2021 PSE Integrated Resource Plan

Chapters 1-9

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DRAFT

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PSE PUGET SOUND ENERGY

2021 PSE Integrated Resource Plan

About PSE

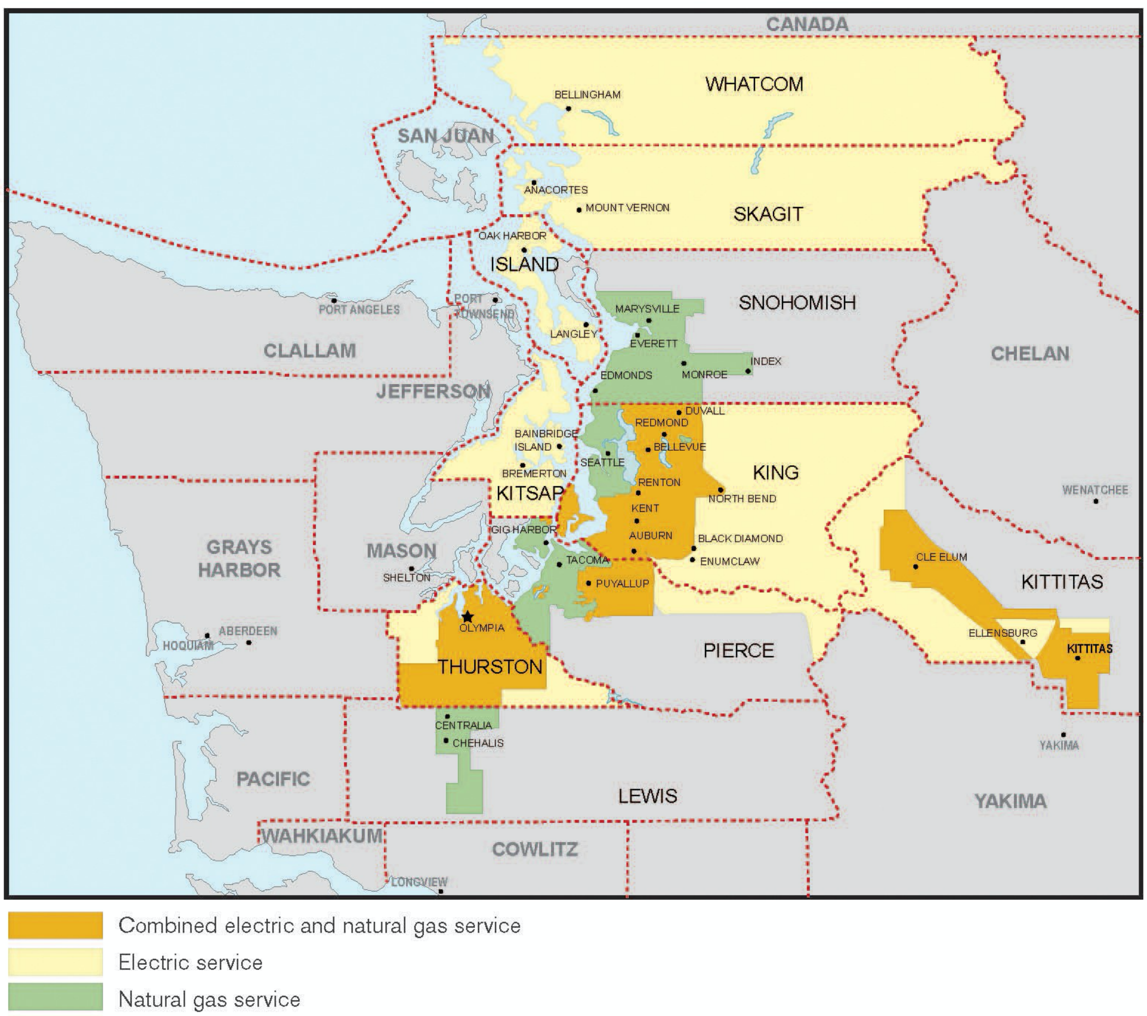
As Washington state's oldest local energy company, Puget Sound Energy serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south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

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

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

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

Figure i-1: PSE's Service Area



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Executive Summary

The IRP is best understood as a thorough analysis of a range of potential future resource portfolios, considering customer energy needs, policies, resource costs, economic conditions and the physical energy system. From this comprehensive view of many different futures, PSE identifies the actions which best balance cost and risk, while meeting both policies and customers' energy needs. Forecasts and plans will change as the future unfolds and conditions change, which is part of PSE's commitment to ensure ongoing reliable, safe, affordable and equitable energy for its customers.

Contents

1. OVERVIEW

PSE is excited to share the first draft resource plan that meets the Clean Energy Transformation Standards and supports all PSE customers in benefitting from a transition to clean energy at the lowest reasonable cost. The draft electric plan:

a. Eliminates all coal-fired resources from meeting PSE customers' electricity needs by the end of 2025.
b. Provides greenhouse gas neutral electricity starting in 2030 through the end of 2044 through the addition of renewable resources.
c. Maximizes cost-effective, reliable conservation and prioritizes distributed energy resources and demand response.

In meeting the Clean Energy Transformation Standards and the requirements of the Clean Energy Transformation Act (CETA), the electric resource plan prioritizes cost-effective, reliable conservation and demand response, distributed and centralized renewable and non-emitting resources, at the lowest reasonable cost to our customers. Through this portfolio, the draft electric resource plan achieves significant carbon reductions, reducing carbon from PSE's electric supply by over 70 percent in direct emissions by 2029, and achieving carbon neutrality by 2030 through energy transformation projects. While implementing this highly decarbonized portfolio, the plan maintains safety, reliability and resource adequacy.

The natural gas resource plan calls for increased and continued conservation investment, which will eliminate the need to lock our natural gas customers into lengthy contracts to expand regional pipeline infrastructure. PSE is exploring the most cost-effective approaches to reduce the overall greenhouse gas emissions from the natural gas system. Further analysis is required to understand reductions in greenhouse gas emissions that may be achieved from cost-effective electrification opportunities and low-carbon gaseous fuels, which have not yet been evaluated in this draft IRP. Further analysis of cost-effective electrification opportunities will be evaluated and included in the final IRP.

The draft electric and natural gas plans were developed with stakeholder input over the last eight months. PSE believes that stakeholder input has improved the 2021 IRP. Public and stakeholder engagement is an essential part of developing an IRP and the engagement generated valuable constructive feedback and suggestions from organizations and individuals that helped inform the IRP analysis. The 2021 IRP had significantly enhanced public participation compared to IRPs, and PSE will continue to learn from this experience and enhance public participation in future IRPs.

Between the last stakeholder meeting hosted on December 15, 2020 and the publication of this draft IRP on January 4, 2021, PSE has continued with the portfolio analysis and has been able to make significant progress, which is reflected in the draft preferred resource plan. The portfolio results and materials included in this draft have not all been shared with stakeholders prior to filing due to the timeline; however, PSE looks forward to stakeholder feedback on the new portfolio results and the draft resource plan presented here in meetings scheduled for early 2021. The IRP analysis is continuing, and areas where additional work is planned between now and the final IRP are summarized below in the “Next Steps” section of the Executive Summary.

The draft IRP is an important step in the public process. PSE will obtain public comments in writing from the Washington Utilities and Transportation Commission (WUTC) and at an upcoming open meeting hosted by the WUTC, and this feedback will be considered in drafting the final IRP, due in April 2021. The draft 2021 IRP is a work in progress. PSE is committed to continuing to improve planning and implementation through this 2021 process and in the years ahead.

The Resource Planning Process

The IRP/Clean Energy Action Plan (CEAP) process evaluates a range of potential futures and identifies the preferred portfolio as the lowest reasonable cost combination of energy conservation, distributed resources and utility-scale supply resources to meet the future needs of our customers. Specific energy efficiency, supply-side resource, distributed resource decisions and implementation of customer programs are not made in the context of the IRP.

The portfolio analysis presented in the IRP is best understood as a forecast of resource additions that appear to be cost effective given what we know today about the future. Advancement in technologies, increased renewable fuel supply options, lower resource costs, new policies, wholesale market evolution and other elements will change these forecasts.

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan (CEIP) and the resource acquisition process. Informed by the IRP/CEAP, the CEIP will prescribe four-year targets for resources, programs, and enabling systems by incorporating more accurate costs and feasibility for programs and projects, as well as the equitable distribution of benefits to customers.

Next Steps

This draft IRP is published three months before the final IRP. The final proposed IRP and CEIP rules were adopted on December 28, 2020, just days before this filing is due. There are several important components of the analysis that are not yet complete; these are summarized below. Both the analysis and the public participation process continue into early 2021. PSE plans to complete the remaining analysis and solicit stakeholder input in two upcoming public meetings, in addition to obtaining feedback from the WUTC's recessed open meeting and written comment period. Once all of the analysis is completed, the Preferred Portfolio, CEAP and Action Plans will be updated and finalized. The WUTC reviews and acknowledges the final IRP after it is filed. The analysis, assessments and evaluation still to be completed for the final IRP are as follows.

- **SCENARIOS AND SENSITIVITIES**. The IRP uses scenarios and sensitivities to evaluate a range of possible future conditions. Stakeholders played an important role in developing the sensitivities in this IRP, as documented in Appendix A. Portfolio results are available for many scenarios and sensitivities in Chapter 8. However, some important sensitivities are yet to be completed, including a gas-to-electric fuel conversion sensitivity and a temperature sensitivity designed to capture climate change impacts on demand. As these results are analyzed, PSE may evaluate additional portfolio sensitivities.
- **MARKET RELIANCE ANALYSIS**. An analysis of short-term and long-term market purchases to meet long-term peak planning will be available in the final IRP. This analysis will inform the degree to which PSE should rely on market purchases for peak capacity planning.
- **ECONOMIC, HEALTH AND ENVIRONMENTAL ASSESSMENT OF CURRENT CONDITIONS.** The methodology and approach for this assessment is described in Appendix K, which builds on the Department of Health's Washington Tracking Network. The assessment is informed by discussions of the Department of Health's draft Cumulative Impact Analysis (the final Cumulative Impact Analysis is not yet available). This adds new elements to consider in determining the lowest reasonable cost analysis, as required by CETA.
- **STOCHASTIC ANALYSIS**. To assess the risk of changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant-forced outages, and to observe how costs change across portfolios, PSE will complete the stochastic analysis for the final IRP.
- **FLEXIBILITY ANALYSIS**. The flexibility analysis explores the sub-hourly flexibility needs of the portfolio and determines how new and existing resources contribute to meeting those needs. PSE presented the draft flexibility analysis modeling approach and results to stakeholders on December 15, 2020 and solicited stakeholder feedback. PSE has met with stakeholders regarding the analysis and is still in the process of incorporating that

feedback. The final flexibility results will be included in the updated portfolio analysis for the final IRP.

- **MAXIMUM CUSTOMER BENEFIT SCENARIO**. This is a new scenario and PSE is working with the WUTC to understand the expectations and realistic options for completing this scenario in the 2021 IRP. Further guidance is required from the WUTC to understand the details of the scenario.
- **ENERGY ASSISTANCE ASSESSMENT.** By July 31, 2021, PSE will provide an assessment to the Department of Commerce of mechanisms pertaining to energy assistance, as well as progress toward meeting customer energy assistance need. Existing PSE programs include bill assistance and weatherization services. Currently, PSE does not have any distributed energy resource (DER) programs as part of its energy assistance strategy. However, in future years, there may be programs and mechanisms that could be used to meet customer energy assistance need, and those programs will be considered and incorporated into the IRP as indicated in draft WAC 480-100-610(3). In examining energy assistance need, PSE will continue review of its recently completed Low-income Needs Assessment. In addition, PSE will conduct further qualitative research and analysis to better understand the barriers to serving low-income customers in order to encourage further participation of income-eligible households in the weatherization and bill assistance programs.
- **AVOIDED COST ANALYSIS.** An analysis of the avoided cost estimate for energy, capacity, transmission, distribution and greenhouse gas emissions will be included in the final IRP.

2. ELECTRIC PREFERRED PORTFOLIO

PSE's commitments to reducing greenhouse gas emissions and maintaining affordability and reliability for PSE customers are embodied in the draft preferred portfolio.

The IRP analyzes a range of potential future resource portfolios to identify the least cost, least risk portfolios that meet energy needs while ensuring reliability and incorporating policy requirements. The resource plan should be interpreted as a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource and technology trends today.

This section describes the draft preferred portfolio and how it meets PSE's electricity needs. The draft preferred portfolio is one of a range of portfolios that PSE modeled for this IRP that meets the Clean Energy Transformation Standards. The inputs were developed through an evaluation of portfolio results from stakeholder-selected sensitivities and tested against the least cost portfolio selected by the deterministic portfolio analysis. Deterministic portfolio analysis assumes perfect foresight about the future, so to assess the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages PSE also performs a stochastic portfolio analysis that will be completed for the final IRP. For a comparison of the resource additions, costs and emissions from the portfolios evaluated so far, see Chapters 3 and 8.

Electric Resource Need

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: (1) peak hour capacity for resource adequacy, i.e., does PSE have the amount of capacity available in each hour to meet customer's electricity needs; (2) hourly energy, i.e., does PSE have enough energy available in each hour to meet customer's electricity needs; and (3) renewable energy, i.e., does PSE have enough renewable and non-emitting resources to meet the annual delivered load.

To ensure that peak capacity needs are met, operating reserves provide additional, accessible electricity available fo unexpected conditions. These are required by contract with the Northwest Power Pool and by the North American Electric Reliability Corporation (NERC) to ensure total system reliability in case of unforeseen changes in generation or delivery availability.

As part of meeting energy needs, Washington State has two laws that require electricity to be supplied by renewable resources. The first is a renewable portfolio standard (RPS), enacted in 2006, which requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs). Under the RPS, PSE must meet 15 percent of its energy needs with RPS-qualifying renewable energy. The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA), enacted by the legislature in 2019 and still in rulemaking. CETA requires that the 2030 electric supply be carbon neutral, such that at least 80 percent of Washington state electric sales (delivered load) are met by non-emitting or renewable resources by 2030, and 100 percent of sales must be met with renewable or non-emitting electricity by 2045.

In addition to peak capacity, energy and renewable energy needs, PSE will evaluate sub-hourly flexibility in this IRP. The sub-hourly analytical framework developed for this IRP has been shared with stakeholders to solicit feedback and will be completed for the final IRP.

Electric Peak Hour Capacity Need

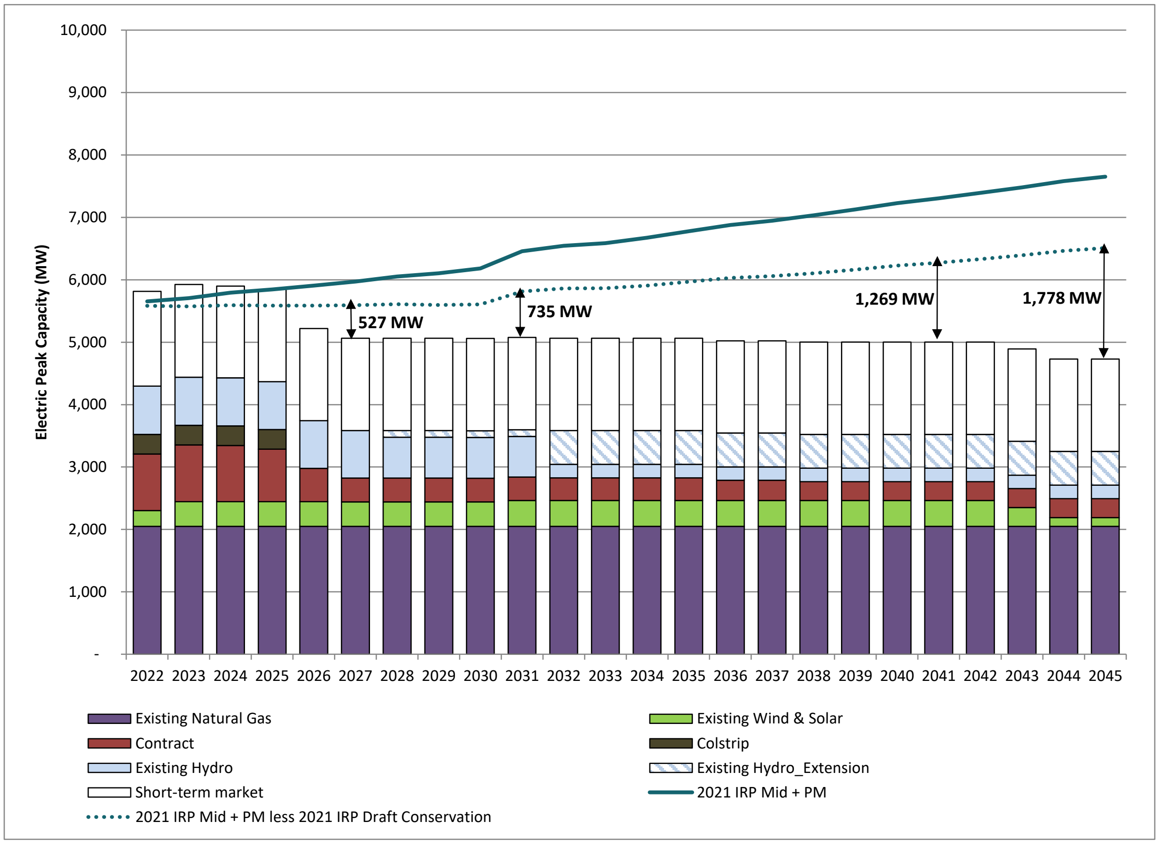
Figure 1-1 compares the existing resources available to meet peak hour capacity[1] with the projected need over the planning horizon. Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW by 2027 and 1,381 MW in 2031 (represented by the teal line). This includes a 20.7 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE's 5 percent loss of load probability (LOLP) planning standard. Figure 1-1 shows a noticeable drop in PSE's resource stack at the end of 2025. The drop is caused by the elimination of Colstrip 3 & 4 from PSE's energy supply portfolio starting in 2026, which removes approximately 370 MW of capacity, and the expiration of PSE's 380 MW coal-transition contract with TransAlta when the Centralia coal plant is retired at the end of 2025.[2]

Cost-effective, reliable demand-side resources (DSR) play an important role in moderating the need to add supply-side resources in the future. This can be seen in the dashed teal demand line in Figure 1-1. The dashed line includes the benefit of DSR, which reduces peak need in 2027 from 907 MW to 527 MW.

