targets

These new targets depart from previous IRPs where we only modeled legislatively binding state policies (i.e., renewable portfolio standards). We include these other clean energy targets in PSE's 2023 Electric Report to reflect their impact on planning and implementing energy in the WECC. Our 2023 Electric Report includes clean energy policies aligned with the work performed by the Northwest Power and Conservation Council's (NPCC) 2021 Power Plan.

Modeling Clean Energy Policies

Puget Sound Energy's 2023 Electric Report features two modeling changes to reflect better the clean energy policies across the WECC.

In previous IRP cycles, we modeled clean energy targets by state consistent with the methodology in the Northwest Power and Conservation Council's (NPCC) Seventh Power Plan. This approach meant we had to add qualifying clean resources to the specific state which set the clean energy target. For example, an operator would have to construct a unit of Washington wind power in-state to fulfill a portion of the Washington renewable energy target.

This requirement is an unrealistic assumption because it limits utilities from sourcing energy from regions with better wind or solar resources than their home state. The NPCC realized this shortcoming and updated its methodology in the 2021 Power Plan to allow utilities to source clean resources beyond their state's boundaries. We adopted similar methods for the electric price forecast in this report. The new methodology set a WECC-wide clean energy target composed of all the clean energy targets for regional states. We then adjusted the NPCC methodology and carved out a small subset for the states of Washington and Oregon to ensure we met state policies more precisely.

In previous IRP cycles, PSE set clean energy targets only for new resources. This method subtracted contributions from existing resource generation from the total clean energy target, and only new resources counted toward meeting the clean energy target. This methodology required extensive accounting of clean energy contributions from existing resources outside the AURORA model, which may have understated the contribution of the existing clean energy resources.

In the 2023 Electric Report, we included existing and new resources in the modeled total clean energy target. We tagged both existing and new resources to contribute to the target. This approach allowed more precise accounting and better representation of all resources using AURORA's dispatch logic.

Both changes are consistent with methodologies used by NPCC in their electric price forecast AURORA model. We calculated clean energy targets using regulations, goals, and policies described in the NPCC 2021 Power Plan supplemental material[2]. We updated the NPCC clean policy targets for recent Oregon and Montana regulatory developments. Oregon adopted a 100 percent clean energy target by 2040 for investor-owned utilities, and Montana repealed its 15 percent renewable portfolio standard.

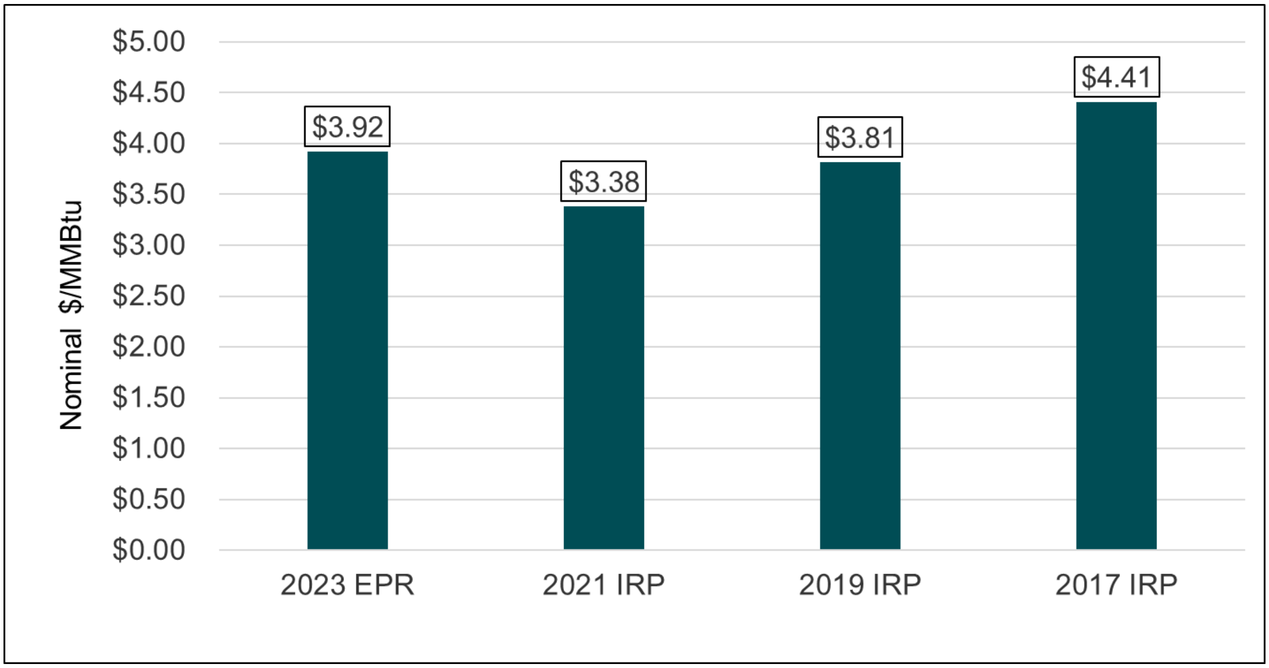
3.1.4. Gas Prices

Puget Sound Energy updated the long-term gas prices in this report to the most recent Wood Mackenzie forecasts and current forward market prices. We used the spring 2022 Wood Mackenzie Forecast, published in May 2022. The

2 2021 Power Plan Supporting Material Site Map (nwcouncil.org)

forecast shows an increase in long-term gas prices compared to the estimates used in the 2021 IRP, shown in Figure G.3.

Figure G.3: Levelized Natural Gas Price for the Sumas Gas Hub for Recent IRP



3.1.5. Climate Change

For the first time, PSE's 2023 Electric Report includes the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC), Part II[3], and selected three scenarios that represented a range of possible climate outcomes. PSE adopted these same three climate change scenarios:

- CanESM2_RCP85_BCSD_VIC_P1; coded as A
- CCSM4_RCP85_BCSD_VIP_P1; coded as C
- CNRM-CM5_RCP85_MACA_VIC_P3; coded as G

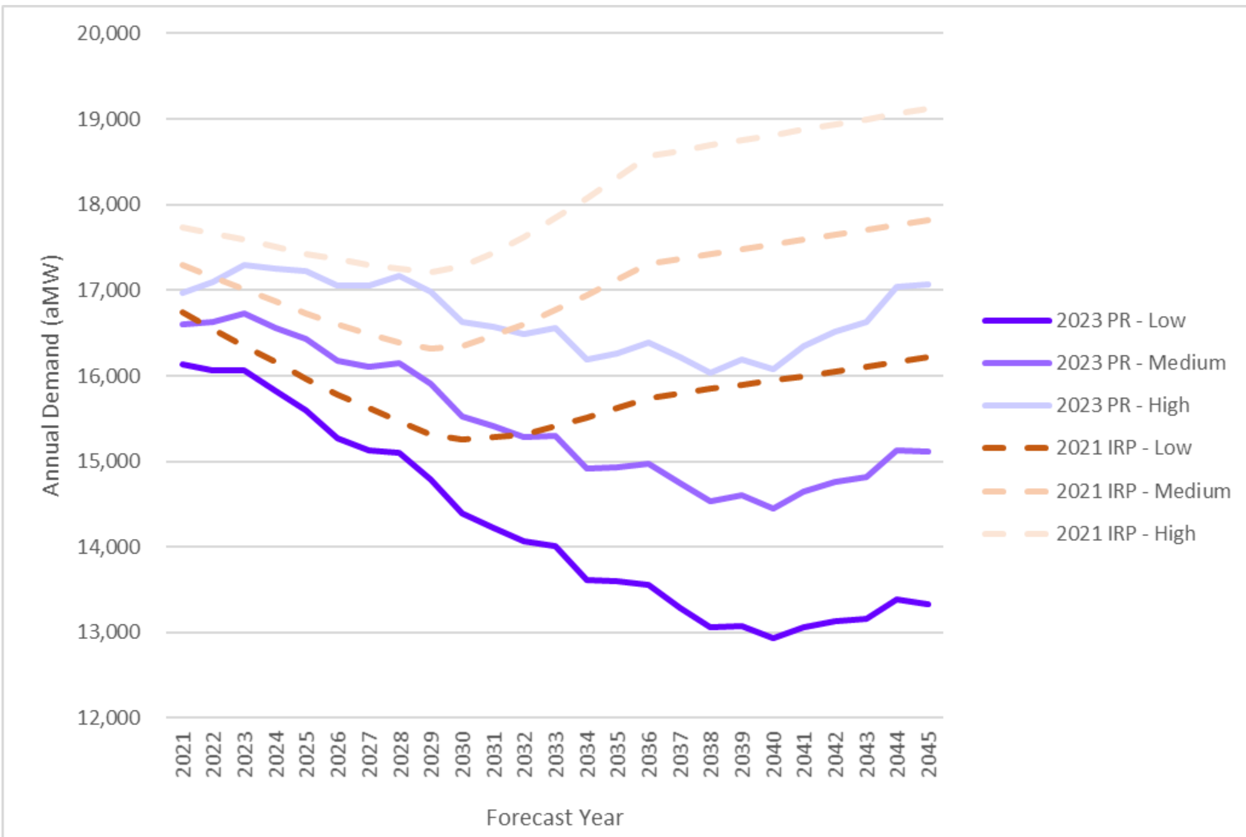
The three climate change scenarios we adopted uniquely impact the Pacific Northwest (PNW) load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the base electric price forecast averaged the effects of each climate change scenario to develop a single climate change case, which retains trends present in all three climate change scenarios.

[3] Climate and hydrology datasets for RMJOC long-term planning studies: Second edition (RMJOC-II) - Technical Reports - USACE Digital Library (oclc.org)

Regional Demand Forecast

For the electric price modeling, PSE used the regional demand from the NPCC 2021 Power Plan. Figure G.4 reflects the PNW regional demand forecast change from the 2021 IRP to the 2023 Electric Report. The demand forecast includes energy efficiency in all cases.

Figure G.4: Annual Average Regional Demand for the Pacific Northwest, 2023 Electric Progress Report and 2021 IRP



Climate Change Regional Demand Forecast

We incorporated the climate change regional demand forecast created by the NPCC for the 2021 Power Plan in the electric price forecast for this report. The regional demand forecast is presented seasonally in Figure G.5, with each forecast year as a separate line; darker lines represent years earlier in the planning horizon and lighter lines later in the planning horizon. We provided selected data from the 2021 IRP regional demand forecast for reference.

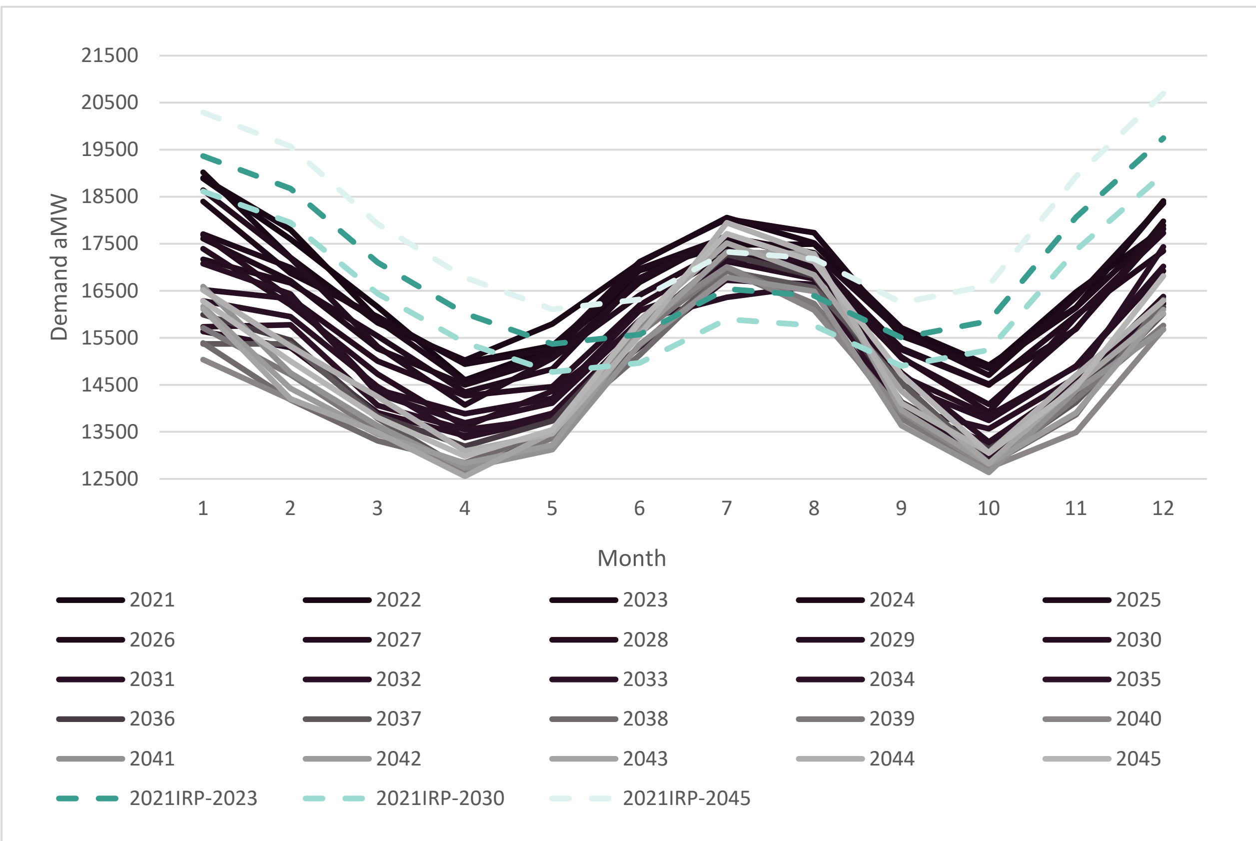
The climate change regional demand forecast shows warming winters and summers, which translates to lower demand in the winter than we modeled in the 2021 IRP and increased demand in the summer.

Climate Change Hydroelectric Forecast

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[4] regional resource adequacy model using streamflow data representative of the climate change scenarios.

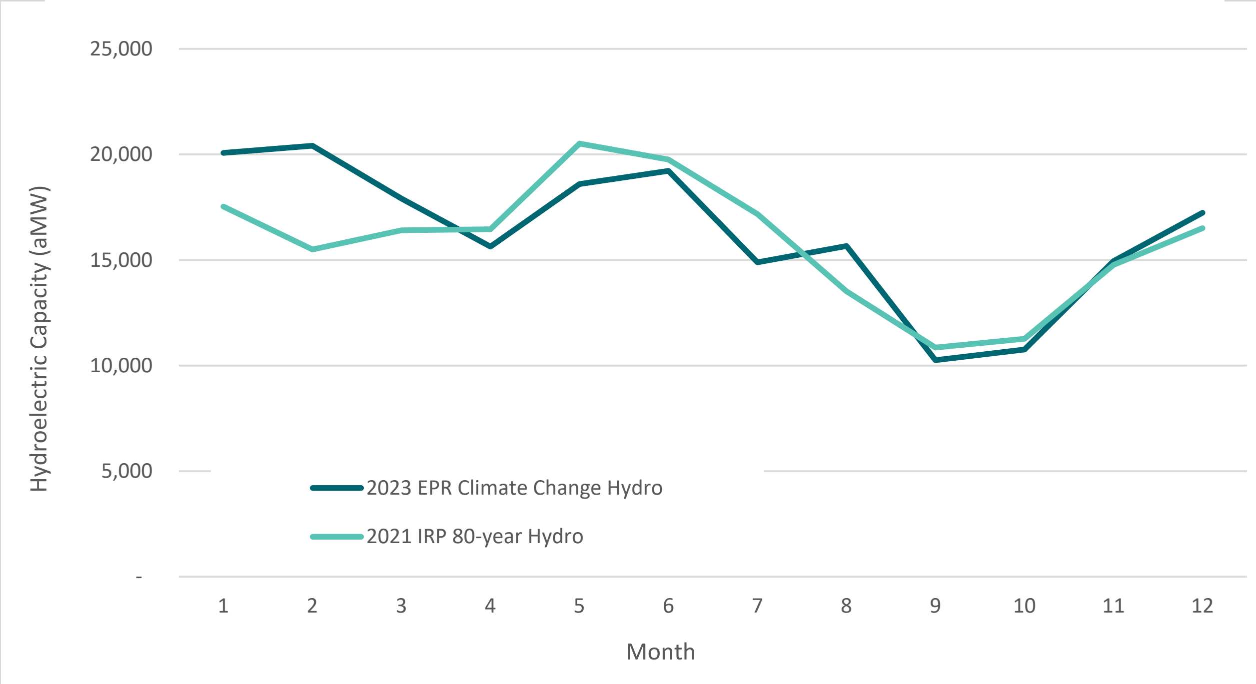
We held the average hydroelectric forecast fixed for all the modeled years. Figure G.6 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year.

Figure G.5: Seasonal Regional Demand for the Pacific Northwest, 2023 Electric Progress Report and 2021 IRP



4 GENESYS Model (nwcouncil.org)

Figure G.6: Pacific Northwest Climate Change Hydroelectric Forecast



3.1.6. Climate Commitment Act

The Washington State legislature passed the Climate Commitment Act (CCA) in 2021, which goes into effect in 2023. The CCA is a cap and invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances of permitted emissions.

The resulting market establishes an opportunity cost for emitting greenhouse gases. We added a price to greenhouse gas emissions for emitting resources within Washington State to model this opportunity cost in the electric price forecast. We only added an emission price to Washington emitting resources to ensure the model does not impact the dispatch of resources outside Washington State that are not subject to the rule.

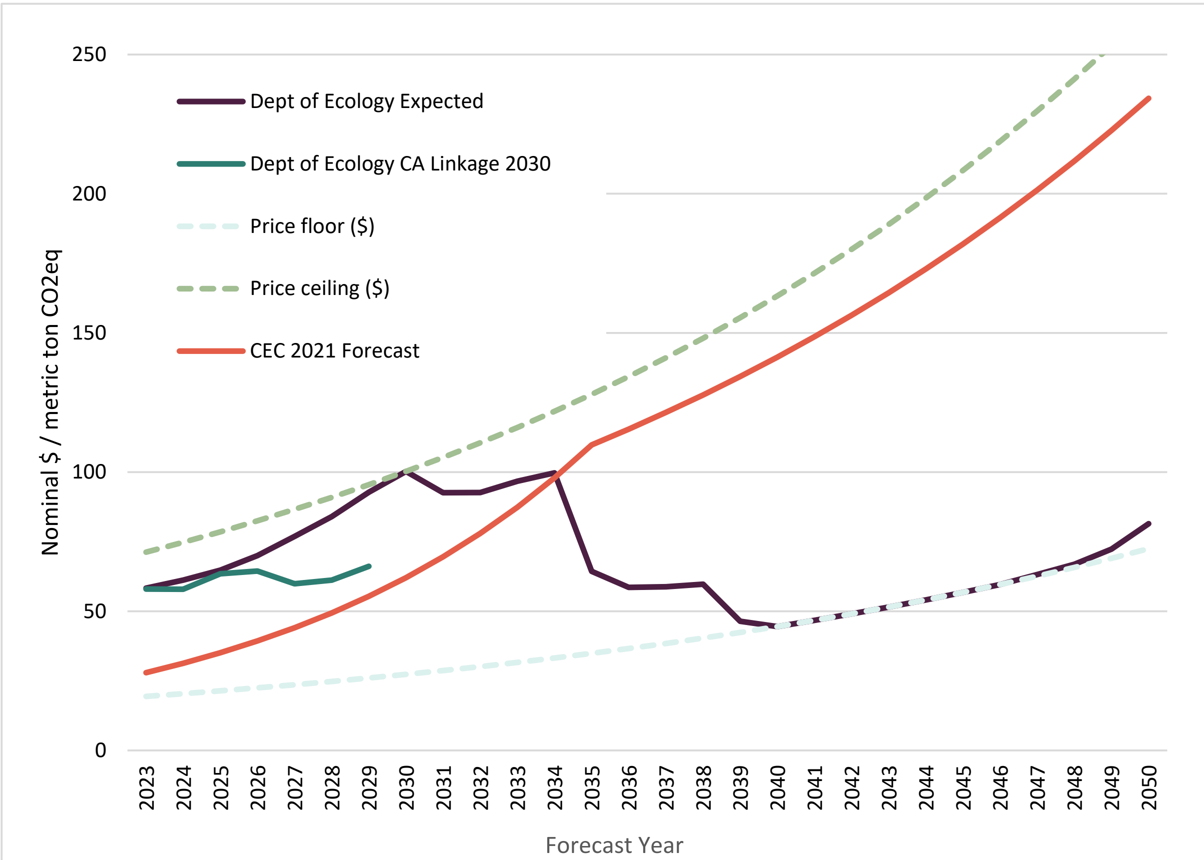
To accurately reflect all costs imposed by the CCA, we will add a hurdle rate on market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_{2eq} per MWh.[5]

Figure G.7 presents the allowance prices considered in the electric price forecast. The expected prices of the Washington State Department of Ecology (Ecology) represent the predicted emission price, assuming no linkage to the California carbon market. We suggest that linkage to the California carbon market is the most likely scenario and has adopted a hybrid scheme that begins with pricing at the rate specified by the Department of Ecology California

[5] RCW 19.405.070

Linkage 2030[6] case, then transitions to the California Energy Commission (CEC) 2021 Integrated Energy Policy Report[7] allowance price forecast for the remainder of the modeling horizon.

Figure G.7: Climate Commitment Act Allowance Prices



4. Electric Price Forecast Results

Figure G.8 compares the annual average Mid-C wholesale electric price from the 2017 IRP to the 2023 Electric Report and the historic Mid-C wholesale electric price. Several factors contribute to the increase in electric prices from the 2021 IRP to the 2023 Electric Report:

1. **Natural gas prices**
   Natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices.

2. **Transmission constraints**
   In the 2023 Electric Report, we modeled the WECC as a 34-zone system instead of the 16-zone system

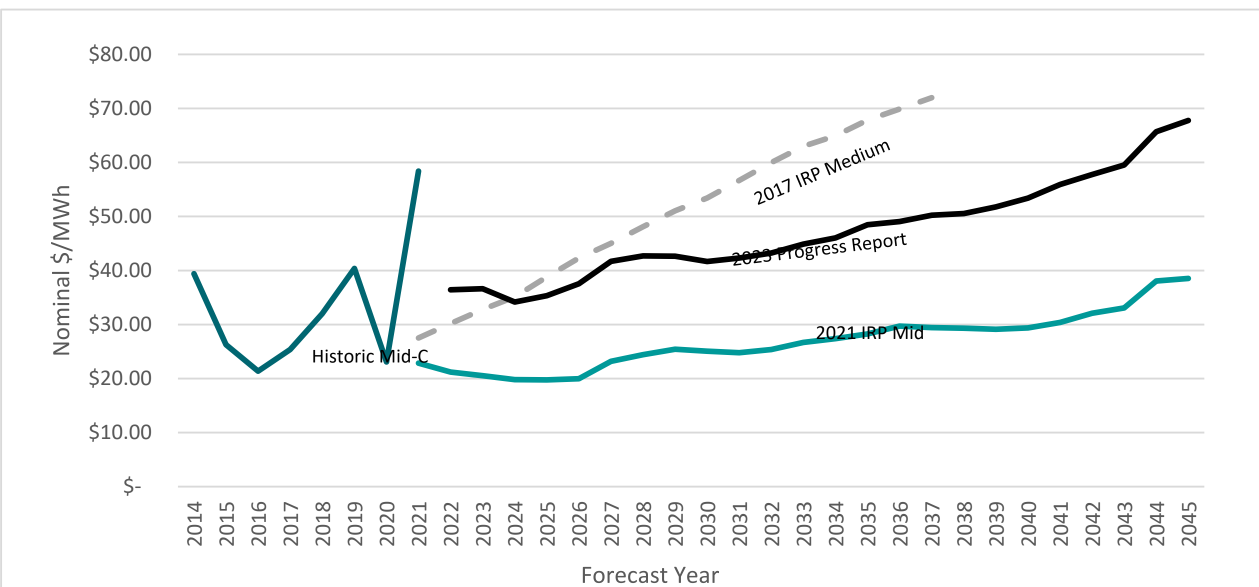
6 Preliminary Regulatory Analyses for Chapter173-446 WAC, Climate Commitment Act Program
7 2021 Integrated Energy Policy Report (ca.gov)

modeled in the 2021 IRP. The increased number of zones increases transmission links within the model and increases wheeling costs as electricity is transported between zones, resulting in higher electricity prices.

3. **Clean energy needs modeling**
   Clean energy requirements accounted for existing and new resources in the 2023 Electric Report, whereas in the 2021 IRP, only new resources contributed to the clean energy targets. The method used in the 2021 IRP may have understated the contribution of existing resources and, therefore, overbuilt new solar resources, which resulted in excess hours with low-cost power, artificially driving prices lower. The method we used in this report resulted in fewer renewable energy additions to the WECC, which results in a tighter energy market and higher prices.

4. **Storage**
   Resources that store energy (e.g., batteries) were unavailable in the 2021 IRP electric price model, resulting in overbuilding of wind and solar resources to provide non-emitting capacity. Overbuilt wind and solar resources lead to lower wholesale electric prices as more hours fill with zero-cost power from these renewable resources. We added storage as an available resource in the 2023 Electric Report, which allows us to shift load and generation and dramatically reduces the number of renewable resources required to meet the load. This scenario creates a tighter market driving up wholesale electric prices overall. Storage can help reduce very high prices through arbitrage and load/generation shifts resulting in more moderate average prices.

Figure G.8: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time



Despite the addition of storage resources, volatility is still present in the wholesale electric price results for the 2023 Electric Report. Price volatility results from the substantial buildout of renewable resources across the WECC.

Figure G.9 shows electric price volatility over a day for each month of the year. Strong morning and evening peaks are present throughout the modeling horizon and will become particularly extreme in the summer months by 2045.

Figure G.10 presents volatility across all hours of each year of the modeling horizon. Price spikes become increasingly common in the latter years of the analysis.

Figure G.9: Daily Price Volatility by Month for the Years 2023, 2030, and 2045

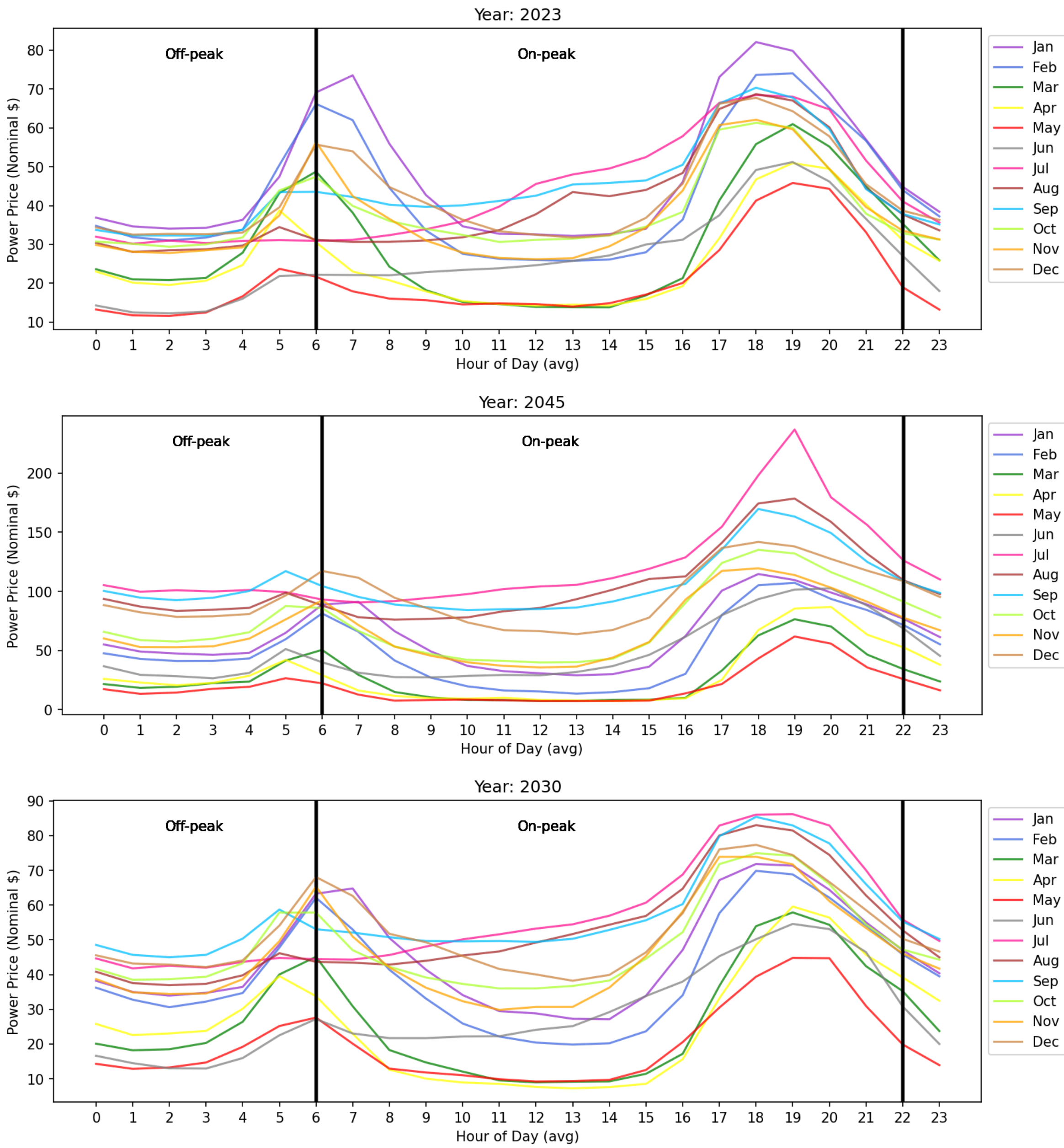
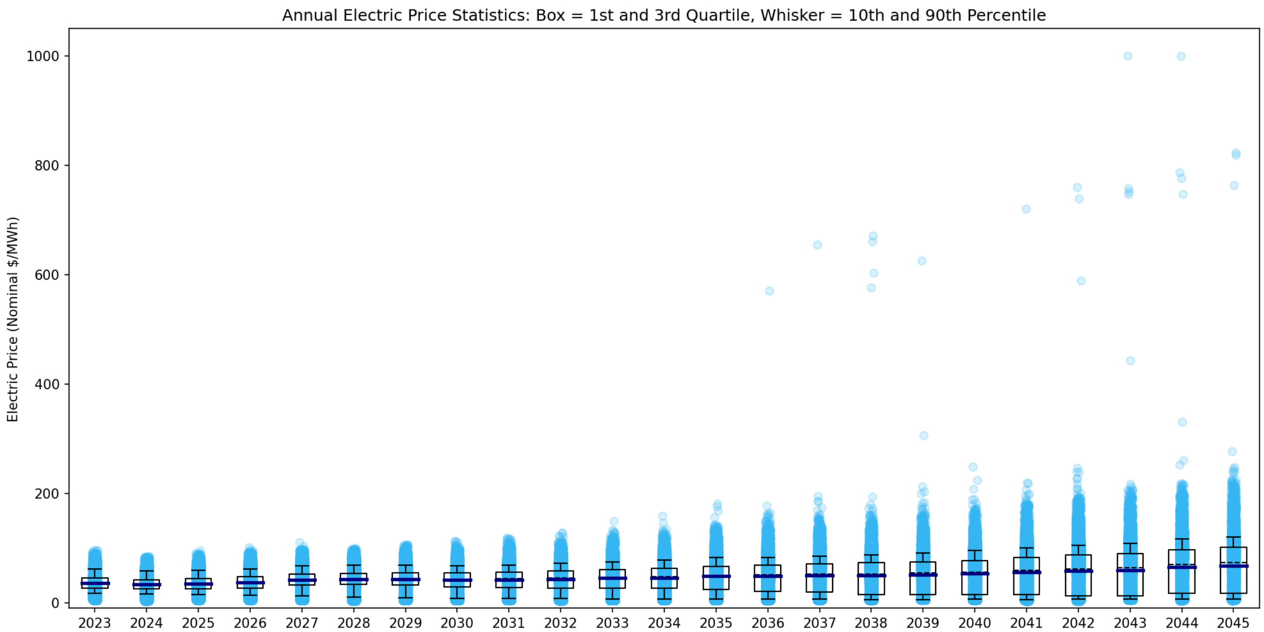


Figure G.10: Hourly Electric Prices over the Modeling Horizon



5. Electric Price Stochastic Analysis

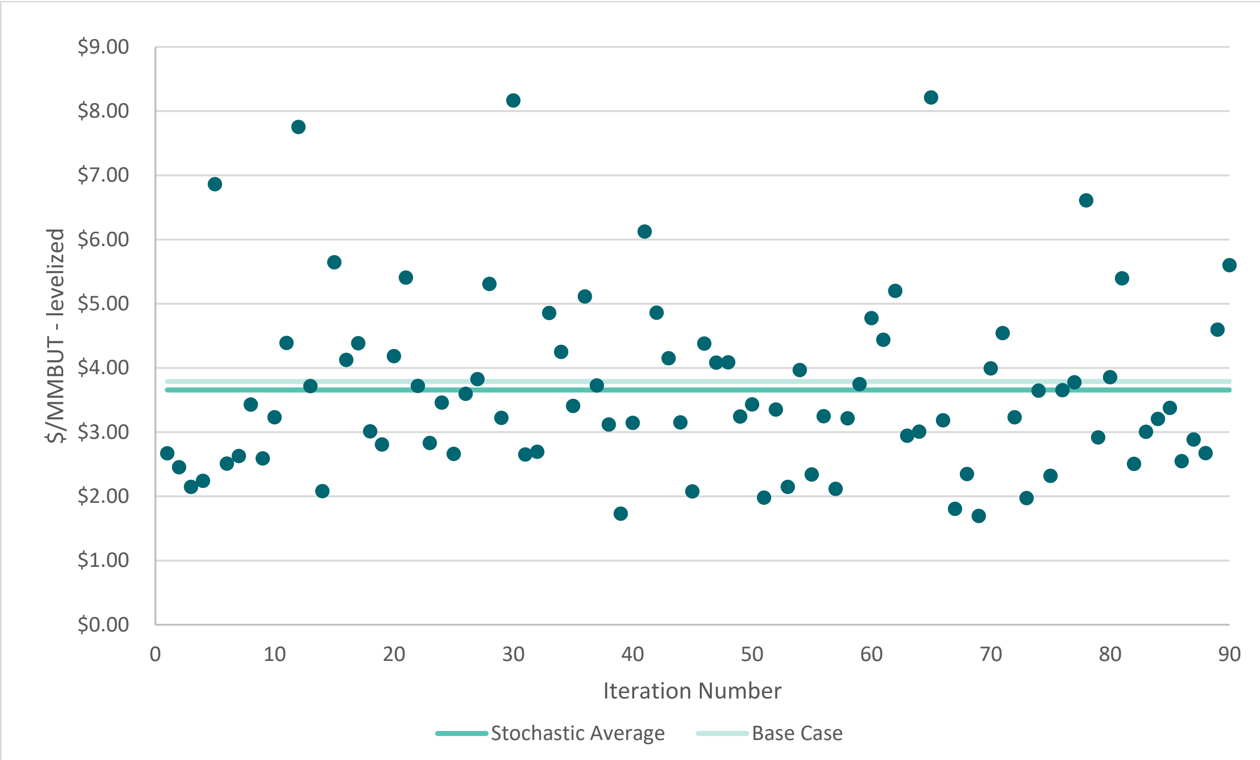
We use AURORA, a production cost model that utilizes electric market fundamentals to generate electric price draws. AURORA uses a Monte Carlo risk capability that allows users to apply uncertainty to a selection of input variables. The user can add variable input assumptions to the model as an external data source, or AURORA can generate samples based on user statistics on a key driver or input variable. This section describes the model input assumptions we varied to generate the stochastic electric price forecast.

5.1. Stochastic Natural Gas Price Inputs

We relied on AURORA's internal capability to specify distributions on select drivers, such as natural gas prices, to generate samples from a statistical distribution. The risk factor represents the model's adjustment to the base value for the specified variable for the relevant time. To calculate the risk factor on natural gas prices, we calculated the correlation of natural gas prices from Sumas, Rockies (Opal), AECO, San Juan, Malin, Topock, Stanfield, and PGE City Gate to Henry Hub with data from Wood Mackenzie's Spring 20222 Long Term View Price Update.

We also evaluated each hub's slow, medium, and high natural gas prices to determine each calendar month's average and standard deviation. We used the standard deviation as a percent of the mean for each calendar month as an input to AURORA for risk sampling. Figure G.11 illustrates the annual draws and the levelized 20-year Sumas natural gas price $/MMBtu generated by the AURORA model.

Figure G.11: Levelized 20-year Sumas Natural Gas Price $/MMBtu



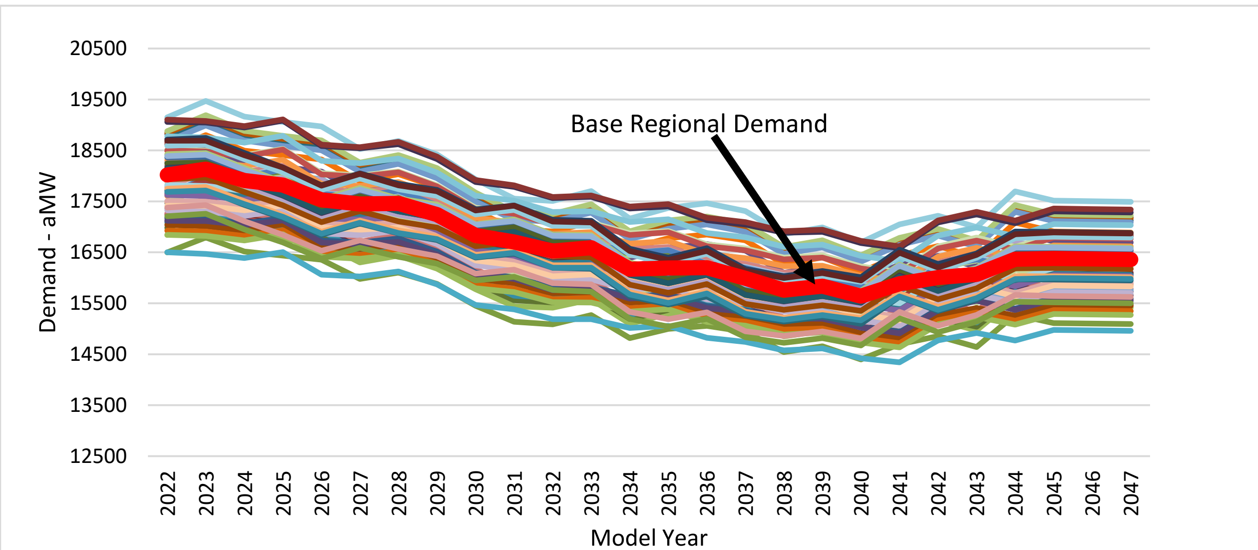
5.2. Stochastic Regional Demand

Like natural gas prices, we relied on AURORA's internal capability to generate samples from a statistical demand distribution. We evaluated low, medium, and high regional demand forecasts used in the deterministic price forecasts to determine the standard deviation as a percent of the mean for the modeling horizon. Table G.1 displays the 23-year levelized demand and the calculated standard deviation for the region. We used the standard deviation as an input to AURORA for the risk sampling of the entire WECC. Figure G.12 illustrates the 90 draws of demand AURORA generated for the Pacific Northwest.

