2021 PSE Integrated Resource Plan

5 Key Analytical Assumptions

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

Contents

1. OVERVIEW

Scenarios, inputs, portfolio modeling assumptions and portfolio sensitivities are presented for the electric analysis first, followed by the natural gas analysis. Because some of the inputs are the same for both the electric and natural gas analyses, readers will note some repetition in the two sections.

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

2. ELECTRIC ANALYSIS

Electric Price Forecast Scenarios

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

Figure 5-1: 2021 IRP Electric Price Forecast Scenarios

	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC

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

Scenario 1: Mid

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

DEMAND

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

NATURAL GAS PRICES

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

CO_2 PRICE AND REGULATIONS

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

CLEAN ENERGY AND RPS REGULATIONS

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

Scenario 2: Low

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

DEMAND

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

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

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

NATURAL GAS PRICES

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

CO_2 PRICE AND REGULATIONS

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

CLEAN ENERGY AND RPS REGULATIONS

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

Scenario 3: High

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

DEMAND

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

NATURAL GAS PRICES

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

CO_2 PRICE AND REGULATIONS

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

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045;

plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Comparison Electric Price Scenario for CETA Rate Impact Cost Control

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

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

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

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

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

Mid + No CETA

DEMAND

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

NATURAL GAS PRICES

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

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

CO_2 PRICE

- CO_2 prices for California are included.

CLEAN ENERGY/RPS REGULATIONS

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

Electric Scenario Inputs

PSE Customer Demand

The 2021 IRP Base, Low and High Demand Forecasts used in this analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period.[4] Significant inputs include the following.

- information about regional and national economic growth
- demographic changes
- weather
- prices
- seasonality and other customer usage and behavior factors
- known large load additions or deletions

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

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

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

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

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

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

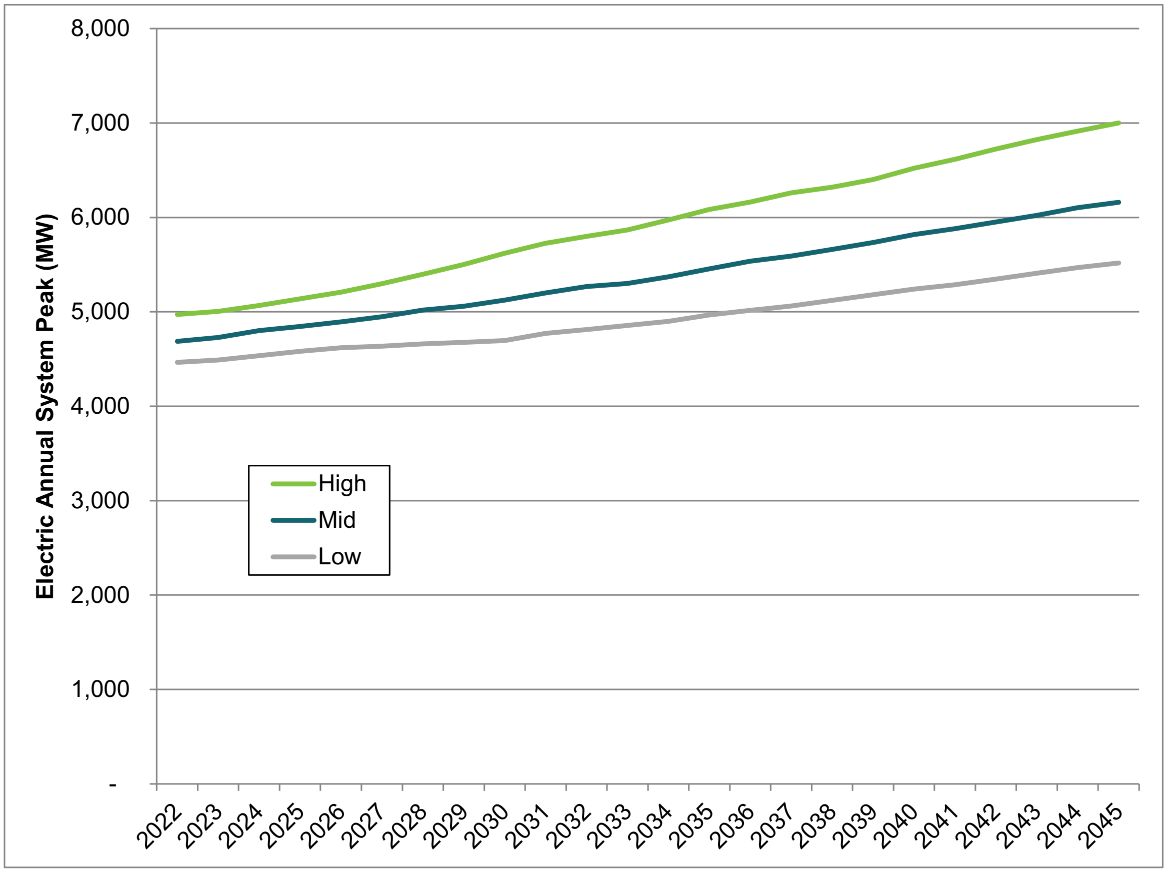
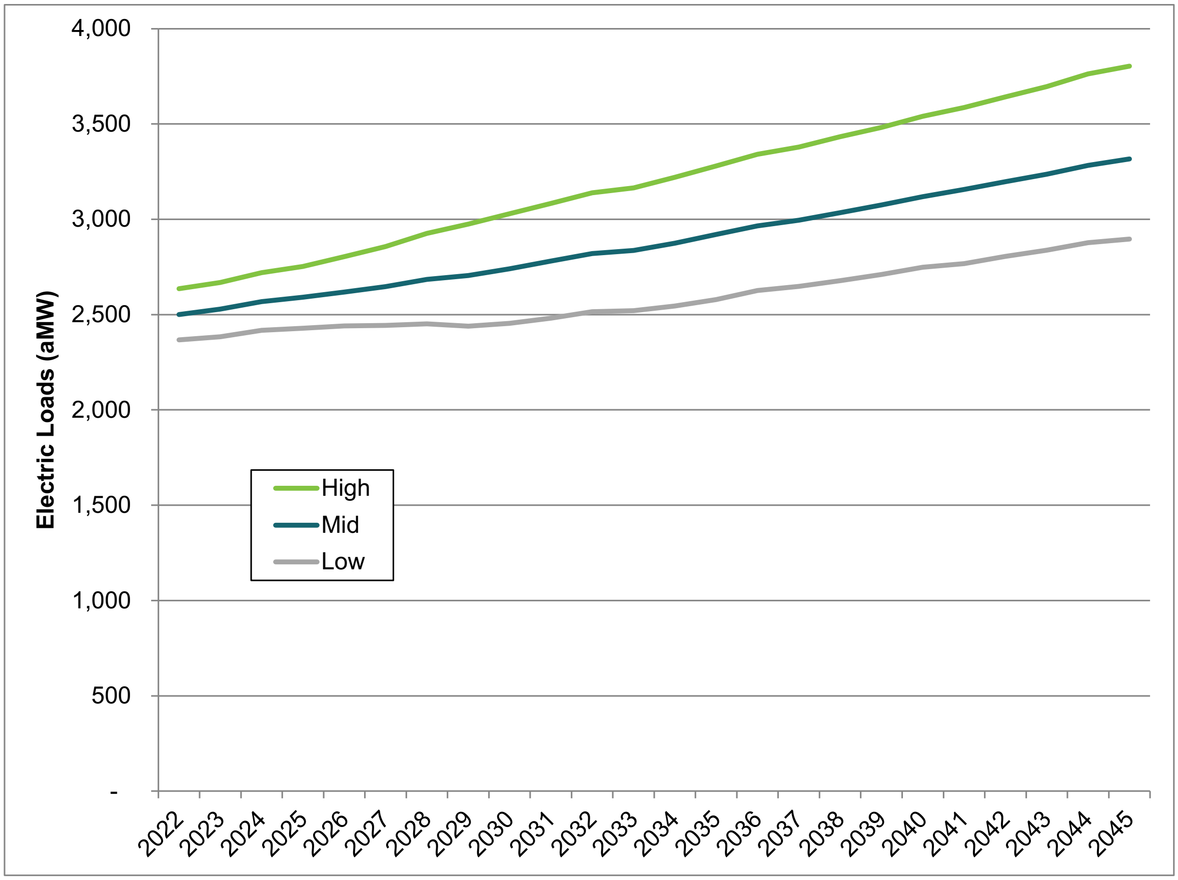