The peak capacity deficit assumes that 1,500 MW of market purchases is available to meet peak capacity need. Further analysis of market availability is forthcoming in the final IRP and may change PSE's electric peak hour capacity need.

1 / Resource capacities illustrated here reflect the contribution to peak, not nameplate capacity. Refer to Chapter 7, Resource Adequacy Analysis, for how peak capacity contributions were assessed.
2 / PSE entered the coal transition contract with Transalta under RCW 80.80 to facilitate the retirement of the only major coal-burning power plant in Washington state.

Figure 1-1: Electric Peak Hour Capacity Resource Need after Cost-effective Demand-side Resources



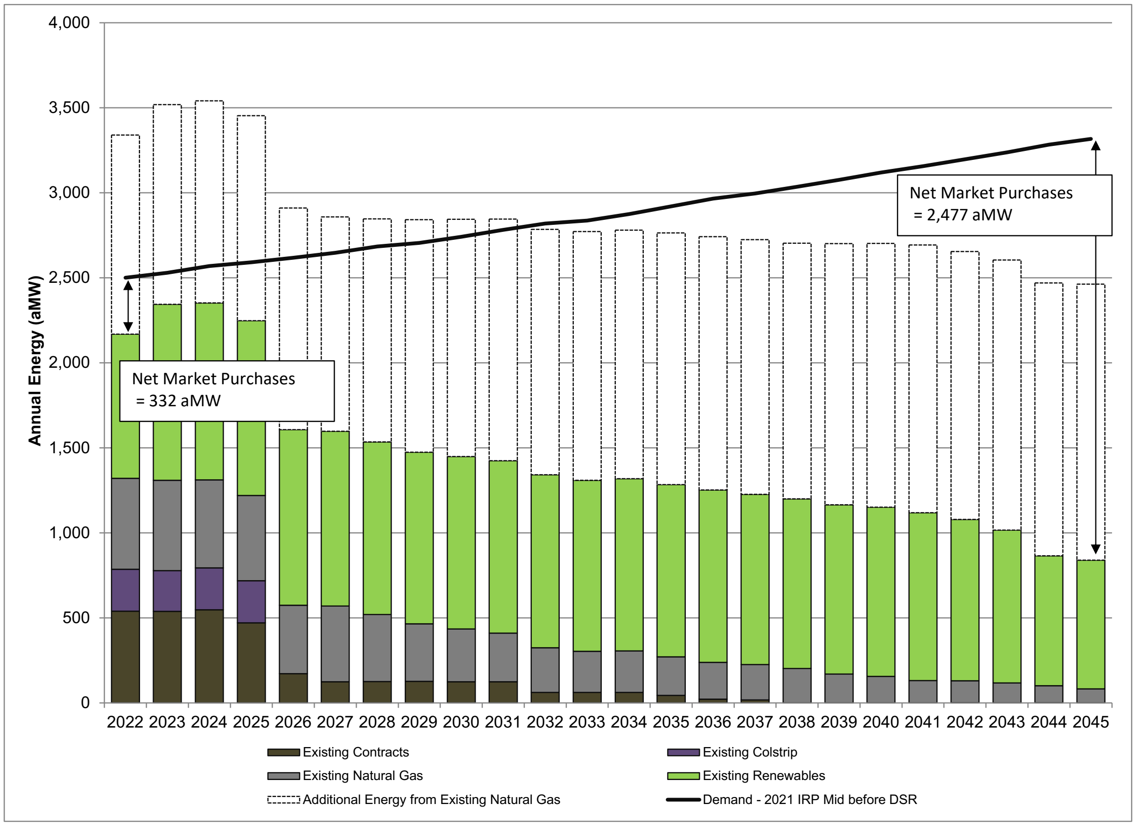
Electric Energy Need

Customers' energy need must be met every hour. PSE's analytical models require portfolios to supply the amount of energy needed to meet physical loads, and also examine how to do this most economically through existing resources, new resources, and purchasing and selling energy from the wholesale market at the Mid-C trading hub.

PSE's existing portfolio of supply-side and demand-side resources could generate more energy than needed to meet load on an hourly basis through to 2031; however, it is often more cost-effective to purchase wholesale market energy than dispatch our existing resources. To model how PSE may make these dispatch or purchase decisions in the future, we do not constrain the model to dispatch resources that are not economic; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. In recent years, the region has experienced periods of high price volatility and limited market liquidity. This presents a potential future risk for PSE's customers, and PSE may have to adjust its market purchase strategy going forward. PSE is evaluating the potential impacts of market purchases becoming unavailable to the portfolio. The full analysis will be available in the final IRP.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the Mid Scenario presented in Chapter 5, Key Analytical Assumptions. The white dashed box at the top of each bar indicates the total energy available from PSE's thermal resources if they were run without regard to economic dispatch. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2031.

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



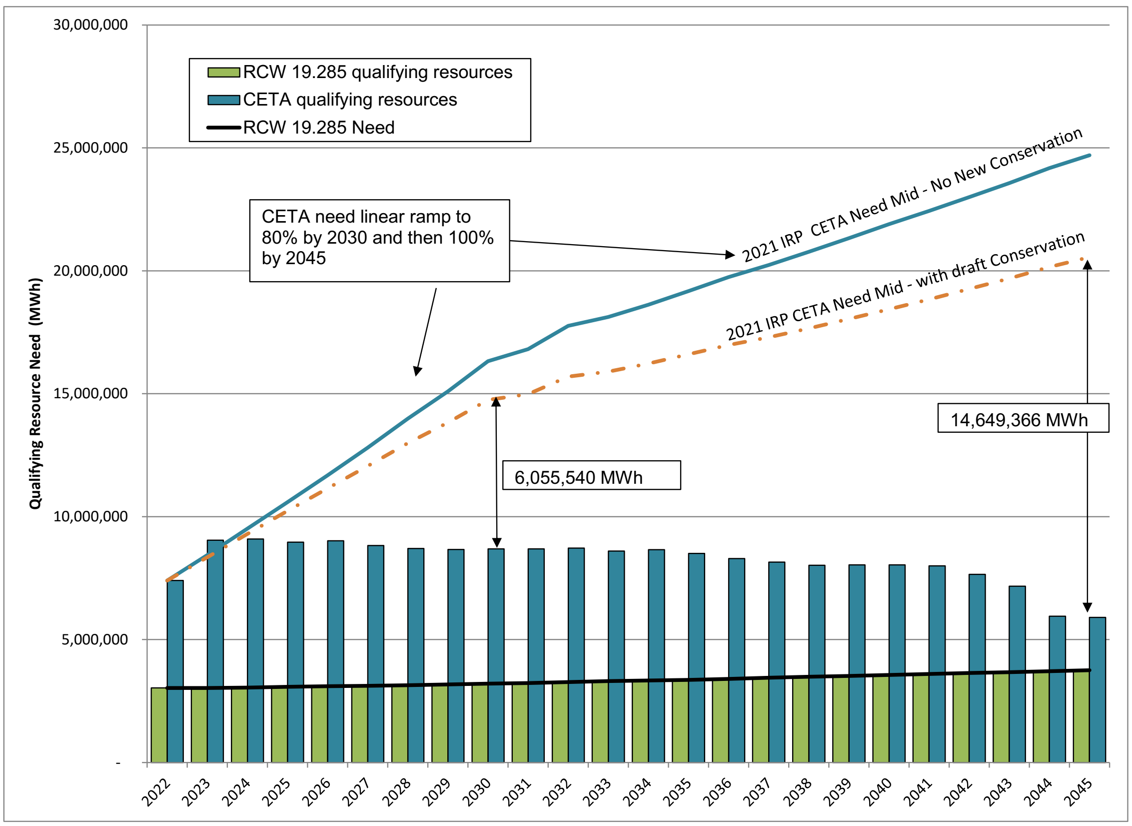
Renewable Need

In addition to reliably meeting the physical needs of our customers, RCW 19.285 – the Washington State Energy Independence Act – establishes three specific targets for qualifying renewable energy, commonly referred to as the state's renewable portfolio standard. Sufficient "qualifying renewable energy" must equal at least 3 percent of retail sales in 2012, 9 percent in 2016, and 15 percent in 2020. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades to existing hydro plants. PSE has sufficient qualifying renewable resources to meet RPS requirements.

Washington State's Clean Energy Transformation Act (CETA) requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting or renewable resources by 2030 and 100 percent by 2045. Demand-side resources decrease electric delivered load, which then decreases the amount of renewable resources needed. One important difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can also be used to meet CETA requirements.

Figure 1-3 illustrates the renewable energy need for both RCW 19.285 and CETA based on the 2021 IRP mid demand forecast. PSE assumed a linear ramp to achieve the Clean Energy Transformation Standards. Figure 1-3 shows the renewable need with draft 2021 IRP cost-effective conservation, which includes energy efficiency, codes and standards, distribution efficiency and customer-owned solar PV. By including these conservation resources, PSE's need for new renewable or non-emitting resources in 2030 drops from 7.6 million MWh to 6.1 million MWh to achieve an 80 percent renewable or non-emitting resource portfolio.

Figure 1-3: Renewable Need after Cost-effective Demand-side Resources



Electric Preferred Portfolio

As explained above, the lowest reasonable cost portfolio produced by the IRP analysis is not an action plan; rather, it is a forecast of resource additions developed by the modeling that appears most cost effective in the future, given the resource and market trends observed today.

As discussed earlier, several components of the IRP analysis will be completed for the final IRP, due to be filed with the WUTC on April 1, 2021. The preferred portfolio presented in this section may change once all of the analyses are complete.

Figure 1-4 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 24 years. This forecast is the "integrated resource planning solution."[3] It reflects the lowest reasonable cost portfolio of demand- and supply-side resources that meets the projected capacity, energy and renewable resource needs described above.

There are many exciting changes in the resource outlook:

- **ACCELERATED ACQUISITION OF ENERGY CONSERVATION**. This plan includes aggressive, accelerated investment in helping customers use energy more efficiently.
- **EMERGENCE OF DISTRIBUTED ENERGY RESOURCES**. Distributed energy resources, such as battery energy storage and rooftop as well as ground-mounted solar, play an important role in balancing large-scale utility investments and transmission constraints. They may also meet specific, long-term needs identified on the transmission and distribution system.
- **INCREASED DEMAND RESPONSE**. Compared to previous plans, increased demand response appears as a cost-effective resource earlier in the planning horizon.
- **NEED FOR FLEXIBLE, DEPENDABLE CAPACITY**. 750 MW of coal is removed from PSE's portfolio in 2026, which creates a large capacity deficit. While utility-scale renewable resources, distributed energy resources and demand response all contribute to meeting peak hour capacity need, additional flexible capacity is needed to maintain an adequate resource system.
- **SIGNIFICANT INVESTMENTS IN RENEWABLE RESOURCES**. Meeting the clean energy transformation standards will take large amounts of utility-scale renewable resources located both inside and outside of Washington state. Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest because it provides a higher contribution to peak capacity needs.

3 / Chapter 3 includes a detailed explanation of the reasoning that supports each element of the preferred portfolio.

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

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Demand Side Resources	256 MW	360 MW	1,168 MW	1,784 MW
Battery Energy Storage	75 MW	125 MW	550 MW	750 MW
Solar - ground and rooftop	80 MW	150 MW	450 MW	680 MW
Demand Response	10 MW	161 MW	44 MW	215 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DER	443 MW	820 MW	2,284 MW	3,547 MW
Renewable Resources	600 MW	1,100 MW	2,762 MW	4,462 MW
Flexible Capacity	0 MW	237 MW	711 MW	948 MW

Demand-side Resources (DSR): Energy Efficiency

The draft IRP analysis looks at the amount of energy efficiency that is cost effective to meet the portfolio's capacity and energy needs, optimizing lowest cost against distributed and centralized resources. PSE's draft analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy to meet the renewable requirements. Analysis in this IRP applies a 10-year ramp rate for acquisition of DSR discretionary measures. Demand-side resources include energy efficiency, the Washington State Energy Code (WSEC) and federal and state equipment codes and standards, distribution efficiency and the customer-owned solar PV forecast.

Distributed Energy Resources: Battery Energy Storage

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

Distributed Energy Resources: Solar–Ground-mounted and Rooftop

Distributed solar was modeled as a residential-scale resource in western Washington. Although utility-scale solar is a lower cost option for meeting CETA renewable requirements, given the transmission constraints outside of PSE's service territory, distributed solar resources have become an important part of the plan. PSE modeled both ground-mounted and rooftop solar as an option to both help meet CETA and help with local distributed solutions.

Distributed Energy Resources: Demand Response

This IRP includes 16 potential demand response programs available in PSE service territory. The preferred portfolio includes 14 of the 16 programs, which means that 215 MW of the total 222 MW of available demand response nameplate capacity is included. The only two programs not included cost over $300/kw-yr. The model selected four of the programs starting in 2022 and the remaining ten programs starting in 2025. The first four programs were part of the least cost optimization in most of the portfolio sensitivities. Demand response takes a couple of years to set up before savings are achieved, so although these four programs start in 2022, the total nameplate by 2025 is only 10 MW. As the demand response programs are gradually ramped, they grow to 150 MW nameplate by 2030 and 215 MW nameplate by 2045. The demand response programs in the 2021 IRP demand response assessment have been maximized for all but 7 MW of the total potential savings. A new assessment will be completed for the next IRP, which will capture new demand response developments and technologies.

Delivery System Planning (DSP) Non-Wire 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 advantage 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 in how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

Renewable Resources

The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources do contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio that relies on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up portfolio costs. Wind was modeled in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and off the coast of Washington. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States, including eastern and western Washington, Idaho and Wyoming.

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest because it offers higher capacity value and brings resource diversity to supply. However, existing transmission constraints also impact the availability of resources to serve load. Given these transmission constraints, resources located outside of the Pacific Northwest region are limited. After the Montana and Wyoming wind, costs between eastern Washington wind and solar are very close.

Flexible Capacity

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

Transmission Constraints

Transmission capacity constraints have become an important modeling consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet clean energy transformation targets. In contrast to thermal resources, 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 that depend on local wind or solar conditions, therefore they cannot always follow load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak capacity needs as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory. Transmission within PSE service territory will be needed, but was assumed unconstrained due to delivery system planning processes and specific identified projects.

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

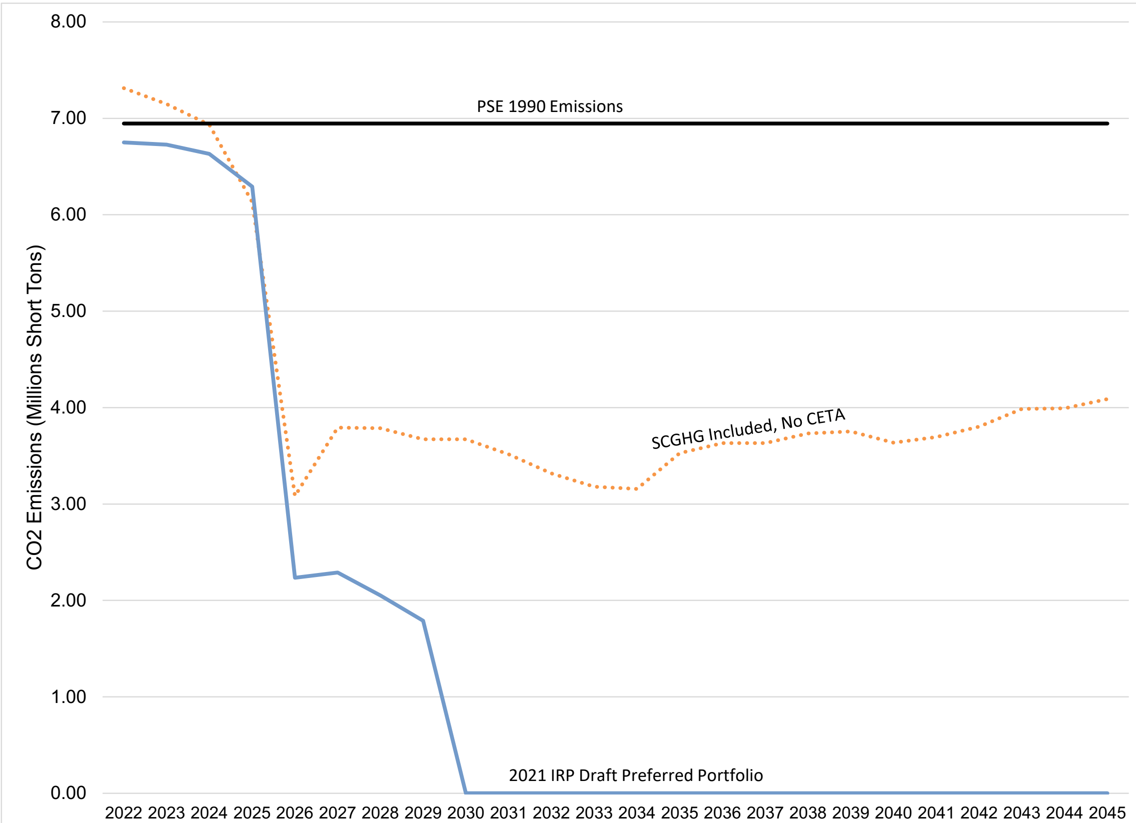
Carbon Emissions and Portfolio Costs

Portfolio Carbon Emissions Associated with Electric Service

The draft preferred portfolio achieves significant emission reductions, as shown in Figure 1-5. There is a substantial drop in emissions at the end of 2019, with the retirement of Colstrip 1 & 2. In 2026, there is another significant decrease in emissions due to the exit of Colstrip 3 & 4 and the end of the coal-transition contract with TransAlta, along with a significantly lower economic dispatch of existing fossil-fueled resources. Altogether this reduces total portfolio emissions by more than 60 percent by 2029. Market purchases are not included in the calculation of direct emissions, because the specific resources used to meet the market purchases are unknown, and PSE does not want to assume a fixed emission rate which will in fact change over time.