Table G.1: 24-year Levelized Demand Statistics for PNW

2023 Electric Price Forecast Statistic	Quantity
Low - mean(aMW)	18,557
Medium - mean (aMW)	20,023
High - mean (aMW)	21,484
Mean of means	20,021
St Dev	1,195
St Dev Percent	0.06

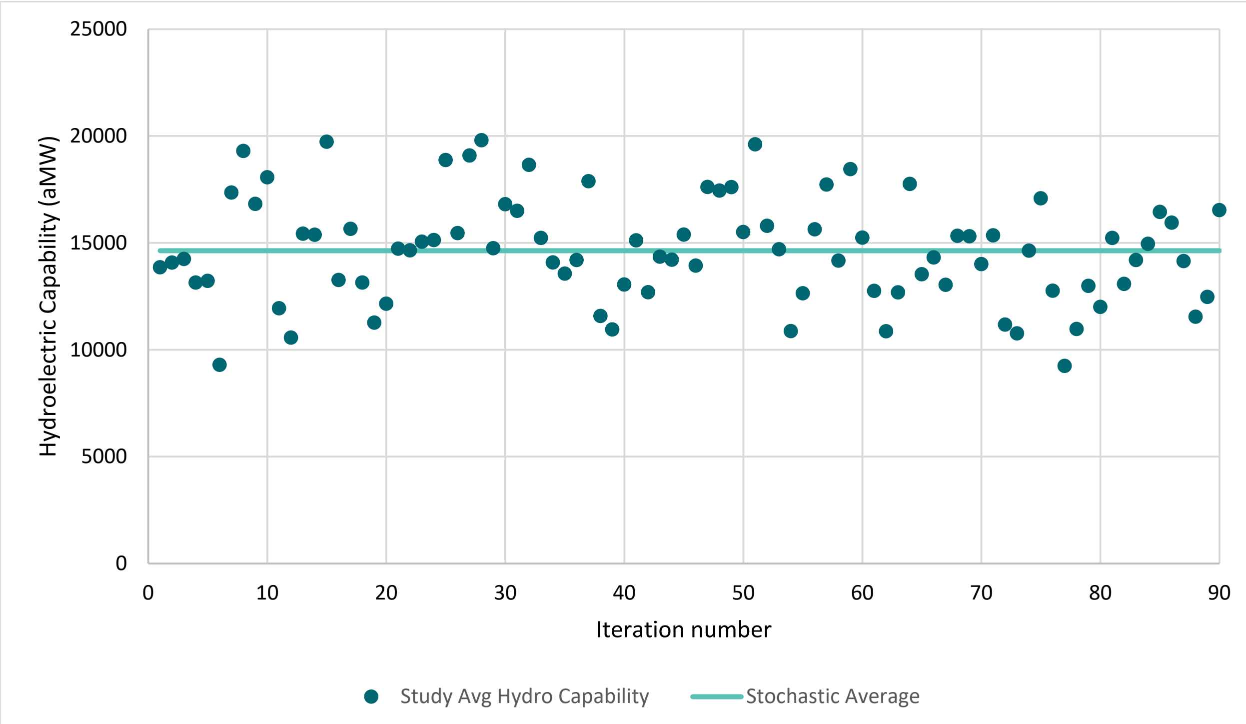
Figure G.12: Pacific Northwest Demand Draws (aMW)



5.3. Stochastic Hydroelectric Inputs

We derived stochastic hydroelectric inputs for this report's electric price forecast from the climate change hydroelectric data in this appendix. We obtained hydroelectric generation estimations for three climate change models with thirty years of data available for each model for 90 unique hydroelectric draws used in the stochastic analysis. Figure G.1 provides the 90 draws of hydroelectric capability for the Pacific Northwest.

Figure G.13: Hydroelectric Capability for the Pacific Northwest for 90 Iterations



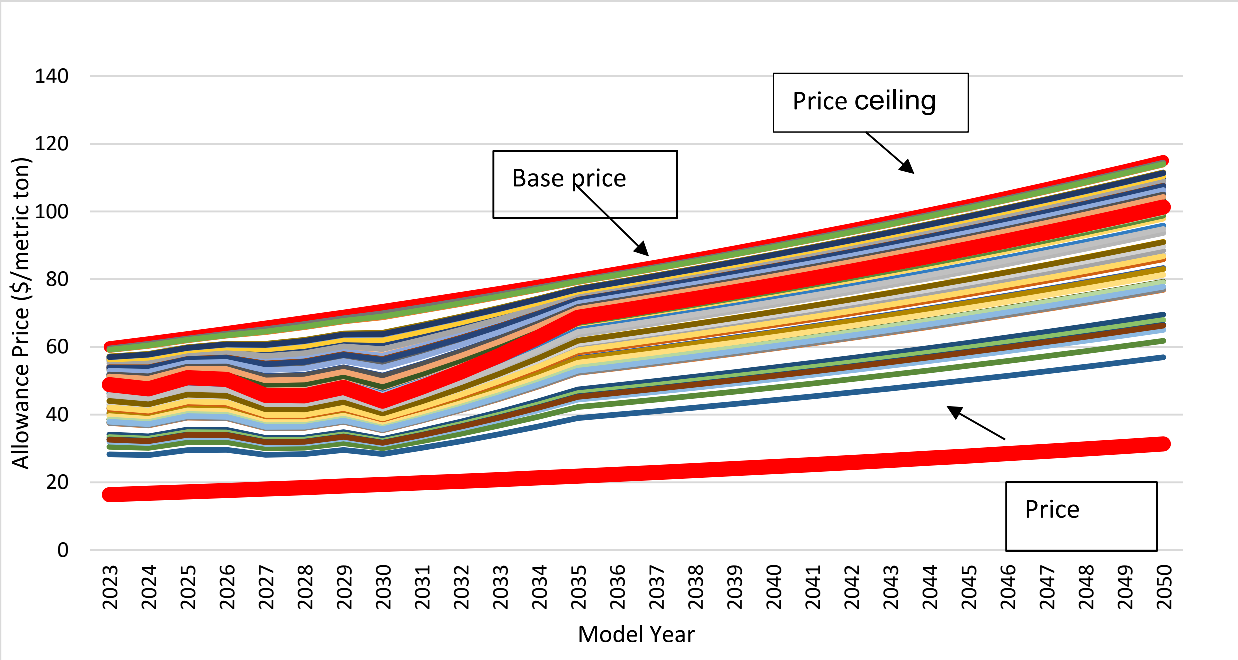
5.4. Stochastic Wind Inputs

Energy Exemplar developed wind shapes in the default AURORA database relying primarily on generation estimates from the National Renewable Energy Laboratory's (NREL) Wind Integration National Database (WIND) 2014 Toolkit, using data from the years 2007–2012. We averaged the generation from clusters of NREL wind sites with similar geography and capacity factors to form each delivered wind shape. For each wind region, we developed hourly shapes with capacity factors appropriate for three wind classes, low, medium, and high. For the electric price stochastic model, we randomly assigned an appropriate regional shape a low, medium, or high wind class for each wind project modeled in the analysis.

5.5. Stochastic Climate Commitment Act Prices

We generated 90 draws of allowance prices to represent the impact of the Climate Commitment Act in the stochastic electric price model. The ensemble price described earlier in this appendix was used as a basis and varied between the Washington Department of Ecology allowance price floor and ceiling.

Figure G.14: Climate Commitment Act Allowance Prices — 90 Iterations



5.6. Stochastic Electric Price Forecast Results

AURORA forecasts market prices and operations based on the forecasts of key fundamental drivers such as demand, fuel prices, and hydroelectric conditions. AURORA can generate 90 iterations of electric price forecast using the risk sampling for demand, fuel, and the pre-defined iteration set hydro and wind. Figure G.15 and Figure G.16 provide the stochastic electric price forecasts' annual and levelized power prices.

Figure G.15: Annual Electric Price Stochastic Results

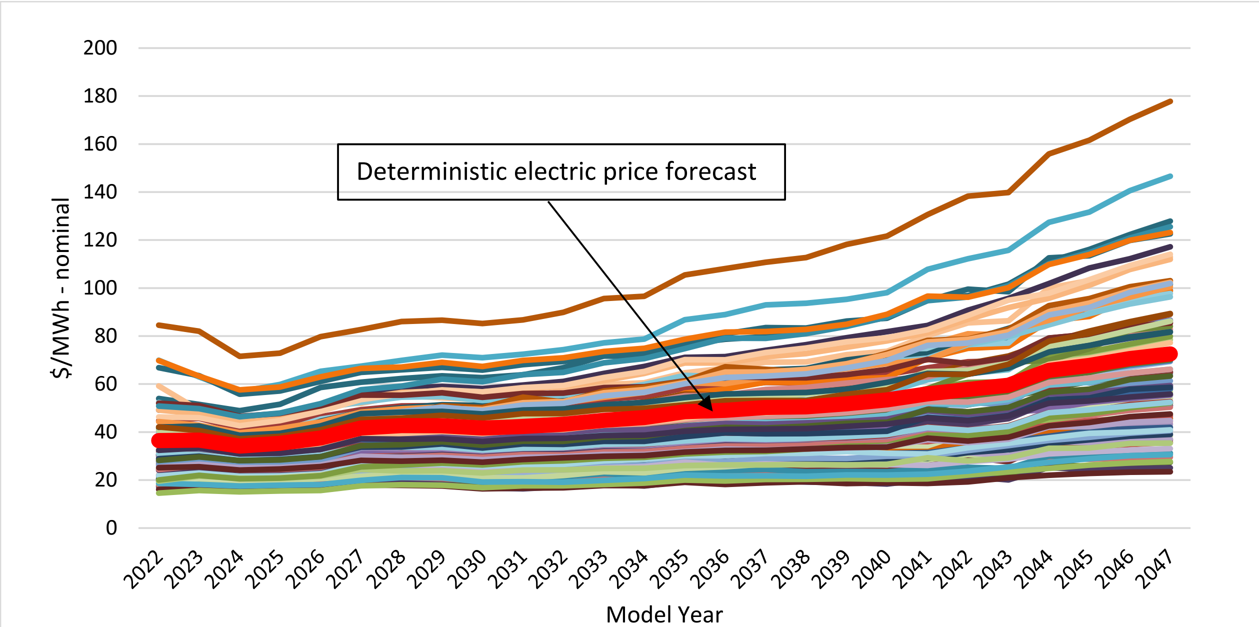
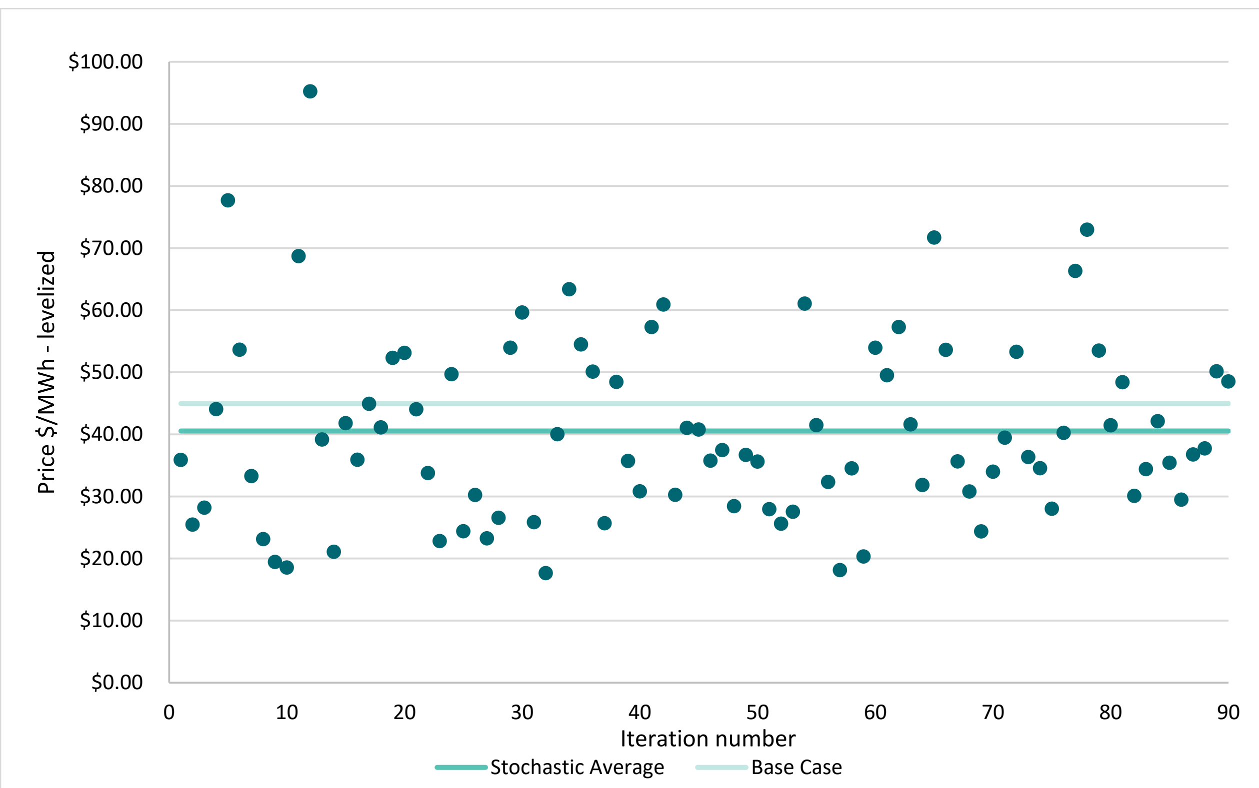


Figure G.16: Levelized Stochastic Electric Price Forecast Results - 90 Iterations



ELECTRIC ANALYSIS AND PORTFOLIO MODEL

APPENDIX H

Contents

1. Introduction

Puget Sound Energy uses three models in our electric integrated resource planning: AURORA, PLEXOS, and a stochastic resource adequacy model. This appendix provides a detailed description of those models and our analyses.

We use AURORA in several ways:

1. To analyze the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch.
2. To create optimal portfolios and test them to evaluate PSE's long-term revenue requirements for the incremental portfolio and the risk of each portfolio.
3. To create simulations and distributions for various variables in the stochastic analysis.

PLEXOS estimates the cost savings due to sub-hour operation for new generic resources.

We use resource adequacy models in the following ways:

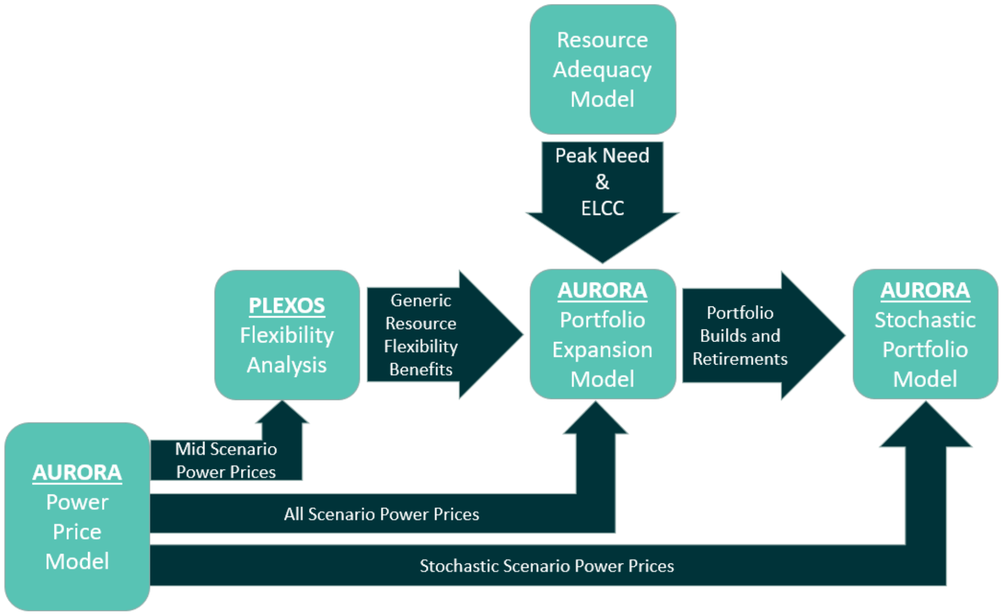
1. To quantify physical supply risks as PSE's portfolio of loads and resources evolves.
2. To establish peak load planning standards to determine PSE's capacity planning margin.
3. To quantify the peak capacity contribution of a renewable and energy-limited resource (effective load carrying capacity, or ELCC). The peak planning margin and ELCCs are inputs in AURORA for portfolio expansion modeling.

➔ A full description of resource adequacy modeling is in Chapter Seven: Resource Adequacy Analysis.

Figure H.1 demonstrates how the models are connected. We used the following steps to reach the least-cost portfolio for each scenario and sensitivity.

1. Create Mid-Columbia (Mid-C) power prices in AURORA for each electric price scenario.
2. Using AURORA's Mid Scenario Mid-C prices, run the flexibility analysis in PLEXOS to find the flexibility benefit for each generic supply-side resource.
3. Run a resource adequacy model to find the peak capacity need and ELCCs.
4. Using the electric price forecast, peak capacity need, ELCC, and flexibility benefit, run the portfolio optimization model in AURORA for new portfolio builds and retirements for each scenario and sensitivity portfolio.
5. Develop stochastic variables in AURORA around power prices, gas prices, hydro generation, wind generation, PSE loads, and thermal plant forced outages.

Figure H.1: Electric Analysis Methodology



2. AURORA Electric Price Model

We use Energy Exemplar's AURORA program to perform the electric price forecast process. AURORA is algebraic solver software used for decades in the utility industry to complete analyses and forecasts of the power system. The software allows us to perform comprehensive analyses and maintain a rigorous record of the data we used in the simulations.

We used the AURORA electric price model to forecast Mid-Columbia (Mid-C) wholesale electric prices over the planning horizon. The electric price model models all balancing authorities in the Western Electricity Coordinating Council (WECC).

➔ A full description of the electric price modeling is in Appendix G: Electric Price Models.

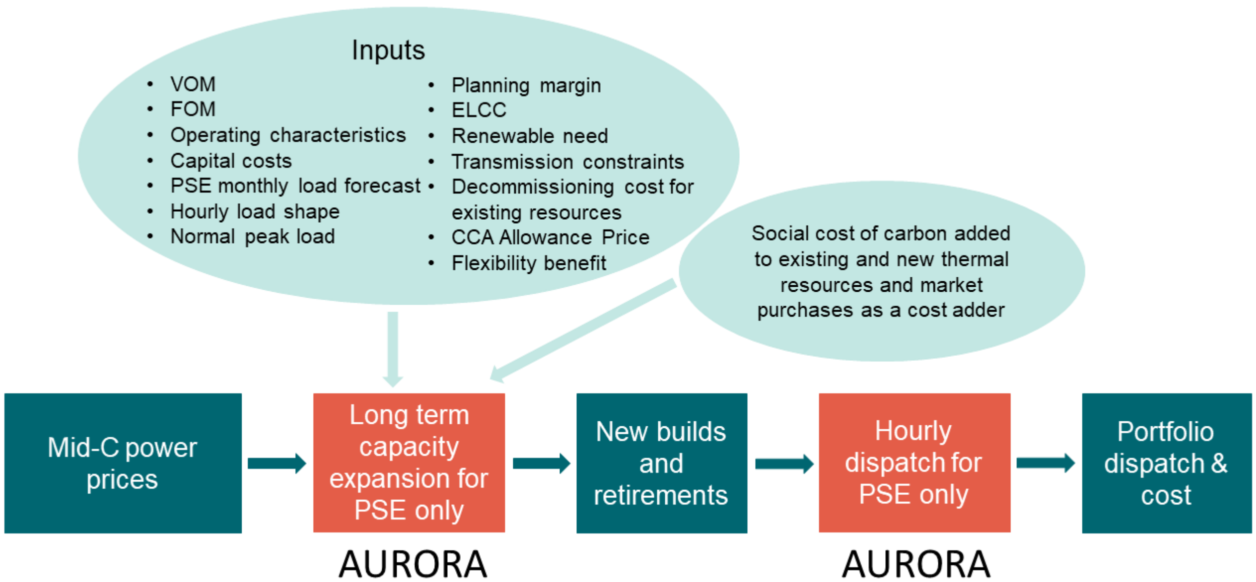
3. AURORA Portfolio Model

Puget Sound Energy's electric portfolio model follows a four-step process:

1. We use a long-term capacity expansion (LTCE) model to forecast which resources to install and retire over a long-term planning horizon to keep pace with energy and peak needs and to meet the renewable requirement in the Clean Energy Transformation Act (CETA).
2. The LTCE run produces a set of resource builds and retirements, that includes the impact of the social cost of greenhouse gases.

3. The final set of builds and retirements is then passed to the standard zonal model in AURORA to simulate every hour of the 22 years for a complete dispatch.
4. The standard zonal hourly dispatch then produces the portfolio dispatch and cost.

Figure H.2: Aurora Portfolio Model



3.1. Long-term Capacity Expansion Model

We used a long-term capacity expansion model to forecast the installation and retirement of resources over a long period. Over the study period of an LTCE simulation, the model may retire existing resources and add new ones to the resource portfolio. We used AURORA to perform the LTCE modeling process.

We began the resource planning process by deploying the LTCE model to consider the current fleet of resources available to PSE, the options available to fill resource needs, and the planning margins required to fulfill our resource adequacy needs. The model used the demand forecast to calculate the resource need dynamically as it performed the simulation. The LTCE model has the discretion to optimize the additions and retirements of new resources based on resource needs, economic conditions, resource lifetime, and competitive procurement of new resources.

We established which new resources would be available to the model before we ran it. In consultation with interested parties, we identified potential new resources and compiled the relevant information to these resources, such as capital costs, variable costs, transmission needs, and output performance. We did not include contracts in the modeling process, since that information is not publicly available for transparency in the 2023 Electric Report.

3.2. Optimization Modeling

Optimization modeling finds the optimal minimum or maximum value of a specific relationship, called the objective function. The objective function in PSE's LTCE model is to minimize the revenue requirement of the total portfolio — the cost to operate the fleet of generating resources.

The revenue requirement at any given time is:

$$RR_t = \sum_{Resource} (Capital\ Costs_{Resource} + Fixed\ Costs_{Resource} + Variable\ Costs_{Resource}) + Contract\ Costs + DSR\ Costs + Market\ Purchases - Market\ Sales$$

Where t is the point in time, and RR_t is the revenue requirement at that time.

Over the entire study period, the model seeks to minimize the *Present Value* of the total revenue requirement, defined as:

$$PVRR = \sum_{t=1}^{T} RR_t * [\frac{1}{(1+r)^t} + \frac{1}{(1+r)^{20}}] * \sum Resource\ End\ Effects$$

Where PVRR is the present value of the Revenue Requirement over all time steps, and r is the inflation rate used.

To reach optimization, we use various methods, including linear programming, integer programming, and mixed-integer programming (MIP). AURORA uses MIP, a combination of integer and linear programming.

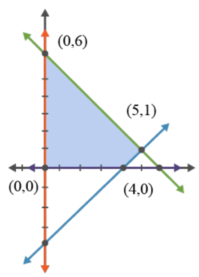
3.2.1. Linear Programming

Linear programming, or linear optimization, is a mathematical model represented by linear relationships and constraints. Linear programming optimizes a value constrained by a system of linear inequalities. In a power system model, these constraints arise from the capacities, costs, locations, transmission limits, and other attributes of resources. The constraints combine to form the boundaries of the solutions to the objective function. Figure H.3 demonstrates a basic example of linear programming, where an objective function C(x,y) is minimized and maximized

Figure H.3: Basic Example of Linear Programming

$$\textit{constraints:} \begin{cases} x + y \geq 6 \\ x - y \geq 4 \\ x \geq 0 \\ y \geq 0 \end{cases}$$

$$\textit{Objective Function:} \quad C = 2x + y$$



(0,0): $C = 2(0) + (0) = 0$ minimum

(0,6): $C = 2(0) + (6) = 6$

(5,1): $C = 2(5) + (1) = 11$ maximum

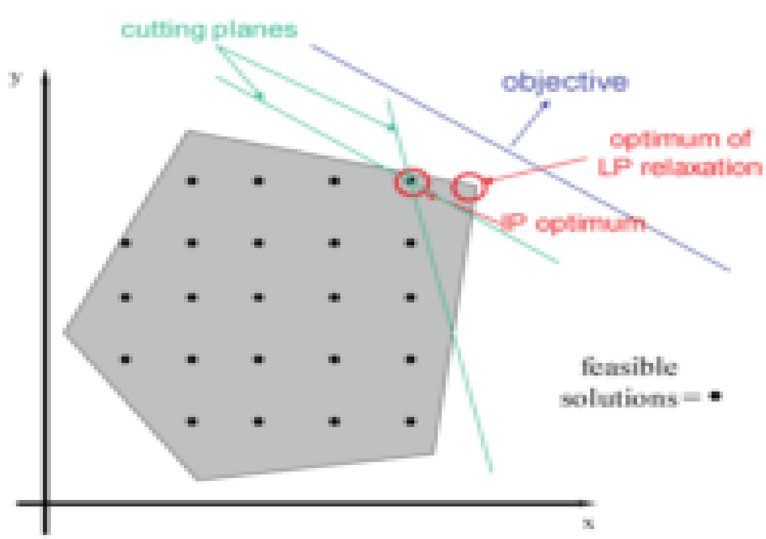
(4,0): $C = 2(4) + (0) = 8$

Calcworkshop.com

3.2.2. Integer Programming

Integer programming is another mathematical optimization method in which some or all the variables are restricted to integer values. The optimal solution may not be an integer value, but the limitation of the values in the model forces the optimization to produce a solution that accounts for these integer values. In the context of a utility, this may come in the form of having a discrete number of turbines that can be built, even though having a non-integer number of turbines will produce the optimal capacity. Figure H.4 shows an example of an integer programming problem. The optimal solution lies in the grey area, but only solutions represented by the black dots are valid.

Figure H.4: Visual Example of an Integer Programming Problem



3.2.3. Mixed Integer Programming

Mixed integer programming (MIP) combines linear and integer programming, where a subset of the variables and restrictions takes on an integer value. MIP methods are best suited for handling power system and utility models, as utilities' decisions and restraints are discrete (how many resources to build, resource lifetimes, how those resources connect) and non-discrete (the costs of resources, renewable profiles, emissions limitations).

In AURORA, MIP methods are the primary solver for completing all simulations, including the LTCE models. The software performs these methods iteratively and includes vast amounts of data, which makes the settings we use to run the model important in determining the runtime and precision of the solutions.

3.2.4. Iterative Solving

Optimization modeling can be deceptively simple when we break it down into sets of equations and solving methodologies. Limitations on computing power, the complexity of the model parameters, and vast amounts of data make a true solution impossible in many cases. To work around this, the LTCE model performs multiple iterations to converge on a satisfactory answer.

Given the complexity of the model, it does not produce the same results for each run. Over multiple iterations, AURORA compares each iteration's final portfolios and outputs with the previous attempt. If the most recent iteration reaches a certain threshold of similarity to the prior (as determined by the model settings) and has reached the minimum number of iterations, the program considers the solutions converged and provides it as the final output. If the model has reached the maximum number of iterations (also entered in the model settings), the last iteration will be considered the final output.

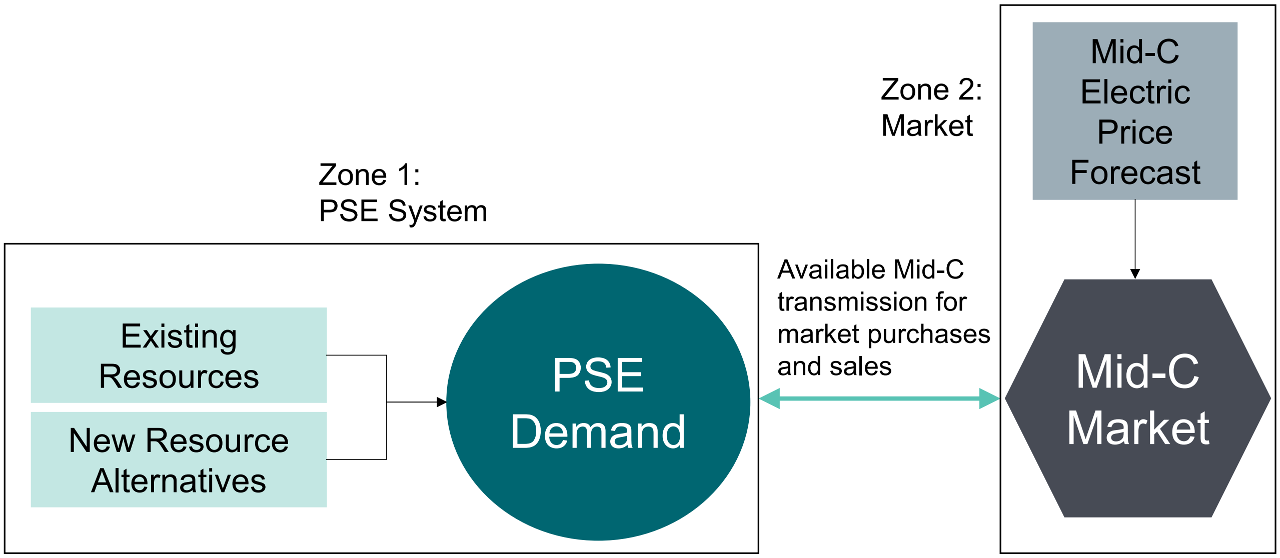
3.3. System Constraints

The solutions provided by optimizing the LTCE model seek to provide a path to meet PSE’s load and minimize the total price of the fleet. Without constraints, the LTCE optimization model selects the resource that produces the most power per resource dollar and builds as many as needed. This trivial solution provides no useful insight into how the utility should manage real resources. Constraints allow the model to find an effective solution.

3.3.1. Zonal Constraints

We divided the model into zones. The only transmission limits in the standard model are between zones, though we may add more transmission constraints for most simulations at the expense of runtime and computing power. The zonal model works best for generation optimization. We can use the nodal model for more detailed transmission optimization. Given the current constraints on technology and computing power, there is no integrated model for generation and transmission. Figure H.5 shows how this two-zone system operates in AURORA, where zones are represented as rectangular boxes, and the arrows between them represent transmission links.

Figure H.5: PSE's Two-zone System Set-up in AURORA



We operate a two-zone system for all simulations. This system limits the amounts of market purchases we can make at any given time due to transmission access to the Mid-C market hub.

3.3.2. Resource Constraints

We defined resources in the model by their constraints. A resource must be defined by constraints to make its behavior in the model match real-world operating conditions.

- **Resource Costs** — Generic resource costs give the model information about the capital costs in addition to variable and fixed operation and maintenance costs to make purchasing decisions.
- **Operating Characteristics** — Generic resource inputs contain information about when the resources can operate, including fuel costs, maintenance schedules, and renewable output profiles. These costs include transmission installation.
- **Availability** — Resources have a finite lifetime and a first available and last available year they can be installed as a resource. Resources also have scheduled and random maintenance or outage events that we include in the model.

3.3.3. Renewable Constraints

The model must meet all legal requirements. The most relevant renewable constraints PSE faces are related to the Renewable Portfolio Standard (RPS) and CETA.

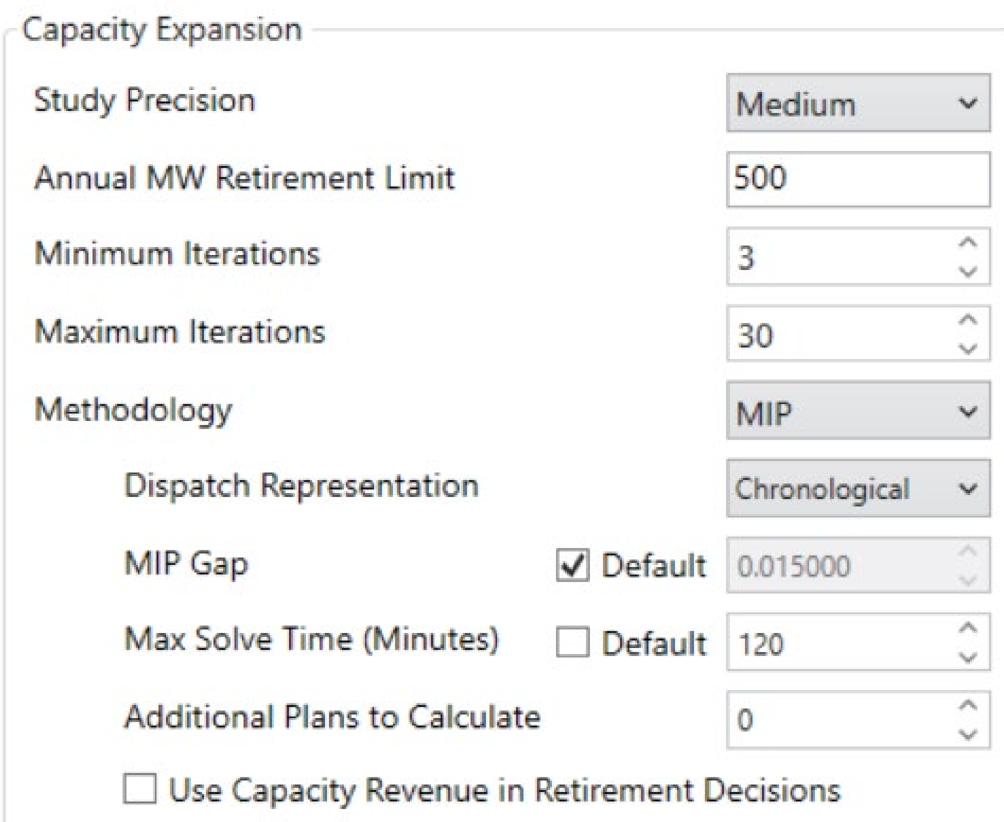
➔ See Chapter Five: Key Analytical Assumptions and Appendix D: Generic Resource Alternatives for more details on renewable constraints.

3.4. Model Settings

Our explanations for LTCE models rely heavily on the AURORA documentation provided by Energy Exemplar; we include relevant excerpts in the following section.

Before each LTCE model, we set parameters to determine how that simulation will run. The default parameters we used are in Figure H.6.

Figure H.6: Standard Aurora Parameters for PSE's LTCE Model



Note: These options are in the project file under Simulation Options → Long Term Capacity Expansion → Study Options → Long Term

3.4.1. Study Precision

During the iterative optimization process, the study precision controls when the model determines a solution is successfully converged. Instead of reaching one correct answer, the optimization process is multiple simulations that gradually converge on an optimized, stable answer given the model's assumptions. A visual representation of this process shows a model range gradually approaching an optimized solution. Users determine what is considered close enough to the absolute ideal answer by setting a percentage value for the study precision. Runtime limitations and computing power are the main drivers that limit the accuracy of a study.

The options for this setting include the following:

- High: Stops when the changes are less than 0.15 percent
- Medium: Stops when the changes are less than 0.55 percent
- Low: Stops when the changes are less than 2.5 percent

By experimenting with these settings, we determined the optimal setting is Medium, considering the tradeoff between runtime and precision.

3.4.2. Annual Megawatt Retirement Limit

The annual megawatt retirement limit restricts how much generating capacity can be economically retired in any given year. This setting does not include predetermined retirement dates, such as coal plant retirements, captured in the resources input data. We kept the default setting of 500 MW as a reasonable maximum for economic resource retirements to prevent outlier years where vast resources are retired.

3.4.3. Minimum Iterations

This setting specifies the minimum number of iterations that the simulation must complete. We set the minimum to three iterations to ensure that model decisions are checked.

3.4.4. Maximum Iterations

This setting specifies the maximum number of iterations that the simulation must complete. We set the maximum to 30 iterations to ensure the model's runtime does not become excessive. A simulation with more than 30 iterations will likely not converge on a usable solution.

3.4.5. Methodology

PSE uses the Mixed Integer Program (MIP) AURORA to perform the long-term capacity expansion model run.

4. Mixed Integer Program Methodology

The MIP methodology uses a Mixed Integer Program to evaluate resource build and retirement decisions. The MIP allows for a different representation of resources within the mode, leading to faster convergence times, more optimal (lower) system costs, and better handling of complex resource constraints. We employ the MIP methodology to take advantage of these benefits over traditional logic.

MIP-Specific Settings: Some settings within the MIP selection refine the performance of the MIP methods. We often use these settings at their default values, which are calculated based on the amount of data read into the AURORA input database for the simulation. The options are in the AURORA documentation and explained in Table H.1.

Table H.1: The MIP-specific Settings Used in the AURORA LTCE Model

Setting	Value Type	Definition
Dispatch Representation	Chronological	This methodology uses the dispatch of units in the chronological simulation (both costs and revenues) as the basis for the valuation of the build and retirement decisions. AURORA determines a net present value (NPV) for each candidate resource and existing resource available for retirement based on variable and fixed costs and energy, ancillary, and other revenue. Given the constraints, the method seeks to select the resources that provide the most value to the system. The formulation also includes internal constraints to limit the number of changes in system capacity between each iteration. These constraints are dynamically updated to help guide the solution to an optimal solution and promote convergence. We used this setting for the LTCE modeling process.
MIP Gap	Percent as a decimal value	This setting controls the precision level tolerance for the optimization. The default setting is generally recommended and will dynamically assign the MIP gap tolerance based on the study precision, objective setting, and potential problem size. When default is not selected, a value (generally close to zero) can be entered; the smaller the value, the harder the optimization works to find solutions.
Max Solve Time	Minutes	This setting controls the time limit for each LT MIP solution. Generally, using the default setting is recommended and will dynamically set the time limit based on the estimated difficulty of the problem (in most cases, about 30 minutes). If the default is not selected, the user can enter a value. If the time limit is reached, results may not be perfectly reproducible, so generally, a higher value is recommended.
Additional Plans to Calculate	Integer Value	When this value exceeds zero, AURORA will calculate additional plans after determining the final new build options and retirements. The program then adds a constraint to exclude the previous solutions, and then another MIP is formulated, and the solver returns its next best solution. The resource planning team sets this to zero.

5. Assumptions for all AURORA Models

The LTCE modeling process is a subset of the simulations we perform in AURORA. We keep most of these settings consistent across all models in AURORA, including the LTCE process. We may adjust sensitivities or simulations that are not converging properly. Table H.2 describes the settings we used in AURORA.

Table H.2: General Settings Used in all AURORA Models

Setting	Value Type	Definition
Economic Base Year	Year	The dollar year we set all currency to in the simulation. We used 2020 across all simulations through all IRP processes in AURORA for consistency, so we converted all inputs into 2020 dollars.