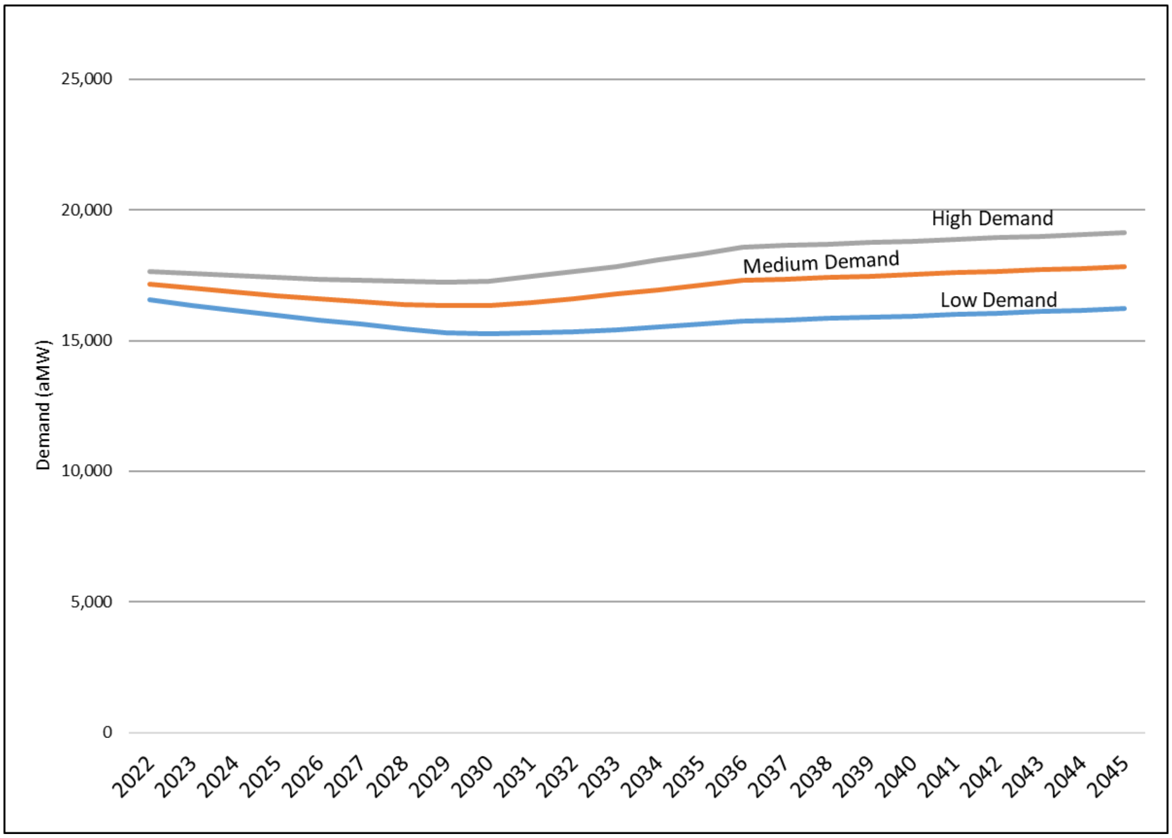
Figure 5-4: 2021 IRP Annual Electric Energy Demand Forecast - Low, Base (Mid) High



Regional Electric Demand

Regional demand must be taken into consideration because it significantly affects power prices. This IRP uses the regional demand developed by the Northwest Power and Conservation Council[5] (NPCC or "the Council") 2019 Policy Update to the 2018 Wholesale Electricity forecast. Regional demand is used only in the WECC-wide portion of the AURORA analysis that develops wholesale power prices for the scenarios.

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



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

Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[6] from Wood Mackenzie.[7]

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

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

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

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

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

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

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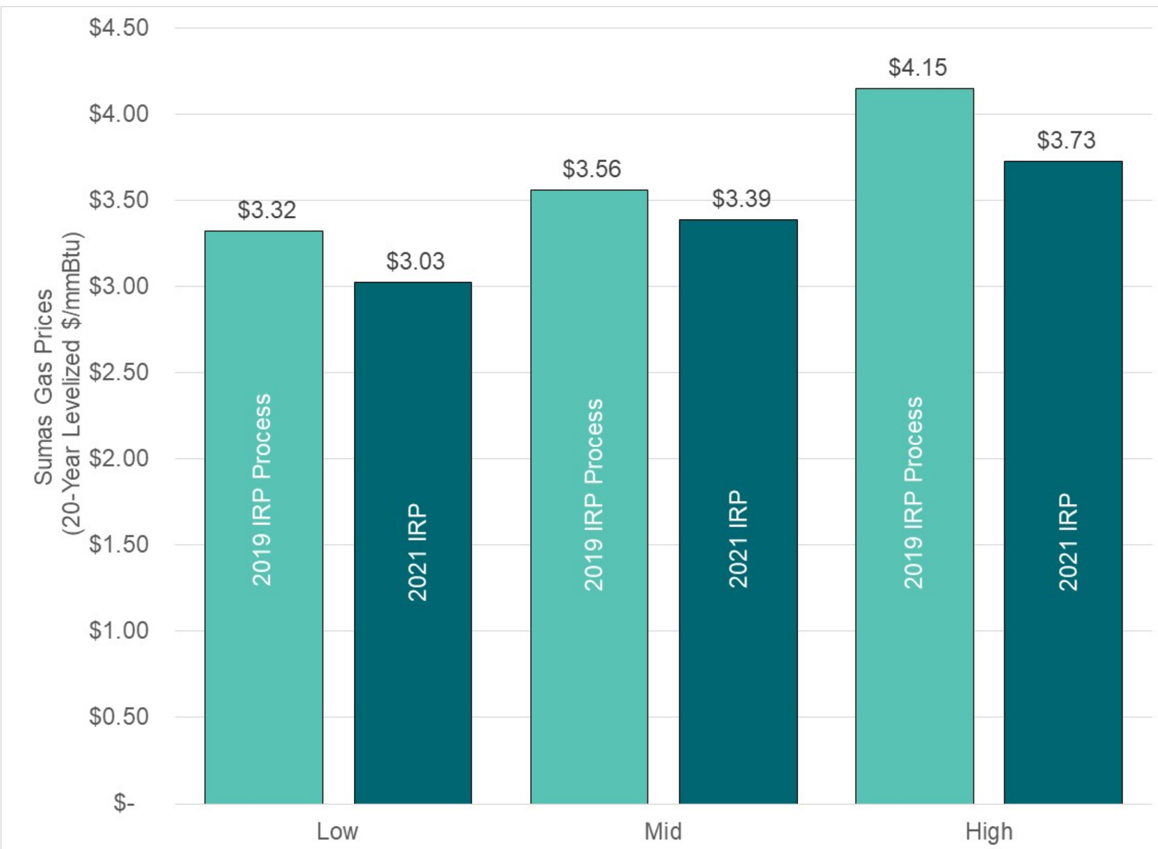
6 / *The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.*

7 / *Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.*

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

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

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



CO_2 Price Inputs

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

SOCIAL COST OF GREENHOUSE GASES (SCGHG). The SCGHG cited in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the *CO_2* prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $238 per ton in 2052,** as shown in Figure 5-7.