From 2030 through to 2045, alternative compliance options can be used to satisfy up to 20 percent of the carbon neutral standard. In 2030, PSE will achieve a carbon neutral electric portfolio. For modeling purposes, alternative compliance mechanisms are represented through renewable energy credits and included as an associated cost. However, actual compliance may be met through renewable resources, energy efficiency, unbundled RECs or transformation projects.

Figure 1-5: Projected Annual Total PSE Portfolio CO_2 Emissions and Savings from Conservation

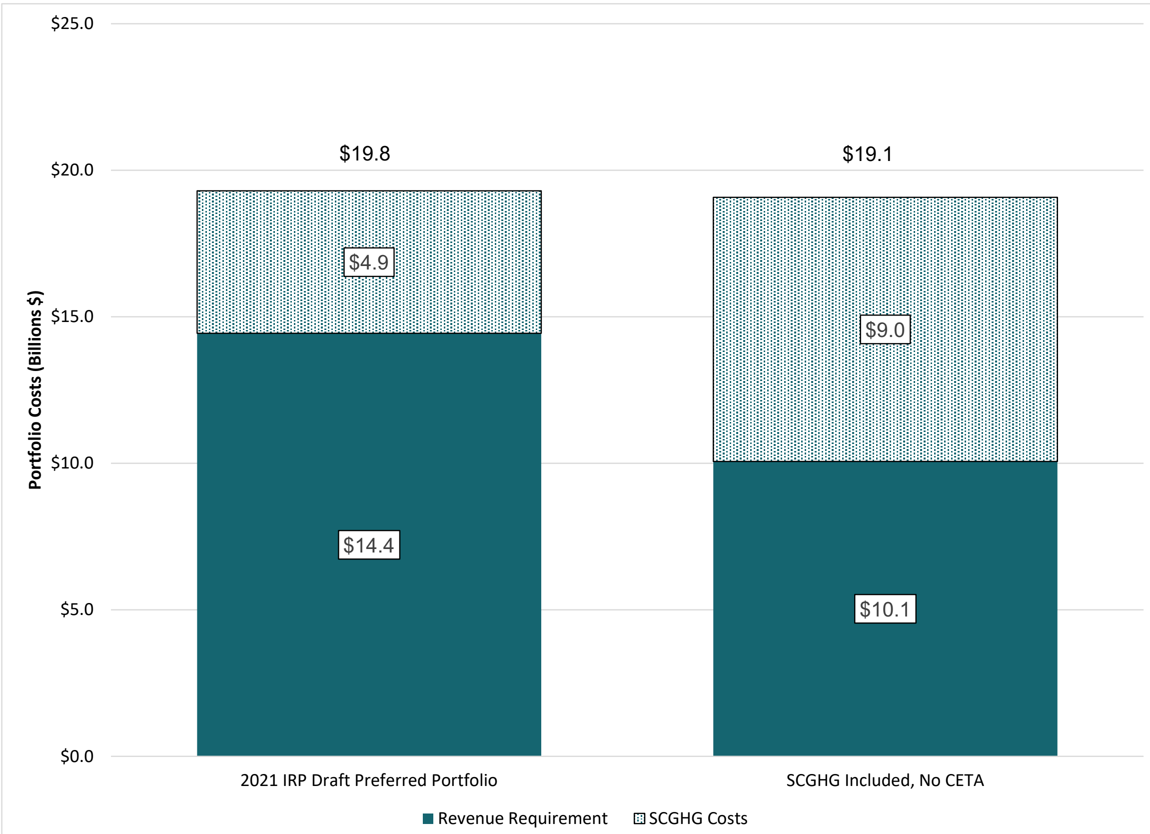


Portfolio Costs

The long-term outlook for incremental portfolio costs has been dynamic across IRP planning cycles since 2003, driven by changing expectations about natural gas prices and costs associated with potential carbon regulation. Since the passage of the Clean Energy Transformation Act, it is difficult to compare the 2021 IRP portfolio costs to other IRPs because the regulations have changed so drastically since the 2017 IRP. A more meaningful comparison may be to compare the cost of the preferred portfolio to a portfolio developed using the same modeling framework and underlying assumptions but removing the renewable requirements from CETA. The social cost of greenhouse gases (SCGHG) is used when evaluating resource options and is included in the portfolio modeling as an additional fixed cost of emissions on emitting resources.

Figure 1-6 illustrates how portfolio costs change without CETA. The SCGHG is shown as a separate cost in the light teal bar on top of the solid teal bar.

Figure 1-6: Portfolio Costs Comparison



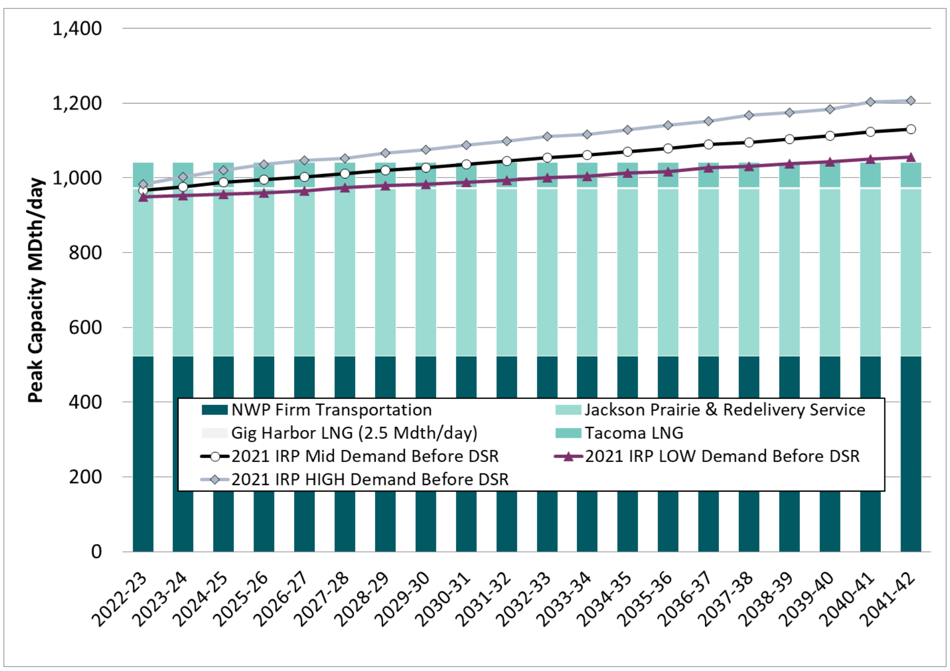
3. NATURAL GAS SALES PREFERRED PORTFOLIO

PSE develops a separate integrated resource plan to address the needs of more than 840,000 retail natural gas sales customers. This plan is developed in accordance with WAC 480-90-238, the IRP rule for natural gas utilities. (See Chapter 9 for PSE's natural gas sales analysis.)

Natural Gas Sales Resource Need – Peak Day Capacity

Natural gas sales resource need is driven by design peak day demand. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD). Like electric service, gas service must be reliable every day, but design peak drives the need to acquire resources. Figure 1-7 illustrates the load-resource balance for the gas sales portfolio. The chart demonstrates PSE has a small resource need beginning in the winter of 2031/32.

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



Natural Gas Sales Resource Additions Forecast

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

Figure 1-8: Gas Resource Plan Forecast, Cumulative Additions in MDth/Day of Capacity

	2025/26	2030/31	2041/42
Conservation (DSR)	21	53	107

Demand-side Resources (DSR)

Analysis in this IRP applies a 10-year ramp rate for acquisition of DSR measures. Analysis of 10- and 20-year ramp rates in prior IRPs has consistently found the 10-year rate to be more cost effective. Ten years has been chosen because it has aligned with the amount of savings that can practically be acquired at the program implementation level; however, this IRP also tests a sensitivity that models an accelerated 6-year ramp rate.

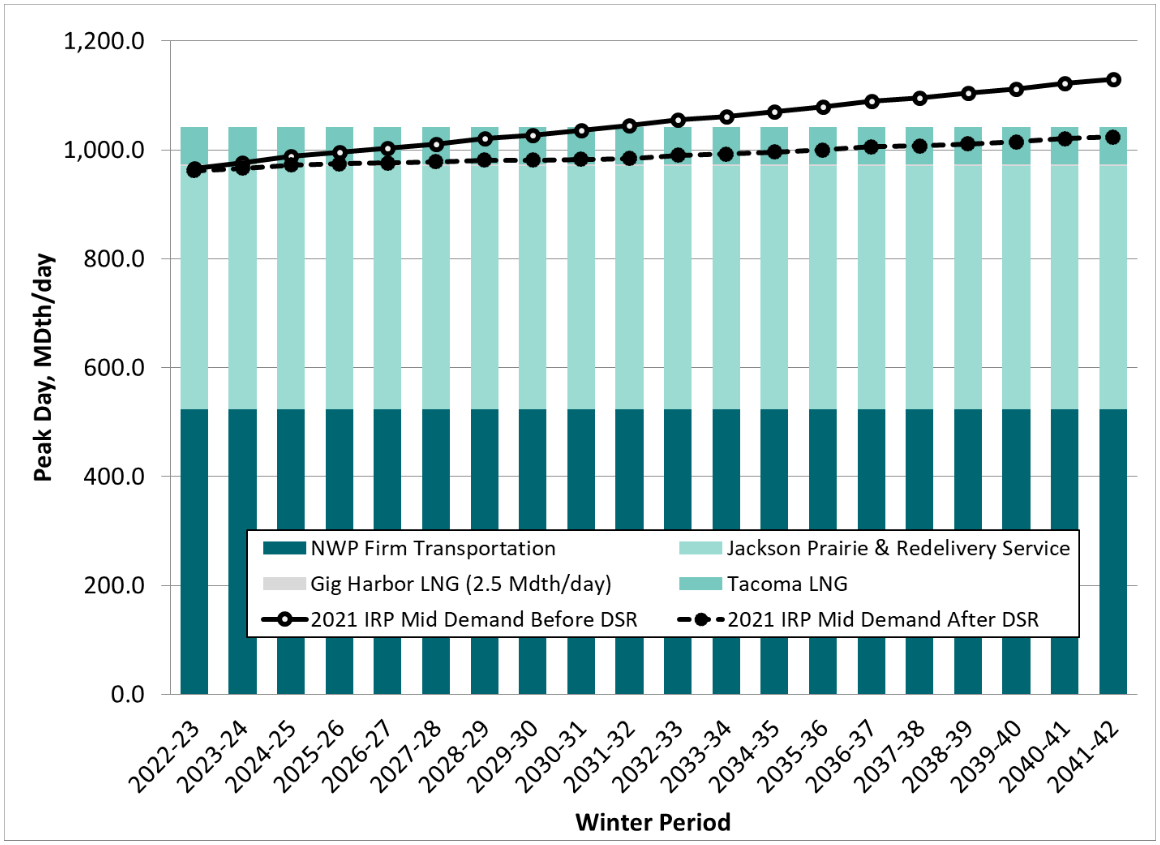
Carbon costs have a big impact on the amount of cost-effective DSR. In the 2021 IRP carbon costs are significantly higher relative to natural gas prices, which is a function of both declining natural gas prices and higher carbon cost assumptions resulting from carbon legislation passed in the state of Washington in 2019, RCW 80.28.380. This legislation requires the inclusion of SCGHG and upstream related carbon emissions in determining cost-effective conservation. These two adders result in a total natural gas cost that is more three times the cost of the natural gas itself, which almost doubles the cost-effective conservation compared to current targets.

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

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

The important role that cost-effective, reliable demand-side resources play in moderating the need to add supply-side resources in the future can be seen in the dashed black demand line in Figure 1-10.

Figure 1-10: Natural Gas Sales Resource Plan



4. ACTION PLANS

The electric and natural gas Action Plans will be presented in the final IRP on April 1, 2021.

5. THE IRP, RESOURCE ACQUISITIONS AND THE CLEAN ENERGY IMPLEMENTATION PLAN

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan (CEIP), as well as for the acquisition process. The formal RFP processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and self-build (or PSE demand-side resource programs) should also be considered when making prudent resource acquisition decisions.

The CEIP will build on the IRP analysis and CEAP and add near-term detail concerning resource portfolio assumptions, modeling, sensitivities and costs. The models used in the IRP consider groups of resources with generic pricing for a 24-year outlook. The CEIP, which focuses on the next four years, will update the resource portfolio modeling by including the CEIP planned investments. The CEIP will use costs based on specific resources and program information, where available. These costs may be derived from projects submitted through the RFP process or through other program plans, though this ability will be limited in the at first due to the compressed timeline of the current planning cycle after the CEIP rulemaking.

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

2 Clean Energy Action Plan

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

Contents

1. OVERVIEW

The Clean Energy Action Plan (CEAP) provides a 10-year outlook, refining the IRP resource plan. Per RCW 19.405.060, the Clean Energy Implementation Plan (CEIP) will be informed by the CEAP in developing a plan for specific targets, interim targets and specific actions over a 4-year period. The CEIP will prescribe the target resources, programs, and enabling systems aligned with the IRP/CEAP.

The content of the CEAP is specifically defined as per WAC 480-100-620 Section 12 of the final proposed rules for the IRP and CEIP Rulemaking Dockets UE-191023 and UE-190698. At the time of this draft, some topics remain unresolved and the rules are not yet in effect. The Clean Energy Transformation Act (CETA) introduced the CEAP as a new aspect of the IRP to identify likely action over the next 10 years. This is the first IRP that includes the draft CEAP. As PSE gains clearer understanding and stakeholder feedback for the CEAP, PSE will refine the CEAP in time for the April 1, 2021 final IRP. As with any new requirement or assessment, the CEAP will evolve over time, and future IRPs will benefit from the lessons learned in this first implementation of the new planning process. PSE looks forward to stakeholder feedback on this draft CEAP.

2. EQUITABLE TRANSITION TO CLEAN ENERGY

Assessment of Current Conditions

CETA sets out important new planning standards that require utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, an Economic, Health and Environmental Benefits Assessment is performed to provide guidance in the development of the utility's CEAP and CEIP. The purpose of the assessment is two-fold: first, to identify and quantify to the extent possible the existing conditions for all customers, and second, to identify disparate impacts to communities within and around PSE's service territory that are affected by resource planning. By incorporating the assessment, the utility can propose actions and programs that are not simply lowest reasonable cost, but also distribute benefits equitably among customers.

The assessment will identify specific metrics and be informed by the cumulative impact analysis from the Washington State Department of Health. The Washington State Department of Health anticipates completing the cumulative impact analysis by the end of December 2020; the results of that study will be reported in the final 2021 IRP filing.

While the cumulative impact analysis is not complete, PSE has worked to incorporate existing information into the assessment for this IRP. PSE presented this information at the November 2020 IRP meeting and solicited stakeholder feedback through a series of questions designed to inform the assessment, and this feedback has been incorporated. Based on the feedback received and the availability of the cumulative impact assessment from the Department of Health, PSE will develop initial set of metrics to quantify existing conditions observed across PSE's customers in order to evaluate disparities between populations within the customer base. The assessment will be available in the final IRP.

PSE recognizes the importance of developing a process where all voices are included and heard and acknowledges that the IRP public participation process is the first incremental step in stakeholder feedback on the assessment. Many populations and communities are not represented in the IRP public participation process. This is an important part of the evolution of the utility planning process, and PSE anticipates additional engagement through the CEIP process, as well as in future IRP cycles.

Role of the Equity Advisory Group

PSE will establish an Equity Advisory Group to provide specific input on the first CEIP, due in 2021, as well as the implementation of that plan. In future planning cycles, the input of the Equity Advisory Group will be important to incorporate starting with the planning for the IRP process. This will be an important area of learning and improvement through the entire planning cycle from IRP through to the CEIP. For this IRP, due to the timing of the rulemaking and establishment of the Equity Advisory Group, PSE will incorporate feedback as much as possible without the Equity Advisory Group in place yet.