Setting	Value Type	Definition
Minimum Generation Backdown Penalty	Cost	Provides flexibility in modeling minimum generation segments and addresses linear programming solution infeasibility, which we can introduce due to hard minimum generation constraints. We set this value to $44.
Resource Dispatch Margin	Percentage	A value used to specify the margin over the cost of the resource required to operate that resource. We set this value to 0 percent.
Remove Penalty Adders from Pricing	Binary	When this option is selected, the model will adjust the zonal pricing by removing the effect of the non-commitment penalty on uncommitted resources and the minimum generation backdown penalty on committed or must-run resources. We used these penalty adders in the LP dispatch to honor commitment and must-run parameters; if this switch is selected, the model fixes resource output at the solved level before deriving zonal pricing without the direct effect of the adders. We selected this setting.
Include Variable O&M in Dispatch	Binary	We use this option to control the treatment of variable operation and maintenance (O&M) expenses. If selected, the variable O&M expenses are included in the dispatch decision of a resource. We selected this setting.
Include Emission Costs in Dispatch	Binary	This option allows the user to include the cost of emissions in the dispatch decision for resources. If not selected, the cost of emissions will not be included in the dispatch decision for resources. We selected this setting when modeling CO_2 price as a dispatch cost in select sensitivities.
Use Operating Reserves	Binary	This option determines whether the dispatch will recognize operating reserve requirements and identify a set of units for operating reserve purposes. When this option is selected, the model will choose a set of units (when possible) to meet the requirement. We selected this setting.
Use Price Caps	Binary	This option allows the user to apply price caps to specific zones in the database. If this option is selected, the model will apply specified price caps to the assigned zones. We selected this setting.

5.1. Resource Value Decisions

When solving for each time step of the LTCE model, AURORA considers the portfolio's needs and the resources available to fill those needs. The needs of the portfolio include capacity need, reserve margins, ELCC, and other relevant parameters that dictate the utility’s ability to provide power. If there is a need, the model will select a subset of resources to fill that need.

At that time step in the program, each resource will undergo a small simulation to forecast how it will fare in the portfolio. This miniature forecast considers the operating life, capacity output, and scheduled availability of the resource. The model then considers resources that can best fulfill the needs of the portfolio on the merits of their costs.

Resource costs include the cost of capital to invest in the resource and fixed and variable O&M costs. Capital costs include the price of the property, physical equipment, transmission connections, and other investments required to acquire the physical resource. Fixed O&M costs include staffing and scheduled resource maintenance under normal conditions. Variable O&M costs include costs incurred by running the resource, such as fuel and maintenance costs accompanying use.

After we forecasted the costs of operating each resource, we compared them to find which had the least cost and served PSE's needs. The goal of the LTCE, an optimization model, is to provide a portfolio of resources that minimizes the cost of the portfolio.

6. Modeling Inputs

Several input assumptions are necessary to parameterize the model. These assumptions come from public and proprietary sources, and some we refined through our engagement process.

6.1. Forecasts

We cannot capture some attributes of the model in a single number or equation. Seasonal changes in weather, population behavior, and other trends that influence utility actions rely on highly time-dependent factors. We included a series of forecasts in the input assumptions to help provide these types of information into the model. Forecasts help direct overall trends of what will affect the utility in the future, such as demographic changes, gas prices, and environmental conditions. These forecasts are not perfect representations of the future, which is impossible to provide. However, they provide a layer of volatility that helps the model reflect real-world conditions.

Table H.3: Forecast Inputs and Sources

Input	Source	Description
Demand Forecast	Internal (see Chapter Six and Appendix F)	Energy and peak demand forecast for PSE territory over the IRP planning horizon.
Electric Price Forecast	Internal (see Appendix G)	The output of the AURORA electric power price model.
Natural Gas Price Forecast	Forward Marks prices, Wood Mackenzie (see Chapter Five)	A combination of the Forward Marks prices and Wood Mackenzie long-term price forecast.
Wind and Solar Generation	DNV	Solar and wind generation shapes dictate the performance of these renewable resources. Some forecasts are from existing PSE wind projects. Consultant DNV provides correlated wind and solar forecasts.

6.2. Resource Groups

Resources are split into two groups, existing and generic resources.

6.2.1. Existing Resources

We provided existing resources to the model as the base portfolio. Existing resources include those already in operation and those scheduled to be in the future. We also provided the model with scheduled maintenance and outage dates, performance metrics, and future retirement dates.

➔ See Appendix C: Existing Resource Inventory for more details of the existing resources modeled.

6.2.2. Generic Resources

Generic resources are the resources available to be added to the LTCE model. These resources represent real resources the utility may acquire in the future. Information about the generic resources includes the fuel used by the resources, costs, and availability. We also included transmission information based on the locations of the resources modeled.

➔ Details of the generic resources modeled are in Appendix D: Generic Resource Alternatives, and the numerical generic resource inputs in Appendix I: Electric Analysis Inputs and Results.

We simplified these resources to obtain representative samples of a particular resource group. For example, modeling every potential site where PSE may acquire a solar project would require prohibitive amounts of solar data from each location. To work around this issue, we used a predetermined site from different geographic regions to represent a solar resource in that area.

We developed the specific generic resource characteristics in partnership with IRP interested parties. As a result of feedback, we changed the costs of multiple resources to reflect more current price trends, and new resources were added, such as renewable and energy storage hybrid resources.

6.3. Capital Cost Calculations

The capital cost of a resource plays a large role in their consideration for acquisition by the model. Puget Sound Energy finances capital costs through debt and equity. The revenue requirement is the revenue the utility collects from ratepayers to cover operating expenses and the financing costs of the capital investment. The combined revenue requirement of all resources in the portfolio is the portfolio's total revenue requirement, the objective function the LTCE model seeks to minimize.

The revenue requirement is in the following equation:

$$\text{Revenue Requirement} = \text{Rate Base} * \text{Rate of Return} + \text{Operating Costs}$$

$$\text{Rate Base} = \text{Capital Investment}$$

$$\text{Rate of Return} = \text{Financing Costs (Set by the Commission)}$$

$$\text{Operating Costs} = \text{Fixed Operating Costs} + \text{Variable Operating Costs} + \text{Fuel} + \text{Depreciation} + \text{Taxes}$$

6.4. Social Cost of Greenhouse Gases

Per CETA requirements, we included the social cost of greenhouse gases (SCGHG) as an externality cost in the IRP process. We modeled the SCGHG as an externality cost added to the total cost of a given resource because CETA instructs utilities to use the SCGHG to make long-term and intermediate planning decisions. However, we also completed a portfolio sensitivity of the SCGHG as a variable dispatch cost based on requests from interested parties and as ordered by the Commission.

We revised how we applied the SCGHG for this 2023 Electric Report from the methodology presented in the 2021 IRP. For this report, we modeled the SCGHG as an externality cost adder with the following methodology:

1. We ran the LTCE model to determine portfolio-build decisions over the modeling timeframe. The LTCE model applied the SCGHG as a penalty to emitting resources (i.e., fossil-fuel resources) during each build decision and to market purchases.
    a. We applied the externality adder to emitting resources as follows:
        i. AURORA generates a dispatch forecast for the economic life of an emitting resource. The SCGHG does not impact this dispatch forecast to simulate real-world dispatch conditions.
        ii. The model summed the emissions of this dispatch forecast for the economic life of the emitting resource and applied the SCGHG to the total lifetime emissions.
        iii. The model then applied the lifetime SCGHG as an externality cost to the total lifetime cost of the resource.
        iv. The model based new build decisions on the total lifetime cost of the resource.
    b. We applied the externality cost to market purchases as follows:
        i. Modeled unspecified market purchases with an emission rate of 0.437 metric tons of CO_2eq per MWh.[1]
        ii. Multiplied the annual social cost of greenhouse gases by this emission rate and applied it as a hurdle rate added to the cost of market purchases in the LTCE model.
2. The LTCE model creates a portfolio of new builds and retirements. Since the LTCE runs through many simulations, we used a sampling method to decrease run time; so, in the final step, we passed the portfolio to the hourly dispatch model, which can model dispatch decisions at a much higher time resolution. The hourly dispatch model cannot make build decisions but more accurately assesses total portfolio cost to ratepayers. Since the SCGHG is not a cost passed to ratepayers, we did not include the SCGHG in the hourly dispatch modeling step.

[1] RCW 19.405.070

In the 2021 IRP, we calculated the fixed cost adder based on a separate AURORA dispatch model run to estimate the emissions expected for each emitting resource type. We then applied the fixed cost adder statically to subsequent simulations. In this progress report, we used the AURORA dispatch model's improved functionality to apply the SCGHG to emitting resources dynamically. In the revised methodology, AURORA dispatches emitting resources not subject to the SCGHG, then applies the SCGHG for all emissions over the resource's lifetime to the total cost of the resource when calculating the resource value for addition and retirement decisions. The 2023 model's SCGHG accounting is a marked improvement from the 2021 IRP methodology because the new accounting method more accurately represents the emissions of resources which may vary by simulation due to input changes or variation in the resource mix.

We applied the SCGHG to market purchases consistently in this report and the 2021 IRP — we added a hurdle rate to the cost of market purchases that reflects the unspecified market purchase emission rate. Modeling the SCGHG on market purchases as a hurdle rate impacts the dispatch of market purchases in the modeling framework. Reflecting the SCGHG as a dispatch cost on market purchases and as an externality cost to emitting resources introduces bias against market purchases into the model. We identified this bias late in the 2023 Electric Report modeling process and are actively working to identify a solution for future IRP cycles.

Interested parties requested that we include the SCGHG as a dispatch cost on emitting resources. We implemented this request as follows in Sensitivity 15:

1. Run a long-term capacity expansion (LTCE) model to determine portfolio-build decisions over the modeling timeframe. Apply the SCGHG in the LTCE model as a penalty to emitting resources during each build decision as a dispatch cost, which means the total energy produced by the resource decreased due to the higher dispatch cost.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simulations, use a sampling method to decrease run time, then pass the portfolio to the hourly dispatch model, which can model dispatch decisions at a much higher resolution. The hourly dispatch model cannot make build decisions but will more accurately assess total portfolio cost to ratepayers. We omitted the SCGHG in the hourly dispatch modeling step.

➔ See Chapter Eight: Electric Analysis for more information on sensitivity 15.

6.5. Climate Commitment Act

The Climate Commitment Act (CCA) is a cap-and-invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances representing permitted emissions. The resulting market creates an opportunity cost for emitting greenhouse gases.

We added an emission price to greenhouse gas emissions in the electric price forecast model for emitting resources within Washington State to model this opportunity cost. We only added the emission price to Washington State emitting resources to ensure the model reflects any change in dispatch without impacting that of resources outside

Washington State not subject to the rule. To accurately reflect all costs imposed by the CCA, we added a hurdle rate on transmission market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO2eq per MWh.[2]

We modeled the CCA allowance as a variable cost on both emitting resources and market purchases. This method means the impact of the CCA allowance price will impact the dispatch of these resources, reducing the amount of energy generated by these resources. We included the CCA allowance prices in the LTCE and hourly dispatch models because it is a direct cost on emitting resources and market purchases.

➔ See Chapter Five: Key Analytical Assumptions and Appendix I: Electric Analysis Inputs and Results for additional information on the CCA allowance price.

7. Embedding Equity

This section describes the methods we used in the 2023 Electric Report to quantify how different portfolios can improve equitable outcomes for named communities.

We analyzed these benefits outside the AURORA model with an Excel-based analysis called the portfolio benefit analysis. The AURORA program is a production cost model that seeks to identify the lowest-cost portfolio given constraints. Currently, elements of an equitable portfolio are difficult to translate into cost values; therefore, AURORA is ill-equipped to incorporate equity into its solution. Consequently, we developed the portfolio benefit analysis to obtain a relative measure of benefits for each portfolio analyzed as part of the planning process.

➔ We discuss the results in Chapter Eight: Electric Analysis. Appendix I: Electric Analysis Inputs and Results is the Excel workbook that contains the data and the numerical analysis results.

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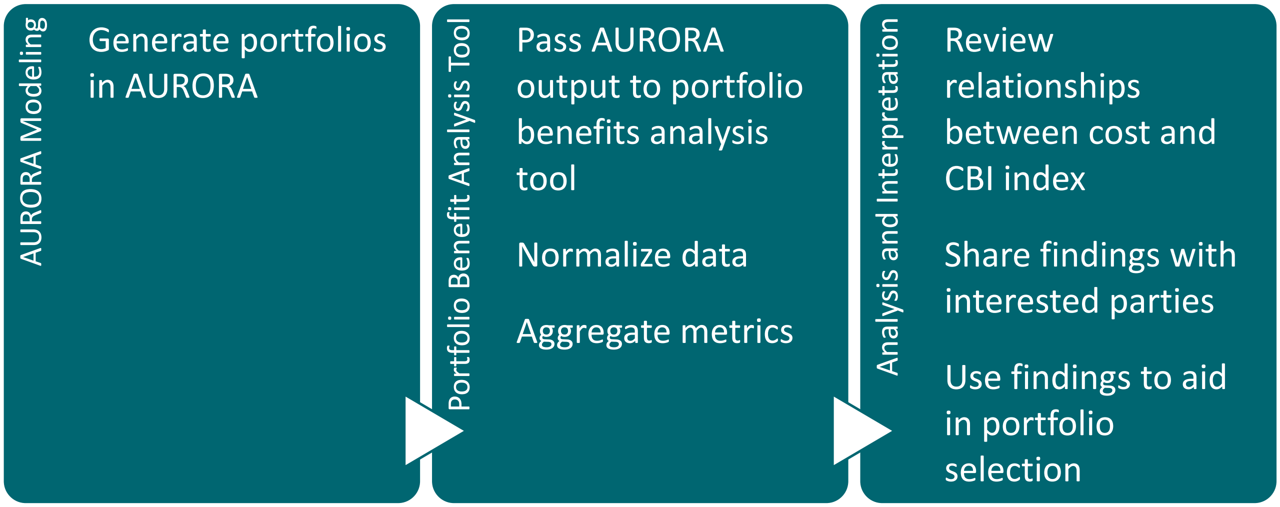
Figure H.7: Elements of the Portfolio Benefit Analysis Process



The portfolio benefit analysis measures the number of customer benefits of each portfolio modeled. We use select metrics from the AURORA output to represent the Customer Benefit Indicators (CBIs) we developed as part of the 2021 Clean Energy Implementation Plan (CEIP), working collaboratively with our Equity Advisory Group (EAG) and customers.

The portfolio benefit analysis measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative customer benefit indicators (CBIs) and their metrics. Customer benefit indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this 2023 Electric Report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA model could quantitatively evaluate them, i.e., AURORA already had a comparable metric.

We describe the elements of the portfolio benefit analysis in the following sections.

7.1. Modeling

The first step in the portfolio benefits analysis is to generate portfolios to review. Portfolios are a collection of generating resources PSE could use to serve electrical demand. First, we create a reference portfolio that represents the lowest-cost portfolio to satisfy the base modeling assumptions. Then we generate a variety of portfolios to represent a range of economic conditions, resource assumptions, and environmental regulations to learn how those changes impact the resource mix and cost of the portfolio.

➔ We describe the AURORA portfolio modeling throughout this appendix and provide results for each portfolio in Chapter Eight: Electric Analysis.

7.2. Data Collection

Following the modeling process, we collected targeted data from the AURORA output for each portfolio. We can measure many CBIs directly from this data, such as emissions and portfolio cost. However, AURORA does not generate job, customer, or participant data. The portfolio benefit analysis combines the technology-specific capacity built over the 22-year planning period with additional data to generate meaningful metrics to evaluate these CBIs.

- **Jobs**: The portfolio benefit analysis uses a technology-specific job per megawatt (MW) metric to convert the technology-specific capacity AURORA provides into a total number of jobs created for a given portfolio. The jobs/MW metric combines the 2022 U.S Energy and Employment Jobs Report[3] data with the technology-specific total capacity operating nationally, sourced from the 2022 Early Release EIA Forms 860[4] and 861[5].

- **Demand Response and Distributed Energy Resources (DER) participation**: We show the number of expected participants in demand response programs in PSE's 2022 Conservation Potential and Demand Response Assessments that we produced for this 2023 Electric Report and provided in Appendix E. Historic DER participation data is from the 2022 EIA Form 861M[6].

Table H.4 summarizes the CBIs, associated metrics, and data sources we evaluated in the portfolio benefit analysis tool.

Table H.4: Metrics and Data Sources in the Portfolio Benefit Analysis

CBI	Measurement Metric (Unit)	Data Source
Reduced greenhouse gas emissions	CO_2 (short tons)	AURORA output
Improved affordability of clean energy	Portfolio cost ($)	AURORA output
Improved outdoor air quality	Sulfur oxides (Sox), nitrogen oxides (Nox), and particulate matter (PM) (short tons)	AURORA output
Increased participation in Energy Efficiency, Distributed Energy Resources, and Demand Response programs	Customer in each program (count)	AURORA output PSE's 2022 Conservation Potential Assessment and Demand Response Assessment 2021 Early Release EIA Form 861M
Increase in the number of jobs	Jobs generated (count)	2022 U.S Energy and Employment Jobs Report and

3 https://www.energy.gov/sites/default/files/2022-06/USEER%202022%20National%20Report_1.pdf
4 https://www.eia.gov/electricity/data/eia860/
5 https://www.eia.gov/electricity/data/eia861/
6 https://www.eia.gov/electricity/data/eia861m/

CBI	Measurement Metric (Unit)	Data Source
		2021 Early Release and EIA Forms 860 and 861
Improved access to reliable, clean energy	Customers with access to storage resources (count)	AURORA output 2021 Early Release EIA Form 861M
Reduction in peak demand	Peak reduction through Demand Response (MW)	AURORA output

7.3. Normalization

The portfolio benefit analysis normalizes all metrics to 1) allow comparison between metrics with different units, such as emissions and job data, and 2) create an overall CBI index to compare portfolios and sensitivities. The portfolio benefit analysis normalizes metrics using a modified z-score, where we set the reference portfolio to equal zero, and each sensitivity converts to an index measuring the number of standard deviations from the reference portfolio. All positive indices indicate a more favorable CBI outcome than the reference portfolio.

7.4. Aggregation

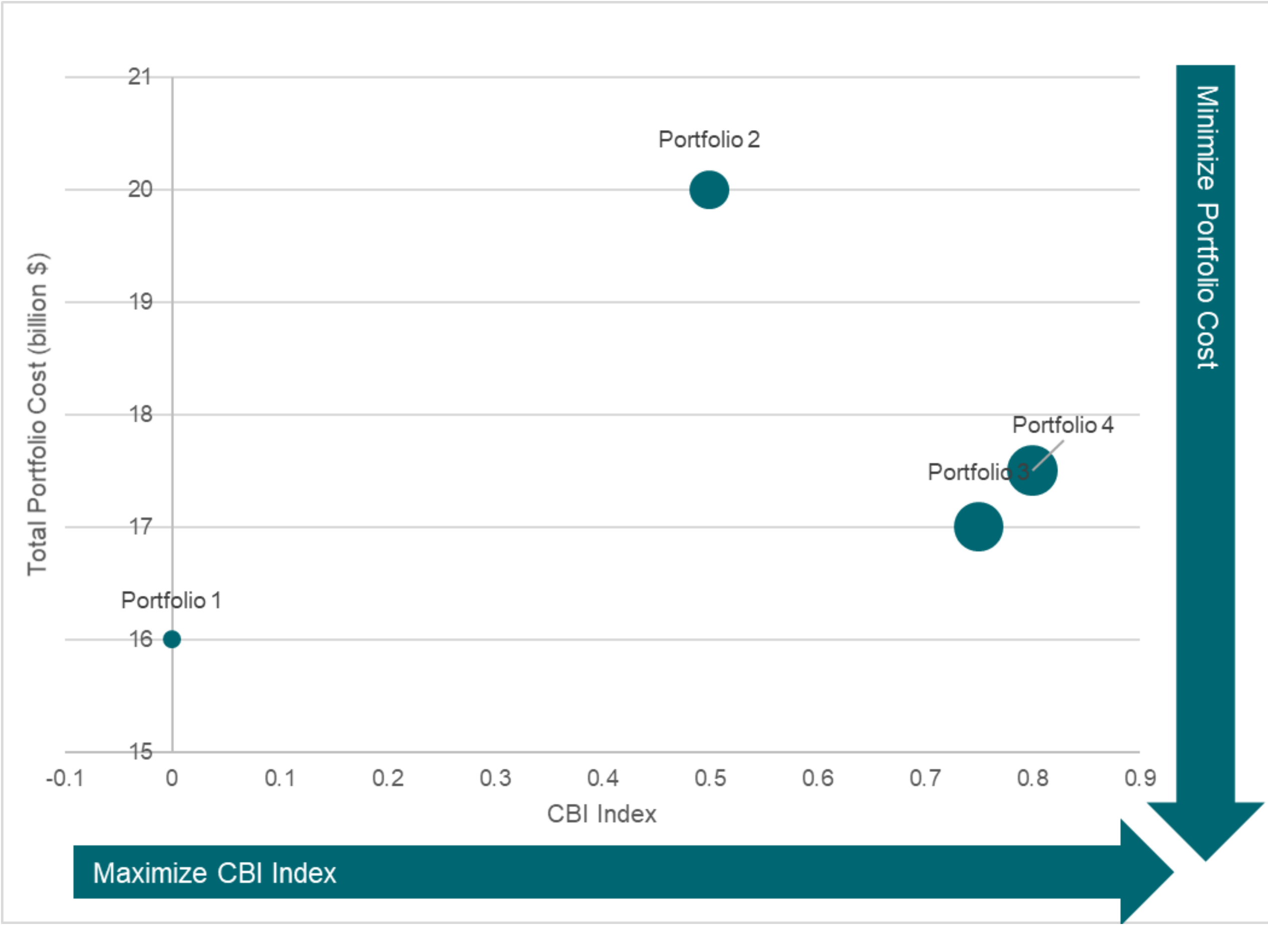
Following normalization, the portfolio benefit analysis combines all CBI indices into a single index for the portfolio using the arithmetic mean. The overall CBI index provides a single value representing the relative quantity of benefits each portfolio provides and facilitates direct comparison between the various portfolios.

7.5. Analysis

We plotted the overall index for each portfolio against the total portfolio cost. This plot illustrates the tradeoff between increasing CBI value and cost. Compared to the reference portfolio, the most efficient portfolios have the greatest CBI indices with minimal increase in portfolio cost.

Figure H.8 illustrates an example scenario where we analyzed four portfolios. We plotted the reference portfolio, Portfolio 1, near the origin. Portfolio 2 demonstrates an inefficient portfolio, where a moderate increase in the CBI index costs four billion dollars more than the reference portfolio. Conversely, Portfolios 3 and 4 illustrate more efficient portfolios, where the relative increase in the CBI index costs an additional one or one and a half billion dollars, respectively. The most efficient portfolios are near the bottom, right side of the plot. The point's radius illustrates the second indication of efficiency; the larger points indicate increased CBI value per dollar spent.

Figure H.8: Sample Portfolio Benefit Analysis Comparison Plot



7.6. Interpretation

Next, we further reviewed the details of the most efficient portfolios, considering the resource mix and the real-world applicability. In the example illustrated in Figure H.6, the relationship between Portfolios 3 and 4 shows a tradeoff between cost and CBI value, often referred to as an efficiency frontier. Portfolio 3 offers a lower cost, while Portfolio 4 offers a higher CBI value. In this case, we must review portfolio-build decisions and consider additional factors.

For example, if Portfolio 4 requires 1,000 MW of distributed rooftop solar installed by 2030, but this is infeasible due to a supply chain shortage and a deficit in interested and available participants, Portfolio 4 would not be selected as the preferred portfolio, even though it has the highest CBI index. Similarly, we would not automatically choose a sensitivity based on cost alone.

After reviewing an initial group of portfolios, we shared initial conclusions with internal and external parties to gain additional perspective on the candidate portfolios. The feedback from interested parties included recommendations that we analyze different portfolios that included or excluded specific resource types. We analyzed these other portfolios and added the results to the portfolio benefit analysis.

Because the portfolio benefit analysis uses a modified z-score methodology to convert raw data into an index, the index is subject to change by introducing new portfolios. Therefore, to minimize user bias, once a portfolio is analyzed, it will remain within the portfolio benefit analysis, even if we deem it inefficient or infeasible.

Further interpretation of the initial and new portfolios together provides context for selecting the preferred portfolio from a selection of candidate portfolios.

8. Financial Assumptions

As the portfolio modeling process takes place over a long-term timeline, we must make assumptions about the financial system the resources will operate in.

8.1. Tax Credit Assumptions

Before the Inflation Reduction Act (IRA), Production Tax Credit (PTC) and Investment Tax Credit (ITC) values were based on the start of construction with a four-year window to complete a qualifying project. We phased down the PTC and ITC, where PTC was set to expire in 2022, and ITC was ramped down to 10 percent indefinitely. The ramp-down created uneven investment decisions to capture the most value for the tax credits. The tax credits were technology specific: PTC for wind and ITC for standalone solar and solar paired with storage.

The IRA extended the PTC to 100 percent value and the ITC back to the maximum 30 percent value. The IRA now makes the PTC and ITC technology neutral. The IRA expanded the tax credits to include standalone storage and advanced nuclear.

There is a bonus incentive that may allow businesses to achieve more project-specific tax credit incentives. The additional credits are as follows:

- Ten percent for domestic consent
- Ten percent energy community credit
- Ten to twenty percent of low-income communities' projects under 5MW (ITC only)

The PTC provides tax credits based on a project's first 10 years of output. The current PTC rate is $26/MWh and is adjusted annually for inflation. Solar projects are now eligible for PTC, which is more economical than the ITC from our analysis.

We apply the 30 percent ITC to investments in a qualifying project. The ITC provides a large benefit for standalone storage, now providing a 30 percent discount on capital costs.

8.2. Discount Rate

We used the pre-tax weighted average cost of capital (WACC) from the 2019 General Rate Case of 6.8 percent nominal.

8.3. Inflation Rate

Unless otherwise noted, we used a 2.5 percent escalation for all assumptions. This is the long-run average inflation rate the AURORA model uses.

8.4. Transmission Inflation Rate

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

8.5. Gas Transport Inflation Rate

Natural gas pipeline rates are not updated often, and recent history indicates the rates are 0 percent. We assumed zero inflation on pipeline rates because our major pipelines have declining rate bases, and we will incrementally price major expansions. We expect growth in service costs from operating costs and maintenance capital additions to be offset by declines due to depreciation.

8.6. Transmission and Distribution Costs

The transmission and distribution (T&D) benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Electric Report included a T&D benefit of $74.70/kW-year for DER batteries. The model forecasted this estimated $74.70/kW-year based on our different transmission and delivery system needs under such a scenario. This increase is a significant change from the $12.93/kW-year we used in the 2021 IRP which used backward-looking metrics instead of the revised forward-looking scenario described above.

9. AURORA Stochastic Risk Model

A deterministic analysis is a type of analysis where all assumptions remain static. Given the same set of inputs, a deterministic model will produce the same outputs. In PSE's resource planning process, the 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. In this report, PSE modeled additional deterministic sensitivities, which allowed us to evaluate a broad range of resource options and associated costs and risks. The sensitivity analysis is a type of risk analysis. We can isolate how one variable changes the portfolio builds and costs by varying one parameter.

Stochastic risk analysis deliberately varies the static inputs to a deterministic analysis to test how a portfolio developed in the deterministic analysis performs concerning cost and risk across a wide range of possible future power prices, natural gas prices, hydro generation, wind generation, loads, and plant forced outages. By simulating the same portfolio under different conditions, we can gather more information about how a portfolio will perform in an uncertain future. We completed the stochastic portfolio analysis in AURORA.

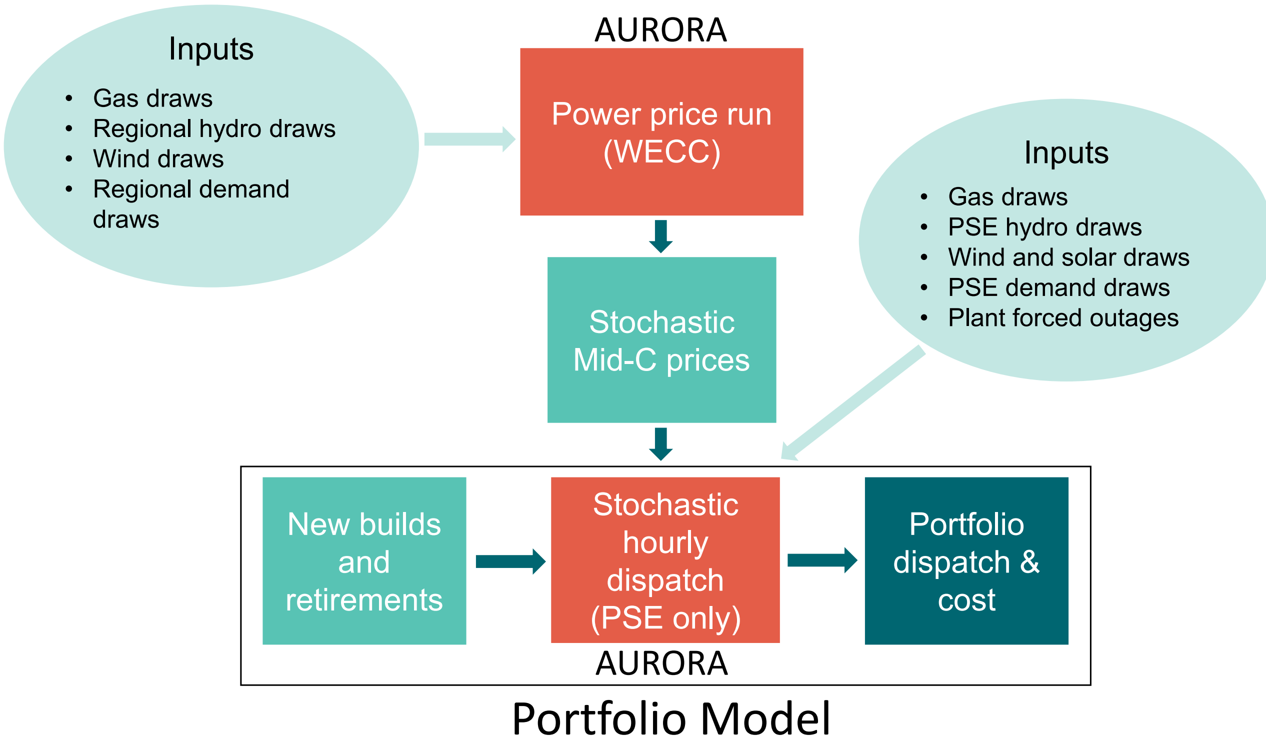
The stochastic modeling process aims to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of different forecasts, such as high prices, low hydroelectric, and the adverse impacts of their occurrence for any given portfolio.

The modeling process used to develop the stochastic inputs is a Monte Carlo approach. Monte Carlo simulations generate a distribution of resource energy outputs (dispatched to prices and must-take), costs, and revenues from AURORA. The stochastic inputs considered in this report are electric power prices at the Mid-Columbia market hub, natural gas prices for the Sumas and Stanfield hubs, PSE loads, hydropower generation, wind generation, solar generation, and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.

9.1. Development of Stochastic Model Inputs

A key goal in the stochastic model is to capture the relationships of major drivers of risks with the stochastic variables in a systematic way. One of these relationships, for example, is the correlation of variations in electric power prices with variations in natural gas prices contemporaneously or with a lag. Figure H.9 shows the key drivers we used to develop these stochastic inputs. Long-term economic conditions and energy markets determine the variability in the stochastic variables.

Figure H.9: Major Components of the Stochastic Modeling Process



Our stochastic model used the following process to simulate 310 futures of portfolio dispatch and cost:

1. Generate electric price draws. Like the deterministic wholesale price forecast, we used the AURORA model to simulate resource dispatch to meet demand and various system constraints. We vary regional demand, gas prices, and hydro and wind generation to create electric price draws. We use the price forecast for the Mid-C zone as the wholesale market price in the portfolio model.
2. Pull the electric and natural gas price draws generated in the first step into the hourly portfolio dispatch model.
3. Run the different portfolios drawn from the deterministic scenario and sensitivity portfolio through 310 draws that model varying power prices, gas prices, hydro, wind, and solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can observe how robust or risky the portfolio may be and where significant differences occur when we analyze risk.

9.2. Stochastic Electric Price Forecast

We use AURORA, a production cost model that utilizes electric market fundamentals to generate electric price draws. AURORA offers a Monte Carlo Risk capability that allows users to apply uncertainty to a selection of input variables. Users can add the variability of input assumptions into the model as an external data source, or AURORA can generate samples based on user statistics on a critical driver or input variable.

➔ Appendix G : Electric Price Models describes the methods and assumptions used to generate the stochastic electric price forecast and the simulation results.

9.3. Stochastic Portfolio Model

We use AURORA for stochastic portfolio modeling and apply a pre-defined iteration set to modify the input data in the model. We take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 310 draws that model varying power prices, gas prices, hydroelectric generation, wind generation, solar generation, load forecasts (energy and peak), and plant-forced outages. This section describes the model input assumptions we varied to generate the portfolio dispatch and cost.

9.4. Electric and Natural Gas Prices

The model packaged each completed set of power prices with gas prices and the assumed hydroelectric inputs when it generated the power price forecast. This bundle of power, gas prices, and hydroelectric conditions are input to the stochastic portfolio model. By packaging the power price, gas price, and hydroelectric year, the model preserved the relationships between gas prices and Mid-C prices and between hydro and power prices. Since there are only 90 draws generated from the stochastic electric price forecast, we sampled the electric price and natural gas uniformly to generate 310 draws.

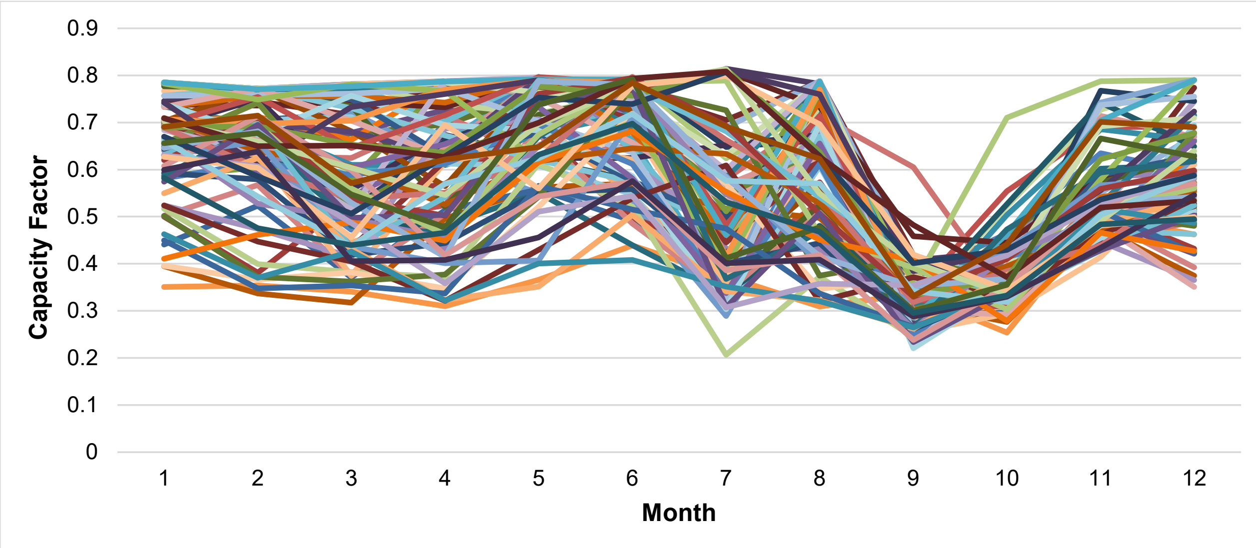
➔ Appendix G: Electric Price Models describes electric and natural gas price inputs.

9.5. Hydroelectric Variability

We use the same climate change hydroelectric data described in Appendix G: Electric Price Models for the stochastic electric price model. It is also the same hydroelectric data the Northwest Power and Conservation Council used for its 2021 Power Plan. Staying consistent with the other entities is essential since we all model the same hydropower projects.

Puget Sound Energy does not significantly depend on owned or contracted hydroelectric resources, so variations have a smaller effect on our ability to meet demand. The hydroelectric variations have a larger impact on the market for short-term purchases, as captured in the market risk assessment. The hydroelectric output of all 90 hydroelectric years is in Figure H.10. We uniformly sampled the 90 hydroelectric draws to generate 310 draws.

Figure H.10: Monthly Average Capacity Factor for 5 Mid-C Hydro Projects, 90 Draws



9.6. Electric Demand

The demand forecasts assume economic, demographic, temperature, electric vehicle, and model uncertainties to generate the set of stochastic electric demand forecasts.

The model derives the high and low monthly and annual demand forecasts from the distribution of these stochastic forecasts.

➔ Chapter Six: Demand Forecast and Appendix F: Demand Forecasting Models fully explain the stochastic demand forecasts.

9.7. Wind and Solar Variability

Consultant DNV generated wind and solar shapes to use in this Electric Report. On behalf of PSE, DNV used location information with the turbine model and power data as inputs to a stochastic model. The stochastic model generated 1,000 stochastic time series to represent the net capacity factor of a given wind or solar project for each site over the 22-year planning period. This methodology maintained daily, seasonal, and annual cycles from the original data. The stochastic model also maintained spatial coherency of weather, generation, and system load to preserve the relationships of projects across a region. DNV then randomly selected a sample of 250 annual hourly draws for each site, verified that the data represented the total distribution, and provided the data to PSE for modeling purposes.

We used the 250 wind and solar draws in the stochastic analysis. After the model selected each wind or solar draw once, it uniformly resampled the data to fill the remaining draws needed to generate 310 stochastic iterations.

➔ Appendix D: Generic Resource Alternatives contains a complete description of the wind and solar curves.

9.8. Forced Outage Rates

AURORA uses the frequency duration method, assigning each thermal plant a forced outage rate. This value is the percentage of hours in a year where the thermal plant cannot produce power due to unforeseen outages and equipment failure. This value does not include scheduled maintenance. In the stochastic modeling process, the model used the forced outage rate to randomly disable thermal generating plants, subject to the resource's minimum downtime and other maintenance characteristics. Over a stochastic iteration, the total time of the forced outage events will converge on the forced outage rate. This outage method option 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 frequency and duration method assumes units are either fully available or out of service.

9.9. Stochastic Portfolio Results

We tested the reference and preferred portfolios (sensitivity 11 B2) with the stochastic portfolio analysis.

➔ Stochastic results are in Chapter Eight: Electric Analysis, and the data is in Appendix I: Electric Analysis Inputs and Results.

10. PLEXOS Flexibility Analysis Model

Developed by Energy Exemplar, PLEXOS is an advanced production cost modeling tool we use for its capability to represent real-world, short-term operational decision cycles. This sophisticated platform allows us to appropriately model cost and reliability impacts associated with subhourly forecast uncertainty and renewable resource intermittency. Our flexibility analysis model provides for studies of interactions within our Balancing Authority Area (BAA), which designates the collection of electrical resources PSE controls and uses to balance supply and demand in real time. The BAA is different from our electric service area because some resources, such as wind and solar generators, could be physically located in the service area of another utility but are still considered part of PSE's BAA obligations. Our flexibility analysis model provides critical insights into PSE’s capabilities to integrate renewable resources into our BAA and understand the benefits of additional flexible generation resources beyond capacity and energy value.