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

UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[8]

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

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[9] (PSCAA). PSCAA used two models to determine these rates, GHGenius[10] and GREET.[11] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-8: Upstream Natural Gas Emissions Rates

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

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

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

Renewable Portfolio Standards (RPS) and Clean Energy Standards

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

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g., 3 percent in 2012, 9 percent in 2016, then 15 percent in 2020 for Washington State RCW 19.285). Each state's requirements are applied to the state's load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing renewable resources are accounted for, they are subtracted

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

from the total WECC RPS need, and the net RPS need is added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet RPS need. Technologies modeled included wind and solar.

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

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

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

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

Power Price Inputs

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

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

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

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

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

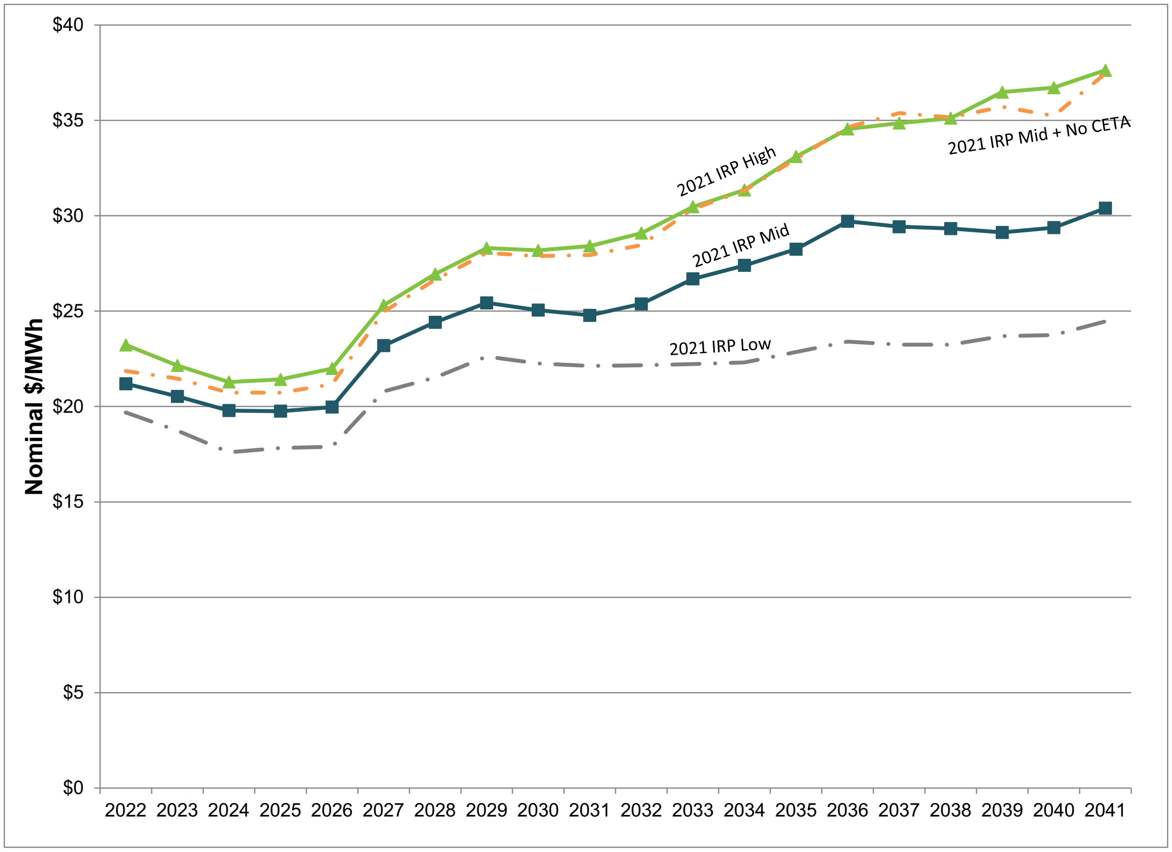
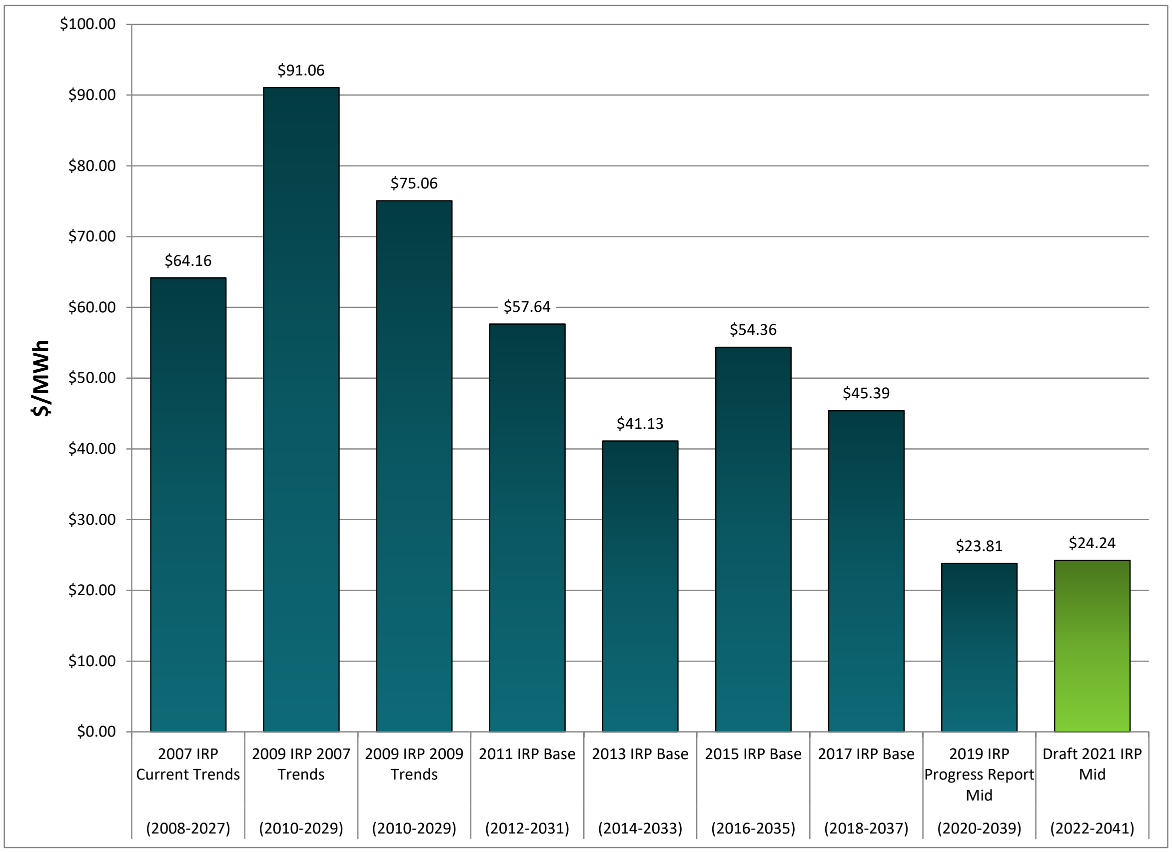


Figure 5-11 below compares the 2021 Mid Scenario power prices to past IRP power prices. In previous IRPs, the downward revisions in forecast power prices corresponded to the downward revisions in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by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

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



Electric Portfolio Modeling Assumptions

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

Electric Resource Assumptions

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

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

Demand-side resources included the following.

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

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

DISTRIBUTION EFFICIENCY. Voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

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

Distributed energy resources included the following.

DISTRIBUTED SOLAR GENERATION – CUSTOMER OWNED. Distributed solar generation refers to small-scale rooftop solar panels located close to the source of the customer's load.

DISTRIBUTED SOLAR GENERATION – PSE OWNED. Distributed solar generation refers to small-scale rooftop solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-12. Solar data was obtained from the National Solar Radiation Database[12] and processed with the NREL System Advisory Model.[13]

Figure 5-12: Distributed Solar Capacity Factors

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

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

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

Supply-side resources included the following.