Developing Customer Benefit Indicators

An assessment of current conditions must be completed before customer benefit indicators are developed. The assessment informs the development of the CEAP and the CEIP. Under the draft rules, indicators are specifically developed during the CEIP. Feedback on indicators for this first planning cycle under CETA will be captured through the CEIP. The initial qualitative and quantitative metrics developed through the assessment give a snapshot in time of specific measures related to economic, health, environmental, and energy security and resiliency impacts. Indicators will be evaluated over time to measure progress tied to an attribute of a resource or a program. As the assessment is completed and metrics and indicators are developed, PSE will be able to identify specific actions to ensure equitable distribution of benefits and reduction of burdens in the final IRP.

3. CLEAN RESOURCE ADDITIONS 10-YEAR SUMMARY

Conservation Potential Assessment

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

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP. While these were evaluated through the CPA process for this IRP, the CEIP establishes specific targets for renewable energy, energy efficiency and demand response, and may evaluate programs aligned with those categories to better reflect and evaluate the targets.

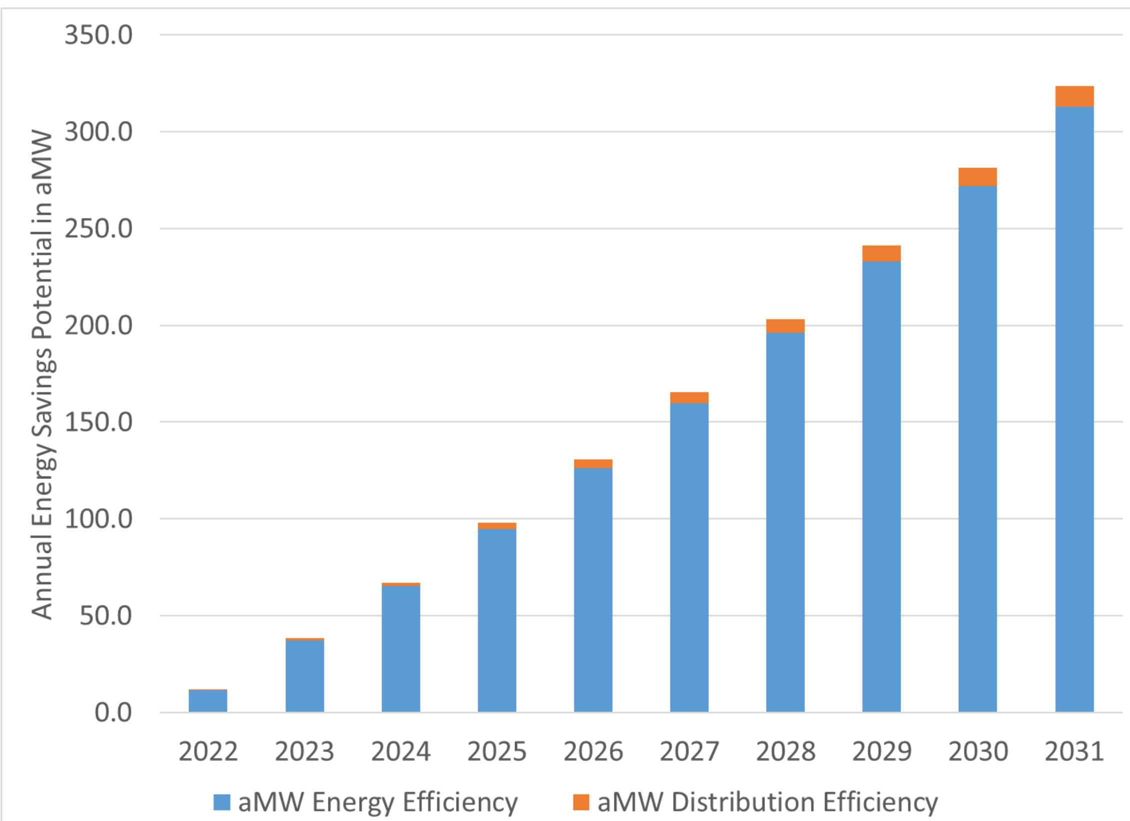
- **ENERGY EFFICIENCY MEASURES.** This includes a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, lighting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

Figure 2-1: 10-year Demand Side Resource Savings

Demand-side Resources	Nameplate (MW)	Energy Savings in 2031 (aMW)	Peak Sapacity in 2031 (MW)
Energy Efficiency	458 MW	266 aMW	458 MW
Distributed Generation: Solar PV	58 MW	7 aMW	1 MW
Distribution Efficiency	12 MW	11 aMW	12 MW
Codes and Standards	169 MW	93 aMW	177 MW

NOTES
1. Demand response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency.

Figure 2-2: Electric Achievable Technical Potential Forecast Cumulative 2022 - 2045



The draft IRP analysis looks at the amount of energy efficiency that is cost effective to meet the portfolio's capacity and energy needs, optimizing lowest cost against distributed and centralized resources. PSE's draft analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy to meet the renewable requirements. Significant changes in avoided cost because of CETA renewable requirements had a huge impact how much conservation could be acquired cost effectively. Because of the large amounts of renewable resources needed, the portfolio is moving into higher cost demand-side resources to meet that need. Conservation lowers the load so that less renewable resources are needed to meet the 100 percent renewable requirement by 2045. Figure 2-3 below is a table of the total nameplate additions of energy efficiency, customer solar PV forecast, distribution efficiency and codes and standards.

Figure 2-3: Cost-effective Demand-side Resources

Incremental Nameplate Additions

Nameplate Additions (MW)	2022-2025	2026-2030	2030 Total
Demand-side Resources	256 MW	360 MW	616 MW
Energy Efficiency	157 MW	245 MW	402 MW
Distributed Generation: Solar PV	2.5 MW	37.7 MW	40.2 MW
Distribution Efficiency	3.9 MW	6.3 MW	10.2 MW
Codes and Standards	92 MW	71 MW	163 MW

NOTES
1. Demand Response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency.

Resource Adequacy

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

As an important part of resource adequacy analysis, PSE quantifies the peak capacity contribution of renewable (wind, hydro and solar) resources (its effective load carrying capacity, or ELCC) to assess the amount of peak capacity each resource can reliably provide. ELCC is calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP resource adequacy metric constant. By using this calculation, the capacity contribution of different resources such as wind, solar and hydro can be identified. Energy-limited resources such as batteries and demand response programs use a similar methodology but use expected unserved energy (EUE) metric aligned with the 5 percent LOLP resource adequacy metric because it better captures adequacy impacts of longer duration, which may deplete energy storages. Further details on the resource adequacy metrics and analysis can be found in Chapter 7.

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

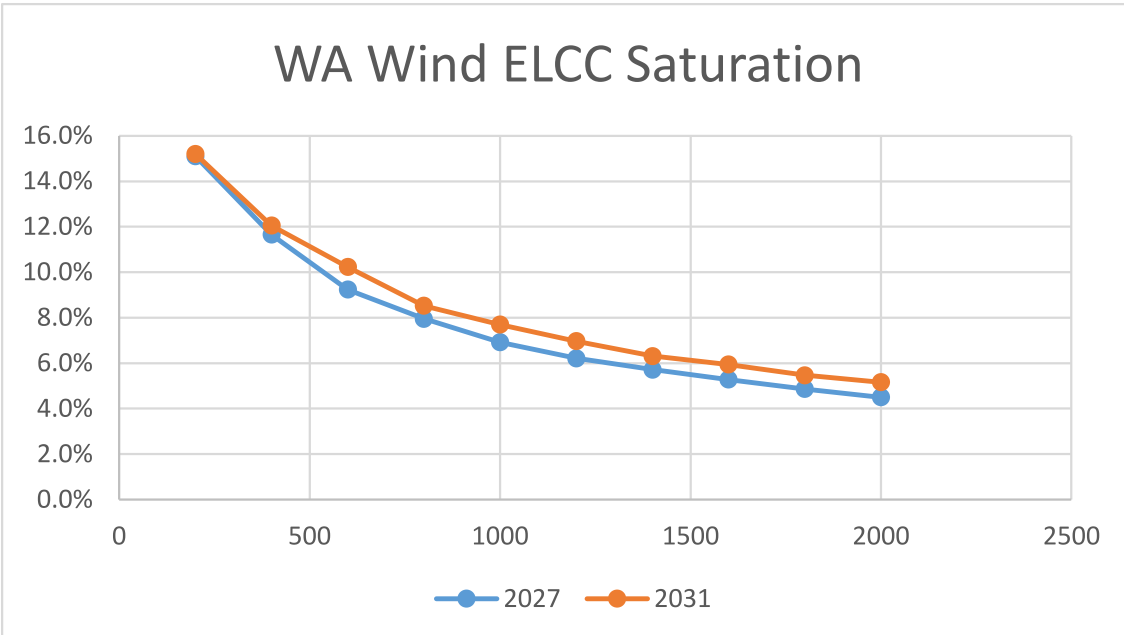
Figure 2-4: Peak Capacity Credit for Wind and Solar Resources

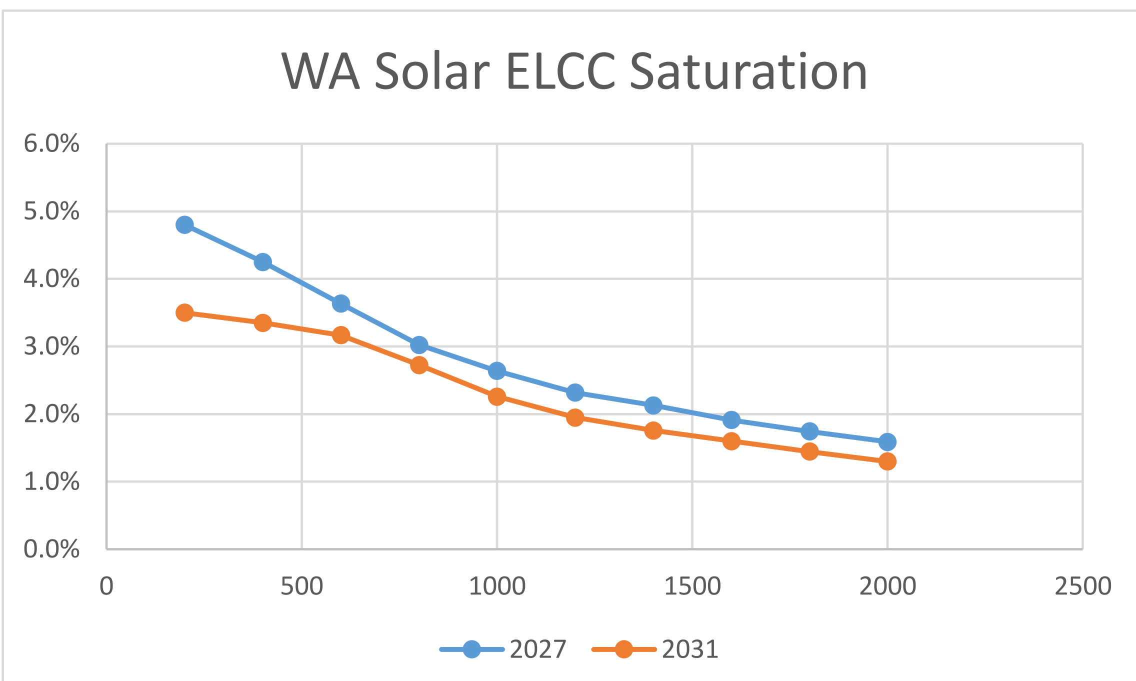
Based on 5% LOLP

WIND AND SOLAR RESOURCES	2021 IRP Year 2027	2021 IRP Year 2031
Existing Wind	9.6%	11.2%
Skookumchuck Wind	29.9%	32.8%
Lund Hill Solar	8.3%	7.5%
Golden Hills Wind	60.5%	56.3%
Generic MT East Wind1	41.4%	45.8%
Generic MT East Wind2	21.8%	23.9%
Generic MT Central Wind	30.1%	31.3%
Generic WY East Wind	40.0%	41.1%
Generic WY West Wind	27.6%	29.4%
Generic ID Wind	24.2%	27.4%
Generic Offshore Wind	48.4%	46.6%
Generic WA East Wind[1]	17.8%	15.4%
Generic WY East Solar	6.3%	5.4%
Generic WY West Solar	6.0%	5.8%
Generic ID Solar	3.4%	4.3%
Generic WA East Solar[1]	4.0%	3.6%
Generic WA West Solar – Utility scale	1.2%	1.8%
Generic WA West Solar – DER Roof	1.6%	2.4%
Generic WA West Solar – DER Ground	1.2%	1.8%

ELCC saturation curves. Figure 2-5 shows a decreasing ELCC as more wind or solar is added in the same region.

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





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

Figure 2-6: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	2021 IRP Year 2027	2021 IRP Year 2031
Lithium-ion, 2 hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-lin, 4 hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4 hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6 hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8 hr, 80% RT efficiency	100	37.2%	43.8%

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response program is also estimated using EUE, since this resource is also energy limited like storage resources. The same methodology was used as for storage resources. The estimated peak capacity contribution of demand response is shown in Figure 2-7.

Figure 2-7: Peak Capacity Credit for Demand Response based on EUE at 5% LOLP

DEMAND RESPONSE	Capacity (MW)	2021 IRP 2027	2021 IRP 2031
Demand Response, 3 hr duration, 6 hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4 hr duration, 6 hr delay, 10 calls per year	100	32.0%	37.4%

Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times requesting them to reduce their energy use. Some program types require action by the customer, whereas others can be largely automated. In an example of an automated program, this might mean that the customer's thermostat automatically warms their home or building earlier than usual. Because of the remote function of demand response, no action is required from customers to initiate their reduction in load, and they can always choose to opt out of an event. In an example of a program type that requires customer action, a wastewater plant may be asked to curtail pumping during certain peak energy need hours if they can operationally do so.

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

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

Figure 2-8 lists the estimated resource potentials for all winter demand response programs modeled for the residential, commercial and industrial sectors during winter. The total DR nameplate achievable potential is 228 MW. The peak capacity credit of demand response programs is shown in Figure 2-7. To illustrate the total impact on system peak, the system peak load is also shown in Figure 2-XX. This system peak was calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019. Further details can be found in Appendix D.

Figure 2-8: Demand Response Achievable Potential and Levelized Cost by Product Option, 2045

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

This IRP evaluated 16 different demand response programs and 14 of those were found to be cost effective. To reflect the time needed to enroll customers in programs, 4 of the programs ramped in starting in 2022 and the remaining 10 programs ramped in starting in 2025. The four programs starting in 2022 were part of the least cost optimization in most of the portfolio sensitivities. Demand response takes a couple of years to set up before savings are achieved, so even with four programs starting in 2022, the total nameplate by 2025 is only 10 MW because of the time it takes to establish the programs and enroll customers. The total DR program size grows to 161 MW nameplate capacity by 2030.

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

Resource Additions (MW)	2022-2025	2026-2030	Total
Demand Response	10 MW	161 MW	171 MW

Renewable Resources

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

Energy storage resources were modeled in combination with the renewable resources. Two battery storage technology systems were analyzed, lithium-ion and flow technology. These systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. Pumped hydro storage 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. PSE analyzed an 8-hour pumped hydro resource. In addition to stand-alone generation and energy storage resources, PSE modeled hybrid resources which combine two or more resources at the same location to take advantage of synergies between the resources. PSE modeled three types of hybrid resources, including eastern Washington solar + 2-hour lithium-ion battery, eastern Washington wind + 2-hour lithium-ion battery, and Montana wind + pumped hydro.

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources out of the Pacific Northwest region are limited. The timing of renewable resource additions is driven by CETA renewable requirements and is shown in Figure 2-10 below.

Figure 2-10: Renewable Resources Incremental Nameplate Capacity

Resource Additions (MW)	2022-2025	2026-2030	Total
Renewable Resources	600 MW	1,100 MW	1,700 MW

Distributed Energy Resources

While the adoption of distributed energy resources (DER) is still low in PSE's service territory, about 1 percent of PSE customers are participating in net metered solar, with an installed capacity of approximately 85 MW. As DER technology evolves and prices decline, customer adoption will increase. DERs will play an important role balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs.

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

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

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

NON-WIRES ALTERNATIVES. The role of distributed energy resources (DER) in meeting delivery system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs and 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.

Figure 2-12: Distributed Energy Resources Incremental Nameplate Capacity

Resource Additions (MW)	2022-2025	2026-2030	Total
Distributed Energy Resources			
Battery Energy Storage	75 MW	125 MW	200 MW
Solar - ground and rooftop	80 MW	150 MW	230 MW
DSP Non-Wire Alternatives	22 MW	24 MW	46 MW
Total DER	177 MW	299 MW	476 MW

4. DELIVERABILITY OF RESOURCES

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

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

Data

Data availability, integrity and granularity are critical aspects to planning for and operating DERs. Through our ongoing investment in Advanced Metering Infrastructure (AMI) and SCADA at distribution substations, PSE will have new data and visibility that can be utilized for delivery system planning, customer program planning and operational analytics. AMI is an integrated system of smart meters, communications networks and data management systems that enables two-way communication between utilities and customers. AMI meters will serve to provide significant enhancements to the types and granularity of data PSE can collect to proactively plan for growth, integrate new technologies, offer services to customers, respond to system needs quicker and operate the system safely. SCADA provides real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility and enhance overall reliability of the distribution system.

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

Monitoring, Control and Metering

In addition to SCADA and AMI investments, PSE is currently implementing an Advanced Distribution Management System (ADMS). ADMS is a computer-based, integrated platform that provides the tools to monitor and control our distribution network in real time. The implementation of ADMS will ultimately lead to advanced operational capabilities for DERs including an integrated Distributed Energy Resource Management System (DERMS).