To appropriately reflect conditions on a subhourly basis, we must develop the PLEXOS model to reflect cycle-specific decisions and recourse actions carefully. We must make some decisions based on their decision cycle, such as a day-ahead block transaction at Mid-C occurring in a day-ahead model. However, the energy schedule of generators in a day-ahead model is generally not required to remain constant across the studied day. Modeling these decisions, which we must fix in models of later decision cycles and allowing recourse actions to occur as uncertainty resolves, such as peaker commitments, are critical to reflect the subhourly flexibility of PSE's system accurately. Currently, our flexibility analysis model studies scheduled system impacts down to 15-minute segments.

The starting point of this analysis is a base portfolio comprised of PSE's existing resources scheduled to be operational through 2029, plus sufficient firm capacity, so the model is not resource inadequate, on an hourly timeframe, based on the results of the Resource Adequacy study. However, the model fixes firm capacity hourly, so it does not affect the analysis of subhourly flexibility. In this way, the model design prevents insufficient capacity or energy from affecting the results, with a resource-deficient starting position and no knowledge of the portfolio in 2029. When the model adds new resources, the firm capacity available to make the hourly model resource sufficient is adjusted down, so the total peak capacity in the model matches the peak need in 2029.

We ran the base case, what is presently known about our portfolio through the year 2029, and pivot cases, which are each the base case portfolio plus the addition of one new resource, through the simulation phases. The model then calculates the subhourly dispatch cost associated with each case. A difference in the subhourly costs of each pivot case against the base case is the flexibility benefit associated with the resource decision. This benefit is the cost difference of the study year divided by resource nameplate rating and determines a benefit per year ($/kW-year). As part of the IRP's decision framework, our flexibility analysis model uses subhourly benefits associated with new resource pivots calculated and made available to the LTCE model in AURORA by applying the flexibility benefit as a fixed benefit per year.

10.1. PLEXOS Simulation Phases

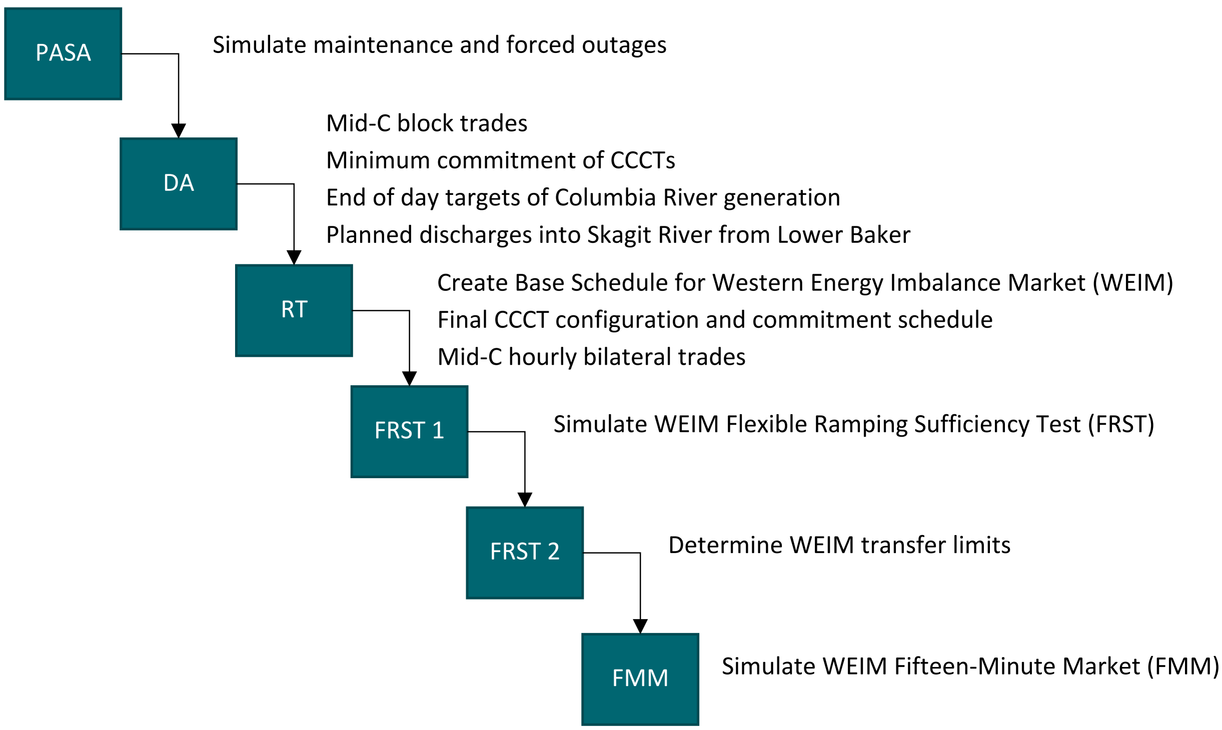
We used a multi-stage simulation approach in PLEXOS. Each stage runs separately but in sequence, so the model appropriately reflects critical decisions from earlier cycles in later decision cycles.

1. First, a model cycle in PLEXOS called Projected Assessment of System Adequacy (PASA) incorporates scheduled maintenance and random outages. It simulates the availability of the generation units with the given forced outage rates and scheduled maintenance information.
2. Then, the day-ahead stage determines a minimum plant commitment schedule for PSE's combined-cycle combustion turbine (CCCT) units, end-of-day targets for our Columbia River hydroelectric resources, planned discharges into the Skagit River from Lower Baker (Lake Shannon), and block trades for peak and off-peak hours at the Mid-C market.
3. Next, an hourly bilateral model performs finer-granularity trades at the Mid-C market and establishes the final CCCT schedule of run hours and combustion turbine (CT) commitment choices. This stage simulates a Base Schedule submitted to the California Independent System Operator's (CAISO's) Western Energy Imbalance Market (WEIM). As such, peaking units needed to balance hourly must run for the entire binding trade hour, while peaking units not committed are free to be committed by the WEIM. Additionally, as part of the Base Schedule submission, this model cycle selects operating reserves that CAISO cannot dispatch into (Spin and Non-Spin) and Regulation Up and Regulation Down, which CAISO terms Available Balancing Capacity (ABC) and can use sparingly.
4. Following the model, which simulates the creation of a Base Schedule, two 15-minute resolution models are used to perform the Flexible Ramping Sufficiency Tests (FRSTs) that CAISO uses to determine if WEIM participants have sufficient flexibility. The first model (Part 1) performs the test by simulating procurement of

the two Flexible Ramping Products (FRPs), FRP Up and FRP Down, from our system in isolation. If PLEXOS cannot procure enough FRP in one direction and/or the other, access to the WEIM market is limited to that of the previous Fifteen Minute Market (FMM) schedule in the direction(s) of test failure. The second model (Part 2) simulates WEIM interactions in the absence of any transfer limitation to determine what the transfer limits should be.

5. Finally, the model simulates FMM with all the upstream binding model decisions and FRST results.

Figure H.11: PLEXOS Simulation Phases



10.2. PLEXOS Model Inputs

We calibrated the inputs to the PLEXOS model to be as close to AURORA's input as possible for model framework consistency.

10.2.1. Contingency Reserve

Bal-002-WECC-1 requires balancing authorities to carry reserves for every hour: three percent of online generating resources and three percent of load to meet contingency obligations.

10.2.2. Balancing Reserve

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 short-term, forced-outage reliability benefit as contingency reserves triggered by specific criteria. Balancing reserves are resources that can ramp up and down quickly as loads and resources fluctuate within a given operating hour.

E3 assessed PSE's balancing reserve requirements based on CAISO's flexible ramping product calculations. The results depend heavily on the mean average percent error (MAPE) of the hour-ahead forecasts vs. real-time values for load, wind, and solar generation.

➔ Further discussion of reserves is in Chapter Seven: Resource Adequacy Analysis.

10.2.3. Natural Gas Prices

We used a combination of forward market prices and fundamental forecasts acquired in spring 2022 from Wood Mackenzie for natural gas prices. The natural gas price forecast is an input to the AURORA electric price modeling and portfolio model.

➔ The natural gas price inputs are in Chapter Five: Key Analytical Assumptions.

10.2.4. Electric Prices

We developed the electric price forecast for the Mid-C day-ahead and hourly trades using AURORA and input to PLEXOS. We determined subhourly prices by creating imbalance supply and demand stacks from the AURORA price forecast model's solutions for Pacific Northwest resources. This methodology reflects the limited market depth subhourly and prevents PLEXOS from overestimating opportunities in imports or exports.

10.2.5. Demand Forecast

We added PSE's demand forecast to PLEXOS using the monthly energy need (MWh) and peak need (MW). We layered on historical forecast errors from CAISO's forecasting of PSE's load in 2021 and 2022 to develop day-ahead, hour-ahead, and 15-minute forecasts.

➔ A description of our demand forecast is in Chapter Six: Demand Forecast.

10.3. Flexibility Benefit

To estimate the flexibility benefit of incremental resources, PLEXOS first runs the base case, which contains only PSE's current resource portfolio, and the firm capacity necessary for the model to be resource sufficient hourly. Then, we rerun PLEXOS with one new generic resource, adjusting the firm capacity down based on the new generic resource's peak capacity contribution. We then compare the subhourly production cost result of the case with the base portfolio to the production cost of the case with the additional resource.

We ensure sufficient hourly capacity and energy by providing firm capacity up to the peak need identified in the resource adequacy study. However, we must do more work to ensure that subhourly flexibility benefits do not double-count benefits by inadvertently including traces of capacity or energy value.

Current processes in AURORA step down to hourly resolution. In the current PLEXOS framework, to perform the flexibility analysis, this reflects the hourly bilateral model described. This model simulates creating and submitting a Base Schedule to the WEIM, where charges and credits are assessed based on movements away from the Base Schedule.

In the WEIM, the load buys imbalance energy when demand is above the Base Schedule hourly load forecast and sells imbalance energy when demand is below the Base Schedule hourly load forecast. This transaction occurs because of the resolved load forecast error that refines and improves with each decision cycle. Energy generators in the WEIM sell imbalance energy when their dispatch schedule exceeds the Base Schedule energy forecast and buy imbalance energy when their dispatch schedule is below the Base Schedule energy forecast. Generators may do this by economically optimizing interactions in the WEIM and taking advantage of opportunities to the changing load forecast and resource outages.

In order to attach subhourly values to hourly decision models in AURORA, we must first determine the net direct generation cost difference as the PLEXOS model moves from its hourly bilateral cycle to the WEIM FMM cycle. For example, if the model forecasts a gas generator to dispatch at 100 MW for some operating hour (100 MWh of energy) of an hourly cycle and then schedules it to generate 50 MWh total in the FMM cycle, there is a reduction in direct generation expenses associated with producing 50 MWh less energy. Each cycle's total direct generation cost is the sum of start-up costs, fuel costs of energy dispatch, variable operations and maintenance costs, and direct emissions costs.

The model then calculates the net cost of the WEIM energy products for scheduled movements associated with the load and generators. Finally, it assesses congestion rent to reflect the revenue we receive from the price separation between PSE's system and the WEIM. When dynamic transfers are binding along the EIM Transfer System Resource (ETSR) ties between PSE and neighboring WEIM participants, price separation is likely to occur, resulting in congestion revenue associated with the transfer. Current WEIM rules establish that any ETSR not directly connected to the CAISO full market footprint has revenues split equally among the interconnecting systems. As such, the model calculates one-half of the congestion revenue returns to PSE for this flexibility benefit calculation.

The flexibility benefit is the difference between the pivot case's and the base case's subhourly costs. This value as the cost difference in a year, divided by the nameplate of the pivot resource, is used to determine the flexibility benefit in $/kW-year.

The flexibility benefit calculation process is summarized as follows:

1. Run the base case, all models from day-ahead to FMM.
2. Run the pivot case, all models from day-ahead to FMM.

3. Calculate the subhourly cost of the base case and pivot cases:
    a. Subhourly cost =
    Net direct generation cost difference
    + net cost of imbalance energy market products for PSE BAA load
    + net cost of imbalance energy generation products by PSE merchant
    + congestion revenue
4. Calculate the difference between the subhourly costs between the pivot case and base case.
5. Divide by nameplate rating to determine the nominal flexibility benefit in $/kW-year.

11. Avoided Costs

Consistent with WAC 480-100-620(13),[7] the estimated avoided costs in this section provide only general information about the costs of new power supplies, and we only used them for planning purposes. This section includes estimated capacity costs consistent with the resource plan forecast, transmission and distribution deferred costs, greenhouse gas emission costs, and the cost of energy.

11.1. Capacity

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

➔ The indicative avoided capacity resource costs are in Appendix I: Electric Analysis Inputs and Results.

The costs are net capacity costs — we deducted the energy or other resource values using the Mid Scenario results. For example, frame peakers can dispatch into the market when the cost of running the plant is less than market, which creates a margin that flows back to reduce customers' rates.

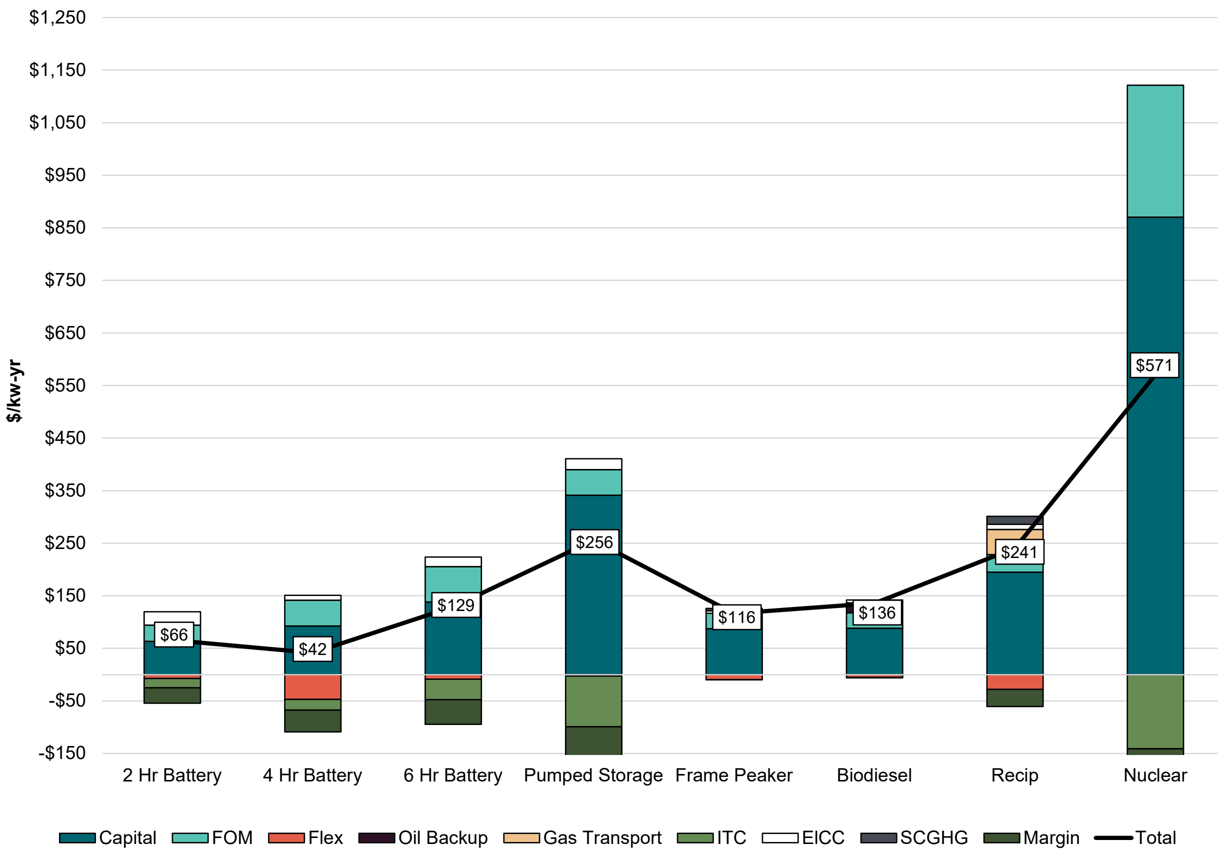
In addition to the avoided capacity cost expressed in $/kW-yr, the capacity credit of different resources needs to be specified. After specifying the annual avoided capacity resource costs by year, the avoided capacity costs include indicative adjustments to peak capacity value from this report's effective load carrying capability (ELCC) analysis.

The ELCC for a firm dispatchable resource would be 100 percent, but different intermittent resources have different peak capacity contributions. The capacity contributions used here are consistent with those described in Chapter Seven: Resource Adequacy. These results reflect the first tranche of ELCC, the first 1000 MW added to the system.

7 WAC 480-100-620

As we add more resources to the system, the resources provide less peak capacity benefit. Figure H.12 shows the levelized cost of capacity (LCOC) compared across capacity resources.

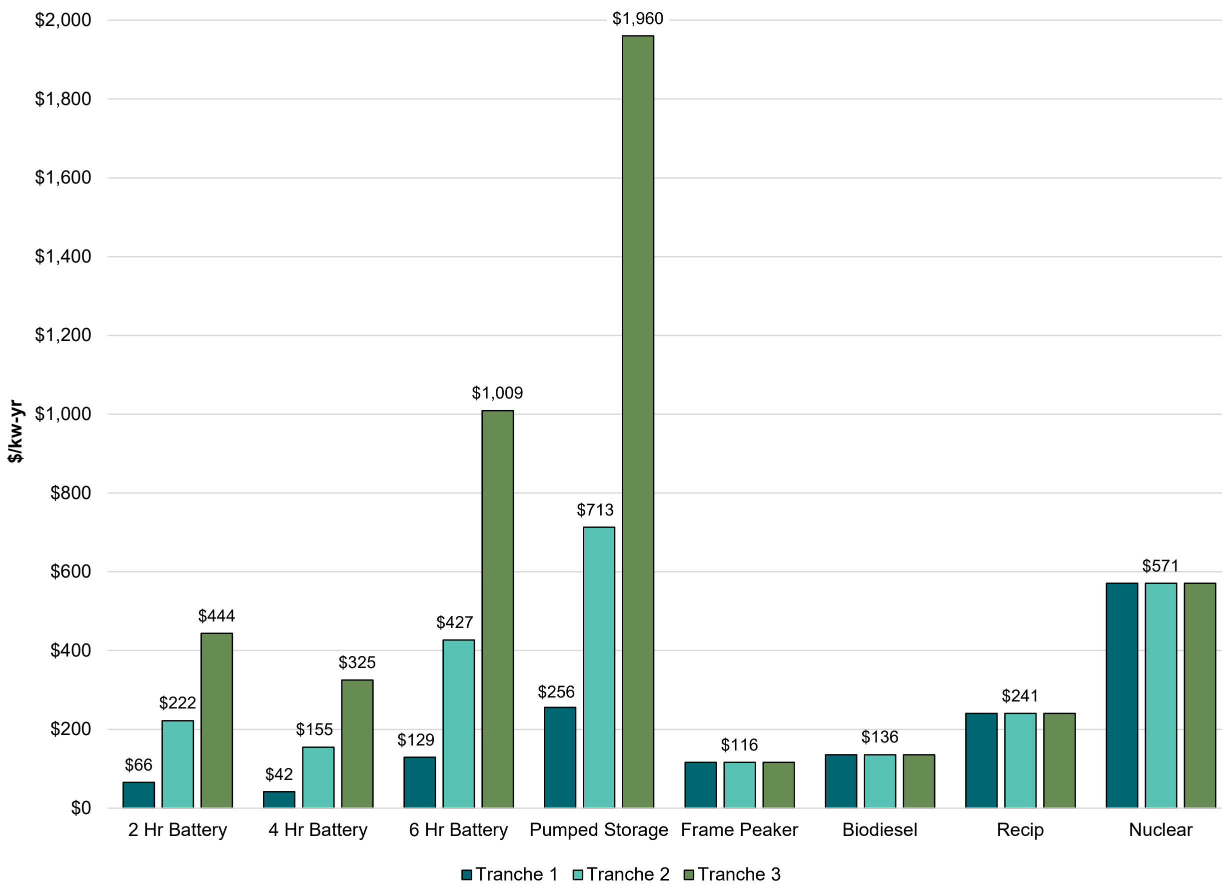
Figure H.12: Net Cost of Capacity in the Reference Portfolio



11.1.1. Saturation Curves

As we add more storage to the system with limited duration, it has less of an impact on meeting peak demand. Initially, storage can clip peaks with the shorter duration. As we add more storage to the system, the peak will flatten and require longer-duration resources to meet the peak. Figure H.13 illustrates the levelized cost impact of the tranches as described in Chapter Seven: Resource Adequacy Analysis. For example, the cost of peak capacity for a Lithium-ion 2-hour battery in Tranche 1 is $66/kW-year, and Tranche 3 is $444/kW-year.

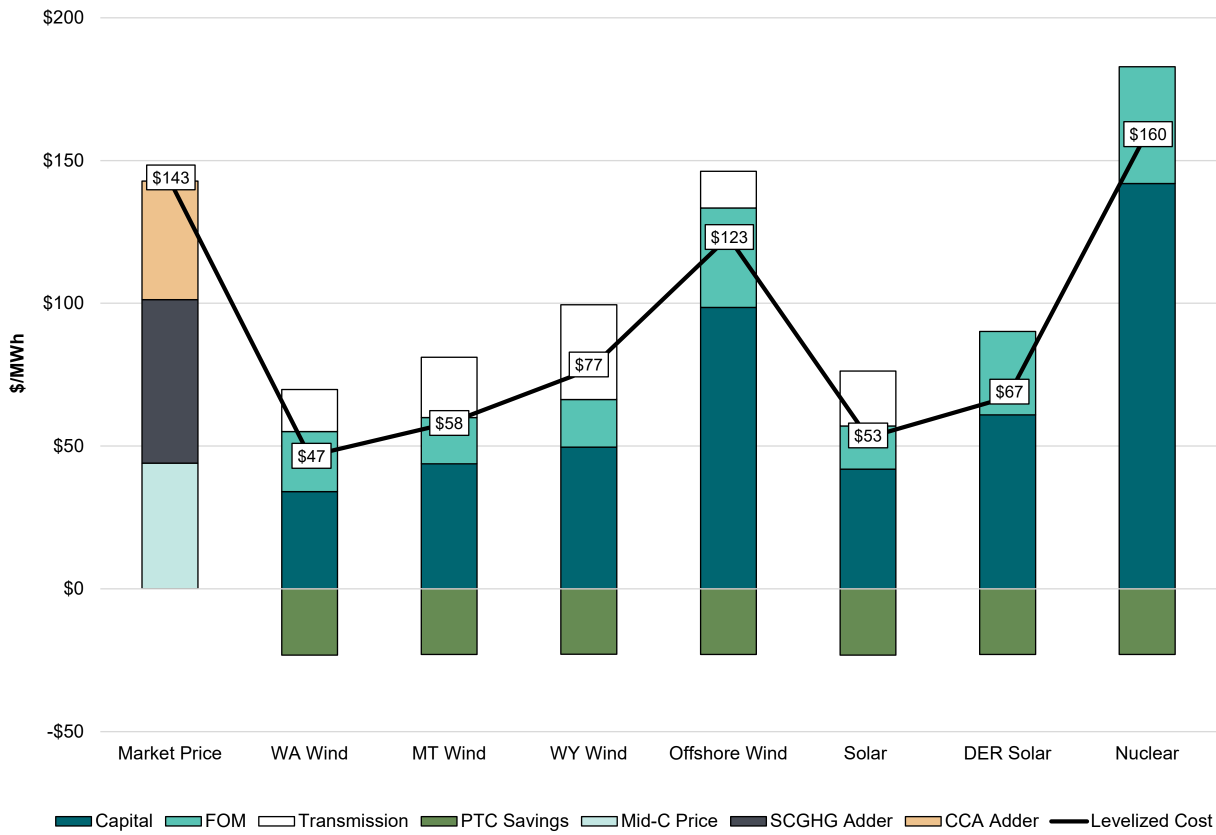
Figure H.13: Impact of Saturation Curves



11.2. Levelized Cost of Energy

We evaluated the levelized costs of energy from renewable resources based on assumptions in the reference portfolio. Renewable resource costs benefit from increased tax credits as a result of the Inflation Reduction Act. We can see the benefits in the cost component chart, Figure H.14, below the x-axis. The total energy costs do not include the peak capacity contribution to the portfolio. For example, Washington wind is the lowest cost in terms of energy because of reduced transmission costs compared to Montana and Wyoming wind. However, Montana and Wyoming wind have significantly higher peak capacity values than Pacific Northwest wind. Eastern Washington utility-scale solar is competitive in terms of energy but provides minimal peak capacity benefit. Figure H.14 illustrates the levelized costs of renewable resources to meet CETA.

Figure H.14: Levelized Cost of Energy



11.2.1. Conservation

We use bundles as the supply curve to determine the cost-effective demand-side management measures to reduce load and peak capacity. The following charts provide the cumulative cost impact as one moves up the supply curve. Figure H.15 shows an energy perspective, and Figure H.16 a capacity perspective.

Figure H.15: Conservation Cumulative Cost of Energy by Bundle

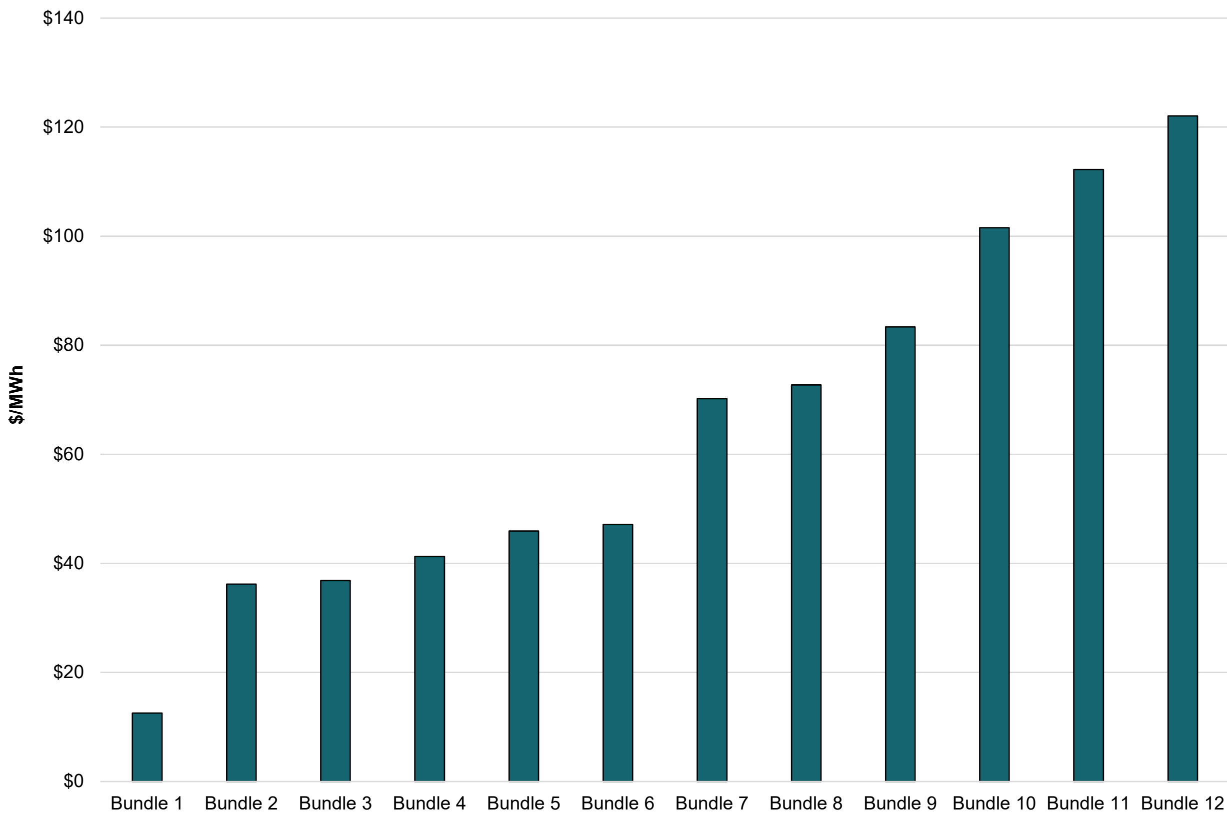
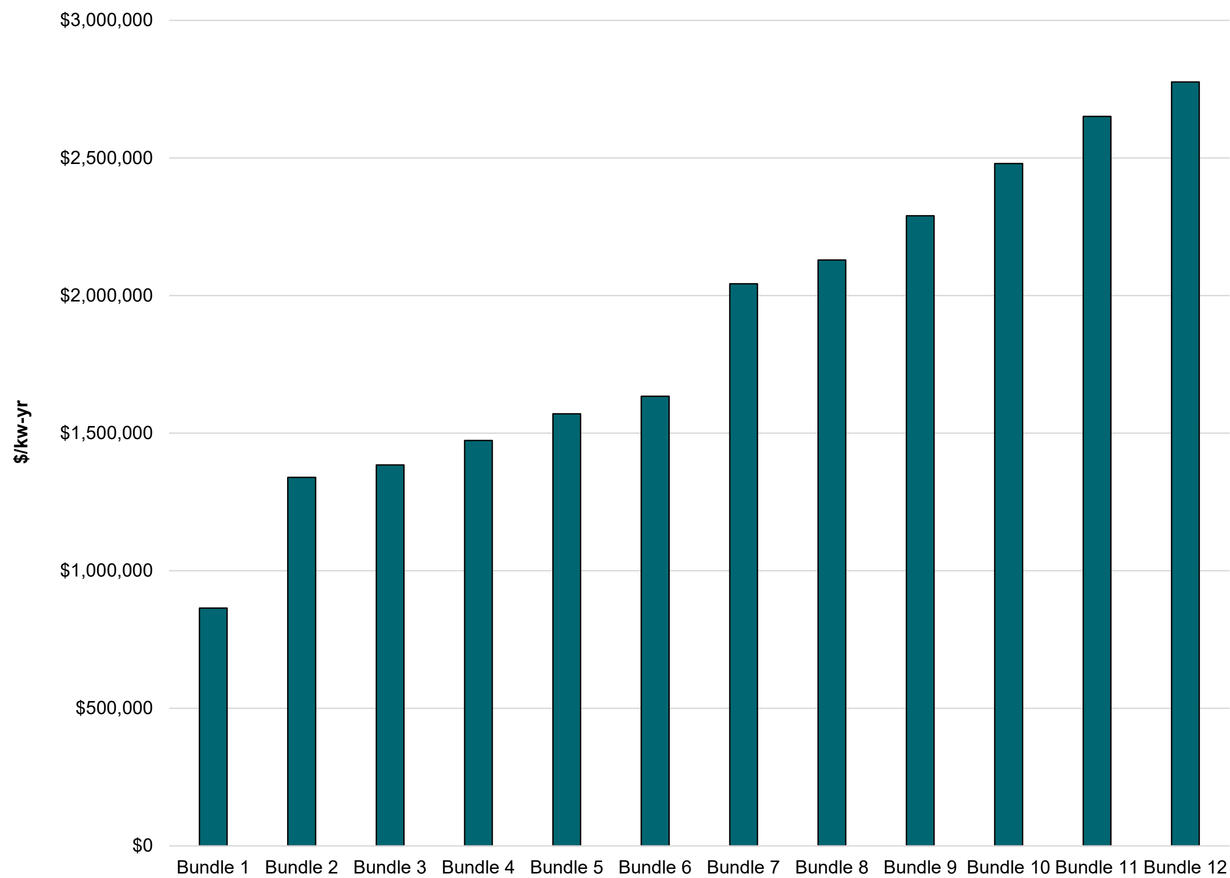


Figure H.16: Conservation Cumulative Cost of Capacity by Bundle



11.3. Deferred Transmission and Distribution Cost

The estimated avoided T&D cost is $74.70/kW-year. See the Transmission and Distribution Cost in the Financial Assumptions section of this appendix.

11.4. Avoided Costs of Greenhouse Gas Emission

This 2023 Electric Report includes modeling the SCGHG and an allowance price for the Climate Commitment Act. The emission rate for unspecified market purchases, as outlined in RCW 19.405.070, is 0.437 metric tons of CO_2/MWh. Therefore, the carbon price for unspecified market purchases is the combined total of the SCGHG and the CCA GHG emission costs. See Table H.5.

Table H.5: Avoided Carbon Costs Unspecified Market Purchases $/MWh

Year	SCGHG ($/MWh)	CCA ($/MWh)	Total ($/MWh)
2024	35.43	25.31	60.74
2025	36.50	27.75	64.25
2026	37.04	28.16	65.20
2027	37.58	26.16	63.74
2028	38.11	26.73	64.84
2029	38.65	28.90	67.55
2030	39.19	27.12	66.30
2031	39.72	30.39	70.12
2032	40.26	34.06	74.32
2033	40.80	38.18	78.98
2034	41.33	42.79	84.12
2035	41.87	47.96	89.83
2036	42.41	50.45	92.85
2037	43.48	53.06	96.54
2038	44.02	55.81	99.83
2039	44.55	58.71	103.26
2040	45.09	61.75	106.84

Year	SCGHG ($/MWh)	CCA ($/MWh)	Total ($/MWh)
2041	45.63	64.95	110.58
2042	46.17	68.32	114.49
2043	46.70	71.86	118.57
2044	47.24	75.59	122.83
2045	47.78	79.51	127.29

11.5. Avoided Cost of Capacity

In Chapter Three, we documented our preferred portfolio for the 2023 Electric Report and explained why we added different resources. The first resource we added to the portfolio for capacity needs is the biodiesel peaker in 2024 at $136/kW-year. Even though we added other resources to the portfolio in the early years, we added them for different reasons. For example, distributed energy resources (DERs) such as batteries make lower peak capacity contributions and have higher costs. However, DERs play an essential role in balancing utility-scale renewable investments and transmission constraints while meeting local distribution system needs and improving customer benefits, which is why we used the frame peaker as the avoided cost of capacity.

Table H.6: shows the avoided capacity costs we estimated in this 2023 Electric Report. Under WAC 480-106-040(b)(ii),[8] the 2023 report's first capacity addition in 2024 is a biodiesel peaker, the basis for the peak capacity avoided cost. The results reflect the cost of the biodiesel peaker net of the ELCC for the biodiesel peaker, wind, and solar.

Table H.6: 2023 Avoided Capacity Costs (Nominal $/kW-yr)

Year	Capacity Resource Addition	(a) Levelized Net $/kW-year Delivered to PSE	(c)=(a) Firm Resource ($)	(d)=(a)*0.13 Wind Resource ELCC=13% ($)	(e)=(a)*0.04 Solar Resource ELCC=4% ($)
2024	Baseload Resource	135.69	135.69	17.64	5.43
2025	Baseload Resource	135.69	135.69	17.64	5.43
2026	Baseload Resource	135.69	135.69	17.64	5.43
2027	Baseload Resource	135.69	135.69	17.64	5.43
2028	Baseload Resource	135.69	135.69	17.64	5.43
2029	Baseload Resource	135.69	135.69	17.64	5.43

[8] WAC 480-106-040

Year	Capacity Resource Addition	(a) Levelized Net $/kW-year Delivered to PSE	(c)=(a) Firm Resource ($)	(d)=(a)*0.13 Wind Resource ELCC=13% ($)	(e)=(a)*0.04 Solar Resource ELCC=4% ($)
2030	Baseload Resource	135.69	135.69	17.64	5.43
2031	Baseload Resource	135.69	135.69	17.64	5.43
2032	Baseload Resource	135.69	135.69	17.64	5.43
2033	Baseload Resource	135.69	135.69	17.64	5.43
2034	Baseload Resource	135.69	135.69	17.64	5.43
2035	Baseload Resource	135.69	135.69	17.64	5.43
2036	Baseload Resource	135.69	135.69	17.64	5.43
2037	Baseload Resource	135.69	135.69	17.64	5.43
2038	Baseload Resource	135.69	135.69	17.64	5.43
2039	Baseload Resource	135.69	135.69	17.64	5.43
2040	Baseload Resource	135.69	135.69	17.64	5.43
2041	Baseload Resource	135.69	135.69	17.64	5.43
2042	Baseload Resource	135.69	135.69	17.64	5.43
2043	Baseload Resource	135.69	135.69	17.64	5.43
2044	Baseload Resource	135.69	135.69	17.64	5.43
2045	Baseload Resource	135.69	135.69	17.64	5.43
2046	Baseload Resource	135.69	135.69	17.64	5.43
2047	Baseload Resource	135.69	135.69	17.64	5.43

11.6. Schedule of Estimated Avoided Costs for PURPA

This schedule of estimated avoided costs, as prescribed in WAC 480-106-040,[8] identifies the estimated avoided costs for qualifying facilities and did not provide a guaranteed contract price for electricity. The schedule only identifies general information to potential respondents about the avoided costs. The schedule of estimated avoided costs includes table H.7.