12 / https://nsrdb.nrel.gov/
13 / https://sam.nrel.gov/

WIND. Wind was modeled in seven locations throughout the northwest United States including: eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and offshore the coast of Washington. A summary of capacity factors for each wind resources are provided below in Figure 5-13. Wind data was obtained from the National Renewable Energy Laboratory's (NREL) Wind Toolkit Database[14] and processed using an in-house heuristic wind production model.

Figure 5-13: Wind Capacity Factors

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

SOLAR. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-14. Solar data was obtained from the National Solar Radiation Database[15] and processed with the NREL System Advisory Model.[16]

14 / https://www.nrel.gov/grid/wind-toolkit.html
15 / https://nsrdb.nrel.gov/
16 / https://sam.nrel.gov/

Figure 5-14: Solar Capacity Factors

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

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

ENERGY STORAGE: PUMPED HYDRO. Pumped hydro resources are generally large, on the order of 250 to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties. Pumped hydro resources can provide sub-hourly flexibility values similar to batteries at utility scale. Because they are located remote from substations, they cannot contribute the transmission and distribution benefits that smaller battery systems can provide at the local system level. Pumped hydro can provide some benefits to the bulk transmission system, however, such as frequency response and black start capability. PSE analyzed an 8-hour pumped hydro resource.

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

BASELOAD THERMAL PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTs).
F-type, 1x1 engines with wet cooling towers are assumed to generate 348 MW plus 19 MW of duct firing, and to be located in PSE's service territory. These resources are designed and intended to operate at base load, defined as running more than 60 percent of the hours in a year.

FRAME PEAKERS (SIMPLE-CYCLE COMBUSTION TURBINES OR SCCTs). F-type, wet-cooled turbines are assumed to generate 237 MW and to be located in PSE's service territory. These resources are modeled with either natural gas or an alternative fuel as the fuel source.

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

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

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

Electric Resource Cost Assumptions

Generic resource cost assumptions were generated through review of numerous data sources related to generating resources costs and collaboration with the IRP stakeholder group. The generic resource cost assumption methodology was inspired and informed by the Northwest Power and Conservation Council (NPCC) Generating Resource Advisory Committee's (GRAC) cost assumption process.[17]

In brief, the methodology begins with accumulation of generic resource cost estimations from various organizations and regional IRP estimates. Since cost estimations were acquired from different sources, each cost estimate may include a different set of base assumptions, such as inclusion or exclusion of owner's or interconnection costs. Cost estimates were adjusted to align these assumptions as closely as possible. Cost estimates were then arranged by technology vintage year and summary statistics including average, median, minimum and maximum cost were calculated for each vintage year. All cost estimations and statistics were presented to the IRP stakeholder group with the recommendation that PSE use the average cost for modeling purposes. Stakeholder feedback, such as inclusion of new data sources and removal of specific data sources, was incorporated into final generic resource cost assumptions. The spreadsheet used for calculation of generic resource cost assumptions is available for review on the PSE IRP website.[18] This spreadsheet includes a full list of the data

17 / https://www.nwcouncil.org/energy/energy-advisory-committees/generating-resources-advisory-committee
18 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx

sources used for cost estimate purposes and a breakdown of cost estimations by generic resource type.

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

Resource costs are generally expected to decline in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the National Renewable Energy Laboratory (NREL) 2019 Annual Technology Baseline (ATB).[19] The NREL ATB provides three cost curves for each resource, labeled as: Low, Mid and Constant Technology Cost Scenarios. PSE has selected the Mid Technology Cost Scenario for the IRP cost curves as it represents the "most-likely" future cost projection.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes engineering, procurement and construction, owner's costs, and interconnection costs. Interconnection costs include, as needed, natural gas pipelines and 5 miles of transmission from the substation to the main line. The costs calculated using the methodology described above resulted in "overnight capital costs" which typically exclude allowance for funds used during construction (AFUDC) and interconnection costs. PSE has assumed AFUDC costs at 10 percent of the overnight capital cost. PSE derived interconnection costs from a 2018 study on Generic Resource Costs for Integrated Resource Planning[20] prepared by consultant HDR for PSE. PSE believes the estimates used here are appropriate and reasonable.

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

19 / https://atb.nrel.gov/electricity/2019/index.html?t=lw
20 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Figure 5-15: New Resource Generic Cost Assumptions

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

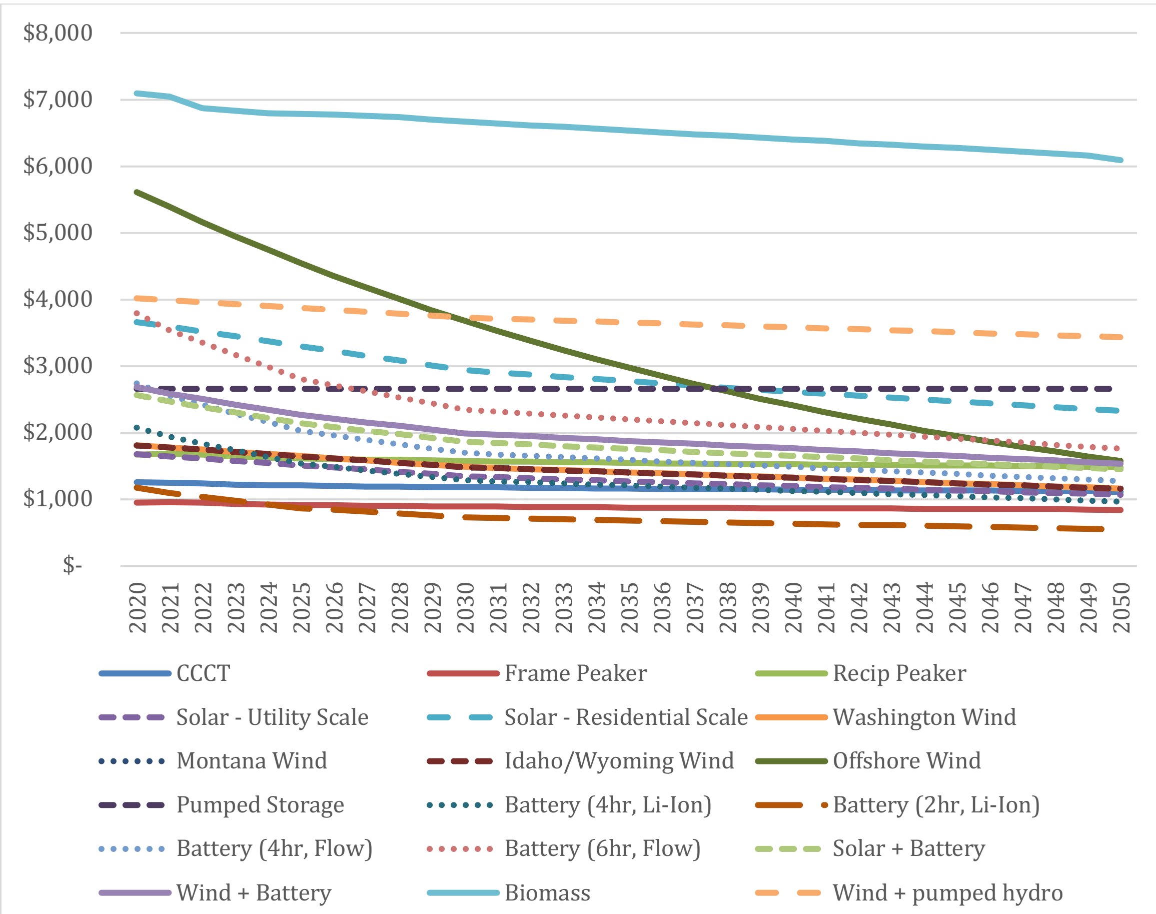
NOTES

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

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

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

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



Flexibility Considerations

The following analysis is based on work done for the 2017 IRP. PSE is working on updating the flexibility analysis, but it was not ready for the draft IRP. PSE presented draft flexibility analysis results to the IRP stakeholders in December 2020 and is still in the process of soliciting feedback on the analysis. The following flexibility benefit will be updated with the new analysis for the final 2021 IRP.