Other advanced capabilities such as Volt-Var Optimization (VVO) and Fault Location, Isolation, Service Restoration (FLISR) will be enabled through the ADMS platform and additional investments in reclosers, switches, voltage regulators, capacitors banks and network communications infrastructure. FLISR will support grid reliability to enable battery energy storage charging and transportation electrification. VVO will manage voltage and reactive power as loads shift due to DER implementation.

DER Forecasting and Planning

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

Security

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

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

Infrastructure Assets

To avoid reactive investments due to unanticipated DER adoption and integration and in addition to the work already described, PSE will pursue targeted, proactive asset management and system upgrades to enable DER integration and transportation electrification. Grid modernization investments will improve the reliability of our systems, improve the ability to withstand and recover from extreme events, and enable smart and flexible grid capabilities. Ongoing and site-specific asset investments are needed such as pole replacement, tree-wire conductor and cable remediation programmatic transformer replacements as DERs and electric vehicles propagate, and substation and circuit enhancements that ensure or expand DER effectiveness. Finally, PSE will continue to upgrade its local transmission system in order to meet NERC compliance requirements and evolving regulations related to DER integration and markets and meet peak demand reliably.

5. ALTERNATIVE COMPLIANCE OPTIONS

Under CETA, up to 20 percent of the 2030 greenhouse gas neutral standard can be met with an alternative compliance option. These alternative compliance options can be used beginning January 1, 2030 and ending December 31, 2044. In order to model the alterative compliance options as part of the portfolio modeling, PSE evaluated two alternative compliance options. For the first option, PSE assumed that renewable energy credits would be purchased for 20 percent of load not met by renewable generation starting in 2030 and decreasing linearly to zero in 2045. Because there isn't a transparent forecast of the future price of renewable energy credits, PSE used the California carbon price as a proxy, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2045. The costs are included in all the portfolios as part of meeting the 2030 standard.

In addition to using carbon prices as a proxy price for renewable energy credits, PSE also modeled a portfolio sensitivity to understand the impact of meeting the 20 percent of load with renewable resources such that 100 percent of PSE's load is met with renewable resources. This compliance option has a total 24-year NPV of over $34 billion, $15 billion more than the preferred portfolio. This portfolio is described in detail in Sensitivity N in Chapter 8.

Actual compliance may be met through other mechanisms that are still under development and may include energy transformation projects, unbundled RECs and other options. As the Department of Ecology develops guidance on methods for assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects may be eligible as energy transformation projects, and includes other options such as transportation electrification, PSE will analyze these mechanisms.

6. SOCIAL COST OF GREENHOUSE GASES

The SCGHG is applied as a cost adder in the development of the electric price forecast and in the portfolio modeling process when considering resource additions. The SCGHG is not included in the final dispatch of resources because it is not a direct cost paid by customers. CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resources options. The SCGHG cost adder is included in planning decisions as part of the fixed O&M costs of that resource, but not in the actual cost and dispatch of any resource. An SCGHG adder is also added to the unspecified market purchases using the 0.437 metrics tons CO_2/MWh emission rate as specified in CETA.

The SCGHG in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists 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. Further details can be found in Chapter 5.

3 Resource Plan Decisions

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

Contents

1. OVERVIEW

As discussed in Chapter 1, there are analyses, assessments and evaluations that still need to be completed for the final IRP. The decisions that went into the development of the draft preferred portfolio are included in this chapter, but we expect the results to change as the analysis is completed. The draft preferred portfolio is one of a range of portfolios that PSE modeled for this IRP that meets the requirements of the Clean Energy Transformation Act. It is informed by evaluation of portfolio results from stakeholder-selected sensitivities and tested against the Mid Scenario portfolio developed using deterministic portfolio analysis. Deterministic portfolio analysis solves for the least cost solution and assumes perfect foresight about the future, so to assess the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages PSE also performs a stochastic portfolio analysis that will be completed for the final IRP.

This discussion assumes the reader is familiar with the key assumptions described in Chapter 5. Further information on the analyses discussed here can be found in Chapters 5, 6, 7, 8, 9 and the Appendices.

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 3-1 summarizes the forecast of resource additions to the preferred electric portfolio that resulted from the draft 2021 IRP analysis. This portfolio prioritizes cost-effective, reliable conservation and demand response, and distributed and centralized renewable and non-emitting resources, at the lowest reasonable cost to our customers. It achieves a more than 70 percent reduction in direct emissions by 2029 and carbon neutrality by 2030 through energy transformation projects and other mechanisms. While implementing this highly decarbonized portfolio, the portfolio maintains required resource adequacy with the addition of flexibility capacity starting in 2030.

This draft preferred portfolio was developed from analysis of various sensitivity results and the insights gained from these analyses were applied in developing the preferred portfolio. Whereas the electric portfolio model minimizes total portfolio costs by delaying new resource additions until the last few years of the planning horizon to capture the benefit of declining resource cost curves, in reality, PSE will need to add new resources over time. The preferred portfolio takes the significant amounts of distributed resources added in the last 5 to 10 years of planning period by the model and ramps them in as must-take resources over time, starting in 2025.

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

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Demand-side Resources	256 MW	360 MW	1,168 MW	1,784 MW
Battery Energy Storage	75 MW	125 MW	550 MW	750 MW
Solar - ground and rooftop	80 MW	150 MW	450 MW	680 MW
Demand Response	10 MW	161 MW	44 MW	215 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DER	443 MW	820 MW	2,284 MW	3,547 MW
Renewable Resources	600 MW	1,100 MW	2,762 MW	4,462 MW
Flexible Capacity	0 MW	237 MW	711 MW	948 MW

Electric Resource Need

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: (1) peak hour capacity for resource adequacy, i.e., does PSE have the amount of capacity available in each hour to meet customer's electricity needs; (2) hourly energy, i.e., does PSE have enough energy available in each hour to meet customer's electricity needs; and (3) renewable energy, i.e., does PSE have enough renewable and non-emitting resources to meet the annual delivered load.

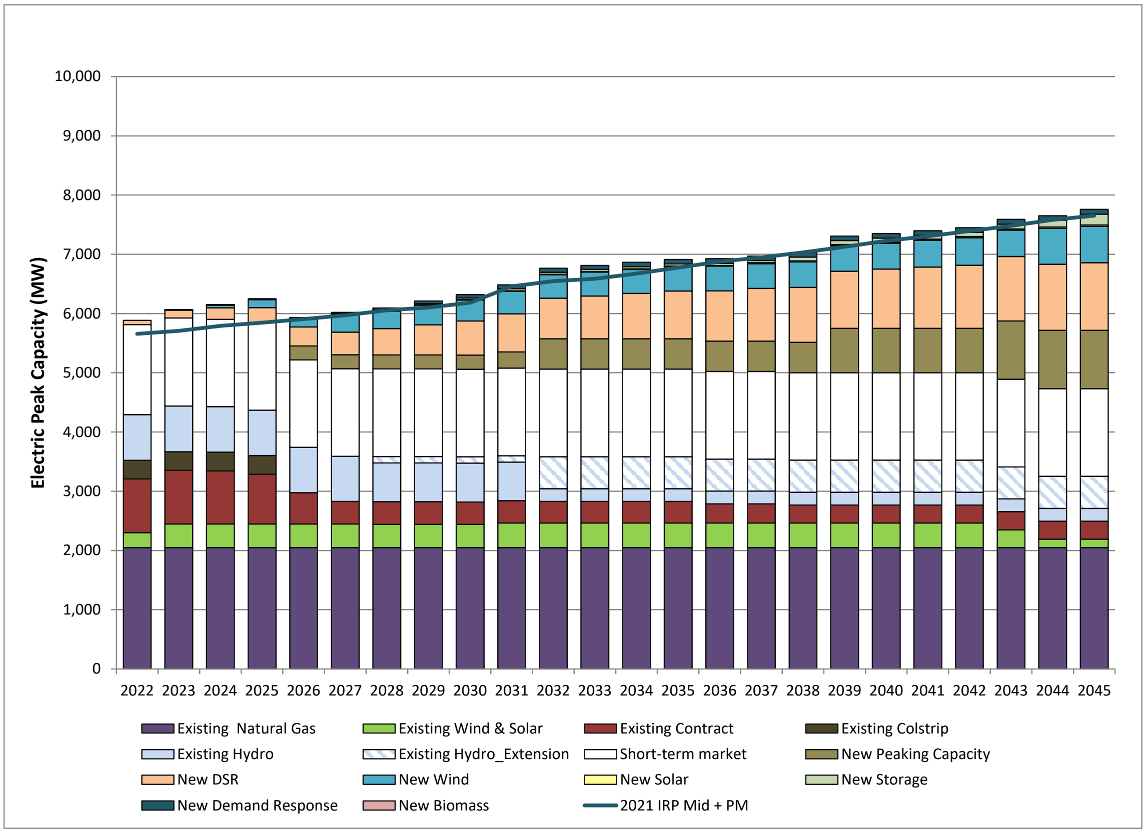
Meeting Peak Capacity Need

All of PSE customer's load obligations must be reliably met by building sufficient generating capacity to be able to meet customer demand with an appropriate planning margin. Planning margins are capacity above customer demand to ensure the system has enough flexibility to handle balancing needs and unexpected events, such as variations in temperature, hydro and wind generation, equipment failure, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Resource adequacy requires that the full range of potential demand conditions are met even if the potential of experiencing those conditions is relatively low.

As an important part of resource adequacy analysis, PSE quantifies the peak capacity contribution of renewable (wind, hydro and solar) resources (its effective load carrying capacity, or ELCC) and energy limited resources (batteries, pumped storage hydro, and demand response) to assess the amount of peak capacity each resource can reliably provide A full description of the peak capacity and ELCC values is in Chapter 8.

Figure 3-2 shows the combination of draft preferred portfolio new and existing resources required to meet the peak capacity need for the mid demand forecast with an appropriate planning margin and reflects the ELCC value of these resources.

Figure 3-2: Draft Preferred Portfolio Meeting Electric Peak Capacity



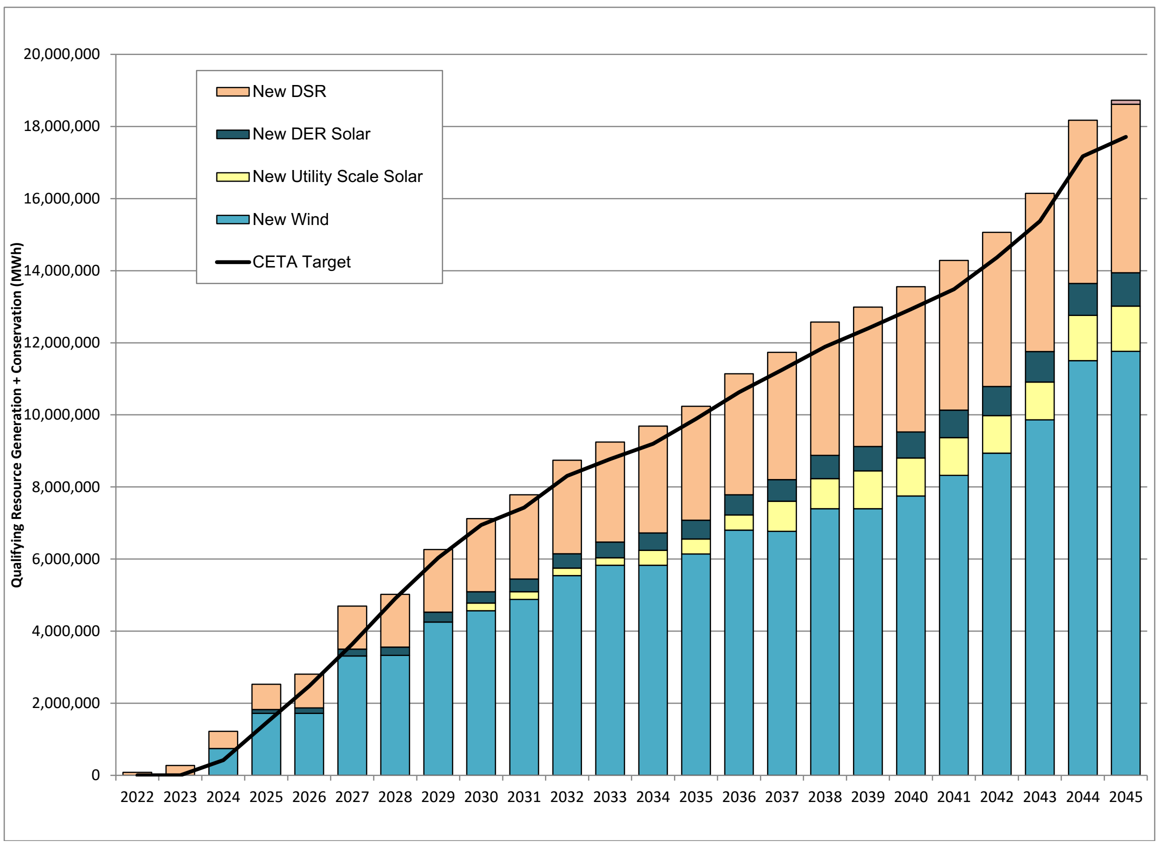
Renewable and distributed resources contribute to meeting peak capacity needs, however, flexible capacity is also needed to maintain reliability and meet the required resource adequacy standard. Over 750 MW of coal is removed from PSE's portfolio by the end of 2025 and the capacity is first replaced by demand-side resources, distributed resources and wind generation. The new flexible capacity is delayed until 2031 when the capacity need increases due to an increase in balancing requirements needed to support new intermittent renewable resources to meet the renewable energy requirements.

PSE evaluated early economic retirement of existing resources but that does not appear to be the least cost option. However, the economic dispatch of existing resources decreases significantly through the planning horizon and is discussed further below.

Meeting Renewable Energy Need

In Chapter 1, Figure 1-3, illustrates the renewable energy need for both RCW 19.285 and CETA, based on the 2021 IRP mid demand forecast. The draft preferred portfolio assumes a linear ramp to achieve the 80 percent Clean Energy Transformation Standard in 2030 and 100 percent standard in 2045. Figure 3-3 shows how the new renewable resources meet the 7.6 million MWh shortfall in 2030 and 17.1 million MWh shortfall in 2045. Demand-side resources (DSR) significantly reduce loads and lower the renewable need; these include cost-effective energy efficiency, codes and standards, distribution efficiency and customer solar PV. The majority of the remaining renewable resource need is met by new wind, and then solar. The wind category includes wind in Montana, Wyoming and eastern Washington, and the utility-scale solar includes solar in eastern Washington. The distributed energy resource (DER) solar includes delivery system non-wire alternatives and ground-mounted and rooftop solar PV. This chart shows the total annual energy (MWh) produced by these resources.

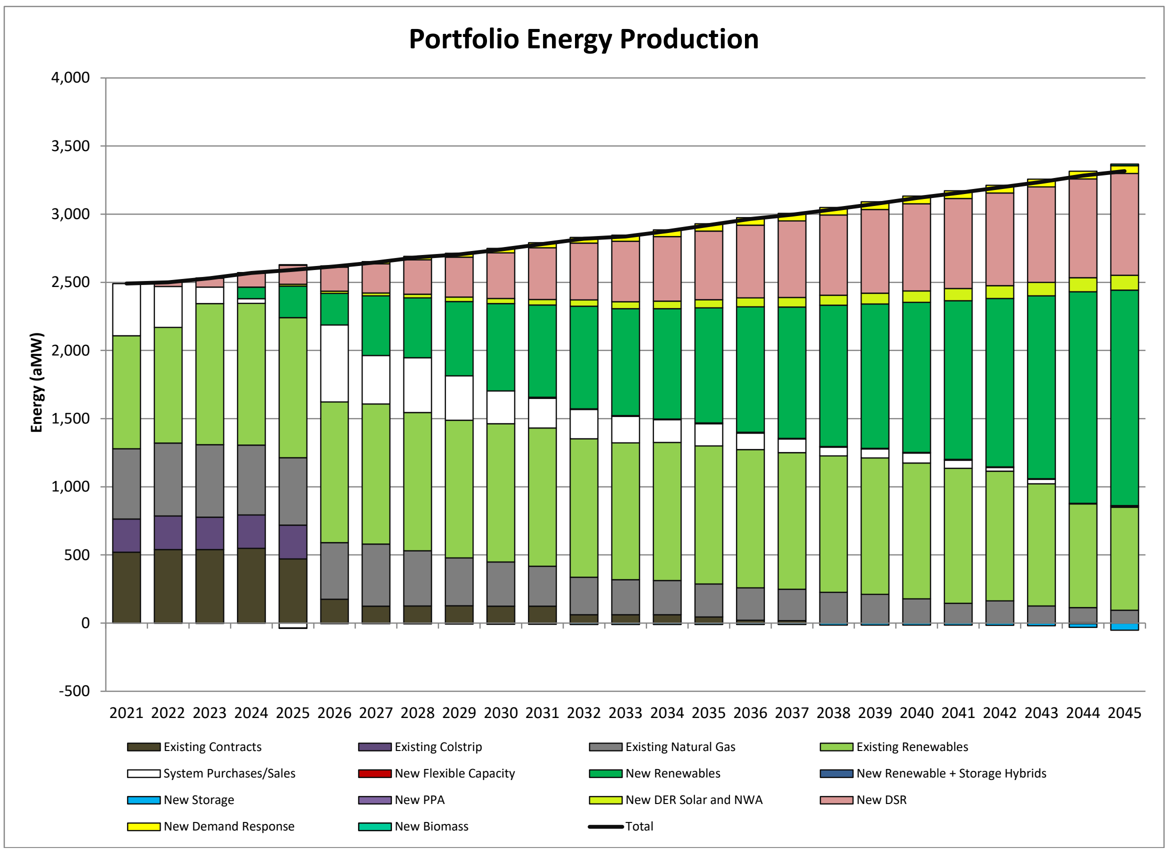
Figure 3-3: Draft Preferred Portfolio Meeting Renewable Energy Requirements



Meeting Energy Need

Figure 3-4 shows the draft preferred portfolio combination of resources needed to meet the 2021 IRP mid demand forecast. Most of the energy need is met with renewable and distributed energy resources. The use of market purchases and sales declines over time. None of the energy need is met with coal resources. The use of existing thermal resources declines, with the capacity factor of PSE's combined-cycle combustion turbines decreasing from 70 percent to 5 percent over the planning horizon. The pink bars represent demand-side resources, which significantly reduce total load. The total demand shown in the chart is for the demand at the generator, so it is grossed up for sales. Distributed energy resources are included in the portfolio but are not visible in this chart because they are a net zero resource, such that they do not produce any energy but rather store the energy that other generators have produced.