Table H.7: Schedule of Estimated Avoided Costs

Year	Jan ($/MWh)	Feb ($/MWh)	Mar ($/MWh)	Apr ($/MWh)	May ($/MWh)	Jun ($/MWh)	Jul ($/MWh)	Aug ($/MWh)	Sept ($/MWh)	Oct ($/MWh)	Nov ($/MWh)	Dec ($/MWh)	Avg. ($/MWh)
2024	39.63	34.62	28.06	25.48	18.80	25.90	41.99	39.52	43.83	37.21	37.83	42.11	34.60
2025	36.53	35.25	28.43	25.91	18.10	25.72	43.40	39.52	45.69	39.52	38.58	44.07	35.07
2026	40.56	37.51	28.65	26.60	19.30	27.72	48.36	43.13	48.76	42.21	40.09	47.36	37.54
2027	44.76	43.26	33.36	29.87	20.67	32.23	54.24	48.89	54.25	46.43	45.05	50.92	42.00
2028	48.81	43.09	33.96	30.33	22.08	32.79	55.96	51.51	54.65	47.06	46.28	54.19	43.42
2029	47.16	41.67	31.04	29.90	21.21	30.97	56.35	53.98	59.35	49.82	47.93	53.70	43.62
2030	47.25	41.25	28.86	27.96	21.28	30.19	57.33	53.89	58.43	49.54	47.17	53.66	43.11
2031	43.73	41.48	28.51	30.42	18.73	30.98	58.78	54.89	59.99	50.06	47.64	54.63	43.35
2032	45.70	40.25	27.30	27.92	17.50	32.21	59.80	56.79	63.91	51.87	48.94	56.06	44.05
2033	45.97	42.63	28.01	27.41	17.08	33.43	66.18	62.35	62.92	54.36	50.75	61.17	46.08
2034	44.72	39.55	29.17	29.93	18.57	34.77	69.13	60.31	65.16	57.12	52.61	60.22	46.84
2035	48.13	42.67	29.00	29.97	18.76	32.11	73.47	67.31	74.18	59.98	54.95	63.40	49.57
2036	51.27	40.68	27.93	28.88	17.96	33.34	78.64	69.53	74.86	58.73	53.78	64.03	50.05
2037	47.53	43.33	31.94	29.07	15.61	34.48	80.66	72.61	79.31	59.44	55.46	66.95	51.45
2038	48.74	39.85	27.70	28.54	16.53	34.02	84.20	70.73	80.97	63.14	56.52	70.80	51.93
2039	51.29	43.69	28.06	28.31	16.45	39.28	86.83	74.81	80.62	62.83	59.70	71.77	53.74
2040	49.87	40.71	29.20	28.94	18.16	40.70	89.73	75.98	82.77	66.41	56.38	73.33	54.45
2041	58.79	45.67	28.21	29.94	14.90	35.20	92.56	83.56	89.62	66.93	63.05	75.47	57.11
2042	59.15	44.92	26.89	29.51	14.59	38.35	101.79	92.74	91.72	66.90	61.39	81.39	59.27
2043	59.81	44.28	30.51	28.65	15.73	42.72	107.66	89.90	96.07	67.15	64.72	84.67	61.16

ELECTRIC ANALYSIS INPUTS AND RESULTS

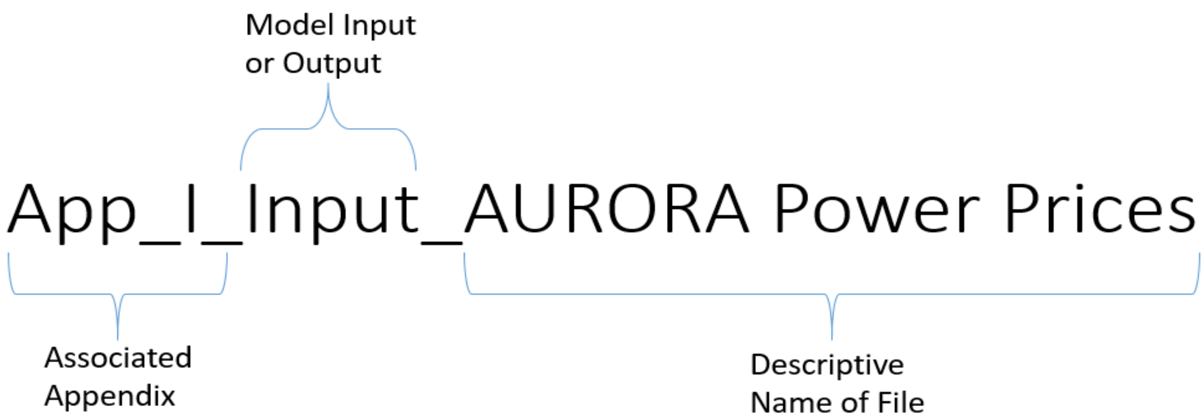
APPENDIX I

Contents

1. Introduction

For the 2023 Electric Progress Report (2023 Electric Report), Puget Sound Energy (PSE) is providing Microsoft Excel files containing input and output data in separate files instead of data tables directly in the report. Direct access to the data provides usable files for interested parties as opposed to static tables in a PDF format. Technical limitations on how PSE is able to submit files to the Washington Utility Transportation Commission (Commission) and host files online for public access has prevented PSE from keeping the files organized in a series of folders. To overcome this, a descriptive naming system has been developed in order to identify different files. Figure I.1 provides an example of how the provided files will be named. Each Excel file also contains a Read Me sheet with specific details related to the data contained in that file.

Figure I.1: Naming Conventions for Appendix I Files



2. Modeling Inputs

The first section of this appendix highlights the inputs to the modeling process. These inputs are split out into subsections categorically, including a group of inputs that are directly linked to the AURORA model and other groups that have background information on more complex inputs such as generic resource costs or shaping of wind and solar resources.

2.1. Aurora Portfolio Model Inputs

The AURORA Long Term Capacity Expansion (LTCE) Portfolio Model files contain the data used in AURORA that PSE is able to share publicly. This includes generic resource assumptions, financial assumptions and specific settings used in AURORA. Table I.1 provides a list of AURORA input files provided in this Report.

Table I.1: AURORA Portfolio Model Input File Names

File Names	Description
App_I_Input_AURORA LTCE Inputs	Contains inputs for the AURORA LTCE model, including generic resource assumptions and modeling parameters. Existing resource information is not included.
App_I_Input_AURORA Power Prices	Contains the results of the hourly power price model, which is used as the power price inputs for other models.
App_I_Input_Electric Demand Forecast	Contains the annual summary of PSE's demand forecasts used in the 2023 Electric Report.
App_I_Input_Climate Change Data	Contains the climate change data that is an input to the electric demand forecast

LTCE Inputs: This file contains the non-hourly inputs into the AURORA LTCE model, including generic resource assumptions and other modeling parameters. Confidential information regarding PSE's existing resources and other assets has been removed. All dollar values that are entered into AURORA are in 2020 dollars.

➔ More documentation of the AURORA modeling process can be found in Chapter Eight: Electric Analysis and Appendix G: Electric Price Models.

Power Prices: This workbook contains all of the hourly power price data developed for this IRP. For sensitivities that change the hourly dispatch, a new hourly price forecast is required. The AURORA power price forecast is run using the conditions of the scenario or sensitivity. Yearly and monthly prices are averages of those periods, and all prices are in $/MWh.

➔ More information about power prices can be found in Chapter Five: Key Analytical Assumptions.

Demand Forecast: This workbook contains the data for the electric system demand forecast. There are two tabs, one for electric demand in aMW and another for system peak in MW. These tabs break down the base scenario, EV demand and other similar adjustments.

Climate Change Data: This is a secondary input, meaning it is an input to an AURORA input. This workbook contains the data and calculations for the climate change models that are an input to the electric demand forecast. It contains all the adjusted temperatures from the different models and tabs showing how those were implemented into the load forecasting process.

➔ More information about the demand forecast can be found in Chapter Six: Demand Forecast.

2.2. Generic Resources

This workbook provides a summary of cost assumptions and details on cost adjustments applied to the Generic Resources PSE will consider in the 2023 Electric Report portfolio planning process. The majority of cost assumptions are sourced from the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) cost report.

Table I.2: Generic Resources File Name

File Name	Description
App_I_Input_Generic Resources	Contains cost assumptions and adjustments used for the generic resources modelled in the 2023 Electric Report.

Generic Resources: This workbook details the various assumptions passed into the model for generic resources. These assumptions include operating life, capital costs, operation and maintenance (O&M) costs, spur line costs, among many.

2.3. Carbon Dioxide Prices

The carbon dioxide (CO_2) Prices file contains the calculations of the Social Cost of Greenhouse Gases (SCGHG) and Climate Commitment Act (CCA) used during the 2023 Electric Report. Figure I.3 provides the name of this file.

Table I.3: CO_2 Prices File Name

File Name	Description
App I_Input_Carbon Prices	Contains the calculations for the SCGHG and CCA values used in the 2023 Electric Report.

Carbon Prices: This workbook contains PSE's calculations for converting the SCGHG and CCA prices into a format compatible with AURORA. This includes the base SCGHG calculation and the H.R. 763 SCGHG calculation.

2.4. AURORA Generic Wind and Solar Shapes

The generic wind and solar capacity factor shapes used to model utility-scale renewable resources all have the same format, which is described below. Figure I.4 provides the file names of these datasets.

Table I.4: Generic Wind and Solar Shape File Names

File Names	Description
App_I_Input_Wind and Solar Shapes	This dataset contains monthly shapes for all solar and wind resources modeled in the 2023 Electric Report

Each tab within the workbook details monthly shaping for a given resource. Resource shapes in the form of monthly capacity factors are provided for existing PSE resources as well as new generic resources modelled. The months run across the top with the Sample ID going vertically, denoting which stochastic simulation it corresponds to. The notes column shows which sample was used in the deterministic portfolio modelling. Each resource has the seasonal Net Capacity Factor (NCF) plotted on the left.

Table I.5: Naming Conventions for the Tabs in Wind and Solar Shapes File

Name	Meaning
Stochastic	This dataset contains 250 capacity factor profiles of the resource location for use in the stochastic modeling process.
Deterministic	This dataset contains the representative capacity factor profile of the resource location that was used in the deterministic portfolio model. This is called out in the notes section.

➔ See Appendix D: Generic Resources for a detailed explanation of the generic renewable resource generation profiles.

3. Modeling Outputs

This section of the appendix details the output files provided from both the AURORA and PLEXOS models. The files from AURORA include information on the fundamental attributes of the various portfolios modeled such as cost, builds, emissions and customer benefit values, as well as information on levelized resource costs and summarized results of the stochastic analysis. The PLEXOS output file presents the flexibility benefits and violations associated with the flexibility analysis model.

3.1. AURORA

The AURORA output files contain the AURORA output data that PSE is able to share publicly. Figure I.6 provides the file names of these datasets.

Table I.6: AURORA Output Files

File Names	Description
App_I_Output_Portfolio Output Summary	Contains an overview of the output data from the AURORA LTCE and hourly dispatch models.
App_I_Output_Portfolio Benefit Analysis	Contains the data and calculations which inform the portfolio benefit analysis for all the portfolios.
App_I_Output_Levelized Resource Costs	Contains the calculations of the levelized costs of new resources in the 2023 report.
App_I_Output_Stochastic Modeling Results	Contains an overview of the results from the AURORA stochastic model.

Portfolio Output Summary: This workbook contains an overview of the output data from each electric portfolio modeled. The portfolio build data, emissions, annual costs and overall portfolio costs is some of the key information included.

Portfolio Benefit Analysis: This workbook provides a tool to measure potential equity-related benefits to customers within the different portfolio options modeled in the 2023 Electric Report. The tool uses AURORA output to measure select Customer Benefit Indicators (CBIs). CBIs are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group and stakeholders. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

Levelized Resource Costs: This workbook contains the calculations for the levelized costs of new resources in the 2023 Electric Report. The information from the raw data is processed in the resource-specific tabs. We then add processed data to the charts and data summaries.

Stochastic Modeling Results: This workbook contains the tables, charts, and data from the AURORA stochastic modeling process used in the 2023 Electric Report. The portfolios PSE examined in the stochastic modeling process are the Reference and Preferred portfolios.

➔ See Chapter Eight: Electric Analysis for a full description of the stochastic portfolio analysis and Appendix H: Electric Analysis and Portfolio Model for more information on levelized costs of resources.

3.2. PLEXOS

The PLEXOS output files contain the PLEXOS output data that PSE is able to share publicly. Table I.7 provides the file names of these datasets.

Table I.7: PLEXOS Output Files

File Names	Description
App_I_Output_Flex Benefits and Violations	Contains the calculation of the generic resource flexibility benefits and violations using output data from the PLEXOS Flexibility Analysis model.

Flexibility Benefits and Violation: This workbook contains the calculations for the resource flexibility benefits and violations. The difference in costs between the test cases and the base case provides the flexibility benefit of the test case resource.

➔ See Chapter Five: Key Analytical Assumptions and Appendix H: Electric Analysis and Portfolio Model for the full flexibility analysis methodology and results.

ECONOMIC, HEALTH AND ENVIRONMENTAL BENEFITS ASSESSMENT OF CURRENT CONDITIONS

APPENDIX J

PUGET SOUND ENERGY

Contents

1. Introduction

The Clean Energy Transformation Act (CETA) requires utility resource plans to ensure all customers benefit from the transition to clean energy. To achieve this goal, we conduct an economic, health, and environmental benefits assessment (assessment) every two years with each Integrated Resource Plan (IRP) and Electric Progress Report. This assessment identifies and quantifies the existing conditions for all customers and identifies disparate impacts to communities within and around PSE's service territory related to resource planning. The assessment subsequently informs development and updates to the utility's Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan (CEIP).

This assessment addresses the following areas, as defined in WAC 480-100-620 (9):[1]

- Energy and non-energy benefits and reduction of burdens to vulnerable populations and highly impacted communities
- Energy security risk
- Long-term and short-term public health and environmental benefits, costs, and risks

We created two primary sections in the assessment to evaluate the equitable distribution of burdens and benefits.

- The first section, Named Communities, discusses how we characterize Vulnerable Populations (VPs) and Highly Impacted Communities (HIC), collectively referred to as Named Communities in the 2023 Electric Report, and the methodology we used to identify communities with higher concentrations of vulnerability factors and environmental burdens in PSE's service area.
- The second section, Customer Benefit Indicators, describes the data we use to measure current disparities in Named Communities. Customer Benefit Indicators (CBIs) are quantitative or qualitative attributes of resources or related distribution investments associated with customer benefits described in RCW 19.405.040 (8).[2] Customer Benefit Indicators will help us ensure an equitable transition to clean energy. This section describes how CBIs have evolved since the 2021 Integrated Resource Plan. (2021 IRP). We will present updates to our CBI metrics in the upcoming CEIP Biennial Update scheduled for release in the fourth quarter of 2023.

This assessment is rooted in the 2021 IRP and provides an update to that analysis. The 2021 IRP was our first attempt to identify Named Communities within PSE's service area and measure disparities in these communities. Since publishing the 2021 IRP, our methods have evolved significantly. The drivers of this evolution are twofold:

- Washington Department of Health (DOH) completed a Cumulative Impact Analysis.[3] This report designated communities highly impacted by climate change and fossil fuel pollution across Washington State.

1 WAC 480-100-620 (9)
2 RCW 19.405.040 (8)
3 Clean Energy Transformation Act – Cumulative Impact Analysis | Washington State Department of Health

- We completed our first CEIP in 2021 with guidance from a new Equity Advisory Group (EAG) and other public participation processes. The 2021 CEIP established CBIs and metrics for measuring these CBIs, and identified metrics to designate vulnerable populations in PSE's service area.

This assessment continues to build on the work completed in the 2021 CEIP to identify and measure equity for more equitable outcomes.

1.1. Purpose of the Assessment

Resource planning is a generalized and forward-looking planning process. This process forecasts new electric resource additions we will need to meet customer demand in the next twenty or more years. This 2023 Electric Progress Report (2023 Electric Report), a two-year update to the 2021 IRP, considers equity from two specific angles. First, we build a resource plan to enable more equitable customer outcomes. Second, we assess our progress toward achieving an equitable clean energy transition to learn where we currently stand. These two angles provide the context for designing specific programs and actions, which we will identify in subsequent CEIP processes.

To evaluate the relative potential for equitable energy outcomes in each electric portfolio for the report, we developed the portfolio benefit analysis tool, described in Chapter Three: Resource Plan and Chapter Eight: Electric Analysis. This tool uses forward-looking metrics to predict which generating resources we need to enable more equitable customer energy outcomes.

This economic, health and environmental benefits assessment requires backward-looking, observational metrics. These data measure our progress toward achieving an equitable clean energy transition. In contrast to the predictive nature of electric resource planning, the metrics we used in this assessment are observed characteristics of our utility, such as counts of customers with installed distributed generation. These data include specific implementation details such as location and form factor.

2. Named Communities

The Clean Energy Transformation Act requires utility resource plans to ensure all customers benefit from the transition to clean energy. The act identifies explicitly vulnerable populations and highly impacted communities as groups that should benefit from the equitable distribution of energy and non-energy benefits and the reduction of burdens. Throughout the 2021 CEIP and 2023 Electric Report development processes, we worked to understand and identify customers who may belong to these named communities through customer outreach, collaboration with the EAG, and demographic analysis of our service territory.

Named communities include vulnerable populations and highly impacted communities, each with a specific definition derived from the CETA statute and subsequent rulemaking:

- Highly Impacted Communities are communities designated by the Department of Health based on the cumulative impact analysis required by RCW 19.405.140[4] or a community located in census tracts that are fully or partially on Indian country, as defined in 18 U.S.C. Sec. 1151.
- Vulnerable Populations is a term defined by CETA as communities that experience a disproportionate cumulative risk from environmental burdens due to adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, linguistic isolation, and sensitivity factors, such as low birth weight and higher rates of hospitalization.

This section discusses how we characterize named communities for the electric progress report.

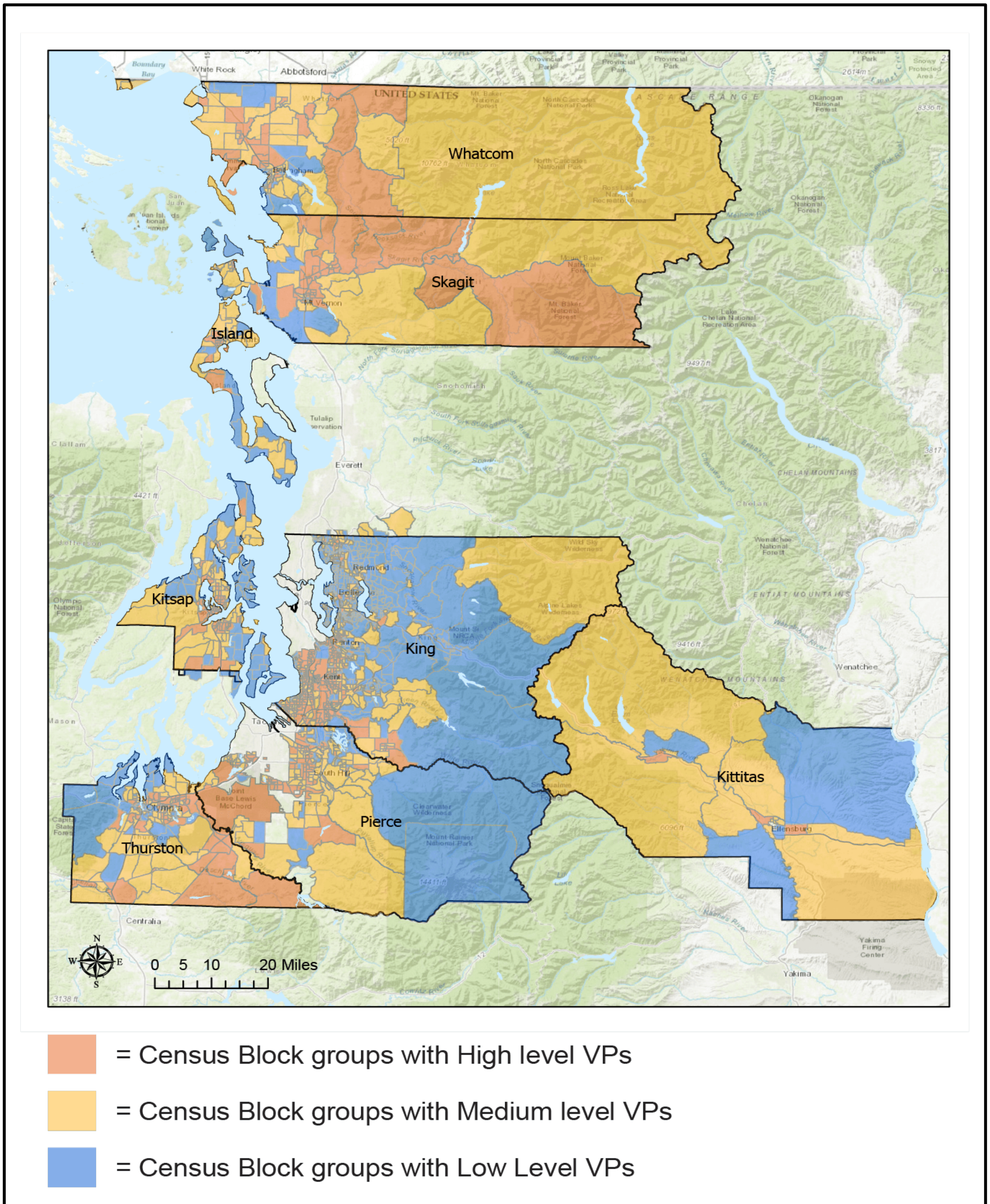
2.1. Vulnerable Populations

The CETA statute and rulemaking provide some guidance on characterizing vulnerable populations, stating that vulnerable populations experience disproportionate cumulative risk from environmental burdens due to socioeconomic and sensitivity factors. However, identifying and classifying the socioeconomic and sensitivity factors was left to the utilities' discretion. We worked with our EAG to identify attributes that may result in increased vulnerability, then aggregated the impacts of these attributes to characterize PSE's service area into three levels of vulnerability. For a complete description of the attributes and methods used to characterize vulnerable populations, please refer to Chapter Three[5] of the 2021 CEIP.

Figure J.1 is a map of vulnerable populations by census block group within PSE's electric service area created as part of the 2021 CEIP. The map illuminates the areas where customers in PSE's service area have high, medium, and low levels of vulnerability. This geographic representation indicates where we should focus outreach or program implementation efforts.

[4] RCW 19.405.140
[5] 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

Figure J.1: Vulnerable Populations by Census Block Groups within PSE Electric Service Area



2.2. Highly Impacted Communities

Highly impacted communities are defined by the Washington Department of Health Cumulative Impact Analysis and identified as census tracts with an overall score on the Environmental Health Disparities Map[6] of nine or ten or any census tract with tribal lands.[7] The cumulative impact analysis identified 164 census tracts in our service area as highly impacted communities, of which 72 are on tribal lands, about 44 percent.

The Department of Health periodically releases a new Cumulative Impact Analysis as the Environmental Health Disparities Map is updated or new information becomes available. The highly impacted communities identified in this report are consistent with those characterized as part of the 2021 CEIP in Chapter Three[8]. We used a cumulative impact analysis from March 2021 in the 2021 CEIP. The Department of Health updated the cumulative impact analysis with the most recent results available from August 2022. We reviewed the most recent cumulative impact analysis results and observed 159 census tracts characterized as highly impacted communities, five fewer than March 2021 analysis. We maintained the highly impacted community results of the March 2021 cumulative impact analysis to preserve consistency between the 2021 CEIP and this report. We plan to explore updating our characterization of named communities as we continue to learn and evolve our methods to measure and implement equitable outcomes.

Figure J.2 presents the census tracts across PSE's service area characterized as highly impacted communities. Highly impacted communities and vulnerable populations encompass various factors to define a specific community. Some PSE customers may overlap categories and fall into either or both groups. Figure J.3 shows the overlap between highly impacted communities and the vulnerable populations within PSE's service areas. Table J.1 shows the approximate number of PSE customers who fall within each group described in this section and is consistent with data published as part of the 2021 CEIP.

6 Information by Location | Washington Tracking Network (WTN)

7 Clean Energy Transformation Act – Cumulative Impact Analysis | Washington State Department of Health

8 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

Figure J.2: Highly Impacted Communities Census Tracts in PSE Electric Service Area

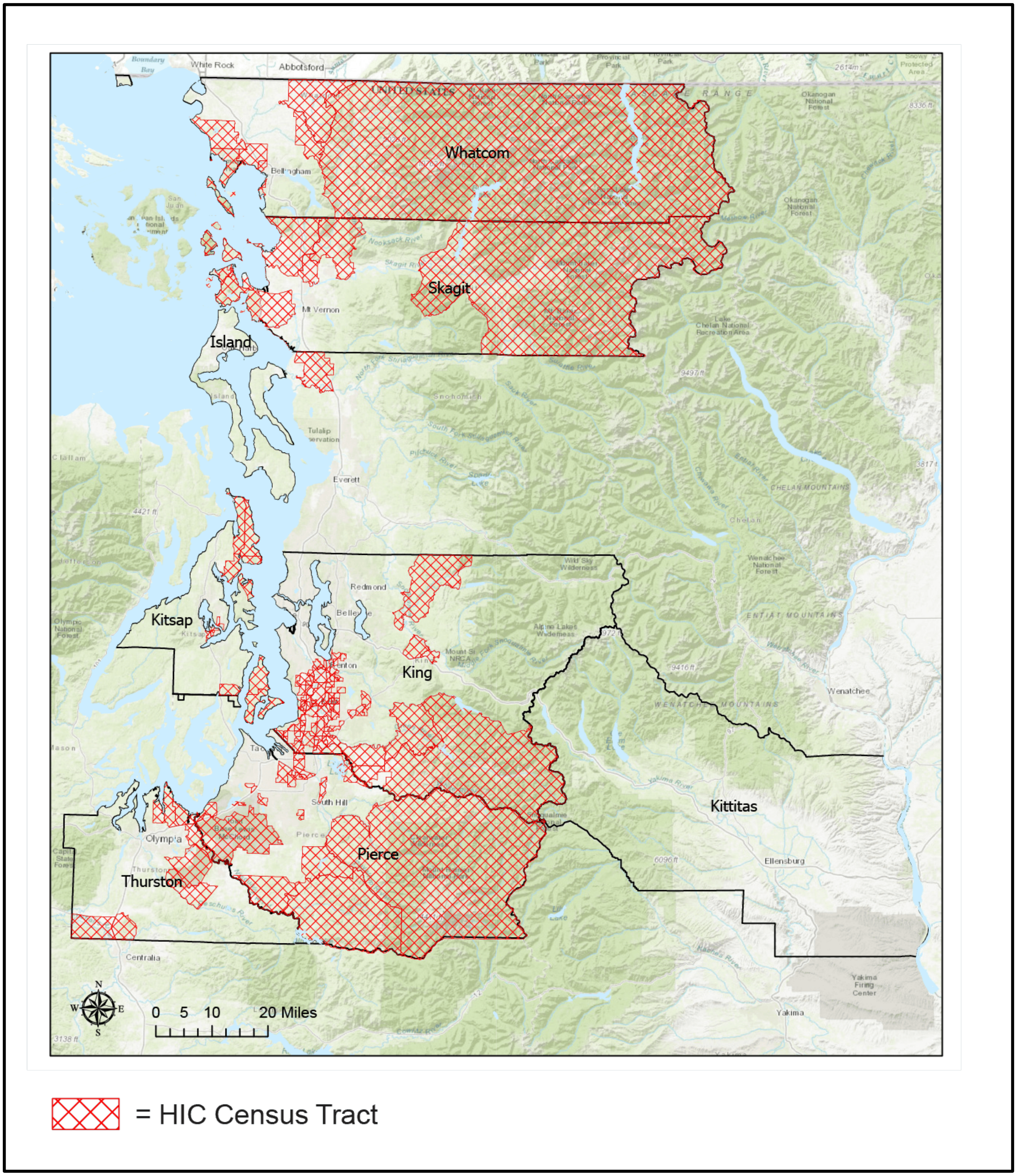


Figure J.3: Combined Vulnerable Populations and Highly Impacted Communities in PSE Electric Service Area

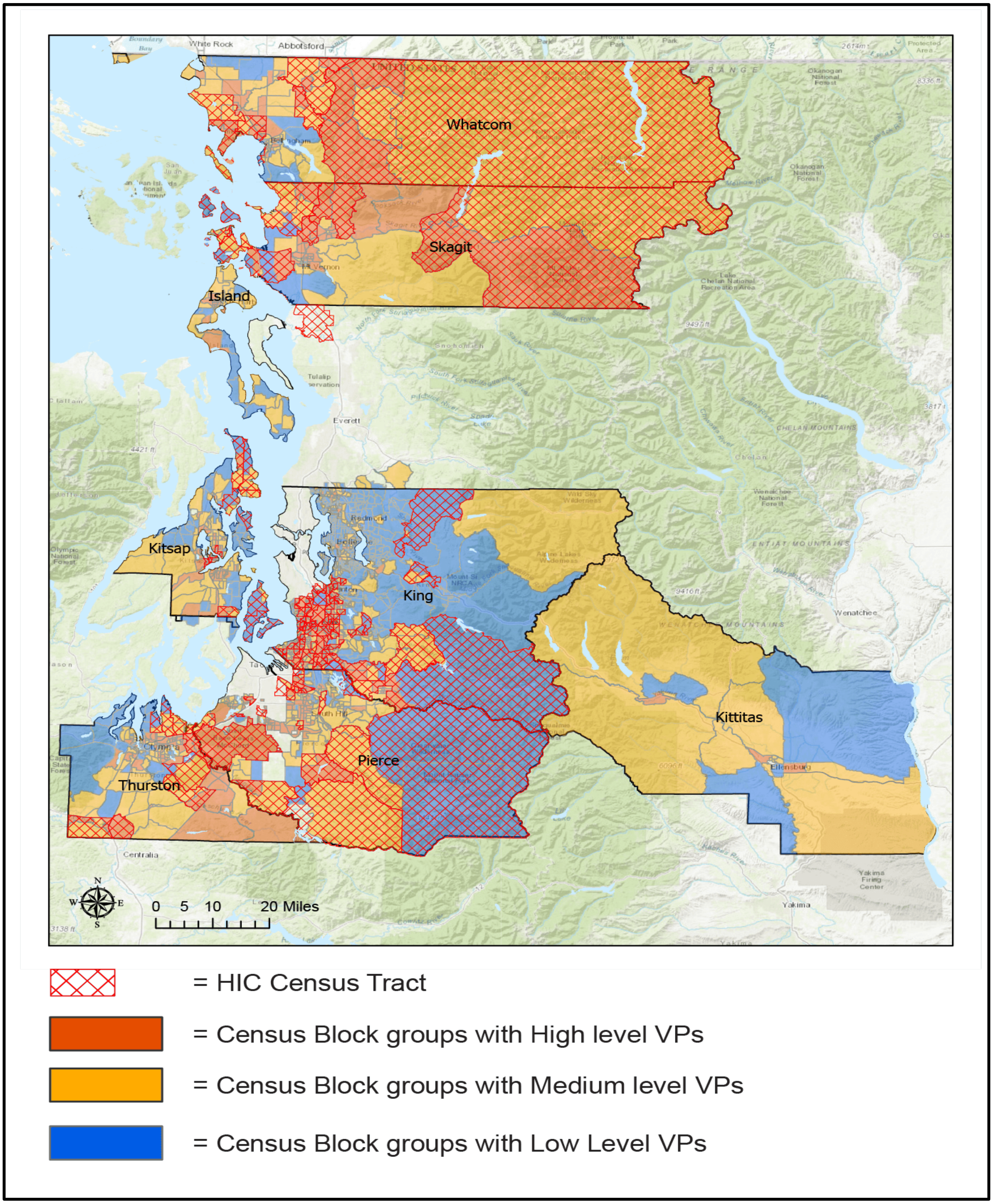


Table J.1: Number and Percentage of PSE Customers in Highly Impacted Communities and Vulnerable Populations

Customer count (PSE's electric customers)	Customers in highly impacted communities	Customers in vulnerable populations Low	Customers in vulnerable populations in Medium	Customers in vulnerable populations High
1,147,383	310,991 (27%)	333,869 (29%)	387,228 (34%)	426,286 (37%)

3. Customer Benefit Indicators

In this assessment, we measure disparities in our existing programs and resources using CBIs. We used specific metrics for each CBI to track and measure the impact of programs on the progress toward ensuring all customers benefit due to the clean energy transformation.

In the 2021 IRP[9], we presented a selection of metrics for this assessment which were our estimates of the characteristics we thought contributed to the equitable distribution of burdens and benefits. Since then, we established the EAG, published the 2021 CEIP, and engaged interested parties about incorporating and measuring equity across PSE's business. In this assessment, we present the CBIs, and accompanying metrics, developed in the 2021 CEIP[10] as a replacement for the metrics initially published in the 2021 IRP. Table J.2 defines these metrics.

Table J.2: Customer Benefit Indicators and Metrics

CETA Category	Indicator	Metric	Data Source	Expected Burdens Reduced
Energy Benefits Non-energy Benefits Burden Reduction	Improved participation in clean energy programs from highly impacted communities and vulnerable populations	Increase the number and percentage of participation in energy efficiency, demand response, and distributed resource programs or services by PSE customers within highly impacted communities and vulnerable populations. Increase the percentage of electricity generated by distributed renewable energy projects	Internal PSE data in which PSE measures the number of programs related to all customers and PSE customers within named communities.	Lack of awareness and education Cost of participation and economic barriers Costs and potential bill increases
Non-energy Benefits	Increase in quality and quantity of clean energy jobs	Increase quantity of jobs based on: • Number of jobs created by PSE programs for residents of highly	Unavailable currently. This information will be available in the future as PSE contracts with vendors and collects this information.	Access to high-quality jobs in clean energy

9 Appendix K: Economic, Health and Environmental Assessment of Current Conditions; 2021 Integrated Resource Plan

10 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

CETA Category	Indicator	Metric	Data Source	Expected Burdens Reduced
		impacted and vulnerable populations • Number of local workers in jobs for programs • Number of part-time and full-time jobs by project Increase the quality of jobs based on: • Range of wages • Additional benefits • Demographics of workers		
Non-energy Benefits	Improved home comfort	Increased non-energy benefits in Energy Efficiency Programs, measured in net present value (NPV) dollars.	Internal PSE data calculated as non-energy impacts within the BCP process.	Lack of awareness and education Cost of participation and economic barriers
Burden reduction	Increase in culturally- and linguistically-accessible program communications for named communities	Increase outreach material available in non-English languages	Internal PSE data that quantifies the number of non-English language materials used by PSE.	Lack of awareness and education
Cost Reduction Burden Reduction	Improved affordability of clean energy	Reduce median electric bill as a percentage of income for residential customers Reduce median electric bill as a percentage of income for residential customers who are also energy-burdened	Internal PSE data in which PSE measures the affordability of clean energy related to all customers and PSE customers within named communities. We may also use the Department of Energy's Lead tool.[11]	Cost of participation and economic barriers
Environment	Reduced greenhouse gas emissions	Reduce PSE-owned electric operations metric tons of annual CO_{2e} emissions. Reduce PSE contracted electric supply metric tons of annual CO_{2e} emissions.	Publicly available data on PSE CO_{2e} emissions.[12]	Adverse climate impacts of CO_{2e} emissions
Environment Risk Reduction	Reduction of climate change impacts	Increase in avoided emissions times the social cost of carbon	Public data on the social cost of carbon as defined by the WUTC[13] and data on PSE's	Adverse climate impacts of CO_{2e} emissions

[11] Low-income Energy Affordability Data (LEAD) Tool
[12] PSE Greenhouse Gas Policy Statement
[13] Washington Utilities and Transportation Commission | Social Cost of Carbon

CETA Category	Indicator	Metric	Data Source	Expected Burdens Reduced
			emissions are available on the PSE website.[14]	
Public Health	Improved outdoor air quality	Reduce regulated pollutant emissions (SO_2, NO_x, PM2.5)	Internal PSE data on emissions.	Adverse health impacts from air pollution
Public Health	Improved community health	Reduce the occurrence of health factors like hospital admittance, and work loss days	Washington Department of Health hospital discharge rates.[15]	Adverse health impacts from air pollution
Resilience	Decrease frequency and duration of outages	Decrease the number of outages, total hours of outages, and total backup load served during outages using System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) Reduction in peak demand through demand response programs	Internal PSE data on named communities and publicly available data regarding PSE's current SAIDI and SAIFI metrics are available on the UTC website.[16] Internal PSE data provided the analysis of named communities.	Dependability of variable clean electricity sources like wind and solar
Risk Reduction Energy Security	Improved access to reliable, clean energy	Increase the number of customers who have access to emergency power	Internal PSE data in which PSE measures the number of customers with storage related to all customers and PSE customers within named communities.	Lack of awareness and education Cost of participation and economic barriers Dependability of variable clean electricity sources like wind and solar

Note: Additional information on metrics used for disparity data is available in Appendix H: Customer Benefit Indicator Metrics[17] of the 2021 CEIP.

We showed data for many of these metrics in Chapter Three of the 2021 CEIP[18] and established a baseline measurement for 2020. We are working to collect and process data to extend this baseline data through recent years to track and measure CBIs across time. We plan to present updated data as part of the upcoming Clean Energy Implementation Plan Biennial Update scheduled for release in the fourth quarter of 2023.

[14] PSE Greenhouse Gas Policy Statement
[15] Hospital Discharge Data (CHARS): Washington State Department of Health
[16] Washington Utilities and Transportation Commission | Annual Reliability Reports of Electric Companies
[17] 2021 CEIP Appendix H: Customer Benefit Indicator Metrics
[18] 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

DELIVERY SYSTEM PLANNING

APPENDIX K

PSE PUGET SOUND ENERGY

Contents

1. Introduction

This appendix summarizes Puget Sound Energy's (PSE's) update to our electric delivery system 10-year plan. For a detailed description of the planning process and the status of each project, refer to the 2021 Integrated Resource Plan (IRP), Appendix M, and the PSE plan[1]. We included significant changes to project statuses from the 2021 IRP.

2. Electric Projects in Implementation Phase

Figure K.1 summarizes PSE projects in the project implementation phase, which includes design, permitting, construction, and close-out. Estimated in-service years reflect the current project status.

Figure K.1: Summary of PSE Electric Projects in Implementation

Summary of PSE Electric Projects in Implementation	Estimated In-service Year
1. Sammamish — Juanita New 115 kilovolt (kV) Line	2023
2. Eastside 230 kV Transformer Addition and Sammamish-Lakeside-Talbot 115 kV Rebuilds (Energize Eastside)	2024
3. Electron Heights — Enumclaw 55-115 kV Conversion	2025
4. Sedro Woolley — Bellingham #4 115 kV Rebuild and Reconductor	2025
5. Bainbridge Island (NWA Analysis Pilot)	2026
6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Analysis Pilot)	2024

Estimated Date of Operation: 2024

Project Need: Puget Sound Energy's 2022 needs assessment study verified a transmission capacity deficiency in the Eastside area under certain contingency conditions in the summer season. Utilizing the latest load forecast and system information, we determined this need requires Corrective Action Plans (CAPs) to manage overloads. Our 2022 needs assessment also identified a winter transmission capacity deficiency in the Eastside area for the base and sensitivity cases in the ten-year planning horizon. These deficiencies will impact reliable power delivery to PSE customers and communities in and around Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, Renton, and the towns of Yarrow Point, Hunts Point, Beaux Arts, and others.

Solution Implemented: Install a 230 kV/115 kV transformer at Richards Creek substation in the center of the Eastside load area and rebuild the 115 kV Sammamish-Lakeside-Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth.

Current Status: The south half of the project has been permitted and will be completed in 2023 when we energize the Richards Creek substation. The north half of the project (between the Sammamish substation and Richards Creek substation) is in the permitting phase; we expect it will be in service by the end of 2024. Supple chain issues, however, may delay the completion of the north half.

[1] http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_FINAL.pdf

3. Electric Projects in Initiation Phase

Figure K.2 summarizes PSE electric projects in the initiation phase, which includes determining need, identifying alternatives, and proposing and selecting solutions. The table also includes projects that have entered the initiation phase since we completed the 2021 IRP. For a detailed description of the initiation phase and the status of each project, refer to the 2021 Integrated Resource Plan: Appendix M and the 2022 PSE Plan.[1] We included significant changes to the status of projects from the 2021 IRP and details for new projects that have entered the initiation phase in this report.