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

The flexibility analysis focused on reflecting the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, different resources can impact how the entire portfolio operates and also impact costs. For example, batteries could avoid dispatch of thermal plants for some ramping up and down. A way to monetize values is needed in order to incorporate theses costs in the portfolio analysis, to ensure lowest reasonable cost.

For the sub-hourly cost analysis PSE used a model called PLEXOS. First a Current Portfolio Case based on PSE's existing resources was created. The Current Portfolio Case begins by creating a simulation that reflects a complete picture of PSE as a BA and PSE's connection to the market. This includes representation of PSE's BAA load and generation on a 5-minute basis, as well as contracts with neighboring BAs, and opportunities to make purchases and sales at the Mid-C trading hub in hourly increments. For this analysis, PSE simulated the year 2022.

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

Figure 5-17 below is the cost savings associated with each resource. For example, a CCCT has a cost savings of $0.03/kw-yr. This cost savings is applied back to the fixed O&M of the generic resource as a reduction to the cost.

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

Resource	Flexibility Cost Savings ($/kw-yr)
CCCT	0.03
Frame Peaker	1.15
Recip Peaker	8.16
Lithium-ion battery 2hr	3.11
Lithium-ion battery 4hr	7.89
Flow battery 4hr	1.53
Flow battery 6hr	7.44
Pumped Storage Hydro 10hr	10.24

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

Transmission Build Constraints: Regional

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

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

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

Transmission Capacity Constraints

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PSE Territory: The assumption for the 2021 IRP is that the PSE system in western Washington is unconstrained, this does not include PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades. See Appendix M, Delivery System 10-year Plan, for detailed descriptions of transmission and distribution projects planned to ensure unconstrained delivery of resources.

Figure 5-20: Transmission and Distribution Planned Work

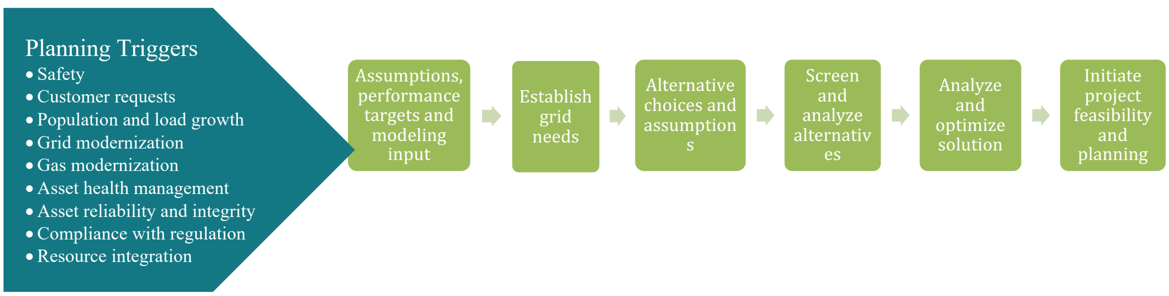
Transmission and Distribution Summary – Planned work to ensure delivery of resources unconstrained	Description (to be completed for final IRP)	Project Phase & Estimated In-service Date	Potential DER Location
Foundational Technology	Advance Metering Infrastructure (AMI) Advanced Distribution Management System (ADMS)	Implementation by 2022 / 2023	
Smart Equipment	600 SCADA devices	Implemention by 2025	
Distribution Circuits / Lines	48 lines	Ongoing	
Cable Replacement	1,400 miles	Implementation by 2031	
Transmission and Distribution Pole Replacement	X,XXX	On-going	
Sammamish – Juanita New 115 kV Line		Implementation 2023	
Eastside 230 kV Transformer Addition and Sammamish-Lakeside-Talbot 115kV Rebuilds (Energize Eastside)		Implementation 2022	
Electron Heights – Enumclaw 55-115 kV Conversion		Implementation 2024	
Sedro Woolley - Bellingham #4 115 kV Rebuild and Reconductor		Implementation 2024	
Bainbridge Island (NWA Pilot)		Implementation 2024	X
Lynden Substation (NWA Pilot)		Implementation 2024	X
Seabeck (NWA Pilot)	Project driver is to ensure reliability	Initiation need exists	X
West Kitsap (NWA Pilot)	Project driver is to ensure stability, capacity and address aging infrastructure	Initiation need exists	X
Kent / Tukwila Capacity and Reliability	Project driver is to ensure adequate capacity	Initiation needed by 2020	
Covington/Black Diamond Area	Project driver is to ensure adequate capacity	Initiation needed by 2020	
Issaquah	Project driver is to ensure adequate capacity	Initiation need exists	
Bellevue-Redmond Gateway	Project driver is to ensure adequate capacity	Initiation needed by 2021	
Inglewood – Juanita	Project driver is to ensure adequate capacity	Initiation needed by 2024	

South Thurston County	Project driver is to ensure stability and adequate capacity	Initiation need exists	
Electron Heights - Yelm Transmission	Project driver is to address aging infrastructure	Initiation needed by 2024	
Lacey Hawks Prairie	Project driver is to ensure adequate capacity	Initiation needed by 2021	

Electric Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs, including effective integration of DERs. The approach and associated planning assumptions are shown in Figure 5-21 below.

Figure 5-21: DSP Operating Model



Assumptions	Description
Demand and Peak Demand Growth	Uses county demand forecast applied based on historic load patterns of substation circuits with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Aging Infrastructure	Known concerns included in analysis
Interuptible / 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

Distributed Energy Resource Forecast

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

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

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

Figure 5-22: Forecasted DER Installation by Year and Type

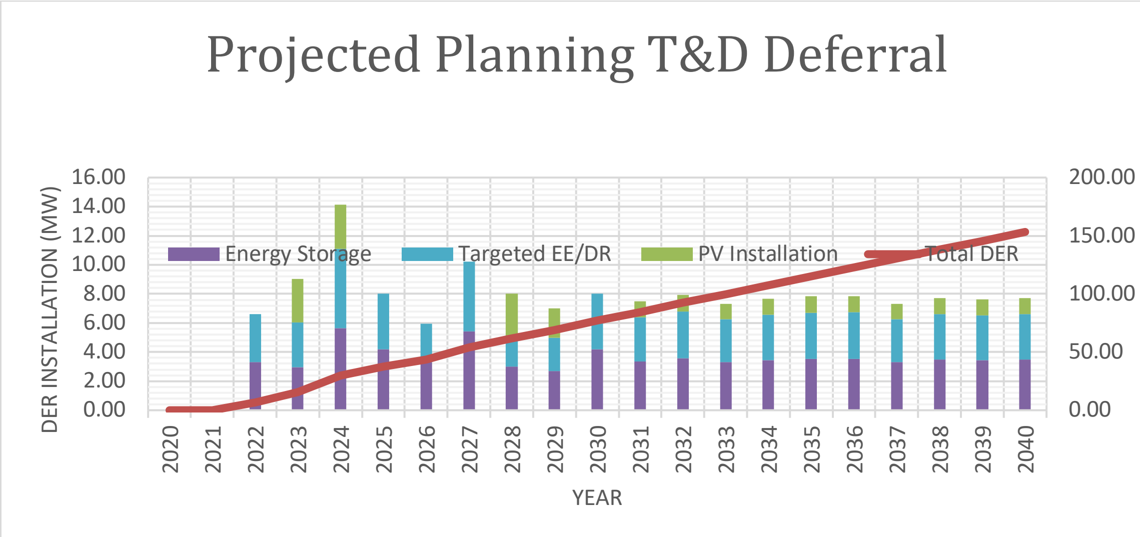


Figure 5-23: 20-year Projected T&D Deferral by Project Type

	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects*	6.6	6.0	0.0	12.6
Planned Substation Capacity Projects	18.1	17.2	6.0	41.3
Future Potential System Needs	44.3	39.2	15.9	99.4
Total	**69.0**	**62.4**	**21.9**	**153.3**

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

Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material and voltage impact the magnitude of transmission line losses. BPA assumes a flat 1.9 percent line loss across its entire transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, PSE has assumed a similar loss given the similar distance. Figure 5-24 provides a summary of the transmission lines losses assumed by resource group region.