Figure 3-4: Draft Preferred Portfolio Meeting Energy Requirements



Portfolio Optimization Results

For the draft IRP, PSE examined three economic scenarios that varied demand, natural gas price, and power price, and 11 portfolio sensitivities developed through a stakeholder process described in Appendix A. Another 15 sensitivities will be analyzed for the final IRP. Sensitivities help us to understand how changing specific assumptions about customer demand, carbon policies, transmission availability, emission reductions, and conservation assumptions and costs can change the mix of resources in the portfolio, portfolio emissions and portfolio costs. The development of the draft preferred portfolio was informed by comparing the sensitivity portfolios with the least cost Mid economic scenario portfolio.

Figure 3-5 below provides a description of each of the scenarios and sensitivities. The shaded sensitivities will be analyzed for the final IRP.

Figure 3-5: 2021 IRP Electric Portfolio Scenarios and Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**Assumptions and Alternatives Analyzed**
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast, mid electric price forecast
2	Low	Low gas price, low demand forecast, low electric price forecast
3	High	High gas price, high demand forecast, high electric price forecast
FUTURE MARKET AVAILABILITY SENSITIVITIES		
A	Renewable Over-generation 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 SENSITIVITIES		
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 SENSITIVITIES		
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 SENSITIVITIES		
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 an externality cost in the portfolio expansion model and the hourly dispatch model.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**Assumptions and Alternatives Analyzed**
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 SENSITIVITIES		
M	Alternative Fuel for Peakers	Peaker plants can use hydrogen as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no 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 and Demand Response	Batteries or pumped hydro storage and demand response programs are added before any natural gas plants.
DEMAND FORECAST ADJUSTMENT SENSITIVITIES		
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 SENSITIVITIES		
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 PORTFOLIOS SENSITIVITIES		
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 peaking capacity	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.

Figure 3-6 summarizes the additions to PSE's existing resource portfolio for the Mid, Low and High Scenario portfolios that result from the deterministic portfolio analysis. The risks examined in these economic scenarios include a wide range of load growth assumptions and natural gas prices, which drive wholesale power prices. Figure 3-7 summarizes additions to PSE's existing resource portfolio across the different sensitivities that result from the deterministic portfolio analysis.

For each scenario and sensitivity, the analysis considered supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (customer demand across all hours), and renewable energy need (CETA requirements).

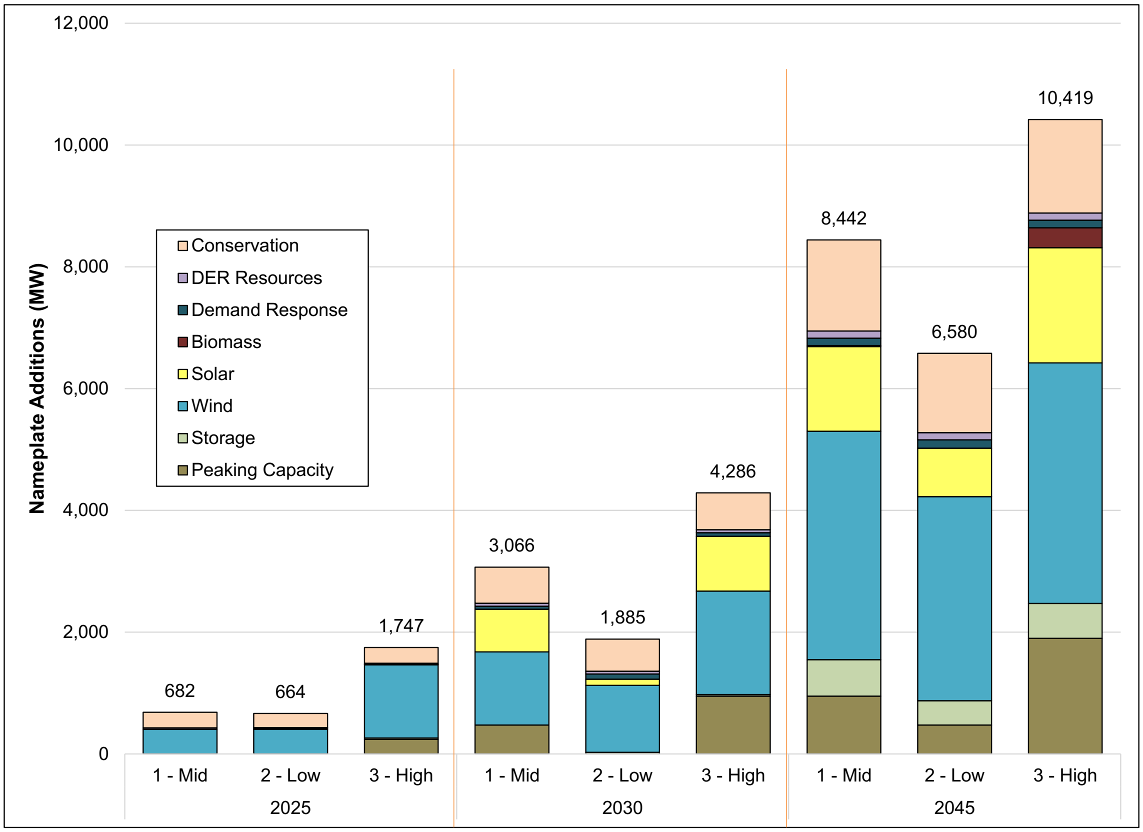
The portfolios in Figures 3-6 and 3-7 also minimize long-term revenue requirements (costs as customers will experience them in rates), given the market conditions and resource costs assumed for each scenario, thereby representing the least cost solution for that scenario or sensitivity.

In all scenarios and sensitivities analyzed, the portfolio model was able to economically retire existing generating resources, but no resources were retired in any of the scenarios and sensitivities.

SCENARIO RESOURCE BUILDS. The Mid Scenario portfolio is the least cost portfolio to meet resource needs, however it does not account for important transmission constraints. In this portfolio, transmission to eastern Washington is assumed to be unlimited and all the renewable requirements are met by utility-scale resources that require transmission back to PSE. Wyoming and Montana wind are the first wind resources added in 2025 and 2026 because their generation profile is well-matched to PSE's load profile; however, these resources are significantly limited by transmission constraints. Washington wind is added consistently throughout the planning horizon starting in 2028 since no transmission constraints are imposed on wind resources. In terms of conservation savings, a total of 1,497 MW nameplate of DSR resources was added to the portfolio by 2045. With the retirement of coal resources in 2025, 474 MW of peaking capacity resources are added to the portfolio in 2026.

The portfolio builds for all three economic scenarios look very much alike given the generic resource options. The mix of resources is similar, and the amount of resources added increased or decreased due to the higher and lower load forecasts modeled in the Low and High scenarios.

Figure 3-6: Resource Build for Mid, Low and High portfolios
Cumulative Additions by Nameplate (MW)



SENSITIVITY RESOURCE BUILDS. Figure 3-7 shows the resource builds by 2045 for each sensitivity modeled in the draft IRP. In all portfolios, new flexible capacity is added, with the exception of sensitivity N and O where flexible capacity is not allowed.

With unlimited transmission assumed, new utility-scale renewable resources are chosen as the lowest cost way to meet the renewable requirements for CETA. Sensitivity C models an important transmission constraint; it limits transmission to eastern Washington, resulting in the addition of almost 2,000 MW of distributed solar in combination with over 1,000 MW of storage in the last 5 years of the planning horizon. The insights gained from the results of Sensitivity C informed the development of the Balanced Portfolio in Sensitivity V. In Sensitivity C (and other sensitivities), the electric capacity expansion model is set to optimize total portfolio costs and therefore delays new builds until the end years of the planning period because all resource cost curves decline over time. This delay produces a lower cost portfolio, but it is not always realistic to wait till the end to add a lot of resources. In Sensitivity C, the model waits till the end years to add a significant amount of distributed resources; the Sensitivity V portfolio takes those distributed resources and ramps them in over time starting in 2025, along with adding more customer programs, to meet CETA requirements. Portfolio W is the Balanced Portfolio that includes an alternative fuel source for flexible capacity. This portfolio became the basis for the preferred plan because it is CETA compliant while also taking into consideration the transmission constraints to regions outside of PSE. The No CETA portfolio (Sensitivity T) is important to understanding the cost impacts of CETA.

Figure 3-7: Relative Optimal Portfolio Builds by Sensitivity
(Cumulative nameplate capacity for each resource addition, in MW by 2045)

		DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Flecible Capacity	Total
1	Mid	1,497	118	121	15	1,393	3,750	600	948	8,442
A	Renewable Over-generation Test	1,545	118	183	525	1,490	2,150	1,125	692	7,828
C	"Distributed" Transmission/Build Constraints - Tier 2	1,537	3,068	125	105	499	2,715	1,050	948	10,047
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	1,372	118	141	120	1,394	3,450	600	966	8,161
N	100% Renewable by 2030	1,304	118	123	0	1,394	4,050	26,100	0	33,089
O	Gas Generation Out by 2045	1,262	118	130	0	1,397	4,150	18,625	0	25,682
P	Must-take Battery	1,304	118	128	0	1,796	3,750	3,775	711	11,582
P2	Must-take Pumped hydro storage	1,304	118	128	0	1,397	3,950	4,100	711	11,708
S	SCGHG Included, No CETA	1,179	118	155	0	0	350	0	1,513	3,315
T	No CETA	1,042	118	133	0	0	350	0	2,151	3,794
V	Balanced Portfolio	1,497	798	211	60	796	3,750	1,125	948	9,060
W	Balanced Portfolio with alternative fuel for peakers	1,658	798	215	15	697	3,750	750	984	8,706

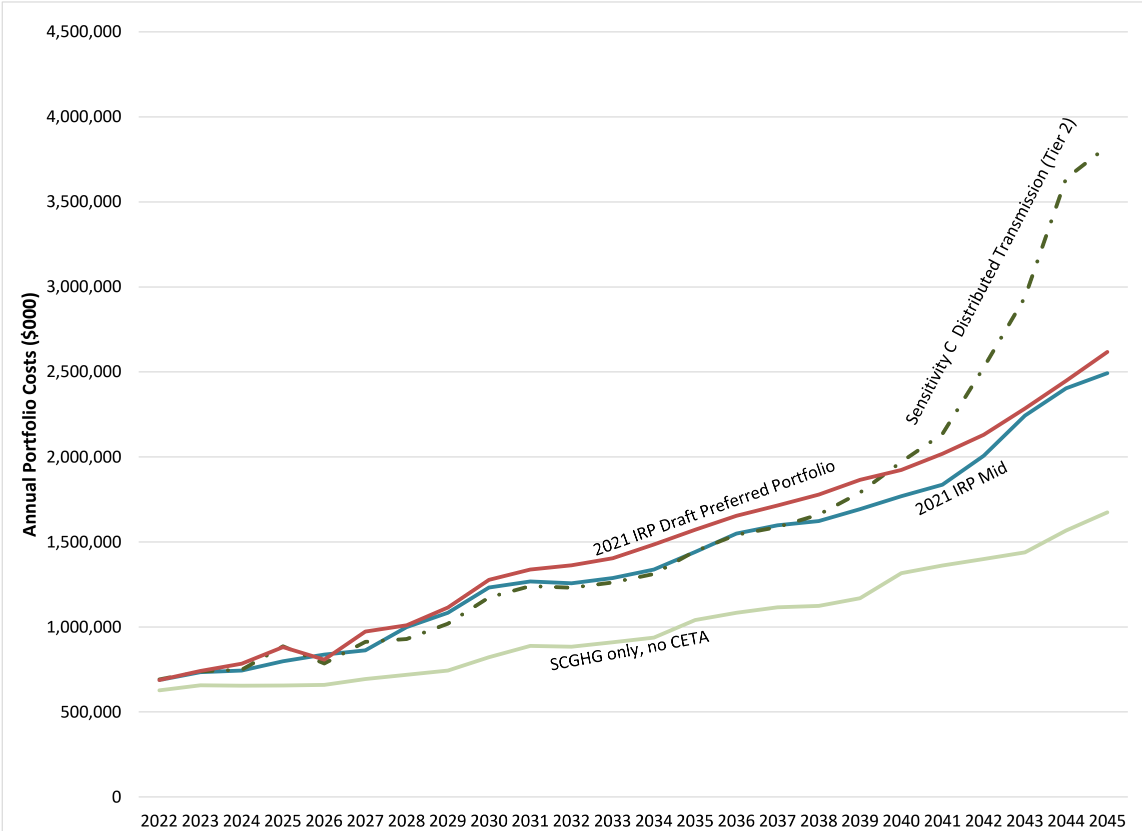
TOTAL PORTFOLIO COSTS. Figure 3-8 compares the total portfolio costs for each sensitivity with the Mid Scenario portfolio cost. The draft 2021 IRP preferred resource plan is based on portfolio W, Balanced Portfolio with Alternative Fuel for Peakers. This portfolio started with Sensitivity C and then made some adjustments. Sensitivity C accounts for the transmission constraints to eastern Washington and includes over 2,000 MW of distributed solar, with an incremental cost of $910 million more than the mid portfolio over the 24-year planning horizon. The adjustments to the portfolio for Sensitivity V brought the incremental portfolio cost down to $620 million more than the mid portfolio.

Figure 3-8: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

		24-Yr Levelized Costs ($Billions)			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
A	Renewable Overgeneration Test	$15.32	$4.24	$19.57	$0.89
C	"Distributed" Transmission/Build Constraints - Tier 2	$14.53	$5.06	$19.59	$0.91
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	$13.65	$4.78	$18.42	($0.25)
N	100% Renewable by 2030	$31.14	$3.42	$34.56	$15.89
O	Gas Generation Out by 2045	$33.90	$6.24	$40.14	$21.46
P	Must-take Battery and Demand Response	$29.09	$6.06	$35.15	$16.47
P2	Must-take PHES and Demand Response	$22.35	$4.36	$26.71	$8.04
S	SCGHG Included, No CETA	$10.06	$9.01	$19.08	$0.40
T	No CETA	$9.40	$0.00	$9.40	($9.28)
V	Balanced Portfolio	$14.37	$5.06	$19.43	$0.75
W	Balanced Portfolio with Alternative Fuel for Peakers	$14.43	$4.86	$19.30	$0.62

ANNUAL PORTFOLIO COSTS. Figure 3-9 below compares the annual portfolio costs of the draft preferred portfolio with Sensitivity T, No CETA, and Sensitivity C, the transmission constrained portfolio. The transmission constrained portfolio sharply increases annual portfolio costs at the end of the planning horizon to minimize total costs by adding all the distributed resources at the end. The preferred portfolio ramps those distributed energy resources in earlier and over time; this smoothes the annual cost increases and closely aligns with the least cost Mid Scenario portfolio. In the 2024 through 2027 time frame, the preferred portfolio (red line) shows two small cost increases due to the demand response programs. Sensitivity S, SCGHG Included, No CETA portfolio that appears in the chart is part of the CETA incremental costs comparison analysis. In the final IRP, PSE will take the next step and evaluate the draft preferred portfolio against the 2 percent CETA cost threshold.