Figure K.2: Summary of 10-year PSE Electric Initiation Projects

Summary of PSE Electric Projects in Initiation	Date Needed	Need Driver
7. Seabeck (Non-wires Analysis (NWA) Pilot)	Existing	Capacity, Reliability
8. West Kitsap Transmission Project (NWA Pilot)	Existing	Capacity, Operational Flexibility, Aging Infrastructure
9. Whidbey Island Transmission Improvements	Existing	Aging Infrastructure, Reliability, Operational Concerns
10. Kent / Tukwila New Substation (NWA Candidate)	Existing	Capacity, Aging Infrastructure
11. Black Diamond Area Distribution Capacity	2030	Capacity, Reliability
12. Issaquah Area Distribution Capacity (NWA Candidate)	2022	Capacity
13. Bellevue Area Distribution Capacity	2022	Capacity, Reliability
14. Juanita-Moorlands Transmission Capacity	2027	Capacity, Reliability
15. South Thurston County Transmission Improvements	2032	Capacity, Reliability
16. Electron Heights-Yelm Transmission Project	2032	Capacity, Aging Infrastructure
17. Lacey Hawks Prairie (NWA Candidate)	2024	Capacity, Reliability
18. Redmond Area Distribution Capacity	2024	Capacity
19. Covington Area Distribution Capacity	2025	Capacity
20. Sumner Area Distribution Capacity	2024	Capacity
21. Yelm Area Transmission	2032	Capacity, Reliability

3.1. West Kitsap Transmission

Estimated Date of Operation: 2028

Current Status: We identified a need to provide additional capacity in Kitsap County to serve existing customers, projected load, and improve transmission reliability for all 134,000 customers in Kitsap County and Vashon Island. We are finalizing the solutions study, which includes an analysis of non-wire alternatives and a preferred solution. The first need we addressed includes constraints on the 115 kV system serving Kitsap County under North American Electric Reliability Corporation (NERC) credible contingencies. We identified an additional need related to bulk capacity serving Kitsap County, which could lead to voltage collapse (i.e., low or rapidly falling voltage resulting in loss of service) under certain conditions. Lastly, we identified an aging infrastructure need on the submarine cables that tie

Kitsap County to King County via Vashon Island. These cables were originally installed in the 1960s and are approaching the end of their projected useful life.

We developed a solution to address these needs, including replacing and increasing the capacity of the submarine cables and the associated overhead ends to allow us to operate this normally open tie normally closed. This action addresses the aging infrastructure and bulk capacity needs for Vashon Island and Kitsap County. We will also build a new, 18-mile-115-kV backbone transmission line from Bonneville Power Administration's (BPA) Kitsap Substation in south Kitsap County to PSE's Foss Corner Substation in northern Kitsap County. This new line will address the 115 kV system constraints within Kitsap County. Our analysis identified BPA as an affected system for this solution, and further coordination with BPA may influence the final scope of this solution. Our interim operating plan to mitigate identified needs is to shift load to the South King County transmission system via the tie across Vashon Island or to shed load in North Kitsap County or Bainbridge Island.

3.2. Redmond Area Distribution Capacity

Estimated Need Date: 2024

The downtown Redmond and Redmond Ridge areas serve roughly 14,500 customers from four substations and one 115 kV transmission line. We expect the area to experience heavy load growth in the next 20 years.

Project Need: The need drivers for this area are capacity related.

Capacity: Several large developments in downtown Redmond and Redmond Ridge will require additional distribution substations and feeder capacity. Substation Group capacity will exceed the planning trigger in 2024, with feeder group capacity exceeded in 2026.

Current Status: A review of solution alternatives is underway, and we expect to select one in 2023.

3.3. Covington Area Distribution Capacity

Estimated Need Date: 2025

Puget Sound Energy has a project in the planning phase that we will develop to address distribution capacity constraints in the Covington area due to anticipated load growth.

Project Need: The need drivers for this area are capacity related.

Capacity: Several large developments in the area will require additional distribution substations and feeder capacity in the 10-year planning horizon.

Current Status: We will start the detailed needs assessment and project initiation to review alternatives in 2023.

3.4. Sumner Area Distribution Capacity

Estimated Need Date: 2024

Puget Sound Energy has a project in the planning phase that will address distribution capacity constraints in the Sumner area due to anticipated load growth.

Project Need: The need drivers for this area are capacity related.

Capacity: Several large developments in the area will require additional distribution substation capacity by 2024 and additional distribution feeder capacity by 2026.

Current Status: A review of the wires solution alternatives is underway. The non-wires analysis will begin in early 2023, and we will select a solution in mid- to late-2023.

3.5. Yelm Area Transmission

Estimated Need Date: 2032

The existing Blumaer-Electron Heights 115 kV line serves approximately 17,450 customers, 14,450 of which are in the Yelm area. Puget Sound Energy's project is in the planning phase that will improve the reliability of the existing system and increase capacity to support anticipated load growth in Yelm in the 10-year planning horizon.

Project Need: The need drivers for this area are reliability and capacity related.

Reliability: We serve customers in this area with a single, 42-mile-long transmission line subject to outages at a rate higher than the system average.

Capacity: Anticipated load growth in the area will require additional transmission lines to avoid overloads on the system under NERC-credible contingencies.

Current Status: We expect to begin the detailed needs assessment and project initiation to review alternatives in late 2023 or early 2024.

RESOURCE ADEQUACY

APPENDIX L

PUGET SOUND ENERGY

Contents

1. Introduction

To perform the resource adequacy analysis used in the 2023 Electric Progress Report (2023 Electric Report), Puget Sound Energy (PSE) contracted with the energy consulting firm Energy and Environmental Economics (E3). The firm used their RECAP model for this analysis. This appendix provides a resource adequacy overview, detailed inputs and updates, the modeling approach, and results.

2. Resource Adequacy Overview

Puget Sound Energy performs resource adequacy planning to ensure we can reliably meet future customers' energy demands. We do this by building generating capacity or acquiring capacity through contracts. Many factors can impact our ability to meet demand reliably, including variations in temperatures, power demand, energy demand, generation of various resources, equipment failures, transmission interruptions, and wholesale power supply curtailment. Resource adequacy planning allows us to consider these many uncertainties when planning our system.

The outputs from our resource adequacy analysis are key inputs to PSE's long-term portfolio analysis presented in this report. The resource adequacy analysis determines the total resource need from future resources to ensure our system remains reliable. The resource adequacy analysis also determines the capacity contributions of different resources so we can appropriately account for each resource's contribution to reliability. This section discusses critical concepts for the resource adequacy analysis, including factors influencing the total resource need and the resources' ability to contribute to satisfying that need.

2.1. Energy Demand

We plan our system to meet customers' future energy demands. Energy demand forms the basis for our plan because generation resources and transmission require years to develop and build, so we must forecast energy demand as part of our plans. Chapter Six: Demand Forecast discusses the load forecast for the 2023 Electric Report in more detail.

In addition to planning to meet expected energy demand, we must also plan our system to respond to variations in energy demand. Energy demand varies significantly throughout the year and between years due to temperature changes, among other factors. For example, demand for heat yields higher energy demand during the winter, and demand for cooling results in higher energy demand in the summer. Extreme temperatures can vary considerably between years. One year could have a week-long cold snap that significantly increases energy demand, and the following year could have a mild winter. We must plan our system to have enough resources to meet energy demands and maintain reliability across various conditions, including extreme events with low probability.

Climate change also impacts PSE's energy demand. Average temperatures have increased in the Pacific Northwest over the past decades, which is predicted to continue to increase in the coming decades. Higher temperatures raise energy demand in the summer. Moreover, climate change can make extreme events more likely, such as the extreme heat dome event the Northwest experienced in 2021. We must account for the effects of climate change on energy demand in our long-term plans to ensure resource adequacy.

2.2. Operating Reserves

In addition to supplying enough generation to satisfy energy demand, we must maintain minimum operating reserves to respond to contingencies and balance short-term, sub-hourly fluctuations in load and generation. Energy demand plus operating reserves determine the total resource requirement in each operating period. We must curtail load if PSE has insufficient resource capacity to meet this requirement and cannot rely on the wider regional energy system to fill the gap.

Load curtailment, also known as a loss of load event, reduces or discontinues energy consumption.

We included two operating reserve requirements: contingency reserves and balancing reserves in the resource adequacy analysis.

2.3. Contingency Reserves

The North American Electric Reliability Corporation (NERC) requires that utilities maintain reserves above end-use demand as a contingency to ensure continuous, reliable operation of the regional electric grid. On October 1, 2014, the Federal Energy Regulatory Commission (FERC) approved rule Bal-002-WECC-1, which requires PSE to carry reserve amounts equal to three percent of load plus three percent of online generating resources. The terms load and generation in the rule refer to the total net load and generation in PSE's Balancing Authority Area (BAA).

Puget Sound Energy participates in the Northwest Power Pool (NWPP) Reserve Sharing Program, which governs our requirement to maintain contingency reserves. In an event that causes PSE to have insufficient resources to satisfy power demand plus operating reserves requirements, we can call on the contingency reserves of other program members to cover the resource loss during the 60 minutes following the event. After the first 60 minutes, we must return to load-resource balance by re-dispatching other generating units, purchasing power, or curtailing load.

2.4. Balancing Reserves

Although we perform resource adequacy analysis hourly, utilities must also have sufficient reserves to maintain system reliability during the operating hour. We must have adequate reserves to meet load or variable resource generation fluctuations on a minute-by-minute and second-by-second basis. The resource adequacy analysis accounts for these sub-hourly fluctuations by requiring balancing reserves be held in addition to serving load and holding contingency reserves. Unlike contingency reserves, which we only utilize when the system meets specific criteria and on a short-term basis, balancing reserves are called upon regularly within an operating hour to balance the system as loads and resources fluctuate.

The consulting firm E3 calculated balancing reserve requirements on behalf of PSE. They estimated the balancing reserves by measuring the amount of intra-hour variability PSE could experience based on anticipated future resource buildouts. Because E3's RECAP model has hourly timesteps, it does not inherently capture sub-hourly variations.

Including balancing reserves in the overall operating reserves requirements ensures that the resource adequacy analysis accounts for the sub-hourly variability we manage and meet hourly system needs.

E3 calculated the balancing reserve requirements by analyzing PSE's system's five-minute load, wind, and solar data. To ensure that the load, wind, and solar profiles correspond to the same underlying weather conditions and incorporate any correlations or relationships between them, E3 first obtained three years of historical weather-matched data from PSE. Then they scaled up load, wind, and solar generation to match PSE's expected future levels. Lastly, E3 subtracted wind and solar generation from the load to obtain a net load profile for subsequent analysis. We ultimately need to manage the net load variability by dispatching other resources.

E3 compared the five-minute fluctuations in the net load to the hourly average net load to determine the magnitude of fluctuations around the hourly average net load levels. E3 then developed a 95 percent confidence interval for these fluctuations to quantify the balancing reserves for the system. The 95 percent confidence interval provides the range of five-minute fluctuations relative to hourly net load that covers 95 percent of all observations.

2.5. Reliability Target

No electricity system is perfectly reliable; there is always some chance that generator outages, transmission failures, and extreme weather conditions that impact supply and demand could lead to insufficient resources and loss of load. Therefore, we cannot plan for zero loss of load events and must set an appropriate reliability target for planning.

A reliability target sets a minimum threshold for one or more reliability metrics, ensuring the system can satisfy power and energy demand and maintain reliability across various weather and system operating conditions. There is no single reliability target in the electricity industry. System planners typically set reliability targets based on the probability of a loss of load event in a year or the frequency of loss of load events.

We plan our system to a reliability target of five percent loss of load probability (LOLP). If we maintain sufficient resources to satisfy this standard, we can expect a loss of load one year out of every twenty years. Puget Sound Energy's five percent LOLP reliability target is consistent with the reliability target used by the Northwest Power and Conservation Council (the Council).

2.6. Total Resource Need

We conduct resource adequacy analysis based on the reliability target to determine the system's total resource need. Total resource need is the capacity in megawatts (MW) required to satisfy the reliability target. When considering all existing and new resources, we must ensure enough capacity to meet the total resource need and the reliability target. If our existing resource portfolio falls short of the total resource need, this indicates a capacity shortfall we must meet with additional resources. The portfolio analysis modeling in the 2023 Electric Report determines what resources we should use to meet that capacity shortfall.

2.7. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it means there is a 50 percent probability of the actual peak load being higher than this forecast and a 50 percent probability of it being lower than the forecast.

The PRM represents the resource need amount beyond the normal peak load PSE must maintain to satisfy the total resource need and, ultimately, the reliability target of five percent LOLP.

2.8. Capacity Credit of Resources

To determine whether PSE's resource portfolio satisfies the PRM, we must determine the total resource capacity that counts toward the PRM. The capacity credit of a resource is the amount the resource counts toward the PRM in MW.

The peak capacity contribution of natural gas resources is different from other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need occurs at 23 degrees Fahrenheit, we set the capacity of natural gas plants to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. However, we adjust ELCC on new generic thermal resources since the model does not account for them in the forced outages.

This adjustment includes natural gas generators and contracted power from Mid-Columbia (Mid-C) hydroelectric plants. We call out contracted power for hydroelectric plants separately from other hydroelectric generation because the contract has firm delivery, meaning the party is financially and physically obligated to deliver the agreed-upon amount of energy or capacity per the agreement. For resources whose capabilities to supply power are variable or limited — also known as dispatch-limited resources —we set the capacity credit equal to the ELCC of the resource. The dispatch-limited resources include hydroelectric, wind, solar, energy storage, contract, and demand response resources.

The ELCC is the quantity of perfect firm capacity that could be replaced or avoided by a resource while achieving our five percent LOLP. The ELCC can be expressed in MW or as a percentage of a resource's nameplate capacity. For example, a resource with an ELCC of 50 percent would mean the addition of 100 MW of the resource could displace the need for 50 MW of perfect capacity without an impact on reliability. Perfect capacity is a benchmark to quantify the contribution of dispatch-limited resources toward the PRM.

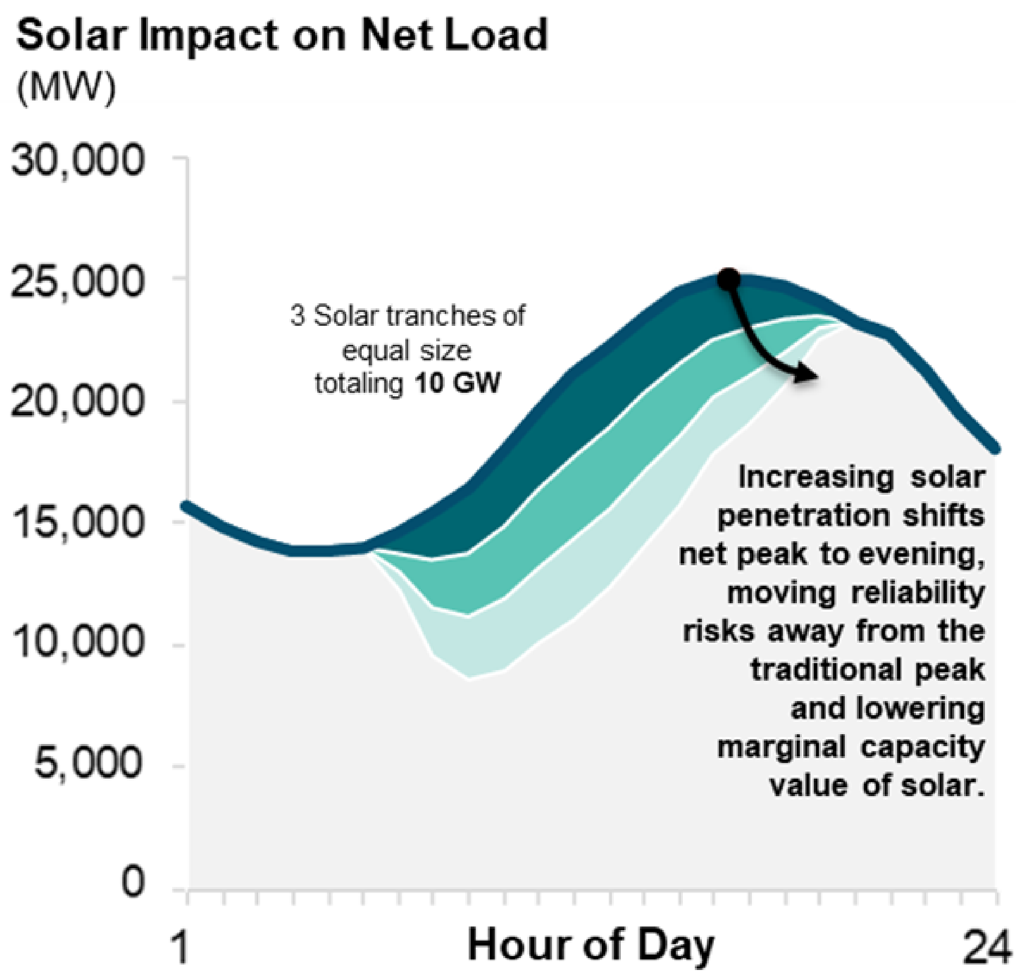
The ELCC for dispatch-limited resources is typically less than 100 percent. Wind and solar resources have an inherently variable output which may not be at maximum levels when the PSE system needs additional capacity. Energy storage resources are limited by the duration of time they can operate at full capacity. Demand response has similar limitations regarding the length and frequency of calls. The ELCC metric ensures we account for the correct contribution of each of these resources toward the PRM, which is increasingly important as we add more dispatch-limited resources to our resource portfolio.

The choice of how to assign capacity credits to resources also impacts the total resource need. Because we count natural gas and Mid-C hydroelectric resources at nameplate capacity despite their limitations — such as forced outages or limited water budget — we must ensure PSE maintains enough capacity to make up for these limitations. We calculate the total resource need to take these limitations into account.

2.9. ELCC Saturation Effect

The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. See Figure L.1 for an example of solar dynamics on a peak summer day. Note this is an illustrative example and does not represent PSE's system. The first tranche of solar produces a great deal of energy during peak demand hours, corresponding to having a relatively high ELCC. However, adding more solar shifts the net peak demand (load minus renewable generation) into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during daytime but can't contribute to the reliability needs during nighttime hours. Wind resources experience this same saturation effect, except rather than shifting the net load from day to nighttime hours, wind resources shift the net load from when wind generation is high to when wind generation is low.

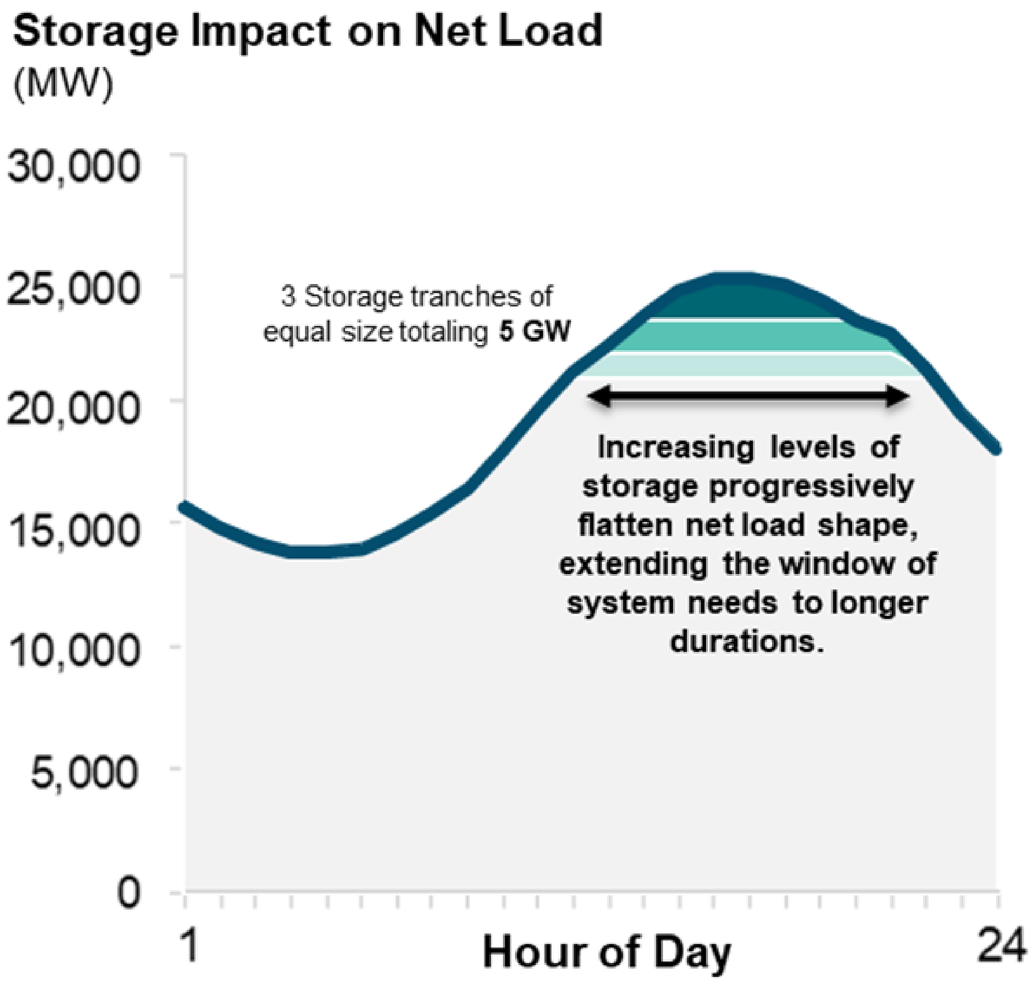
Figure L.1: Example of ELCC Saturation Effect for Solar (Does not represent PSE's system)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure L.2 for an example showing the dynamics for storage on the same peak day. Note that this illustrative example does not represent PSE's system.

The first tranche of energy storage produces a great deal of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as we add more energy storage, the net peak demand (load minus energy storage generation) flattens and spans longer. As a result, the ELCC for these later tranches is lower because the storage is mitigated during the highest peak demand hours but can't contribute the same reliability value over longer hours due to limitations in energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, and the length of calls but without a need of charging.

Figure L.2: Example of ELCC Saturation Effect for Energy Storage (Does not represent PSE's system)



2.10. Loss of Load Probability Modeling

To quantify the total resource need, the PRM, and the ELCC of resources, we rely on loss of load probability (LOLP) modeling. We use LOLP modeling to simulate the availability of resources to meet power demand and operating reserve requirements across a broad range of conditions. The model accounts for factors such as weather-driven load variability, forced outages of power plants, capacity derating at higher temperatures of thermal units, the natural variability of resources like wind and solar, operating constraints for hydroelectric and storage, and the availability of wholesale market purchases. To appropriately capture the risk of rare extreme events, we use LOLP modeling to simulate potential operating conditions on an annual basis hundreds of times using stochastic simulation techniques. By simulating many years, this analysis can generate the LOLP metric by comparing the number of simulations years with loss of load to the total number of simulated years, which we then compare to PSE's reliability target.

Calculating the ELCC of a resource using a LOLP model is a three-step process.

1. First, the LOLP model calibrates the system to the reliability target by adding enough perfect capacity to the existing resource portfolio, so the system exactly satisfies PSE's reliability target.

2. Then, the LOLP model adds the resource of interest to the system. Because this resource will add more resource capacity to the system, the LOLP metric will fall relative to the target: the system becomes more reliable than the reliability target.

3. Lastly, the LOLP model removes enough perfect capacity, so the system returns to PSE's reliability target. The amount of perfect capacity the model removed is the resource's ELCC in MW.

Calculating the total resource need of the system follows a different three-step process.

1. First, we estimate the ELCC of all dispatch-limited resources in the system and wholesale power purchases.

2. Next, we determine the capacity shortfall for the system: the amount of perfect capacity PSE needs in addition to the existing system to satisfy the reliability target.

3. Lastly, we sum the capacity contribution of all resources and the capacity shortfall to get the total resource need. The PRM is a simple derivation from the total resource need.

3. Resource Adequacy Inputs and Updates

We improved the inputs and methodology for the resource adequacy analysis in this report. These improvements relate to future impacts of climate change, seasonal resource needs, better representation of resource capabilities, and other factors. This section details these improvements and how they relate to assumptions in PSE's 2021 Integrated Resource Plan (IRP).

3.1. Background

Puget Sound Energy filed a draft all-source request for proposal (RFP) on April 1, 2021, to meet our capacity and clean energy resource needs established in the 2021 IRP. We received comments from interested parties and Washington Utilities and Transportation Commission (Commission) staff on that draft during a 45-day comment period. As a result of those comments, we filed revisions to the RFP in June 2021 and added a technical workshop for interested parties to discuss our ELCC methodology and assumptions.

On August 31, 2021, we held a public ELCC workshop[1] and presented the modeling approach and assumptions we used to derive the generic and resource-specific ELCC assumptions used in our planning and acquisition analyses. We gave ELCC estimates and solicited feedback from interested parties to guide and inform the 2021 all-source RFP. In response to public feedback, our Independent Evaluator, Bates White, retained consulting firm E3 to review PSE's

1 https://www.pse.com/pages/energy-supply/acquiring-energy

methodology for calculating ELCC values. E3 issued a report[2] on October 8, 2021. Based on their review, E3 found our approach to calculating ELCCs was reasonable but recommended several areas for improvement.

On August 31, 2021, the Commission issued a public notice of opportunity to file written comments in WUTC docket UE-210220 related to PSE's ELCC estimates and use in the company's all-source request for proposals. Comments were initially due by the end of September; however, due to the timing of E3s final report, the Commission extended the comment deadline to October 22, 2021. The Commission received public comments[3] from 13 individuals and organizations regarding PSE's ELCC results and the E3 methodology and assumptions report.

➔ The full Commission docket and public comments are available on the UTC website.

In response[4] to this feedback and E3 recommendations, we made several updates to the 2023 Electric Progress Report and phase two of the 2021 RFP, described in the following sections.

Puget Sound Energy hosted a follow-up informational webinar to discuss resource adequacy on August 24, 2022. In this meeting, PSE presented the summary of E3's resource adequacy modeling results, an overview of the Western Resource Adequacy Program (WRAP), and an overview of the Northwest Regional Forecast by the Pacific Northwest Utilities Conference Committee (PNUCC).

➔ You can find all the materials from the resource adequacy webinar on the PSE website.

3.2. Overview of Updates

E3 proposed six recommendations for improvements to PSE's resource adequacy methodology. In PSE's December 2021 response comments, PSE indicated that it would attempt to incorporate these recommendations for the RFP and the 2023 Electric Report but might not be able to complete all changes due to time requirements to gather data, develop processes, update models, and benchmark results. We worked closely with E3 to implement E3's recommended updates for RFP and the 2023 Electric Report. In summary, we incorporated four of E3's six recommendations and made many other improvements to the resource adequacy analysis. Following is a description of E3's six recommendations and other changes to the analysis compared to the 2021 IRP.

3.3. Years Modeled

E3 performed a five- and 10-year resource adequacy assessment to determine the PRM. The 2023 Electric Report time horizon starts in 2024, so the five-year assessment is for October 2029–September 2030, and the 10-year

2 Review of Puget Sound Energy Effective Load Carrying Capability Methodology, https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/PSE--ELCC-StudySept-202110072021FINAL.pdf

3 https://www.utc.wa.gov/casedocket/2021/210220/docsets

4 https://apiproxy.utc.wa.gov/cases/GetDocument?docID=159&year=2021&docketNumber=210220

assessment is for October 2034–September 2035. These years are two years later than those we modeled in the 2021 IRP.

The modeled years follow the hydroelectric year (October–September) to capture the entire winter and summer seasons, consistent with the Council's GENESYS model. If we had modeled the calendar year instead, it would break up the winter season (November–March).

3.4. Climate Change Impacts

We incorporated future climate change impacts in the resource adequacy analysis for this report and relied on climate change data from the Council. Anticipated future climate change impacted four critical inputs to the resource adequacy analysis:

1. Energy demand
2. Hydroelectric generation
3. Market purchases
4. Duration and frequency of outage events

➔ For a detailed description of the load forecasts development process and inputs, see Chapter Six: Demand Forecast of the 2023 Electric Report.

These load forecasts show that PSE's system would experience much higher energy demand in summer than the load forecast we used in the 2021 IRP. Winter energy demand, however, would be at similar levels because the load data include a 30-year temperature warming trend (2020–2049), and the energy demand in summer increases meaningfully over the 30 years. However, the resource adequacy analysis applies to a single future year (2029 or 2034) and represents the amount of climate change for that year.

E3 detrended the load forecasts to correspond to a single model year (2029 or 2034) to ensure that the climate impacts for the modeled 30 years correspond to the appropriate model year while capturing the range of potential load levels for that model year. In this report, we modeled future load data that include climate change's impacts. In the 2021 IRP, we used historical load data that did not capture the future effects of climate change.

The Council also developed hydroelectric generation forecasts for each climate scenario and the two model years. The climate change forecasts influence the amount and timing of rainfall, snowmelt, and water inflows. The University of Washington Climate Impacts Group (CIG) provided water inflows for the Columbia River and coastal drainages in Washington, covering the Mid-C and Baker hydroelectric plants. The daily inflows are also for the same three climate change scenarios: A, C, and G. We then used this water inflow data to determine the total generation at each hydroelectric plant. The hydroelectric generation varies across 30 weather years, the same future weather years we used for the load forecast. In the 2021 IRP, we utilized 80 years of historical hydroelectric generation to characterize hydroelectric variability.

Lastly, we assessed the availability of market purchases from neighboring utilities and markets. Just as the climate impacts load and hydrological conditions for our system, it also impacts these conditions for the greater Pacific Northwest and the West. We used the Council's Classic GENESYS model to characterize the region's curtailments and California imports. During a Pacific Northwest-wide load-curtailment event, there is not enough physical power supply available in the area (including available imports from California) for the region's utilities to fully meet their firm loads plus operating reserve obligations.

We used the Wholesale Purchase Curtailment model (WPCM) to determine PSE's share of curtailments in the Northwest region and capture how the Pacific Northwest wholesale markets would likely operate in such a situation. To assess a wide range of regional market conditions, we combined the 30 years of energy demand forecasts with each of the 30 years of hydroelectric generation forecasts to simulate the availability of market purchases across 900 simulation years. This report used modeled load and hydroelectric generation data for the future to capture the impacts of climate change and performed 900 simulations. In the 2021 IRP, we used the classic GENESYS model but relied on historical load and hydroelectric generation data to perform 7,040 simulations.

These updates to our methodologies ensured we captured the future impacts of climate change on energy demand, hydroelectric generation, and availability of market purchases from other systems.

3.5. Seasonal Analysis

In the 2023 Electric Report, we performed resource adequacy analysis on a seasonal rather than an annual basis. This more detailed approach allowed us to determine the resource need and assess the contribution of resources to the PRM by season. We modeled two seasons: winter, November–March, and summer, June–September.

E3's seasonal resource adequacy analysis calculated separate PRM and ELCC values for winter and summer. The seasonal PRM sets the total amount of resources needed in that season. The seasonal ELCC is a resource's contribution to the PRM by season. We calculated the PRMs for winter and summer to ensure PSE adds enough resources to satisfy them and meet our annual five percent LOLP target. We calculated the ELCCs for winter and summer, so they only consider how a resource contributes to winter and summer reliability, respectively.

3.6. Wholesale Purchase Curtailments

We updated the wholesale purchase curtailments for this report with the Classic GENESYS and WPCM. Table L.1 shows the wholesale purchase curtailment results for the 2021 IRP and the 2023 Electric Report. We based the results for the 2021 IRP on 7,040 simulations and the results for the 2023 Electric Report on 900 simulations for each climate model — 2,700 total simulations.

In winter, wholesale purchase curtailments are similar between the 2021 IRP and climate model G in the 2023 Electric Report. The average number of curtailment events, length of curtailment events, and the overall amount of curtailment are similar. However, climate models A and C in the 2023 Electric Report show less overall curtailment in winter. These two climate models exhibit more overall warming than climate model G, resulting in lower average winter temperatures and fewer wholesale purchase curtailments.

In summer, wholesale purchase curtailments significantly differ between the 2021 IRP and the 2023 Electric Report. The frequency and magnitude of curtailment events are much larger in the 2023 Electric Report. Climate model G has more curtailment events and overall curtailment than the 2021 IRP. This difference is even more pronounced for climate models A and C, which have more overall warming than climate model G.

The results in this report show wholesale purchase curtailments are less common in winter and much more common in summer. These results mean wholesale purchases will be less limited in winter and more limited in summer relative to the 2021 IRP. One caveat to this assumption is that electrification of heating demands in the future could again make winter a more constrained period for wholesale purchases. The 2023 Electric Report does not consider widespread building electrification in the future.

Table L.1: Wholesale Purchase Curtailments in the 2021 IRP and 2023 Electric Progress Report — Winter Modeling

Metric	2021 IRP[1] Winter	2023 (A)[2,3]	2023 (C)[2,3]	2023 (G)[2,3]
Average # of curtailment events per year	0.22	0.10	0.00	0.18
Average curtailment duration (hours)	37.7	8.8	2.5	28.3
Average amount of curtailment (MWh/year)	5,792	445	2	5,991

Notes:

1. The results for the 2021 IRP correspond to the model year 2027.
2. The results for the 2023 Electric Report correspond to the model year 2029.
3. A, C, and G correspond to climate models for the 2023 Electric Progress Report.

Table L.2: Wholesale Purchase Curtailments in the 2021 IRP and 2023 Electric Progress Report — Summer Modeling

Metric	2021 IRP[1] Summer	2023 (A)[2,3]	2023 (C)[2,3]	2023 (G)[2,3]
Average # of curtailment events per year	0.79	22.10	18.93	10.43
Average curtailment duration (hours)	9.4	10.6	9.6	10.4
Average amount of curtailment (MWh/year)	3,234	189,140	143,927	84,398

Notes:

1. The results for the 2021 IRP correspond to the model year 2027.
2. The results for the 2023 Electric Report correspond to the model year 2029.
3. A, C, and G correspond to climate models for the 2023 Electric Progress Report.

3.7. Energy Storage Modeling

We made several changes to the assumptions we used to calculate the ELCC of energy storage resources in this report:

- Storage can discharge at its rated capacity for its rated duration. A minimum state of charge does not apply to the modeled energy capacity. For example, a fully charged 100 MW four-hour lithium-ion battery resource can discharge to the grid at 100 MW for four consecutive hours.

- Storage can have forced outages. The modeled forced outage rate for lithium-ion storage is two percent, and for pumped storage is one percent.
- Storage can help meet PSE's operating reserve requirements. When providing operating reserves, storage resources are on standby and do not discharge to the grid.
- The NWPP Reserve Sharing Program can be called when an energy storage resource is added to the system.

3.8. Hydroelectric Generation Flexibility

In the 2023 Electric Report model, we allowed specific hydroelectric resources to dispatch flexibly. These resources included PSE's five contracted Mid-C hydroelectric plants, PSE's Upper Baker plant, and PSE's Lower Baker plant. PSE's Snoqualmie plant was not modeled with a climate change model and dispatch flexibility and instead had a fixed generation profile because detailed climate change data was not available from the University of Washington Climate Impacts Group for this resource. In the 2021 IRP, PSE modeled all hydroelectric resources with fixed generation profiles.

E3 modeled daily flexibility at each hydroelectric plant, meaning each can shift hydroelectric generation across hours within a single day. E3 determined the hydroelectric generation available at each plant daily based on PSE's modeling across climate models. The daily hydroelectric generation available, or daily energy budget, varies by model year (2029, 2034), climate model (A, C, G), hydroelectric plant, and day (across 30 years).

E3 also characterized the flexibility for each hydroelectric plant to shift generation within a day. E3 analyzed historical hydroelectric generation (2014 through 2021, subject to data availability) to develop relationships between the daily energy budget and the minimum and maximum hourly generation for each hydroelectric plant. E3 calculated the minimum hourly power output and maximum hourly power output for different daily energy budget ranges at each plant based on this historical data. E3 then programmed RECAP to dispatch hydroelectric plants flexibly, subject to the daily energy budget and minimum and maximum power output constraints.

3.9. Wind and Solar Generation Profiles

In the 2023 Electric Report, PSE switched to new renewable energy profiles. PSE contracted with DNV to obtain renewable profiles for each existing wind and solar resource and each candidate generic wind and solar resource. Each profile spans 250 years at an hourly resolution. These profiles capture the variability that PSE can expect from these resources on an annual, seasonal, and hourly basis. The underlying weather conditions are the same for each resource's profile, so the profiles capture correlations between resources. The 2021 IRP used profiles developed with data from the National Renewable Energy Laboratory (NREL).

3.10. Balancing Reserves

In the 2023 Electric Report, we updated the hourly balancing reserve requirements that PSE must meet. These balancing reserve requirements ensure that we have sufficient reserves to meet sub-hourly fluctuations in load or variable resource generation on a minute-by-minute basis.

E3 calculated the balancing reserve requirements on our behalf. They estimated the balancing reserves by measuring the intra-hour variability PSE could expect to experience based on expected resource buildouts. Because E3's RECAP model has hourly timesteps, it does not inherently capture sub-hourly variations. Balancing reserves as part of the overall operating reserves requirements ensures the resource adequacy analysis accounts for the sub-hourly variability, we must manage in addition to meeting hourly system needs.

E3 calculated the balancing reserve requirements by analyzing PSE's five-minute load, wind, and solar data from the three years of historical weather-matched data we provided. This ensured the load, wind, and solar profiles corresponded to the same underlying weather conditions and incorporated any correlations or relationships. E3 then scaled up load, wind generation, and solar generation to match the expected future levels on PSE's system. Lastly, E3 subtracted wind and solar generation from load to obtain a net load profile for subsequent analysis. We would manage the net load variability by dispatching other resources.

E3 compared the five-minute fluctuations in the net load to the hourly average levels for the net load to determine the magnitude of fluctuations around the hourly average net load levels. E3 then developed a 95 percent confidence interval for these fluctuations to quantify the balancing reserves for the system. The 95 percent confidence interval provides the range of 5-minute fluctuations relative to hourly net load that covers 95 percent of all observations.

Table L.3: shows the balancing reserve requirements in MW for the 2021 IRP and the 2023 Electric Report. The upward balancing reserves — reserves on standby to increase generation on demand — for the 2023 Electric Report fall within the range in the 2021 IRP.

Table L.3: Balancing Reserves Requirements (MW)

Type	2021 IRP 2025	2021 IRP 2030	2023 Electric Report 2029	2023 Electric Report 2034
Wind Capacity Balanced by PSE	875	2,375	1,215	2,915
Solar Capacity Balanced by PSE	-	1,400	-	719
Average Upward Balancing Reserves	141	492	143	210

The balancing reserves in the 2021 IRP and the 2023 Electric Report differ for two reasons:

- The PSE forecast integrated a different amount of wind and solar resources in the 2023 Electric Report.
- E3 utilized a methodology for the 2023 Electric Report that is different from the one we used in the 2021 IRP.

The 2021 IRP analysis compared the difference between the hour-ahead forecast and actual real-time values for the net load. In contrast, for the 2023 Electric Report, E3 compared the difference between the actual hourly and real-time values. E3 made this change because the balancing reserves should capture sub-hourly net load variability but should exclude any hourly forecast error that would be incorporated if using the hour-ahead forecast. Although it is important to consider hourly forecast error in the system, it does not factor into the resource adequacy analysis.

3.11. Reserve Sharing Program

We did not consistently model the NWPP Reserve Sharing Program in the ELCC of energy storage resources in the 2021 IRP. When E3 calculated this report's ELCC of energy storage resources, they maintained the same reserving sharing program assumptions across all cases.

The NWPP Reserve Sharing Program allows PSE to rely on neighboring systems to compensate for insufficient resources for the first 60 minutes following a qualifying event so we do not have to curtail load during this operating hour. E3 incorporated this assumption in their model but allowed PSE to rely on the Reserve Sharing Program only when the rest of the region has sufficient energy supplies. If PSE does not have enough resources and the wider region lacks sufficient resources, then the Reserve Sharing Program is unavailable as a last resort.