Figure 5-24: Transmission Line Losses by Resource Group Region

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

Transmission Cost Constraints

Transmission cost is another factor used in the PSE Portfolio Model to constrain resource build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-yr) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to PSE's service territory. Variable transmission costs are largely composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Figure 5-25 provides a summary of fixed and variable transmission costs by generic resource type.

Figure 5-25: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-yr)	Variable Transmission Cost[b] ($/MWh)
CCCT	0.00[a]	TBD
Frame Peaker	0.00[a]	TBD
Recip Peaker	0.00[a]	TBD
WA Solar East - Utility Scale	30.48	TBD
WA Solar West - Utility Scale	0.00[a]	TBD
Idaho Solar – Utility Scale	32.64	TBD
WY Solar East – Utility Scale	51.84	TBD
WY Solar West – Utility Scale	46.56	TBD
DER WA Solar - Rooftop	0.00[a]	TBD
DER WA Solar – Ground-mount	0.00[a]	TBD
WA Wind	33.36	TBD
MT Wind – East	49.65	TBD
MT Wind - Central	49.65	TBD
ID Wind	35.36	TBD
WY Wind East	56.16	TBD
WY Wind West	50.44	TBD
Offshore Wind	33.36	TBD
Pumped Storage	22.20	TBD
Battery 2hr Li-Ion	0.00[a]	TBD
Battery 4hr Li-Ion	0.00[a]	TBD
Battery 4hr Flow	0.00[a]	TBD
Battery 6hr Flow	0.00[a]	TBD
Solar + Battery	53.97	TBD
Wind + Battery	56.85	TBD
Wind + Pumped Storage	71.85	TBD
Biomass	22.20	TBD

NOTE

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

b. Variable transmission costs are underdevelopment and will be made available for the final IRP filing.

Electric Portfolio Sensitivities

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

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

Figure 5-26: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Market Reliance at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO2 is included in addition to using the SCGHG as a fixed cost adder.
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants can use either hydrogen or biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	Natural Gas Generation Out by 2045	All existing natural gas plants are retired in 2045.
P	Must-take Battery or Pumped Hydro Storage	1. Build batteries to a certain level before adding any other peaking capacity resources. 2. Build pumped hydro storage to a certain level before adding any other peaking capacity resources.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
V	Balanced Portfolio	The portfolio model must take distributed energy resources ramped in over time and more customer programs.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs plus carbon free combustion turbines using biodiesel as the fuel.

A. Renewable Overgeneration Test

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

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

B. Reduced Market Reliance at Peak Hours

PSE currently uses market purchases of energy in order to meet demand at peak demand hours. As CETA pushes the generation mix of the Pacific Northwest to become increasingly renewable, energy may not be available for purchase on the Mid-C market. This sensitivity reduces the amount of market purchases and sales that can be made, allowing PSE to examine an optimized portfolio that does not rely heavily on market. Determining the behavior of the model under different market circumstances can inform PSE how to navigate a market with reduced peak availability.

> **BASELINE ASSUMPTION:** PSE can purchase and sell up to the Mid-C transmission limit, typically 1500 MW.
> **SENSITIVITY >** PSE can purchase and sell up to the Mid-C transmission limit, typically 1500 MW, until 2025. The analysis to establish the limit will be available in the final IRP.

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

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

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

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

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

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

E. Firm Transmission as a Percentage of Resource Nameplate

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

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

F. 6-Year Conservation Ramp Rate

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

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

SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

G. Non-energy Impacts

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

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

H. Social Discount Rate for DSR

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

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

I. Social Cost of Greenhouse Gases as an "Externality Cost" (Dispatch Cost)

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

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

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

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

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

K. AR5 Upstream Emissions

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

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology.

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

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

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

M. Alternate Fuel for Peakers

This sensitivity will include either hydrogen or biodiesel as an available fuel option for peaker plants. Results will provide insight into the costs associated with converting the plants to an alternative fuel to meet CETA requirements.

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

N. 100% Renewable by 2030

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

BASELINE ASSUMPTION: PSE must reach 100% renewable resources by 2045.

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

O. Natural Gas Generation Out by 2045

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

BASELINE ASSUMPTION: Carbon-emitting resources retire at the end of their economic life.

SENSITIVITY > In 2045, all carbon-emitting resources are retired, regardless of their economic viability.

P. Must-take Battery or Pumped Hydro Storage

This sensitivity requires a certain amount of energy storage resources, both batteries and pumped hydro storage, to be selected before the model can consider building any peaking capacity resources. Results from this sensitivity will provide insight into how energy storage provides value to the system that has traditionally been provided by natural gas plants.

BASELINE ASSUMPTION: Resources are acquired when they provide the most value to the portfolio.

SENSITIVITY 1> Batteries are a must-take resource in the portfolio model starting in 2026.

SENSITIVITY 2> Pumped hydro storage is a must-take resource in the portfolio model starting in 2026.

Q. Fuel Switching, Gas to Electric

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

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Base Scenario.

SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory.

R. Temperature Sensitivity

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

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

S. SCGHG Included, No CETA

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

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

T. No CETA

This sensitivity will model the portfolio with no SCGHG as a fixed cost adder and no CETA renewable requirement. Results from this sensitivity will help to quantify the effect of CETA.

Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

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

U. 2% Cost Threshold

CETA is considered fulfilled once renewable targets are met or once the investments imposed by CETA constraints reach 2 percent of the annual revenue requirement.

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

V. Balanced Portfolio

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

> **BASELINE ASSUMPTION**: New resources are acquired when cost effective and needed, conservation and DR measures are acquired when cost-effective.
> **SENSITIVITY >** Increased distributed energy resources and customer programs are ramped in over time as follows:
>
> - Distributed ground-mounted solar: 50 MW in 2025
> - Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
> - Demand response programs under $300/kw-yr
> - Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
> - Increased customer-owned rooftop solar

- Green Direct: additional 300 MW by 2030

W. Balanced Portfolio with Alternative Fuel

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

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

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

3. NATURAL GAS ANALYSIS

Natural Gas Scenarios

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

Figure 5-27: 2021 IRP Natural Gas Analysis Scenarios

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

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

Scenario 1: Mid

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

DEMAND

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

NATURAL GAS PRICES

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

CO_2 PRICE

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

Scenario 2: Low

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

DEMAND

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

NATURAL GAS PRICES

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

CO_2 PRICE

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

Scenario 3: High

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

DEMAND

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

NATURAL GAS PRICES

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

CO_2 PRICE

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

Natural Gas Scenario Inputs

PSE Customer Demand

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

Figure 5-28: 2021 IRP Natural Gas Sales Peak Day Demand Forecast – Low, Mid, High