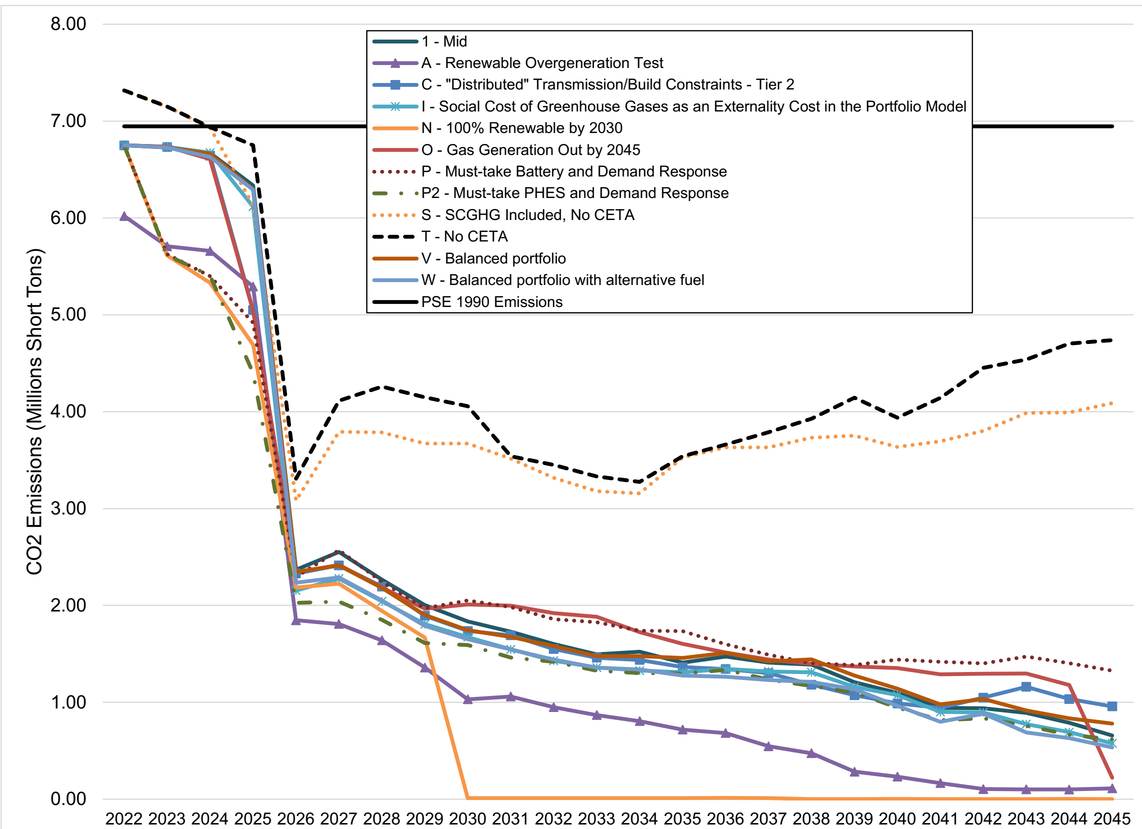
Figure 3-9: Annual Portfolio Costs of Select Sensitivities



Portfolio Emissions

All sensitivities that meet CETA renewable requirements show significant reduction in emissions throughout the planning horizon. Figure 3-10 compares CO_2 emissions for the Mid Scenario portfolio with each sensitivity analyzed so far. The chart shows the direct emissions from each portfolio of resources and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. Direct emissions decrease to zero for Sensitivity N, 100% Renewables by 2030.

Figure 3-10: CO_2 Emissions by Portfolio
(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)



Portfolio Optimization Results by Resource Type

Demand-side Resources (DSR): Energy Efficiency

Demand-side resources for the Mid Scenario portfolio include energy efficiency up to $175/MWh (493 aMW), codes and standards which includes the Washington State Energy Code (WSEC) along with federal and state equipment standards, and customer solar PV forecast. Some portfolio results had 381 aMW of cost-effective energy efficiency, while others showed up to 508 aMW, depending on adjustments that were made to the portfolio. Given the variation in results, the draft preferred portfolio includes the same the demand-side resources as the Mid Scenario portfolio with the exception of the customer solar PV forecast. The customer solar PV forecast is the same forecast as from the sensitivity C, the transmission-constrained portfolio.

Demand Response

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly *when* they use it. For instance, businesses might work with PSE to voluntarily adjust their operations during a specified time range. Residential customers might automate their usage with smart thermostats or water heaters. While there are often financial incentives to participate in DR pilots and programs, it is also a way for both PSE and customers to increase efficiency and reduce their carbon footprints.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean that their thermostat automatically warms their home or building earlier than usual. Because of the remote function of demand response, no action is required from customers to initiate their reduction in load, and they can always choose to opt out of an event.

Demand response programs, evaluated in this IRP, are organized into four categories. These include:

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

This IRP evaluated 16 different demand response programs. PSE modeled the DR programs as being available to start in any year of the planning period. Figure 3-11 below is a breakdown of the cost effective DR programs for each sensitivity and the start year of the program. The numbers in the first column of Figure 3-11 correspond to the following programs:

1. Residential Dynamic Pricing or Critical Peak Pricing – No Enablement
2. Residential Dynamic Pricing or Critical Peak Pricing – with Enablement
3. Residential Direct Load Control Heat-Switch
4. Residential Direct Load Control Heat-BYOT
5. Residential Direct Load Control ERWH-Switch
6. Residential Direct Load Control ERWH-Grid-Enabled
7. Residential Direct Load Control HPWH-Switch
8. Residential Direct Load Control HPWH-Grid-Enabled
9. Small Commercial Direct Load Control Heat-Switch
10. Medium Commercial Direct Load Control Heat-Switch
11. Commercial & Industrial Curtailment-Manual
12. Commercial & Industrial Curtailment-AutoDR
13. Commercial Dynamic Pricing or Critical Peak Pricing – No Enablement
14. Commercial Dynamic Pricing or Critical Peak Pricing – with Enablement
15. Residential EV Direct Load Control
16. Residential Behavioral DR

.

Figure 3-11: Cost-effective Demand Response
(year of program start for each portfolio)

	Program Type	Nameplate (MW)	Sensitivity								
			1	A	C	I	N	O	P	S	T
1	40 hours per season, day ahead	64.5	2025	2022	2022	2022	2022	2022	2022	2022	2022
2	40 hours per season, day ahead	1.9			2022	2022				2022	2029
3	40 hours per season, real time	50.2		2024							
4	40 hours per season, real time	3.2								2022	2029
5	40 hours per season, real time	10.6									
6	Unlimited	57.7	2022	2022	2022	2022	2022	2022	2022	2022	2022
7	40 hours per season, real time	0.2								2027	
8	Unlimited	0.9	2022	2022	2022	2022	2022	2022	2022	2022	2022
9	40 hours per season, real time	6.6		2033		2022				2024	
10	40 hours per season, real time	5.1		2032				2040	2022	2023	2029
11	40 hours per season, day ahead	3.0								2022	
12	40 hours per season, real time	3.0								2027	
13	40 hours per season, day ahead	1.3								2022	
14	40 hours per season, day ahead	1.0				2022				2022	
15	40 hours per season, day ahead	8.5									
16	40 hours per season, day ahead	8.8				2022		2042		2034	

The most-selected DR programs are the unlimited programs which are direct load control programs After that, DLC programs that are more limited in the number of calls per season and the residential critical peak pricing program is picked up in several portfolios. The critical peak pricing program is very similar to a time-of-use (TOU) program. Four programs show up in several portfolios. To determine the cost effectiveness of these programs across multiple sensitivities, there is also a bigger theme regarding the CETA renewable requirement. In

Sensitivity T No CETA, six different demand response programs are selected because without CETA renewable requirements, the capacity need is the dominant factor for selecting resources. There is more demand response and much less energy efficiency (up to 208 aMW in Bundle 2). Similar observations can be made for Sensitivity S, SCGHG only, No CETA. Without the CETA renewable requirement, but with the SCGHG cost adder, 13 demand response programs are cost effective and energy efficiency is selected up to Bundle 6 (or 291 aMW). Still, the capacity need is the driving constraint since there is no renewable need. Once the CETA renewable requirement is included in all the other sensitivities, the portfolio shifts to the energy need being the dominant factor. As a result, the cost-effective energy efficiency bundles increase from 381 aMW to 508 aMW, but demand response decreases because it is limited in helping to meet the CETA renewable requirement. The new renewable resources added to the portfolio have some capacity contribution, so less capacity resources are needed as well.

Distributed Energy Resources: Battery Energy Storage

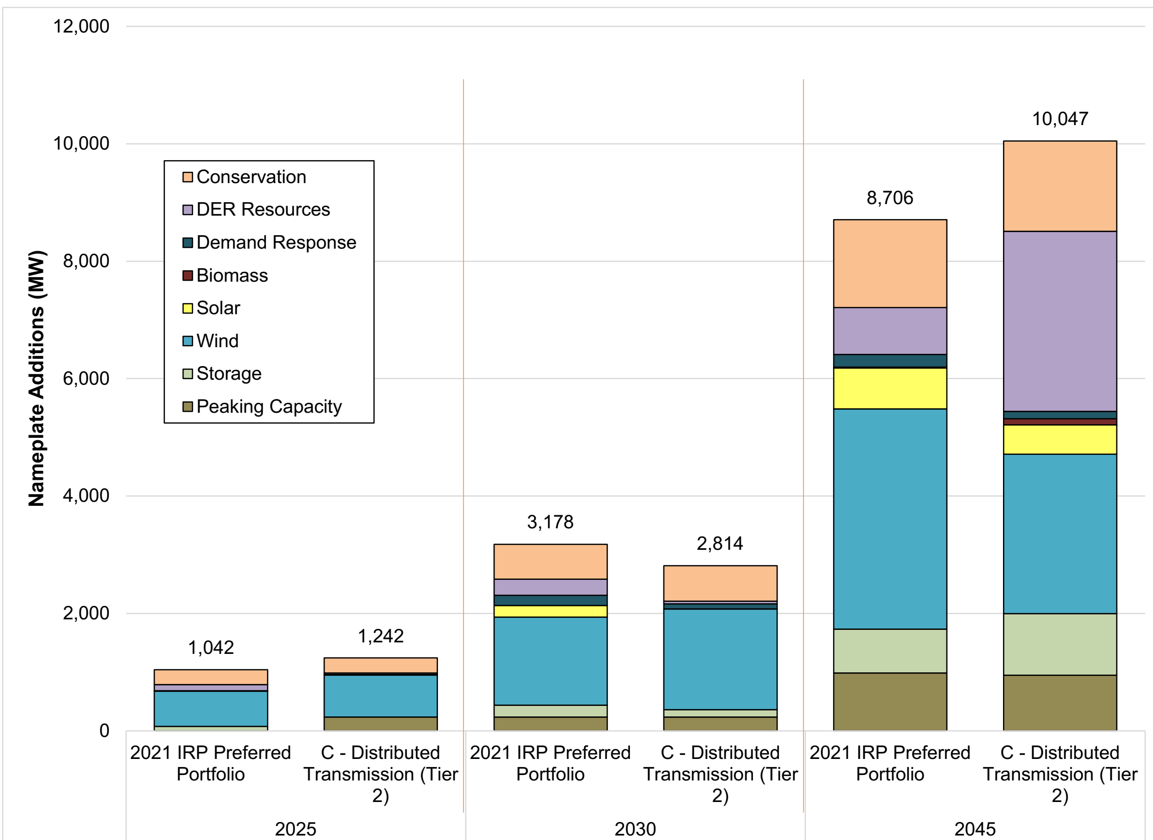
This IRP includes four battery energy storage systems that range from 2 to 6 hours duration along with pumped hydro storage with a duration of 8 hours. Batteries are scalable, and fit well in a portfolio with a small, flat need. Batteries also work as a solution for local distribution upgrades and capacity needs. In all the portfolio results, additional energy storage was not part of the optimized portfolio solution until the last 5 to 10 years of the planning horizon when the renewable requirement increased to more than 90 percent of delivered load. As observed in Sensitivity P, after over 750 MW of coal resources are removed from the portfolio in 2026, energy storage does not appear to be a cost-effective way to replace the capacity. Given the lower peak capacity credit for energy storage, significantly more resources are needed to match the same capacity as the combustion turbines, which are the lowest cost resource. The preferred portfolio includes some additional distributed battery storage resources starting at 25 MW in 2025 and increasing to 175 MW by 2031. With the addition of more distributed resources, one of the peaking capacity resources needed to meet the 2026 capacity shortfall is delayed until 2030.

Distributed Energy Resources: Solar – ground and rooftop

Though utility-scale solar is a lower cost option for meeting CETA renewable requirements, given transmission constraints involved in bringing remote resources to PSE's service territory, distributed solar resources have become an important part of the solution. PSE modeled both ground mount and rooftop solar as an option to both meet CETA renewable requirements and local distribution system needs. Sensitivity C portfolio that restricts transmission availability more than the Mid Scenario portfolio does by analyzing the risk of obtaining new transmission contracts to eastern Washington and the availability of re-using existing transmission contracts. Based on these restrictions, more renewable resources are needed in western Washington to meet CETA renewable requirements. As discussed earlier, in Sensitivity C the portfolio model waits until the end to add a significant amount of distributed resources. The preferred portfolio ramps in the same amount of distributed resources starting in 2025 and ramps them in over time for a total of 680 MW of distributed solar added to the resource plan as a way to comply with CETA requirements. Solar provides very little peak capacity value to PSE, since PSE is a winter peaking utility. Distributed solar is a good way to meet the CETA renewable requirements given transmission constraints, but it makes limited contributions toward meeting the peak capacity need.

Figure 3-12 compares the portfolio builds for the 2021 IRP draft preferred resource plan with Sensitivity C.

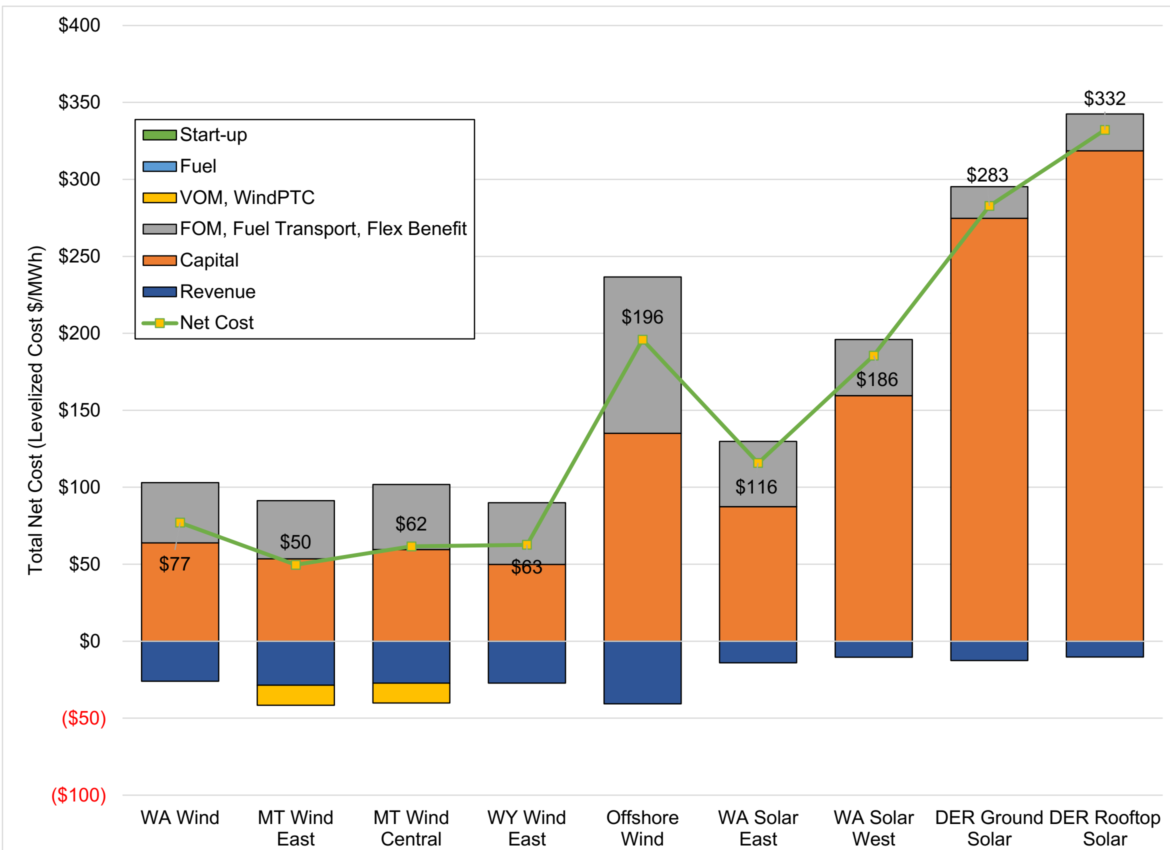
Figure 3-12: Resource Build for Draft 2021 IRP Preferred Portfolio and Sensitivity C, Transmission Build Constraint, Cumulative Additions by Nameplate (MW)



Renewable Resources

The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources do contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio relying on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up the cost of resource portfolios. This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources outside of the Pacific Northwest region are limited. After the Montana and Wyoming wind, costs between eastern Washington wind and solar are very close._Figure 3-13 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resources to meet CETA renewable requirements followed by eastern Washington wind and solar. Actual bids in an RFP process could yield a different conclusion.