3.12. Other Updates Not Incorporated

Due to the limited time to gather data, develop processes, update models, and benchmark results, we could not incorporate two of E3's recommendations for the resource adequacy analysis. Based on the resource adequacy analysis results, E3 changed their guidance for the Classic GENESYS sensitivity and recommended not pursuing one of these recommendations. We will continue to explore the recommendation on correlations between load demand and renewable resources in future resource adequacy analyses. We described these two items in more detail in the next section.

In our December 2021 response comment filing, we said PSE would "run an additional sensitivity of a Classic GENESYS model run assuming regional capacity additions such that the region meets a 5 percent LOLP standard." We did not run this additional sensitivity. E3 initially recommended we perform this sensitivity to see if it would increase the ELCC of storage resources. However, after E3's modeling showed the ELCC of energy storage is very high (>95 percent for a four-hour lithium-ion battery), and there is sufficient energy to charge the energy storage to meet reliability needs, they recommended we not run this sensitivity as it would not add significant value considering the new results.

In our December 2021 response comment filing, we stated PSE would "follow up with E3 to explore different ways to approach correlations between wind/load and solar/load." We also indicated we might need to consider this recommendation for future IRP cycles to allow adequate time for model preparation and quality review.

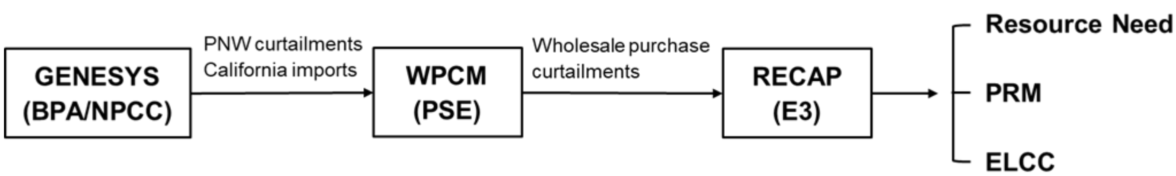
In addition to updating the load profiles based on climate change impacts, we also updated the renewable energy profiles. With changes to load profiles, renewable profiles, and many other assumptions for Phase 2 of the 2021 All-Source RFP and the 2023 Electric Report, we did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future analysis, as they could impact resource adequacy for PSE's system. For example, a cold snap in winter could result in high energy demand and low renewable output simultaneously, resulting in more extreme conditions for maintaining resource adequacy.

4. Resource Adequacy Modeling Approach

In this report, we relied on a similar set of models to those we used in the 2021 IRP. We used the Classic GENESYS model developed by the Council and Bonneville Power Administration (BPA) to analyze load and resource conditions for the Pacific Northwest region. We used PSE's wholesale purchase curtailment model (WPCM) to investigate the impacts of regional load curtailments on our system. Rather than use our resource adequacy model (RAM) to analyze load and resource conditions for PSE's system, we asked E3 to perform LOLP modeling using their proprietary RECAP model[5].

Figure L.3 shows how the three models work together. Because PSE has historically relied on significant wholesale power purchases to maintain reliability, the analysis includes an evaluation of potential curtailments to regional power supplies. The Classic GENESYS model characterizes when the region is short (i.e., insufficient resources to meet energy demand plus operating reserves). The WPCM characterizes how PSE would curtail wholesale power purchases when the region is short on energy. Lastly, RECAP simulates PSE's resource need and availability across hundreds of simulation years to determine the resource need and calculate other reliability metrics. The rest of this section describes each of the three models and the types of inputs for this analysis.

Figure L.3: Models in the Resource Adequacy Analysis



4.1. The Classic GENESYS Model

The Council and the Bonneville Power Administration (BPA) developed the Classic GENESYS model for regional-level load and resource studies. Classic GENESYS is a multi-scenario model that incorporates 30 years of hydroelectric conditions and, as of the 2023 assessment, 30 years of temperature conditions. For the 2023 Electric Report, we started with the Classic GENESYS model from the Council power supply adequacy assessment for 2023.

When the model combines thermal plant forced outages and the mean expected time to repair those units, variable wind plant generation, and available power imports from outside the region, it determines the PNW's overall hourly capacity surplus or deficit in 900 multi-scenario simulations. Since the Classic GENESYS model includes all potentially available supplies of energy and capacity an operator could use to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[6]

[5] Due to staffing constraints, PSE engaged E3 to perform this analysis.

[6] We included operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) in the Classic 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, Classic GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydroelectric resources to the maximum extent possible within a defined set of operational constraints. Classic GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) with forward and short-term purchases.

Since we set the Classic GENESYS model for a 2023 assessment, we made some updates to capture regional load and resource changes to run the model for 2029 and 2034. The updates to the GENESYS model include the following:

- Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW)
- The Council used climate data developed by the River Management Joint Operating Committee (RMJOC) in the Classic GENESYS load model for the 2021 power plan. We used three climate change models, A, C, and G, representing CanESM, CCSM, and CNRM in the GENESYS model[7]. For details regarding the various climate change models, please refer to Chapter Six: Demand Forecast.
- Updated coal plant retirements with retirement years are in Table L.4.

Table L.4: Modeled Coal Plant Retirements

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

We did not include any other adjustments to Classic GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from the Council already built into the model.

4.2. The Wholesale Purchase Curtailment Model

During a PNW-wide load-curtailment event, the region lacks enough physical power supply (including available imports from California) for the area's utilities to meet their firm loads plus operating reserve obligations fully. To mimic how the PNW wholesale markets would likely work in such a situation, PSE developed the wholesale purchase

7 For more details about the climate change model, refer to the NWPCC Climate Change Scenario Selection Process and the River Management Joint Operating Committee (RMJOC) report.

curtailment model (WPCM) as part of the 2015 IRP. The WPCM links regional events to their impacts on PSE's system and our 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 directly impacts how much capacity PSE can purchase. Therefore, the WPCM first assembles load and resource data for the region and many utilities in the region, especially those expected to buy relatively large amounts of energy and capacity during winter peaking events.

We used the capacity data in BPA's 2018 Pacific Northwest Loads and Resources Study for this analysis. The BPA published the 2019 Pacific Northwest Loads and Resources Study[8] in October 2020. Commonly referred to as the White Book, the 2019 report presents the region's load obligations, contracts, and resources for operating years 2021 through 2030. Under critical water conditions, the BPA study forecasts unbalanced energy from a deficit of 194 MW to a surplus of 354 MW. The annual energy deficits and surplus forecasts are similar to the forecasts in the 2018 White Book. We used the same forecasts in the 2021 IRP in this report and will incorporate the updated forecasts for future IRP cycles.

4.2.1. Allocation Methodology

The WPCM then uses a multi-step approach to allocate the regional capacity deficiency among the region's utilities. We reflected these individual capacity shortages via a reduction in each utility's forecasted level of wholesale market purchases. The WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a decrease in PSE's wholesale market purchases hourly. In some cases, PSE's initial desired wholesale market purchase volume reductions could trigger a load-curtailment event in the LOLP portion of RECAP.

To assess a wide range of regional market conditions, we combined the 30 years of energy demand forecasts with each of the 30 years of hydroelectric generation forecasts to simulate the availability of market purchases across 900 simulation years.

In the study, we used the three climate change models to capture the future impacts of climate change on energy demand, hydroelectric generation, and availability of market purchases from other systems. We also updated the model's contracts, third-party generation, and loads.

It is worth noting that no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

4.2.2. Forward Market Allocations

The model assumes each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility can purchase its target capacity in these markets, reducing the remaining capacity available in the spot markets. If the wholesale market does not have enough capacity to satisfy all

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8 BPA's 2019 Pacific Northwest Loads and Resources Study is at https://www.bpa.gov/-/media/Aep/power/white-book/2019-wbk-summary.pdf.

the forward purchase targets, the model reduces those purchases on a pro-rata basis based on each utility's initial target purchase amount.

Besides the market purchase, the WPCM model uses the Mid-C transmission line to transmit the PSE Mid-C project and the Wild Horse site power to PSE. The model also uses transmission capacity to get balancing and spinning reserves, which is 50 percent of the operating reserve. We use the remaining capacity for market purchases.

4.2.3. Spot Market Allocations

For spot market capacity allocation, we assumed each of the five large utility purchasers 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 (usually PSE) is not guaranteed automatic access to a fixed percentage of its capacity need. Instead, all the large purchasers aggressively attempt to locate and purchase scarce capacity from the same sources. Under deficit conditions, the largest purchasers tend to experience the biggest MW shortfalls between what they need and can 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.

4.2.4. WPCM Outputs

For each simulation and hour in which the Council's Classic GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- Puget Sound Energy's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions
- Puget Sound Energy's initial wholesale market purchase amount (in MW) limited only by PSE's overall Mid-C transmission rights
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage

Figure L.4, Figure L.5, Figure L.6, Figure L.7, Figure L.8, and Figure L.9 show the results of the WPCM. The charts illustrate the PSE's average share of the regional deficiency. The results show the deficiency in each of the 900 simulations (gray lines) and the mean of the simulations (red line). The mean deficiency is close to zero, but in some simulations, the market purchases may be limited by 1000 MW (in August 2029 Model A) and 1200 MW (in August 2034 Model A). This means that of the 1,500 MW of available Mid-C transmission, we could only fill 500 MW in August 2029 Model A and 300 MW in August 2034 Modal A.

Figure L.4: Average Curtailment by Month, 2029 Model A

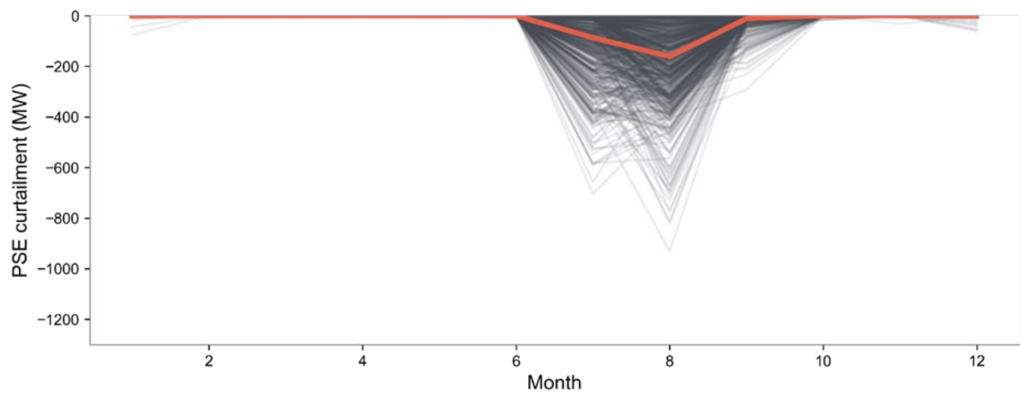


Figure L.5: Average Curtailment by Month, 2029 Model C

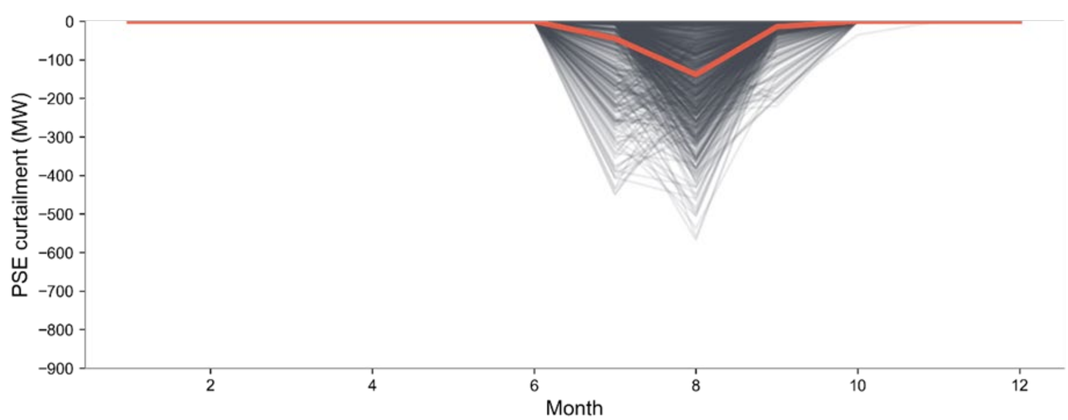


Figure L.6: Average Curtailment by Month, 2029 Model G

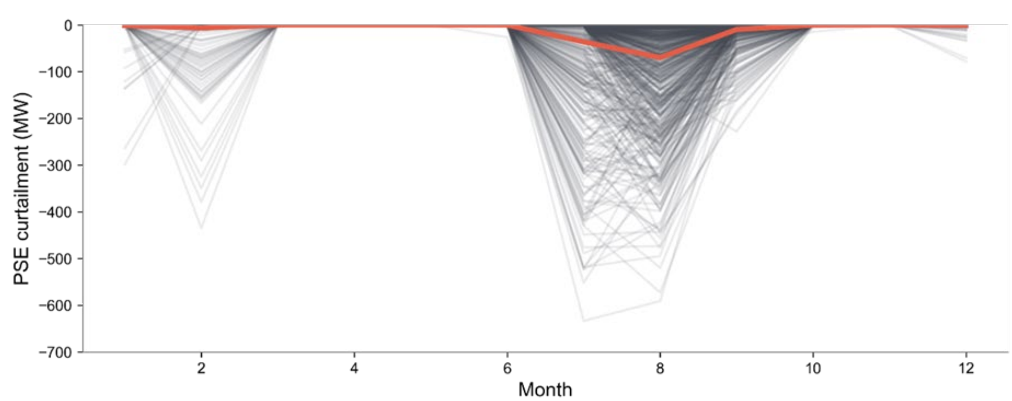


Figure L.7: Average Curtailment by Month, 2034 Model A

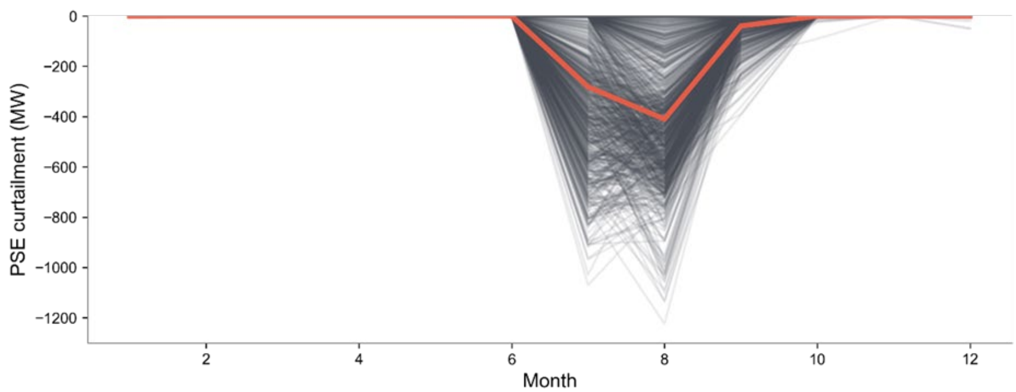


Figure L.8: Average Curtailment by Month, 2034 Model C

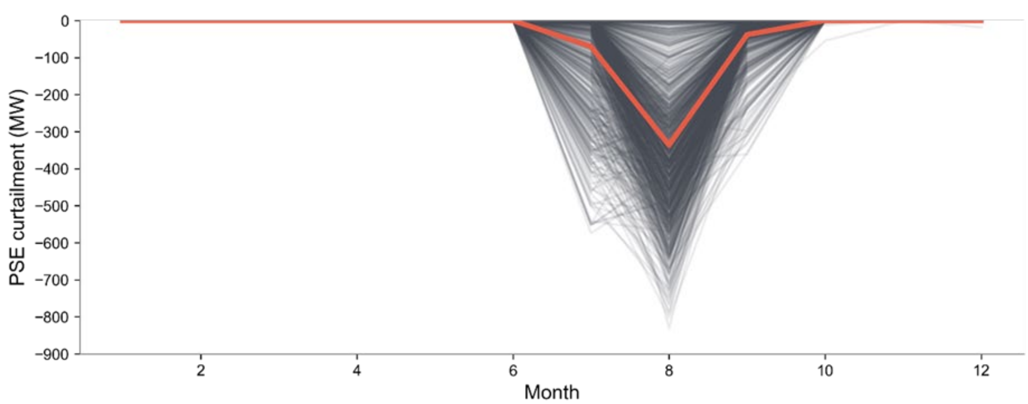
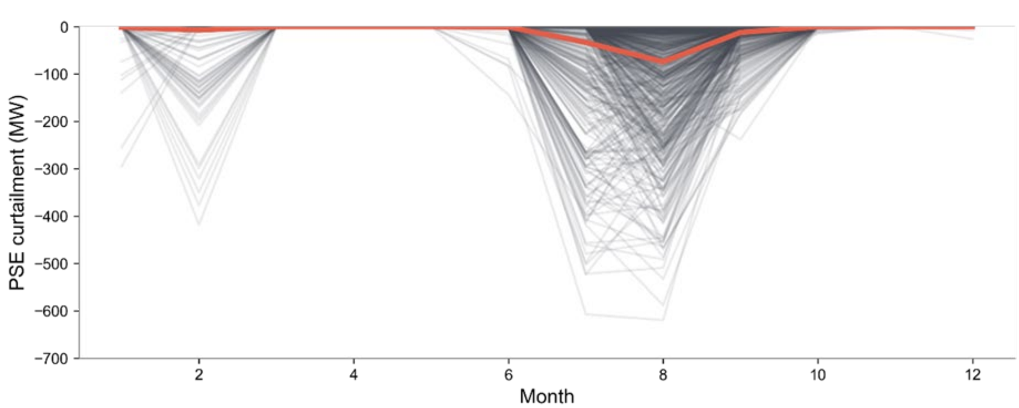


Figure L.9: Average Curtailment by Month, 2034 Model G



In addition to the WPCM results included in PSE's resource adequacy analysis, we also conducted a separate market risk assessment. That assessment is described later in this chapter.

4.3. The RECAP Model

E3 used its RECAP model to determine the PSE system's resource need, PRM, and ELCC metrics. E3 has used RECAP extensively to assess the resource adequacy of electric systems across North America. In the Western United States, E3 used RECAP in the following states: Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, and Washington.

RECAP is a LOLP model that simulates the availability of resources to meet energy demand across a broad range of conditions. RECAP accounts for factors such as weather-driven variability of electric demand, the natural variability of resources such as wind and solar, availability of wholesale purchases, forced outages of thermal power plants, and operating constraints for resources like hydroelectric, storage, and demand response. These simulations determine the likelihood and magnitude of loss of load — energy demand that PSE cannot serve — and provide the basis for assessing resource adequacy for PSE's system.

RECAP simulates system conditions over hundreds of simulation years using stochastic techniques to capture the risk of rare tail events that can significantly impact PSE's system. RECAP simulates the system each hour of a year and repeats this process hundreds of times with different system conditions, which ensures that RECAP captures a wide distribution of potential outcomes, including low-probability but high-risk tail events.

RECAP conducts a Monte-Carlo time-sequential simulation of loads, resources, and power purchases for each simulation year. RECAP first determines the load based on the simulation year and calculates the operating reserve requirements hourly. RECAP then simulates renewable generation and forced outages for thermal generators. After this, RECAP determines the number of wholesale power purchases available based on the simulation year. RECAP then dispatches hydroelectric resources that have the flexibility to shift generation throughout the day to maximize generation during the times when the PSE system has the greatest need. Lastly, RECAP dispatches storage and demand response resources.

Energy storage devices charge when sufficient capacity is available and discharge to meet energy demand not met by other resources. RECAP tracks energy storage resources' state of charge (SoC) to ensure their operations respect physical limitations. Demand response resources serve as a last resort and are constrained by limits on the number and duration of calls. If there is a period when the supply of resources is inadequate to meet the load requirement, there is a loss of load event.

RECAP determines the frequency, duration, and magnitude of the loss of load events across all simulation years. RECAP then uses these outputs to calculate PSE's system's resource need, PRM, and ELCC metrics.

Detailed documentation of E3's RECAP model is on E3's website[9].

[9] https://www.ethree.com/wp-content/uploads/2022/10/RECAP-Documentation.pdf

4.4. Key Inputs to Capture Uncertainty

To perform the resource adequacy analysis, we must appropriately characterize the range of operating conditions PSE can expect over a long time, including low-probability tail events. This analysis must capture the uncertainties in power and energy demand and resource supply that could ultimately lead to load loss. These factors include energy demand, availability of thermal generators, availability of hydroelectric, wind, and solar generation, and availability of market purchases. The resource adequacy analysis for the 2023 Electric Report captures each of these factors, described further in the following and the Resource Adequacy Inputs and Updates sections.

4.4.1. Energy Demand

We modeled hourly system loads as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 30 temperature years. These demand draws created with stochastic outputs from PSE's economic and demographic model and two consecutive historical weather years predict future weather. Each coming weather year from 2020 to 2049 is represented in the 30 weather draws. Since the resource adequacy model examines a hydroelectric year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. The model also examines adequacy in each hour of a given future year; therefore, we scaled the model inputs to hourly demand using the hourly demand model.

4.4.2. Forced Outages

A forced outage is when a generator fails unexpectedly and cannot generate at maximum output for some amount of time until repaired. We accounted for forced outages for natural gas and storage units by modeling forced outage rates (FOR) and mean time to repair (MTTR) for each resource. The method for modeling forced outage rates in the resource adequacy analysis is consistent with our frequency duration outage method in AURORA, which allows units to fail and return to service at any timestep within the simulation.

4.4.3. Hydroelectric Generation

We use the same 30 hydroelectric years, simulation for simulation, as the GENESYS model. Based on PSE's modeling of daily We hydroelectric availability for each hydroelectric year, E3 models PSE's Mid-Columbia and Baker River plants flexibly in RECAP, so each plant can shift hydroelectric generation across hours within a single day, subject to daily energy budget and power output constraints. The 900 combinations of hydroelectric and temperature simulations are consistent with the Classic GENESYS model.

4.4.4. Wind and Solar Generation

We modeled 250 unique 8,760 hourly profiles exhibiting typical wind and solar 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 we preserved this intermittency. The other goal is to ensure that we reflect correlations across wind farms and the seasonality of wind and solar generation. DNV, an energy and atmospheric science consultant, provided wind speed and solar irradiance data to PSE. Wind and solar data were selected for specific sites representing locations of generic resources and processed to give wind and solar production data. DNV utilized its stochastic engine to generate 1,000 unique 21-year production profiles for each site. From the 1,000 unique profiles, we selected 250 to use in the resource adequacy model. Statistical analysis of these 250 randomly selected profiles ensured that they represented the entire population of wind and solar profiles.

➔ Details of the profiles provided by DNV and DNV's methodology are available in Appendix C: Existing Resource Inventory and Appendix D: Generic Resource Alternatives.

4.4.5. Wholesale Market Purchases

These inputs to RECAP are determined in the WPCM, as explained. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same classic GENESYS model simulations as E3's RECAP. We computed the initial set of hourly wholesale market purchases that we import into our system using our long-term Mid-C transmission rights 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 farm and PSE's contracted shares of the Mid-C hydroelectric plants.

To reflect regional deficit conditions, we reduced this initial set of hourly wholesale market imports on the hours when we identified a PNW load-curtailment event in the WPCM. We then used the final set of hourly PSE wholesale imports from the WPCM as data input into RECAP and determined PSE's loss of load probability, expected unserved energy, and loss of load expectation. In this fashion, the LOLP, EUE, and LOLH metrics determined in RECAP incorporate PSE's wholesale market reliance risk.

5. Detailed Results for Generic Resources

The following section shows the detailed results regarding the generic resources we modeled in the 2023 Electric Progress Report.

5.1. Generic Wind and Solar Resource Groups

E3 calculated the ELCC for eight wind resources, two distributed solar resources, and five utility-scale solar resources (see the results section of Chapter Seven: Resource Adequacy). These ELCC values represent the capacity contribution for the first 100 MW of incremental capacity we added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in the next section.

As discussed in section 6.3 of this appendix, the ELCC for a dispatch-limited resource declines as its penetration increases. We modeled an ELCC saturation curve for each wind and solar resource to capture this relationship between ELCC and penetration.

E3 first categorized the generic wind and solar resources into resource groups (see Table L.5). Each resource group includes resources that have highly correlated generation profiles. When one resource in a group has a high generation, additional resources in the group likely have a high generation. Just as higher penetration of a single resource results in a lower ELCC for that resource, higher penetration of highly correlated resources also results in a lower ELCC. Highly correlated resources make similar contributions towards meeting load during critical periods, so adding one of these resources will cause the reliability value — or ELCC — of the other resources to decline or saturate.

Table L.5: Resource Groups for ELCC Saturation

Resource Group	Resources in Group
Pacific Northwest Wind	British Columbia; Washington
Rockies Wind	Wyoming East; Wyoming West; Montana Central; Montana East
Idaho Wind	Idaho Wind
Offshore Wind	Offshore Wind
Solar	Idaho Solar; Washington East; Washington West; Wyoming East; Wyoming West; Distributed Ground Mount; Distributed Rooftop

Note that there can be interactions between all resources, not just those in the same resource group. However, due to the large number of potential resource combinations, it was not feasible for E3 to model the interactive and saturation effects between all resources. Moreover, PSE's capacity expansion model cannot incorporate a multi-dimensional ELCC surface. The more straightforward resource group approach still provides a way to capture the strongest and most important interactions between highly correlated resources, as it allows us to calculate the capacity contribution of an individual resource based on the overall penetration of resources in its corresponding resource group.

5.2. Generic Wind and Solar ELCC Saturation Curves

Figure L.10 shows the winter and summer ELCC saturation curves for the Pacific Northwest wind (including the British Columbia wind and Washington wind). E3 calculated the ELCC for three tranches of Pacific Northwest wind: 0–100 MW, 100–1,000 MW, and 1,000–3,000 MW. The ELCC declines with each successive tranche due to the ELCC saturation effect. For example, the first tranche of Washington wind has an ELCC of 13 percent in winter, the second has an ELCC of 11 percent, and the third has an ELCC of 6 percent.

The ELCC saturation curve determines how much a resource contributes toward the PRM. For example, assume that PSE adds 1,500 MW of Washington wind. The total capacity contribution of this incremental capacity would be 13 MW for the first tranche (100 MW x 13 percent), plus 99 MW for the second tranche (900 MW x 11 percent), and 30 MW for the third tranche (500 MW x 6 percent), for a total of 142 MW.

The total capacity additions within the resource group determine the overall penetration for all resources in the resource group. For example, assume that PSE adds 1,000 MW of Washington Wind in an earlier year and then adds 500 MW of British Columbia Wind in a later year. The ELCC for the 500 MW of British Columbia Wind would be 16 percent because the penetration for the resource group is already at 500 MW, putting the incremental British Columbia Wind in the third tranche.

Figure L.10: ELCC Saturation Curves for Pacific Northwest Wind

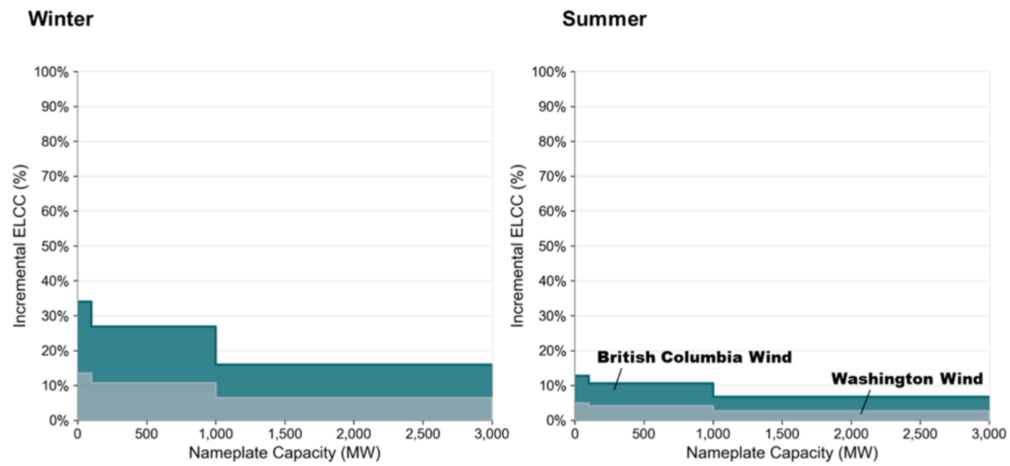


Figure L.11 shows the winter and summer ELCC saturation curves for the Rockies Wind (including Montana Central Wind, Montana East Wind, Wyoming East Wind, and Wyoming West Wind). E3 calculated the ELCC for three tranches for Pacific Rockies Wind: 0–100 MW, 100–1,000 MW, and 1,000–2,000 MW. The Montana East Wind ELCC is lower than the ELCC of the other resources because we already have 350 MW of wind in eastern Montana in its resource portfolio (Clearwater Wind). Note that the ELCC of Montana Central Wind and Wyoming West Wind are very similar in winter, so the figure does not differentiate between these resources. The ELCC of Wyoming East Wind and Wyoming West Wind are similar in summer, so the figure does not distinguish between these two resources.

Figure L.11: ELCC Saturation Curves for Rockies Wind

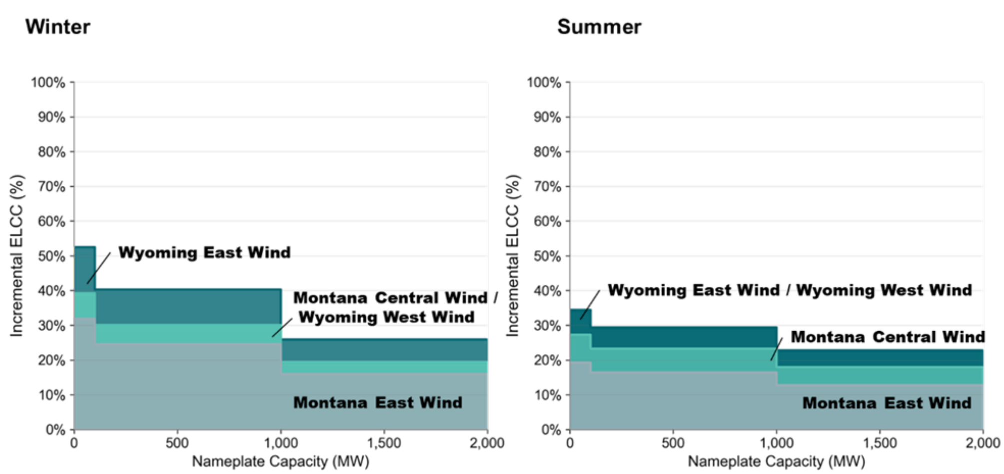


Figure L.12 shows the winter and summer ELCC saturation curves for Idaho and Offshore Wind. E3 calculated two tranches for Idaho Wind: 0–100 MW and 100–800 MW. E3 calculated the ELCC for two tranches of Offshore Wind: 0–100 MW and 100–300 MW. Note that Idaho Wind and Offshore Wind are not in the same resource grouping, so the penetration of one does not impact the penetration of the other when determining ELCC saturation.

Figure L.12: ELCC Saturation Curves for Idaho Wind and Offshore Wind

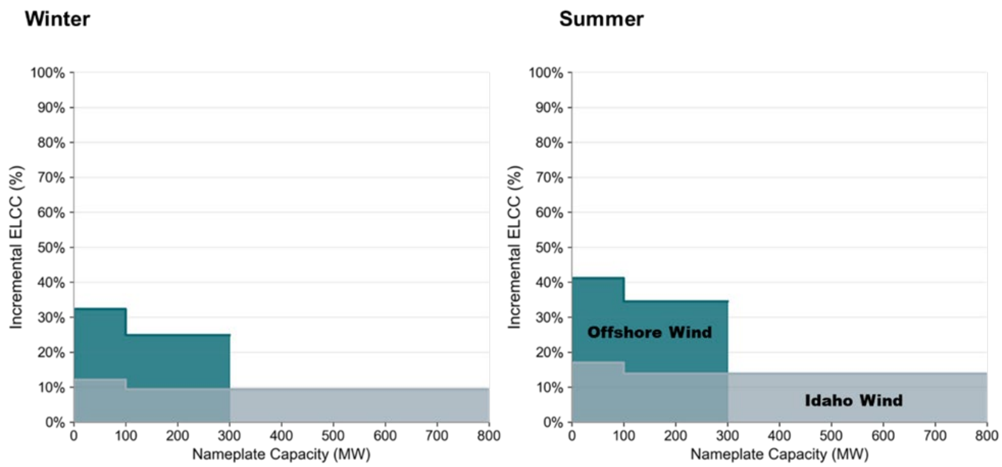
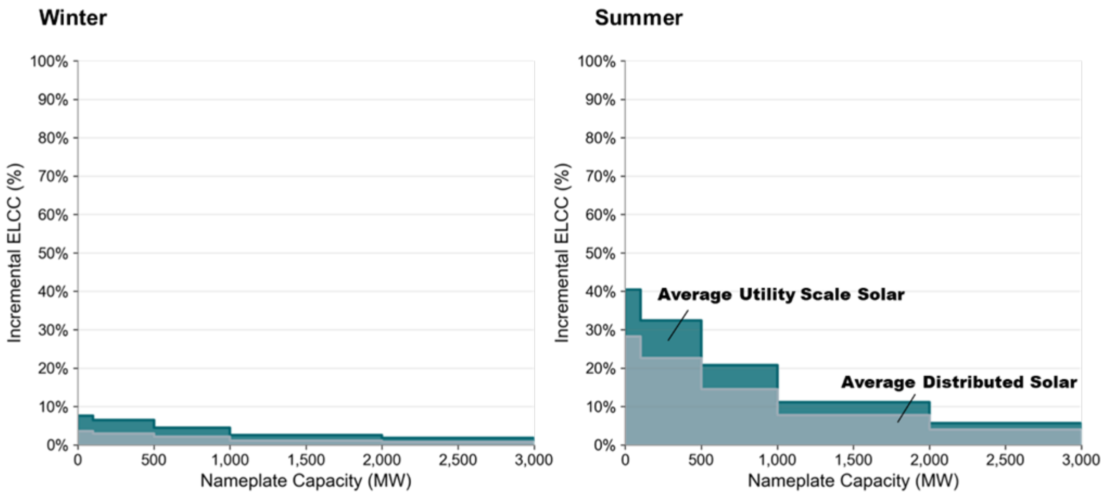


Figure L.13 shows the average winter and summer ELCC saturation curves for utility-scale solar (comprised of Idaho Solar, Washington East Solar, Washington West Solar, Wyoming East Solar, and Wyoming West Solar) and distributed solar (comprised of Distributed Ground Mount Solar and Distributed Rooftop Solar). Utility-scale and distributed solar are in the same resource group, so the overall penetration of solar resources determines the ELCC saturation for each solar resource. E3 calculated the ELCC for five tranches for Solar: 0–100 MW, 100–500 MW, 500–1,000 MW, 1,000–2,000 MW, and 2,000–3,000 MW.

The ELCC for solar is already very low in winter, so the ELCC saturation effect does not have as much impact in winter. On the other hand, the ELCC for solar in summer starts relatively high and then declines rapidly at higher penetration levels. The ELCC begins high because solar generation generally coincides nicely with periods of high energy demand in summer — when air conditioning loads are high — and because PSE's resource portfolio does not have high solar penetration.

At higher penetration levels, the ELCC for incremental solar is much lower. For example, the ELCC for the first tranche of utility-scale solar is 40 percent in summer, but the ELCC for the 2,000–3,000 MW tranche is only six percent in summer. If PSE had 2,000 MW of additional solar in its resource portfolio, this solar would largely mitigate reliability concerns during daytime hours in summer but would not do anything to alleviate reliability concerns during nighttime hours. As a result of the reliability need being low during solar generation hours, the ELCC for additional solar beyond 2,000 MW is low.

Figure L.13: ELCC Saturation Curves for Solar Resources



Tables that list the ELCC for each resource as a function of penetration are in the next section. The values in these tables correspond to the values in the saturation curves earlier in this appendix. Each table contains the ELCC values for all resources within a resource group.

To understand how to interpret these tables, take Table L.6 as an example. E3 calculated the ELCC for three tranches: 0–100 MW, 100–1,000 MW, and 1,000–3,000 MW. For the 0–100 MW tranche, the ELCC of British Columbia Wind in winter is 34 percent. If we added 100 MW of this resource, the capacity contribution would be 34 percent x 100 MW = 34 MW. For the 100–1,000 MW tranche, the ELCC of British Columbia Wind in winter is 27 percent. If we added 1,000 MW of this resource, the capacity contribution of the 900 MW added beyond the first tranche would be 27 percent x 900 MW = 243 MW. The same logic applies to the 1,000–3,000 MW tranche.