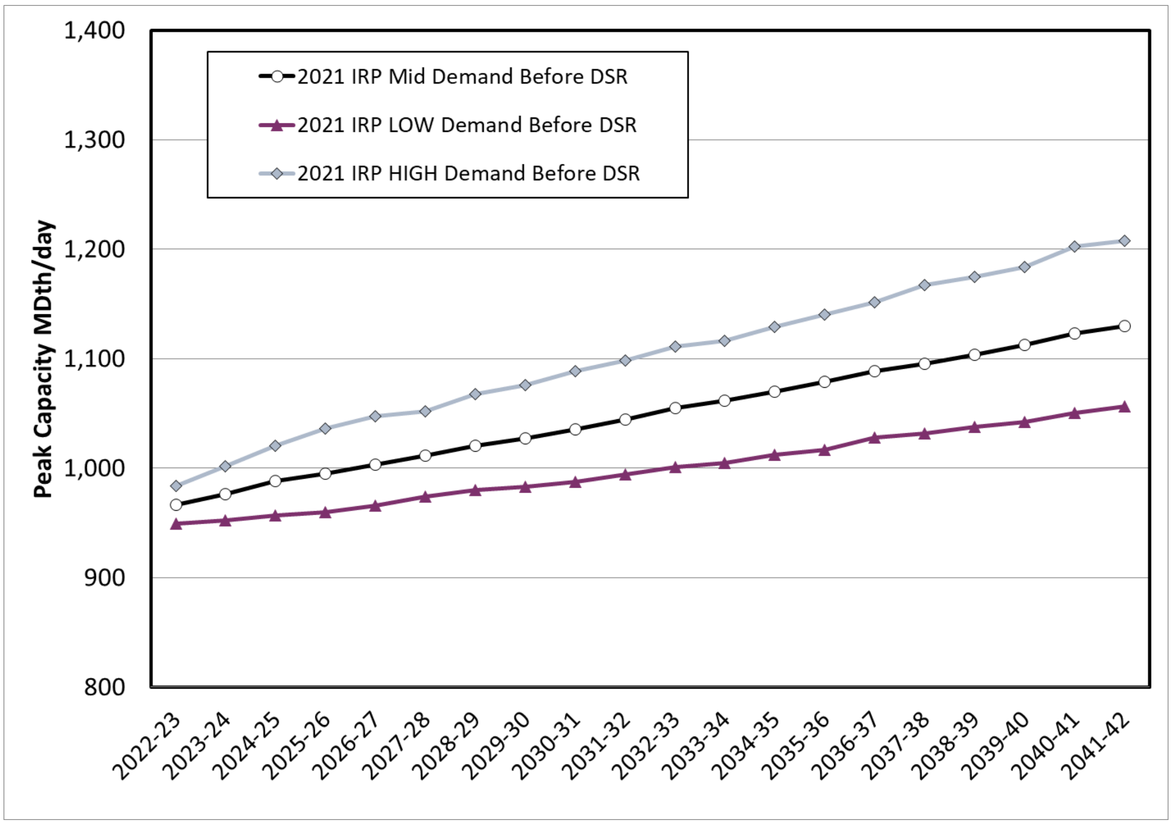
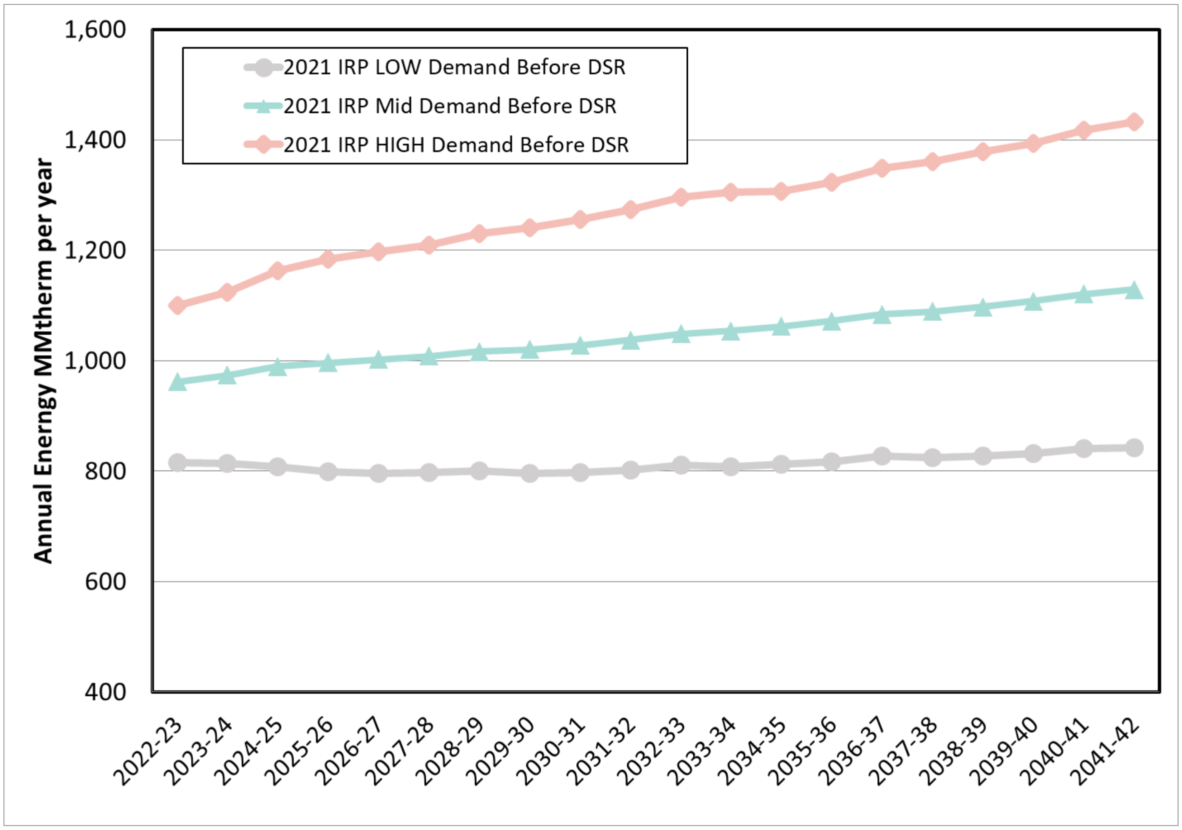


Figure 5-29: 2021 IRP Annual Natural Gas Sales Demand Forecast – Low, Base (Mid),



High

Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[21] from Wood Mackenzie.[22]

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

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

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

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

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

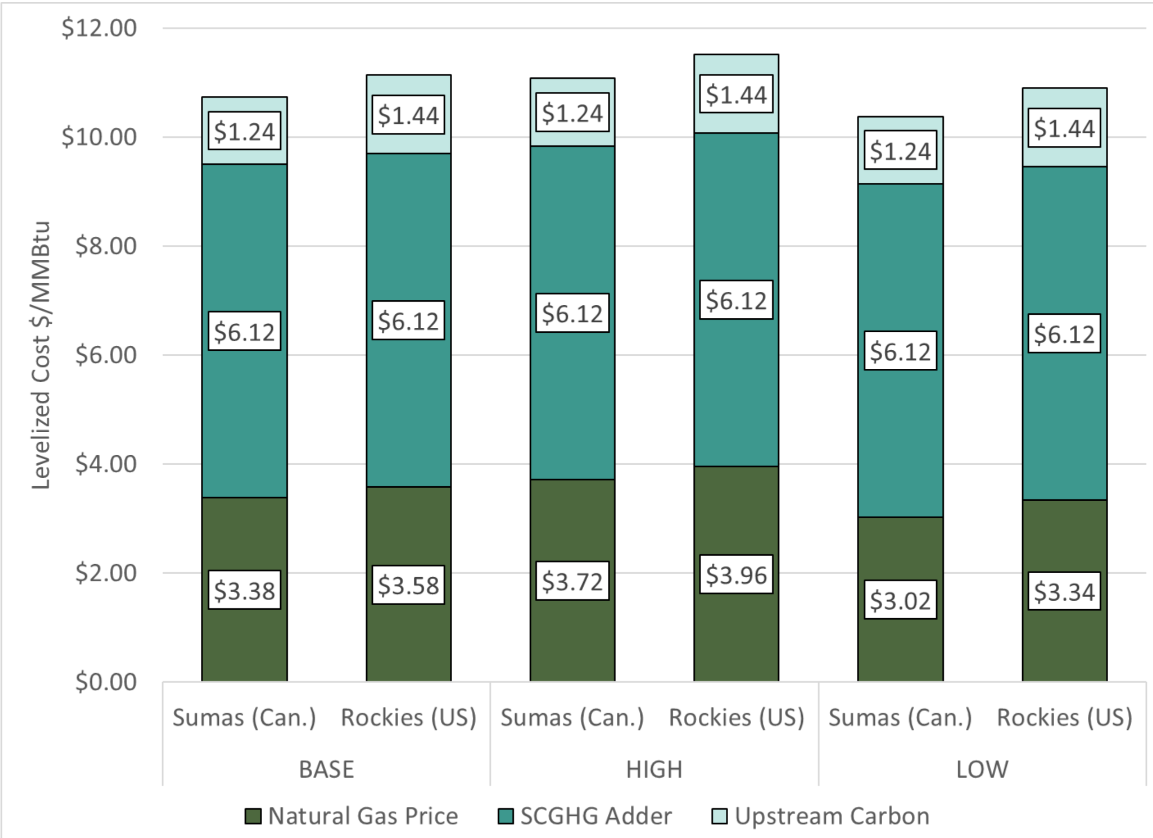
MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

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

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

Figure 5-30 below illustrates the range of 20-year levelized natural gas prices used in the 2021 IRP analysis, along with the carbon adders used to develop the total natural gas cost.