Table L.6: ELCC by Tranche for Pacific Northwest Wind

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	3,000
Winter	British Columbia Wind	34%	27%	16%
	Washington Wind	13%	11%	6%
Summer	British Columbia Wind	13%	11%	7%
	Washington Wind	5%	4%	3%

Table L.7: ELCC by Tranche for Rockies Wind

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	2,000
Winter	Montana Central Wind	39%	30%	19%
	Montana East Wind	32%	25%	16%
	Wyoming East Wind	52%	40%	26%
	Wyoming West Wind	39%	29%	19%
Summer	Montana Central Wind	27%	23%	18%

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	2,000
	Montana East Wind	19%	16%	13%
	Wyoming East Wind	34%	29%	23%
	Wyoming West Wind	34%	29%	23%

Table L.8: ELCC by Tranche for Idaho Wind

Season	Cumulative Capacity by Tranche (MW)	
	100	800
Winter	12%	9%
Summer	17%	14%

Table L.9: ELCC by Tranche for Offshore Wind

Season	Cumulative Capacity by Tranche (MW)	
	100	300
Winter	32%	25%
Summer	41%	34%

Table L.10: ELCC by Tranche for Solar Resources

Season	Resource	Cumulative Capacity by Tranche (MW)				
		100	500	1,000	2,000	3,000
Winter	Idaho Solar	8%	7%	5%	3%	2%
	Washington East Solar	4%	4%	3%	1%	1%
	Washington West Solar	4%	3%	2%	1%	1%
	Wyoming East Solar	11%	10%	7%	4%	3%
	Wyoming West Solar	10%	8%	6%	3%	2%
	DER Ground Mount Solar	4%	3%	2%	1%	1%
	DER Rooftop Solar	4%	3%	2%	1%	1%
Summer	Idaho Solar	38%	30%	19%	10%	5%
	Washington East Solar	55%	44%	28%	15%	8%
	Washington West Solar	53%	42%	27%	15%	7%
	Wyoming East Solar	29%	23%	15%	8%	4%
	Wyoming West Solar	28%	22%	14%	8%	4%
	DER Ground Mount Solar	28%	23%	14%	8%	4%
	DER Rooftop Solar	28%	23%	15%	8%	4%

Table L.11: ELCC by Tranche for Storage Resources

Season	Resource	Cumulative Capacity by Tranche (MW)									
		250	500	750	1000	1250	1500	1750	2000	2250	2500
Winter	Li-ion Battery (2-hour)	89%	80%	46%	30%	18%	17%	13%	13%	10%	10%
	Li-ion Battery (4-hour)	96%	96%	76%	42%	23%	19%	15%	15%	12%	12%
	Li-ion Battery (6-hour)	98%	98%	82%	68%	31%	21%	16%	16%	12%	12%
	Pumped Storage (8-hour)	99%	99%	94%	76%	43%	23%	17%	17%	14%	14%
Summer	Li-ion Battery (2-hour)	97%	80%	57%	42%	33%	30%	23%	23%	20%	20%

Season	Resource	Cumulative Capacity by Tranche (MW)									
		250	500	750	1000	1250	1500	1750	2000	2250	2500
	Li-ion Battery (4-hour)	97%	93%	93%	93%	59%	45%	31%	31%	17%	17%
	Li-ion Battery (6-hour)	98%	98%	98%	98%	89%	82%	32%	21%	15%	15%
	Pumped Storage (8-hour)	99%	99%	99%	99%	98%	92%	47%	24%	15%	15%

Table L.12: ELCC by Tranche for Storage Resources (Continue)

Season	Resource	Cumulative Capacity by Tranche (MW)									
		2750	3000	3250	3500	3750	4000	4250	4500	4750	5000
Winter	Li-ion Battery (2-hour)	10%	10%	8%	8%	8%	8%	6%	6%	6%	6%
	Li-ion Battery (4-hour)	12%	12%	9%	9%	9%	9%	7%	7%	7%	7%
	Li-ion Battery (6-hour)	12%	12%	10%	10%	10%	10%	8%	8%	8%	8%
	Pumped Storage (8-hour)	14%	14%	11%	11%	11%	11%	9%	9%	9%	9%
Summer	Li-ion Battery (2-hour)	20%	20%	16%	16%	16%	16%	10%	10%	10%	10%
	Li-ion Battery (4-hour)	17%	17%	10%	10%	10%	10%	8%	8%	8%	8%
	Li-ion Battery (6-hour)	15%	15%	11%	11%	11%	11%	9%	9%	9%	9%
	Pumped Storage (8-hour)	15%	15%	12%	12%	12%	12%	9%	9%	9%	9%

Table L.13: ELCC by Tranche for Demand Response Resources

Season	Resource	Cumulative Capacity by Tranche (MW)	
		100	**300**
Winter	Demand Response (3-hour)	69%	67%
	Demand Response (4-hour)	73%	72%
Summer	Demand Response (3-hour)	95%	87%
	Demand Response (4-hour)	99%	90%

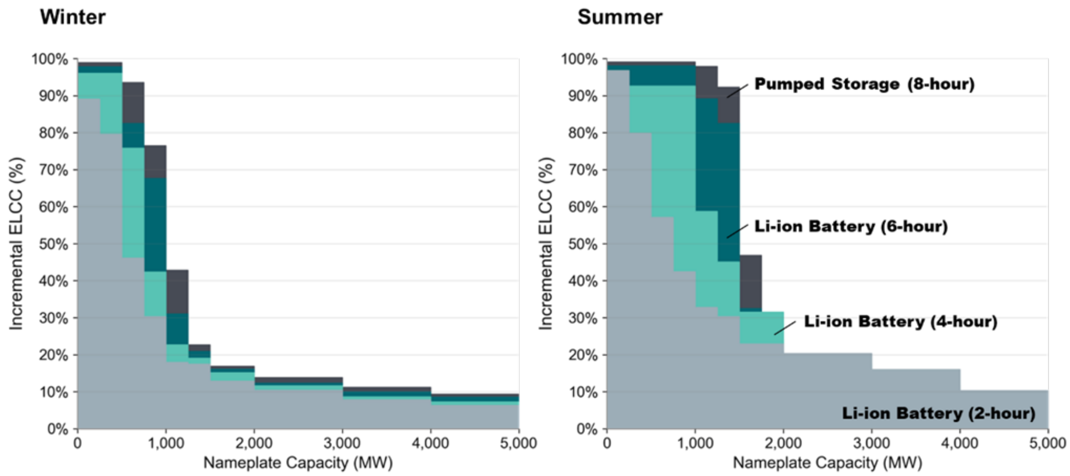
5.3. Generic Energy Storage ELCC Saturation Curves

E3 calculated ELCC saturation curves for each energy storage resource (see Figure L.14). Like other dispatch-limited resources, the ELCC of energy storage declines with increasing penetration levels. E3 calculated the ELCC for ten tranches for energy storage resources: 250–1,500 MW, 1,500–2,000 MW, and 1,000–5,000 MW. E3 calculated separate ELCC saturation curves for each individual energy storage resource.

The ELCC starts high and then declines at increasing penetration levels. The ELCC starts very high because energy storage is effective at supplying energy during a relatively short loss of load event. However, as we added more storage to the system, the net peak load (load minus renewable and storage generation) flattened, and the next tranche of storage must discharge over a longer period to help satisfy the new net peak lead. The ELCC declines more rapidly in winter than in summer. The ELCC starts falling rapidly after approximately 500 MW in winter and 1,000 MW in summer because the net peak load in summer is narrower than in winter. Limited duration energy storage can provide more reliability value in summer because power demand is high for shorter periods relative to winter.

The ELCC saturation curve declines more slowly for longer-duration energy storage. For example, in summer, Pumped Storage (8-hour) has an ELCC greater than 90 percent for the 1,250–1,500 MW tranche, while Lithium-ion Battery (2-hour) has an ELCC of 30 percent for the same tranche. The ELCC for longer-duration storage declines slower because it can discharge longer. As the net peak load flattens and storage must discharge over longer periods, a storage resource with eight hours can discharge at a higher level than a storage resource with only two hours. This does not necessarily mean shorter-duration energy storage is only valid up to a certain penetration level. The selection of different energy storage resources ultimately depends on their relative economics, which depends on the ELCC and other factors, such as resource costs and value from balancing system generation. The portfolio analysis assesses all of these factors together.

Figure L.14: ELCC Saturation Curves for Storage Resources



5.4. Generic Hybrid Resources

E3 modeled the ELCC of four types of hybrid resources (see Table 7.13 in Chapter Seven: Resource Adequacy Analysis) on behalf of PSE. We assumed we would site these hybrid resources in Washington. The solar resource corresponds to Washington East Solar, the wind resource corresponds to Washington Wind, and the storage resource corresponds to Lithium-ion Battery Storage (4-hour). For each hybrid resource, we assumed the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the storage capacity, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Figure L.15 shows the ELCC results for the hybrid resources. The figure provides the ELCC for each hybrid resource (black line) and compares this to the sum of the ELCCs for the individual resources that make up the hybrid resource (stacked bars).

Figure L.15 notes three major findings. First, the Wind + Storage and Solar + Wind + Storage resources have the same ELCCs as the sum of the ELCCs for the individual resources. This similarity indicates that the interconnection limits for these resources are not binding during times of reliability need. Second, as opposed to the hybrid wind resources, the two Solar + Storage resources have lower ELCCs than the sum of the ELCCs for the individual resources, especially in summer.

The lower ELCCs for Solar + Storage indicates that the interconnection limits for these resources are binding during times of reliability need. During summer peak loads, the solar output is relatively high. When this is the case, it limits the amount of storage that can be discharged to serve reliability needs, as the interconnection is only 100 MW. Lastly, the charging restriction for the Solar + Storage resource does not significantly impact the ELCC for the resource because, most of the time, there is sufficient energy from the solar project to charge the battery between reliability events.

Figure L.15: ELCC for Hybrid Resources

5.5. Generic Natural Gas Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic natural gas resources (see Table 7.14 in Chapter 7: Resource Adequacy Analysis). Three factors influence the capacity contribution of these resources: ambient temperature derates, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing natural gas plants. The summer rating is lower than the winter rating for combined cycle and frame turbine units. There is no derate in summer for reciprocating engines.

The ELCC for these natural gas resources is less than 100 percent because of forced outages. There is a chance that a unit is on forced outage when the PSE system needs the resource to ensure reliability. The assumed forced outage rates are 3.88 percent for combined cycle units, 2.38 percent for frame turbine units, and 3.30 percent for reciprocating engines.

The forced outage rates and the unit sizes influence the ELCC results. The higher the forced outage rate, the greater the chance the unit is on outage when needed and the lower the ELCC. If the unit is large, then this will result in a lower ELCC because, when a larger unit is on forced outage (e.g., 367 MW combined cycle plant), this has a greater chance of causing reliability problems for PSE's system than if a smaller unit is on forced outage (e.g., 18 MW reciprocating engine).

The ELCC for the combined cycle is lower because it has the highest forced outage rate and the largest unit size. The ELCC for a frame turbine unit is similar to the ELCC of a reciprocating engine. Although the forced outage rate for a frame turbine unit is smaller, the unit size is larger. These factors largely offset each other. The ELCC percent values are higher in summer for combined cycle and frame turbine units because the rated capacities are lower than in winter; in other words, the unit size is smaller.

6. Compared: the 2023 Electric Report and the 2021 Integrated Resource Plan

This section compares the results of the 2023 Electric Report with the results from the 2021 IRP. Because we made many updates to the inputs and methodology in the 2023 Electric Report, there are meaningful changes to several key outputs of the resource adequacy analysis.

6.1. Planning Reserve Margin

See Table L.14 for a comparison between the PRM in the 2021 IRP and the 2023 Electric Report.

Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, we can think of the results for the 2021 IRP as akin to the winter results for the 2023 Electric Report. Comparing the results from the 2021 IRP to the 2029 winter results from the 2023 Electric Report shows that the capacity contributions of resources are similar (5,062–5,072 MW in the 2021 IRP and 5,047 MW in the 2023 Electric Report). The median peak load is also similar (4,949–5,199 MW in the 2021 IRP and 5,004 MW in the 2023 Electric Report. The additional perfect capacity need for 2029 in the 2023 Electric Report falls between 2027 and 2031 in the 2021 IRP.

The PRM for the 2023 Electric Report (26 percent) is higher than that of the 2021 IRP (20–24 percent). One of the main reasons for this discrepancy is that the 2023 Electric Report shows an increased risk of loss of load in the summer, whereas the 2021 IRP shows little to no risk of loss of load in the summer. Because the 2023 Electric Report shows a much greater risk of loss of load in the summer, we must ensure the risk of loss of load in winter is meaningfully less than five percent to ensure an annual LOLP of five percent. To achieve this, we need more resource capacity in winter. Because the 2021 IRP shows little to no risk of loss of load in summer, we do not need this additional buffer in winter.

Because of the preceding reasons, the 2021 IRP results are not directly comparable to the 2023 Electric Report results for the summer. The differences between the 2021 IRP results and the 2023 Electric Report results for summer are similar to the reasons for the differences between the 2023 Electric Report results for winter and 2023 Electric Report results for summer, which we discussed in the Resource Adequacy Inputs and Updates Section.

Table L.14: Compared: PRM in the 2021 IRP and the 2023 Electric Report (MW)

Resource	2027[1]	2031[1]	2029 Winter[2]	2034 Winter[2]	2029 Summer[2]	2034 Summer[2]
Natural Gas	2,050	2,050	2,050	2,050	1,688	1,688
Mid-C Hydroelectric	560	560	560	560	560	560
Wind, Solar, Baker, Other Contracts	981	989	997	981	244	252
Market Purchases	1,471	1,473	1,440	1,434	961	751
Additional Perfect Capacity Need	907	1,381	1,272	1,746	1,875	2,856
Total Resource Need	5,969	6,453	6,319	6,771	5,329	6,107
Normal Peak Load	4,949	5,199	5,004	5,382	4,171	4,831
Planning reserve margin	20%	24%	26%	26%	28%	26%

Notes:
1. 2021 IRP
2. 2023 Electric Progress Report

6.2. Generic Wind and Solar Resources

See Table L.15 for a comparison between the renewable resource ELCC values in the 2021 IRP and the 2023 Electric Report. The 2021 IRP did not model British Columbia wind. The ELCC for Idaho wind is lower in the 2023 Electric Report because the profile from DNV indicates a significantly lower generation than the profile used for the 2021 IRP. Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, the ELCC results from the 2021 IRP are akin to the winter ELCC from this report. The ELCCs differ due to changes in the resource profiles and the timing of the loss of load events.

For solar resources, the ELCC results in the 2021 IRP are generally lower than the winter ELCC results in this report. In the 2021 IRP, loss of load events were usually longer and, in some cases, spanned multiple days. As a result, many loss of load events spanned nighttime hours when solar generation is lower or nonexistent. In this report, by contrast, loss of load events do not span the entire day or multiple days. Most loss of load hours are during daytime hours when solar output would be higher. As a result, the winter ELCC results in this report are higher than the ELCC results in the 2021 IRP.

Table L.15: Compared: Wind and Solar ELCCs in 2021 IRP and 2023 Report (First Tranche: 100 MW)

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	46	32	41
Washington	Wind	18	15	13	5

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
DER Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report

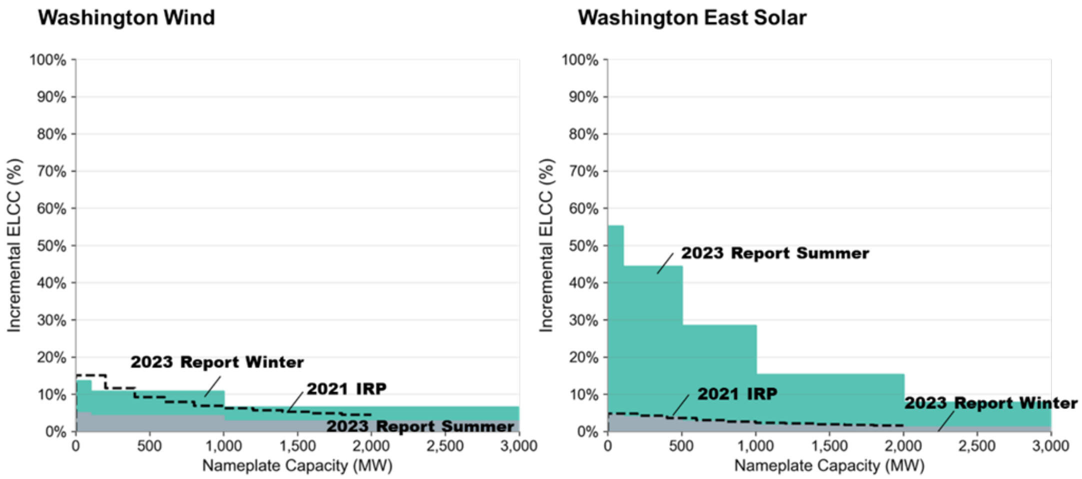
6.3. Generic Wind and Solar ELCC Saturation Curves

Figure L.16 compares the ELCC saturation curves in the 2021 IRP and the corresponding ELCC saturation curves in the 2023 Electric Report. The 2021 IRP included saturation curves for Washington wind and Washington East Solar through 2,000 MW, while the 2023 Electric Report E3 calculated saturation curves through 3,000 MW. The 2021 IRP calculated annual saturation curves, while the 2023 Electric Report E3 calculated separate saturation curves for winter and summer.

The results for Washington wind are similar. The ELCC in the 2021 IRP is similar to the winter ELCC in the report at lower penetration levels. At higher penetration levels, the ELCC in the 2021 IRP is between the winter ELCC and summer ELCC values.

The results for Washington East Solar are similar for winter but not summer. Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, the ELCC from the 2021 IRP can be considered akin to the winter ELCC from the 2023 Electric Report. The two are very similar. As discussed earlier in this section, the summer ELCC in the 2023 Electric Report is much higher than the winter ELCC.

Figure L.16: Compared: ELCC Saturation Curves in 2021 IRP and 2023 Electric Report



6.4. Generic Storage and Demand Response Resources

Table L.16 shows the storage and demand response ELCC results for the 2021 IRP and the 2023 Electric Report. Overall, the ELCC results in the 2023 Electric Report are much higher than those in the 2021 IRP. For example, the range of ELCC values for the 2023 Electric Report is 69-99 percent across resources and seasons, while the range of ELCC values for the 2021 IRP is 12-44 percent across resources.

There are two main reasons why the 2023 Electric Report sees higher ELCCs than the 2021 IRP: First, while PSE remains a winter-peaking system, the magnitude, frequency, and duration of critical reliability periods have changed substantially. Specifically, the duration of critical reliability periods has shortened relative to the 2021 IRP. As a result, energy-limited resources such as energy storage and demand response can perform more similarly to a perfect capacity resource to ensure reliability, the biggest driver for higher ELCC values, as even short-duration resources now have relatively high ELCC values.

Second, we changed how we modeled energy storage resources in the 2023 Electric Report. Allowing energy storage resources to discharge at maximum capacity for their rated duration increases their capabilities relative to the 2021 IRP. Allowing energy storage resources to provide operating reserves without discharging also increases their capabilities relative to the 2021 IRP. Lastly, the 2023 Electric Report ensures that the NWPP Reserve Sharing Program provides the same value to PSE's system when modeling the ELCC of energy storage.

Table L.16: Compared: Storage and Demand Response ELCCs in 2021 IRP and 2023 2023 Electric Report (First Tranche)

Resource[3]	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98

Resource[3]	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report
3. Demand response first tranche is 100 MW. Storage first tranche is 250 MW.

6.5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs, modeled in the AURORA database to perform long-term expansion planning and hourly dispatch to optimize new builds and mimic the hourly operation of existing and new resources. Multiple tranches on resource ELCC add model complexity and increase run-time significantly. To manage the large-scale optimization problem run-time and meet the ERP study needs, we adjusted the planning reserve margin and resource ELCCs.

6.6. Planning Reserve Margin

We modeled three climate change load forecasts in the resource adequacy analysis to calculate the seasonal generation capacity needed to meet five percent LOLP. To calculate the planning reserve margin in percentage, we used the normal peak forecast in summer and winter and formulated the following equations:

$$\text{Planning Reserve Margin in Summer } \% = (\text{Generation Capacity Needs in Summer} - \text{Normal Peak Loads in Summer}) / \text{Normal Peak Loads in Summer} \times 100\%$$

$$\text{Planning Reserve Margin in Winter } \% = (\text{Generation Capacity Needs in Winter} - \text{Normal Peak Loads in Winter}) / \text{Normal Peak Loads in Winter} \times 100\%$$

The normal peak loads in summer and winter and the P50 load forecast of the average of the three climate change load forecasts are in Table L.17.

Table L.17: Peak Load

Load	Winter 2029	Winter 2034	Summer 2029	Summer 2034
Normal Peak Forecast (MW)	5,104	5,588	4,300	4,845
P50 Peak Load (MW)	5,004	5,382	4,171	4,831

6.7. Storage ELCC Tranches

In the resource adequacy analysis, we defined ten tranches to capture the storage ELCC saturation up to 5000 MW storage build, as shown in Figure L.14. The AURORA simulation shows a significant run-time requirement to dispatch storage with the ten tranches implemented in the model. Ten tranches are consolidated into three tranches to balance the complexity and accuracy of the storage saturation modeling, as shown in Table L.18.

Figure L.17: ELCC Saturation Curves for Storage Resources

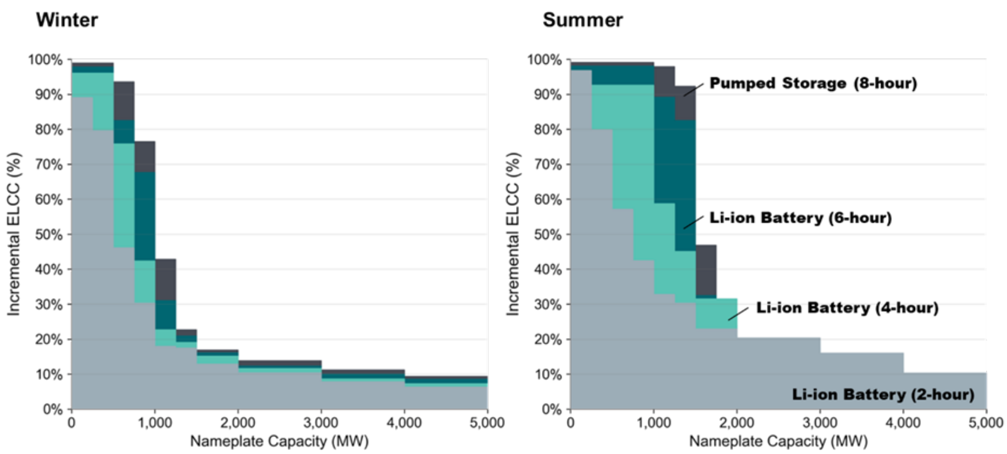
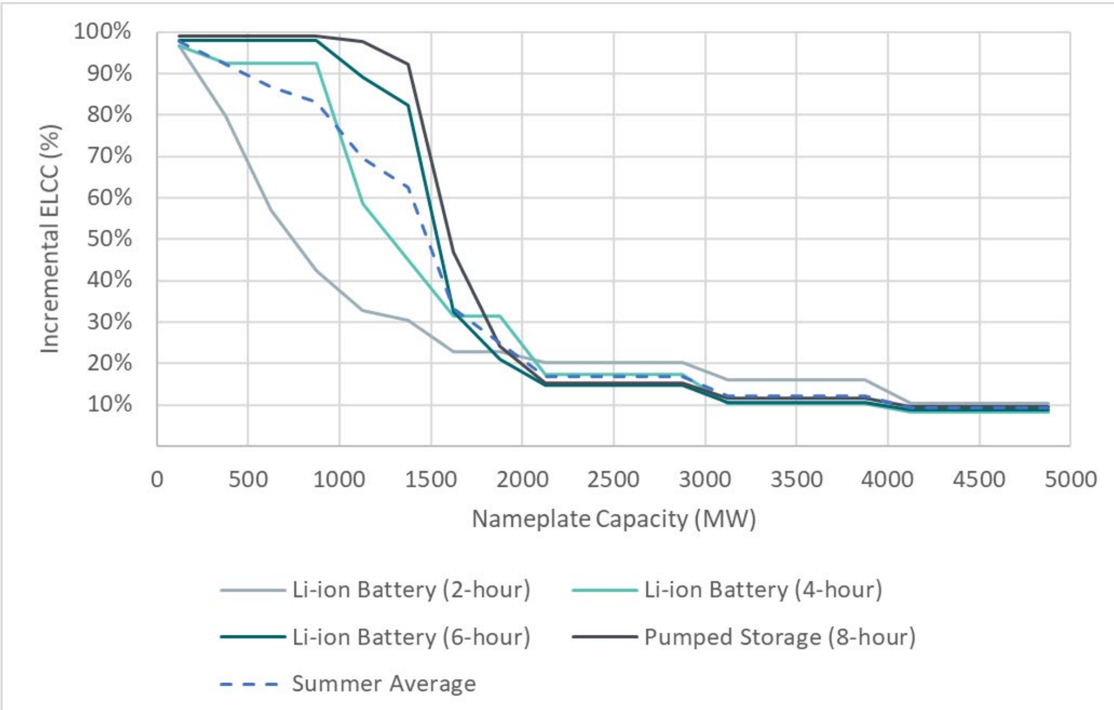


Table L.18: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 (%)	ELCC 2 (%)	ELCC 3 (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15
Cumulative Capacity by Tranche (MW)	Winter	1,000 MW	1,500 MW	5,000 MW
Cumulative Capacity by Tranche (MW)	Summer	1,000 MW	1,500 MW	5,000 MW

In the new tranches, 1000 MW and 1500 MW capacity are selected as points to break tranches to accommodate the saturation effects' trends and degree of accuracy. We used the summer curves to choose breakpoints since summer peak needs are more likely constrained.

Figure L.18: Storage ELCC Saturation Curves in Summer



6.8. Demand Response Tranches Consolidation

In the 2023 Electric Report, we estimate we could add up to 300 MW demand response to the portfolio. We defined two tranches in the resource adequacy analysis to catch the range of the potential builds, as shown in Figure L.19. The ELCCs in the second tranche do not reduce significantly from the ELCCs in the first tranches for winter and summer. The two tranches are consolidated into a single tranche to save the run-time of the AURORA simulation, as shown in Table L.19.

Figure L.19: ELCC Saturation Curves for Demand Response Resources

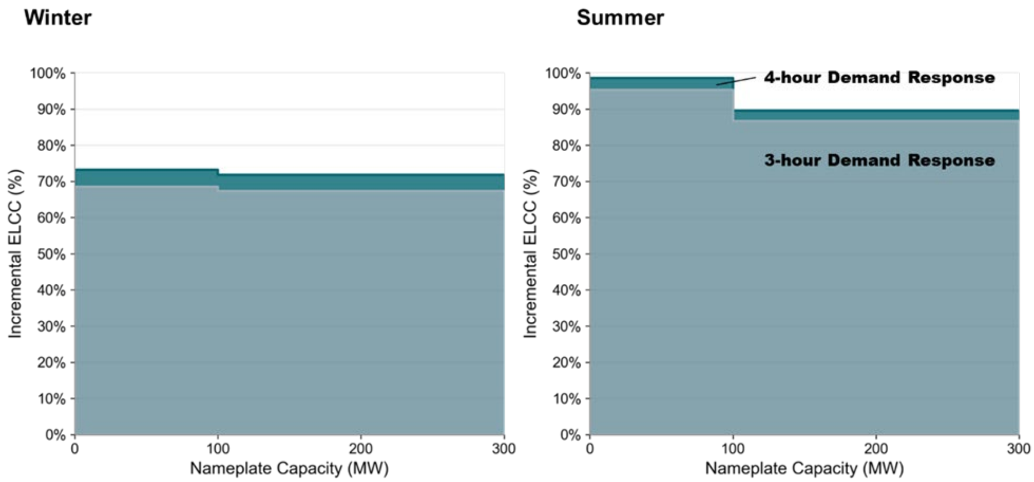


Table L.19: DR ELCC Tranches Consolidation — Incremental ELCC by Tranche in 2029

Resource	Season	1
Demand Response (3-hour)	Winter	68%
Demand Response (4-hour)	Winter	72%
Demand Response (3-hour)	Summer	90%
Demand Response (4-hour)	Summer	93%
Cumulative Demand Response	Winter	300 MW
Cumulative Demand Response	Summer	300 MW

6.9. Solar Tranches

The resource plan will build many renewable energy resources to meet the CETA needs. We calculated five-tranche ELCCs for wind and solar resources to capture the saturation effects in Figure L.10, Figure L.11, Figure L.12, and Figure L.13. The first three tranches cover the maximum builds for each wind resource group. Solar ELCCs go up to five tranches. We consolidated the five to three tranches to reconcile the run-time of the AURORA simulation and preserve the renewable resource ELCC saturation, as shown below in Table L.20.

Table L.20: Solar ELCC Tranches — Incremental ELCC by Tranche in 2029

Resource	Season	Tranche 1 (%)	Tranche 2 (%)	Tranche 3 (%)
DER Ground Mount Solar	Winter	4	3	1
DER Rooftop Solar	Winter	4	3	1
Idaho Solar	Winter	8	7	3
Washington East Solar	Winter	4	4	2
Washington West Solar	Winter	4	3	1
Wyoming East Solar	Winter	11	10	4

Resource	Season	Tranche 1 (%)	Tranche 2 (%)	Tranche 3 (%)
Wyoming West Solar	Winter	10	8	3
DER Ground Mount Solar	Summer	28	23	8
DER Rooftop Solar	Summer	28	23	8
Idaho Solar	Summer	38	30	10
Washington East Solar	Summer	55	44	15
Washington West Solar	Summer	53	42	14
Wyoming East Solar	Summer	29	23	8
Wyoming West Solar	Summer	28	22	7
Cumulative Resource	Winter	100 MW	500 MW	6,000 MW
Cumulative Resource	Summer	100 MW	500 MW	6,000 MW

6.10. Hybrid System ELCC Saturation

In the 2023 Electric Report, we modeled the following four hybrid systems as generic resources we could build:

- 100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery
- 100 MW Washington Solar East Solar +50 MW 4-hour Li-ion Battery
- 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery
- 200 MW Montana Wind Central + 100 MW 8-hour PHES

The hybrid ELCC and the sum of the standalone ELCC of each hybrid system are in Table L.21 and Table L.22.

Table L.21: Hybrid ELCC (MW)

Resource	Winter 2029	Summer 2029
Solar + Storage	51	87
Solar + Storage (Restricted Charging)	51	87
Wind + Storage	61	53
Solar + Wind + Storage	66	108
Wind + PHES	142	141

Table L.22: Sum of Standalone ELCC (MW)

Resource	Winter 2029	Summer 2029
Solar + Storage	52	103
Solar + Storage (Restricted Charging)	52	103
Wind + Storage	61	53
Solar + Wind + Storage	66	108
Wind + PHES	142	141

We calculated the saturation curves of each standalone renewable resource and storage resource in the RA study. We estimated the hybrid system ELCC saturation curves using the standalone resource ELCC saturations, as shown in Table L.23.

Table L.23: Hybrid Systems ELCC Tranches (MW) in 2029

Resource	Season	Tranche 1	Tranche 2	Tranche 3
Solar + Storage	Winter	40	11	5
Wind + Storage	Winter	49	15	5
Solar + Wind + Storage	Winter	51	16	5
Wind + PHSE Storage	Winter	142	33	12
Solar + Storage	Summer	61	28	6
Wind + Storage	Summer	51	28	7
Solar + Wind + Storage	Summer	77	36	7
Wind + PHSE Storage	Summer	141	95	15
Cumulative ELCC	Winter	1,000	1,500	5,000
Cumulative ELCC	Summer	1,000	1,500	5,000

7. Western Resource Adequacy Program Methodology

The Western Power Pool produced the methodology for the WRAP metrics.

➔ For details regarding their approach, please refer to this document on the WPP website.

7.1. Planning Reserve Margin

The planning reserve margin (PRM) measures the quantity of capacity needed above the median year peak load to meet the loss of load expectation (LOLE) standard, which serves as a simple and intuitive metric that can be utilized broadly in power system planning. The PRM is primarily determined on a system-wide basis.

We based the WRAP metrics on modeling completed with data from current Phase 3A participants. These metrics are only representative if the WRAP exists, has participants, and can share the load and resource diversity among participants as anticipated, if current participants move forward with the WRAP in the future, and if participants are subject to binding obligations to share diversity. Until this threshold is reached, participants will continue to assess circumstances and determine how to interpret modeling results and what reserve margins to keep.

We obtained the methodology for the PRM from the Western Power Pool in Section 2, Appendix C of the WRAP methodology document (2021-08-30_NWPP_RA_2B_Design_v4_final.pdf). We modeled the WRAP PRM footprint in two main subregions: Northwest (NW) and Desert Southwest / East (DSW/E).

The calculation for the allocation of the capacity requirement of the PRM follows:

$$Allocated\ capcity\ requirement = \left(\frac{Participant's\ P50\ Load}{\sum All\ Participant's\ P50\ Load}\right) \times regional\ capacity\ need$$

7.2. Qualifying Capacity Contributions

Table L.24, which can be found in the August 24, 2022, Resource Adequacy webinar, shows the methodology for resource capacity accreditation.

Table L.24: WRAP Qualifying Capacity Contributions

Resource Type	Accreditation Methodology
Wind and Solar Resources	Effective Load-Carrying Capability (ELCC) analysis
Run-of-river Hydroelectric	Average monthly output on capacity critical hours (CCHs)
Storage Hydroelectric	The WPP-developed hydroelectric model that considers the past 10 years of generation, potential energy storage, and current operational constraints
Thermal	Unforced capacity (UCAP) method
Short Term Storage	ELCC analysis (recent update — to be completed next model run)
Hybrid Resource	Sum-of-parts method where energy storage will use ELCC, and the generator will use the appropriate method as outlined
Customer-side Resources	Can register as a load modifier or as a capacity resource

7.3. WRAP Solar ELCC Zones

The WRAP footprint is comprised of two zones for solar resource ELCC modeling. Zone 1 contains the Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Zone 2 includes the Southern states in the West, such as California, Nevada, Utah, and Arizona. The allocation of ELCCs within each zone is based on the average monthly output of CCHs, which is anticipated to capture the time zone and geographic (East/West) diversity of resources. For solar ELCC calculations, the historical average hourly net power output analysis utilizes at least three years of data, if available. We can adjust the allocation of zonal ELCC to individual resources as the actual production data is accumulated.

Figure L.20 depicts the solar zones which can be found in the August 24, 2022, Resource Adequacy webinar.

Figure L.20: WRAP Area and Solar Zones

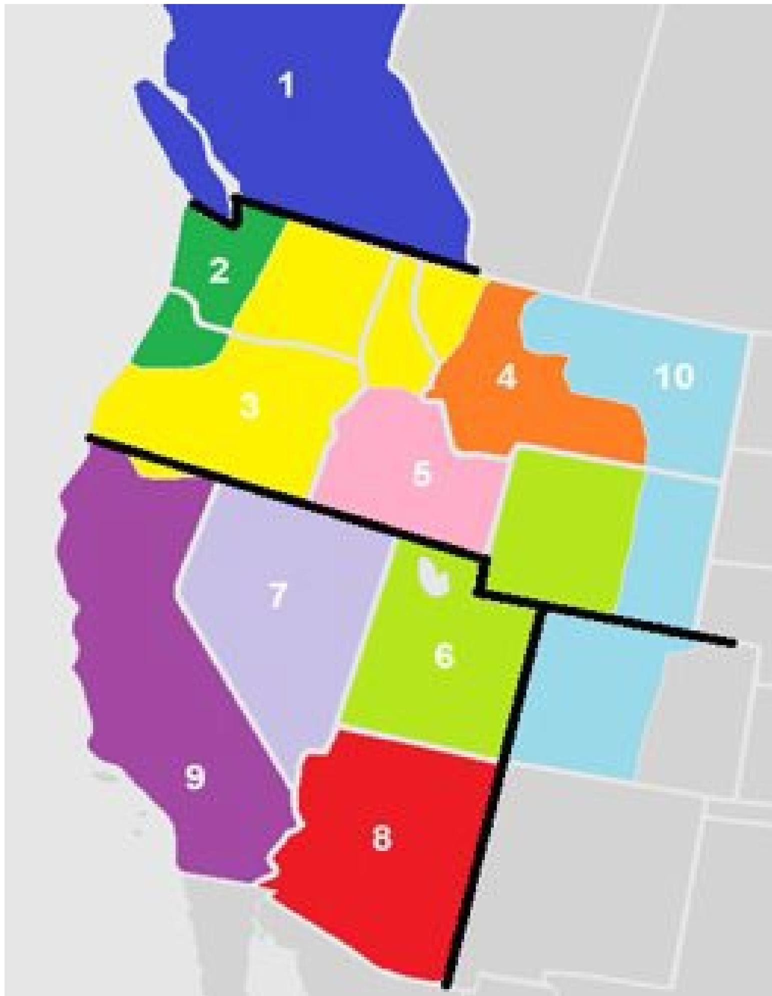


Table L.25: WRAP Solar ELCCs

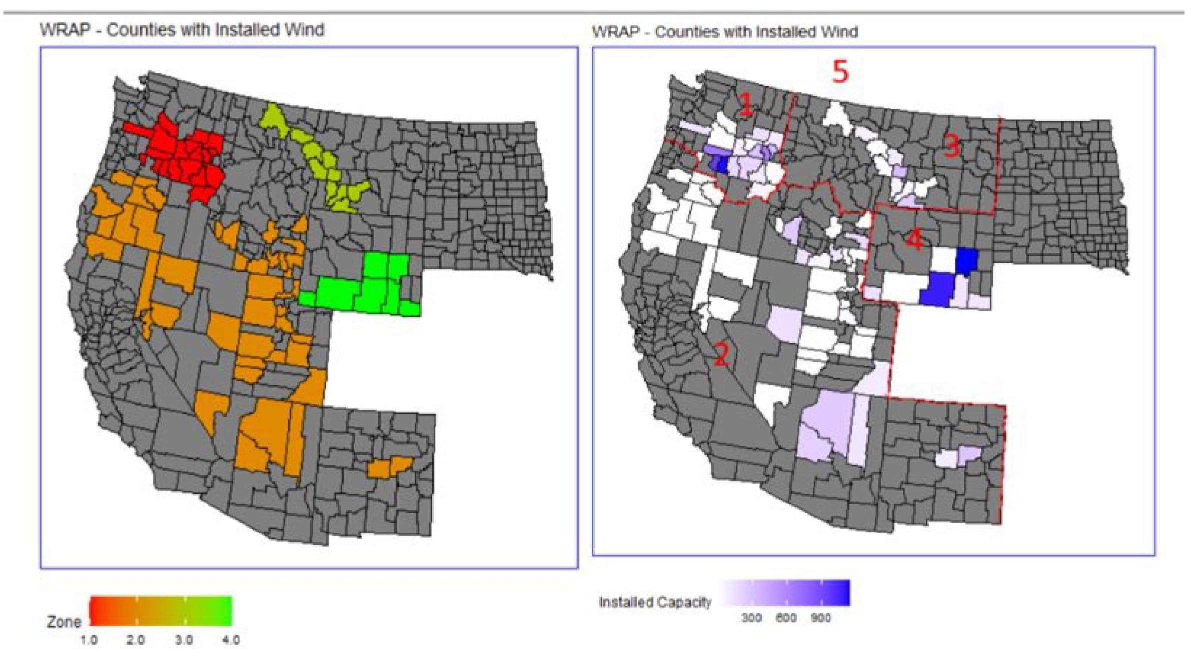
Zone	Nameplate (MW)	Winter 2023-2024					Summer 2024			
		Nov. (%)	Dec. (%)	Jan. (%)	Feb. (%)	Mar. (%)	Jun. (%)	Jul. (%)	Aug. (%)	Sep. (%)
1 (North)	2,138	2	3	3	4	5	23	30	24	13
2 (South)	9,024	3	5	7	7	5	16	24	23	11

7.4. WRAP Wind ELCC Zones

The WRAP footprint includes five wind ELCC zones. Zone 1 models the Columbia Gorge, spanning Southern Washington and Northern Oregon. Zone 2 comprises all other U.S. installed wind, including everything but the Columbia Gorge, Montana, and Wyoming. Zone 3 includes Montana, Zone 4 is Wyoming, and Zone 5 models British Columbia. For wind ELCC calculations, the historical average hourly net power output analysis utilizes at least three years of data, if available. The allocation of zonal ELCC to individual resources may be adjusted as the production data is accumulated.

Figure L.21 shows the WRAP counties with installed wind and their associated zone and capacity from the August 24, 2022, Resource Adequacy webinar.

Figure L.21: WRAP Counties with Installed Wind[10]



[10] https://www.westernpowerpool.org/private-media/documents/2021-12-21_RAPC_Minutes.pdf

Table L.26: WRAP Wind ELCCs

Zone	Nameplate (MW)	Winter 2023–2024					Summer 2024			
		Nov. (%)	Dec. (%)	Jan. (%)	Feb. (%)	Mar. (%)	Jun. (%)	Jul. (%)	Aug. (%)	Sep. (%)
1 (WA+)	5,734	10	9	8	11	13	19	22	18	13
2	2,400	32	30	28	32	34	18	18	16	16
3 (MT)	1,378	30	29	28	23	25	13	12	13	14
4 (WY)	2,429	36	32	30	27	31	15	16	14	14
5 (BC)	747	29	28	23	24	22	18	17	21	22