Figure 5-30: Levelized Natural Gas Prices and Carbon Adders Used in Scenarios, 2021 IRP

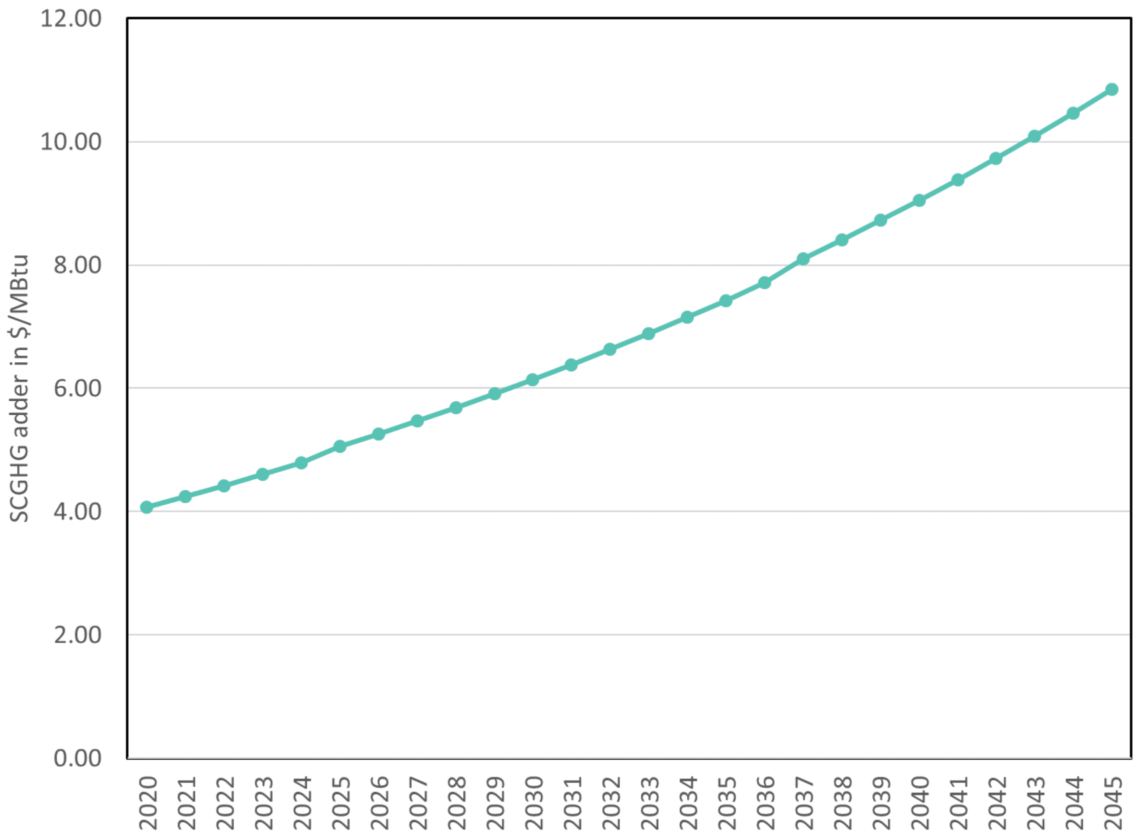


CO_2 Price Inputs

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

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

Figure 5-31: Social Cost of Greenhouse Gases Used in the 2021 IRP ($/MMBtu)



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[23]

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[24] (PSCAA). PSCAA used two models to determine these rates, GHGenius[25] and GREET.[26] Emission rates developed in the GHGenius model apply to

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

natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-32: Upstream Natural Gas Emissions Rates

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

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

Delivery of Natural Gas within the PSE System

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

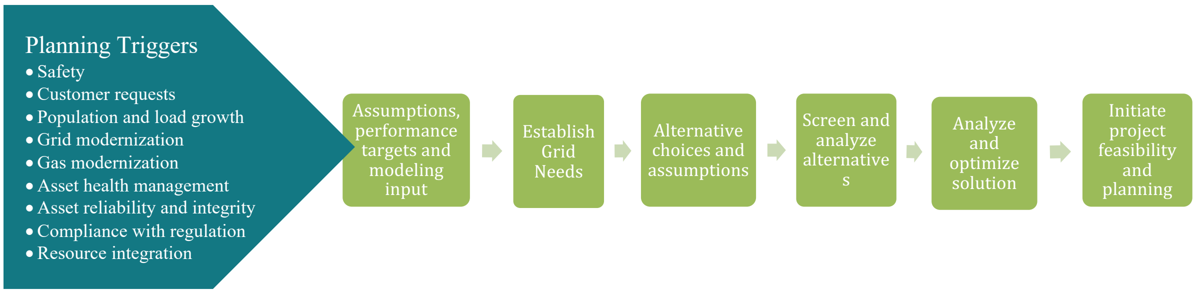
Figure 5-33: Natural Gas Distribution System Planned Work

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

Natural Gas Delivery System Planning Assumptions

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

Figure 5-34: DSP Natural Gas Operating Model



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

Natural Gas Alternatives Modeled

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

***> > >** See **Chapter 9, Gas Analysis**, for detailed descriptions of the resources listed here.*

***> > >** See **Appendix E, Conservation Potential Assessment and Demand Response Assessment**, for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

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

Supply-side resources included the following.

Transport pipelines that bring natural gas from production areas or market hubs to PSE's service area generally require assembling a number of specific segments and/or natural gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Seven alternatives were analyzed in this IRP.

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2025, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded Northwest Pipeline (NWP) to PSE's service area. Natural gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2019 to October 2024 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Westcoast. Availability is estimated to begin no earlier than November 2025. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) natural gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE. As a major greenfield project, this resource option is dependent on significant additional volume being contracted by other parties.

Combination # 3 – Cross Cascades – NWP from AECO

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

Combination # 4 – Mist Storage and Redelivery

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

Combination # 5 – Plymouth LNG with Firm Delivery

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

Combination # 6 – LNG-related Distribution Upgrade

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

Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility discussed above. The upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network, and could be available on three years' notice as early as winter 2024/25.

Natural Gas Resource Build Constraints

Natural gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent "lumpiness" in natural gas pipeline expansion, since expanding pipelines in small increments every year is not practical. Pipeline companies need minimum capacity commitments to make an expansion economically viable. Thus the model is constrained to evaluate pipeline expansions in four-year blocks: 2025, 2028 and 2033, 2037. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility's upgrade and the LNG distribution system upgrade were made available in two year increments since these resources are PSE assets.

Natural Gas Portfolio Sensitivities

Figure 5-35: 2021 IRP Natural Gas Portfolio Sensitivities

2019 IRP NATURAL GAS ANALYSIS SENSITIVITIES		
A	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
B	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
C	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
D	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
E	Temperature Sensitivity on Load	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.

A. AR5 Upstream Emissions

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

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology.

SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology.

B. 6-Year Conservation Ramp Rate

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

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

SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

C. Social Discount Rate for DSR

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

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

D. Fuel Switching, Gas to Electric

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

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

E. Temperature Sensitivity

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

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

(CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council's climate model.