Figure 3-13: Levelized Cost of Wind and Solar Resources



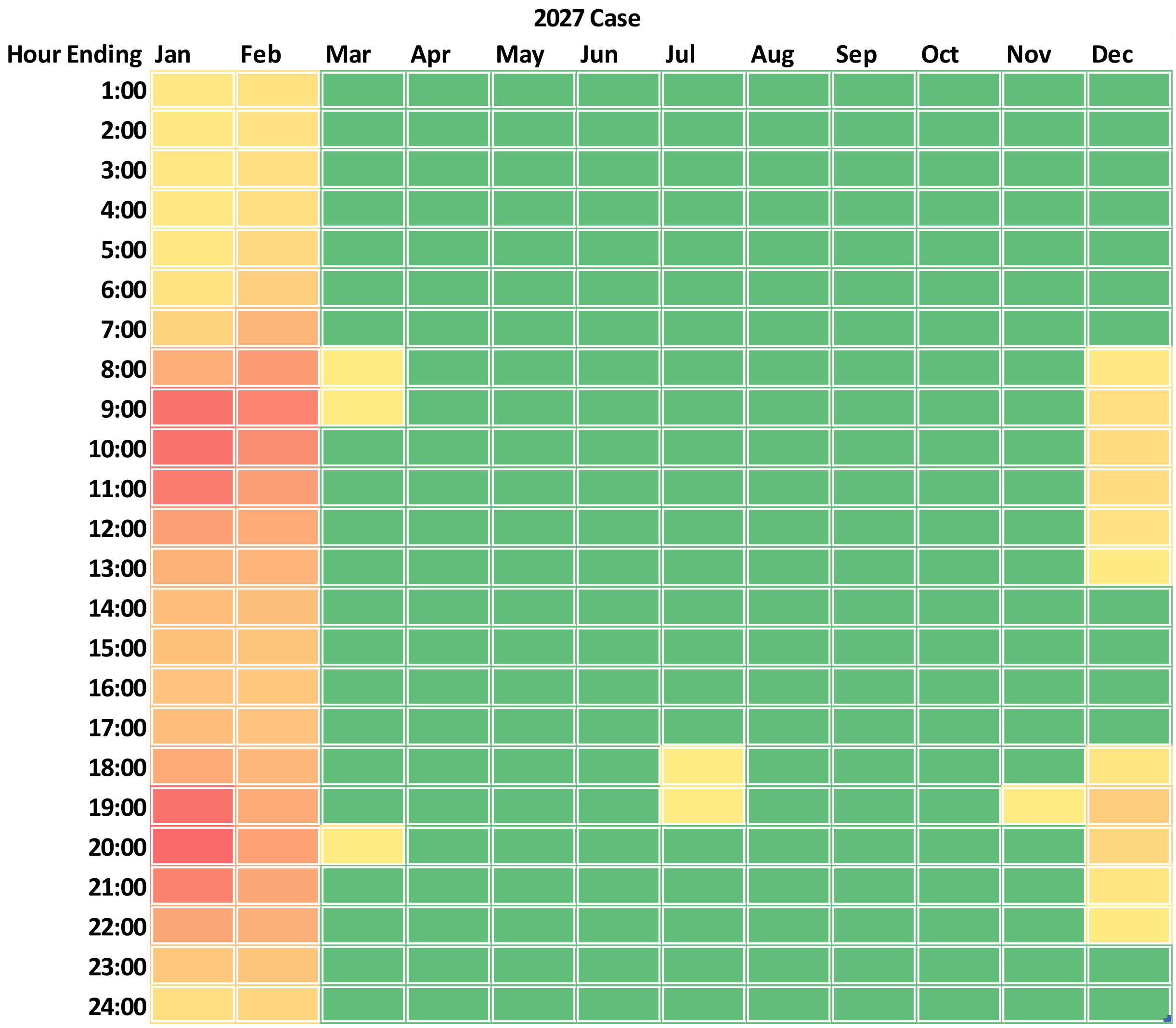
Flexible Capacity

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

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

Figure 3-14 is a 12x24 table that shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events using generic resources. Given current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability. The portfolio model meets the capacity shortfall with resources that can be dispatched for 24 hours or more.

Figure 3-14: Loss of Load Hours for 2027



Transmission 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 clean energy transformation targets. In contrast to thermal resources, 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 always follow load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak capacity needs as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory. Transmission within PSE service territory will be needed, but was assumed unconstrained due to delivery system planning process and specific identified projects.

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

3. NATURAL GAS SALES RESOURCE PLAN

Resource Additions Summary

The natural gas sales resource plan is summarized in Figure 2-15, followed by a discussion of the reasoning that led to the plan. The years shown here reference the gas year, so 2025/26 means the gas year starting November 2025 through October 2026.

Figure 3-15: Natural Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

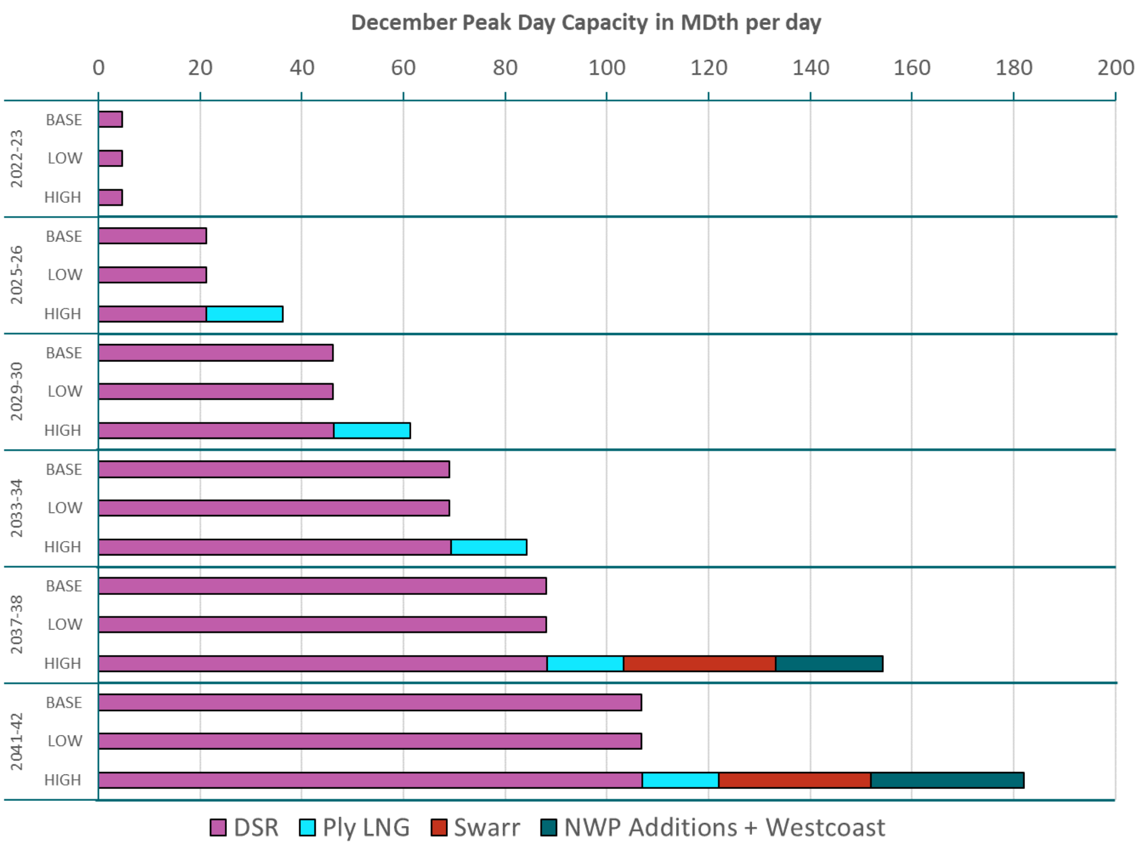
	2025/26	2030/31	2041/42
Conservation	21	53	107

The natural gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. In the draft 2021 IRP conservation was the most cost effective resource and it alone was enough to meet the need over the entire study period.

Natural Gas Sales Results across Scenarios

As with the electric analysis, the natural gas sales analysis examined the lowest reasonable cost mix of resources across a range of scenarios. Three scenarios were tested in the 2021 IRP: mid, low and high. Figure 2-16 illustrates the lowest reasonable cost portfolio of resources across various potential future conditions.

Figure 2-16: Natural Gas Sales Portfolios by Scenario (MDth/day)

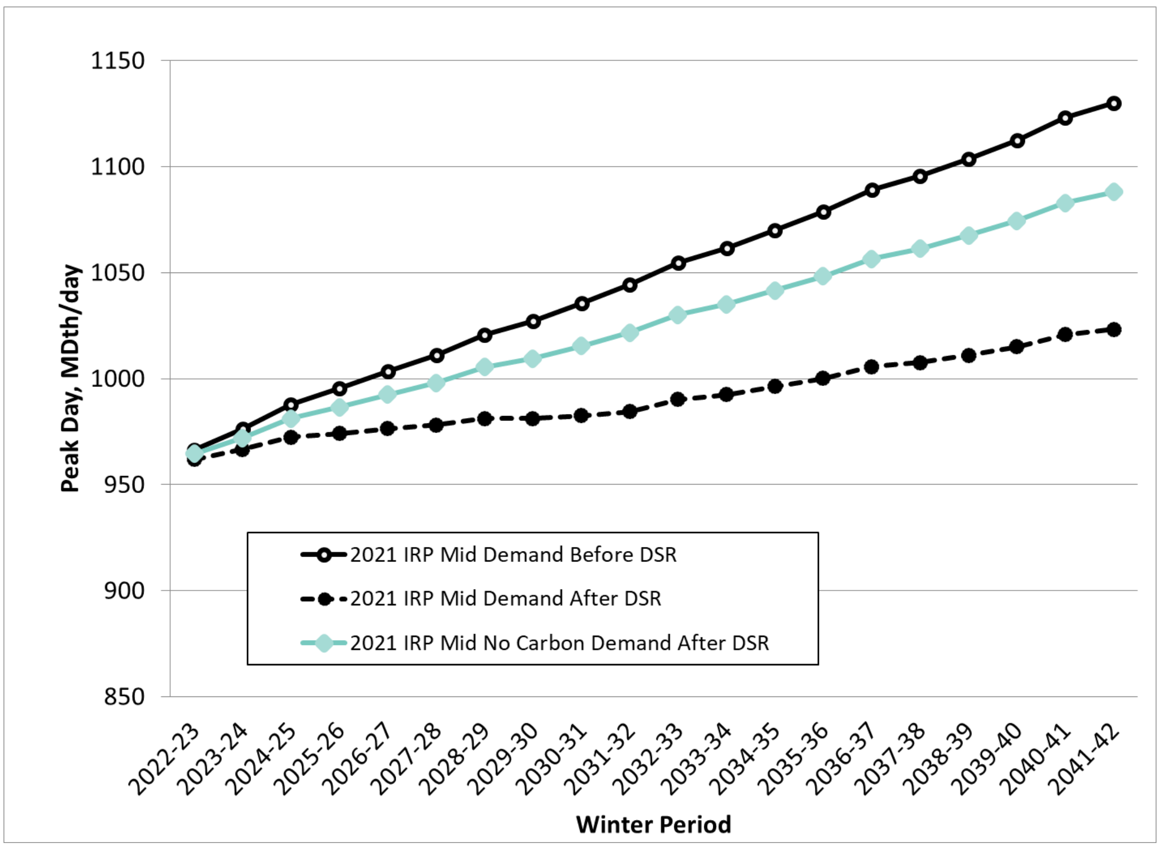


Key Findings by Resource Type

Demand-side Resources

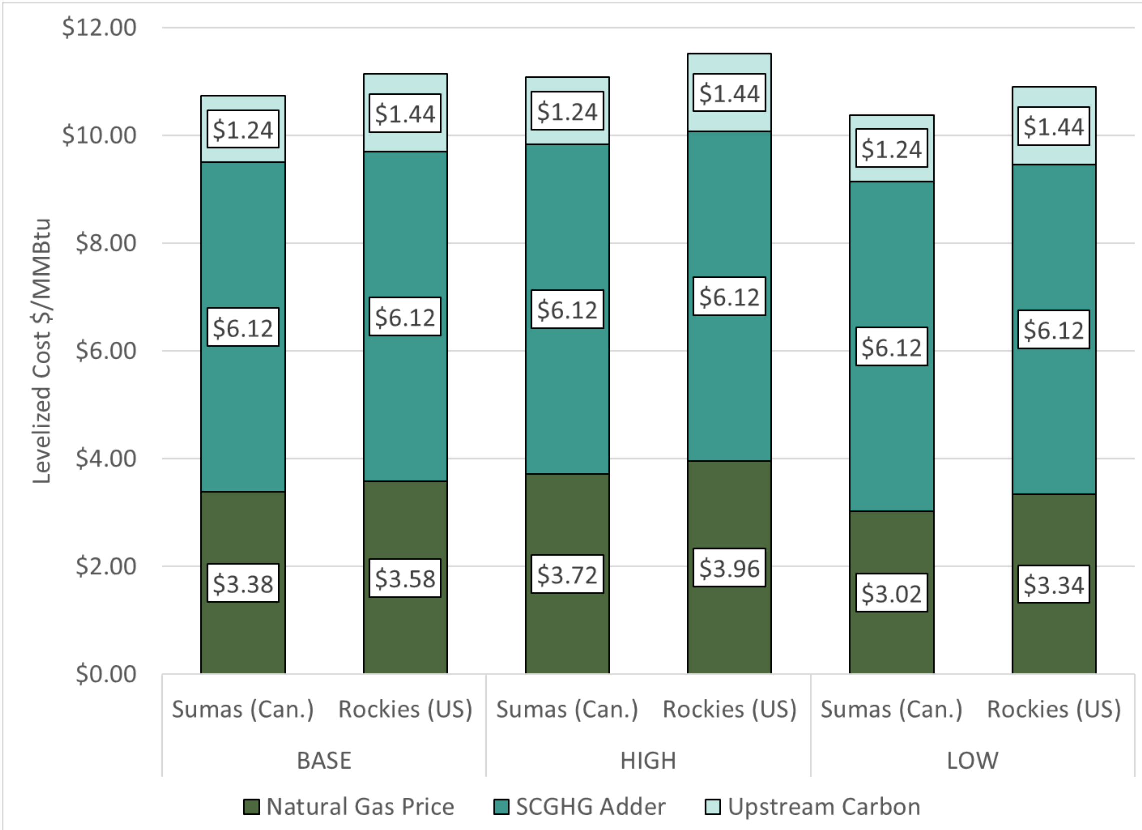
Cost effective DSR (conservation) does not vary across scenarios. In other words, the same level of conservation is chosen in all the scenarios. The conservation is driven by the total natural gas costs more than it is to the other factors such as the resource need. Figure 2-17, below, shows the results of cost-effective DSR for the mid scenario with and without the carbon adders, and we see that the amount of cost effective DSR is significantly lower when the total cost of natural gas consists of the gas commodity costs only. This in contrast to the earlier stated results of the cost effective DSR is not changing when the resource need changed from Low to High Scenarios.

Figure 2-17: DSR Cost Effective Levels are Driven by Total Natural Gas Costs



Conversely, in Figure 3-18, we see that the total cost of natural gas once the carbon adders are included varies only slightly from one scenario to the next. This results in the same level of DSR being selected in all the three scenarios.

Figure 3-18: Total Cost of Natural Gas (Commodity + SCGHG + Upstream Emissions)



Swarr Upgrades

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

Plymouth LNG

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

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines North, to Station 2, is cost effective in the high scenario. In the high load growth scenario, 21 MDth/day is added in 2034/35, growing to 30 MDth/day by the end of the planning horizon.

Resource Plan Forecast – Decisions

The resource plan forecast additions described above are consistent with the optimal portfolio additions produced for the Mid Scenario by the SENDOUT gas portfolio model analysis tool, including results. SENDOUT is a helpful tool, but results must be reviewed based on judgment, since real-world market conditions and limitations on resource additions are not reflected in the model. The following summarizes key decisions for the resource plan.

Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Mid Scenario – the same as the Low and High Scenarios, as shown in the table in Figure 2-18, above. Gas prices appear to have little impact on DSR regardless of the load growth forecast. The primary variable that affects the resource decision is the assumption for SCGHG adders. Figure 2-18 illustrates the different SCGHG adders. The SCGHG adders are derived from requirements stated in HB1257 which became law in 2019 legislative session, the SCGHG adders are to be incorporated into the planning analysis as part of capacity expansion decisions. The results show that cost effective conservation in the Mid Scenario is likely to be a safe decision as the same level of conservation is still cost effective even when the demand forecast varies as low as the 10th percentile and as high as the 90th percentile represented by the Low and High Scenarios respectively.

Supply-side Resources

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

2021 PSE Integrated Resource Plan

4 Planning Environment

This chapter reviews the conditions that defined the planning context for the 2021 IRP. This chapter will be updated for the final IRP due in April 2021.

Contents

1. CLEAN ENERGY TRANSFORMATION ACT RULEMAKINGS

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

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

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

WUTC CETA Rulemakings

The WUTC anticipates completing three rulemakings at the end of 2020 to implement CETA: the Energy Independence Act (EIA) Rulemaking, the IRP/CEIP Rulemaking, and the Purchase of Electricity Rulemaking. At this time of this writing, these rules are not final or in effect yet.

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

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

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

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

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

Department of Commerce CETA Rulemaking

The Department of Commerce (Commerce) is charged with developing rules for implementation of CETA for consumer-owned utilities. Additionally, Commerce is responsible for developing reporting procedures for all utilities, investor-owned and consumer-owned. Commerce expects to file final rule language by the end of December 2020.

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

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

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

- Programs and mechanisms to reduce energy burden, including the effectiveness of those programs and mechanisms for both short-term and sustained energy burden reduction
- Outreach strategies used to encourage participation of eligible households

- A cumulative assessment of previous funding levels for energy assistance compared to funding levels needed to meet 60 percent of the current energy assistance need, or increasing energy assistance by 15 percent over the amount provided in 2018, whichever is greater, by 2030; and 90 percent of the current energy assistance need by 2050.

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

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

Department of Health Cumulative Impact Analysis

CETA directs the Department of Health (DOH) to develop a cumulative impact analysis (CIA) of the impacts of both climate change and fossil fuels on population health, in order to designate highly impacted communities. The results of the CIA will be used to inform power utilities' planning in the transition towards cleaner energy. While DOH set out to carry out this work collaboratively with robust input from stakeholders through work group meetings and subcommittees, DOH's plans for stakeholder engagement were scaled back in 2020 after the onset of the COVID-19 pandemic. DOH anticipated having a draft tool available by the end of November 2020 and a final CIA tool available in December 2020, but, at the time of this writing, stakeholders have not seen the tool.

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

Department of Ecology Rulemaking

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

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

While Ecology's rules are not final yet, the near-final set of rules indicates that Ecology intends to adopt in its rulemaking: (1) the default unspecified emissions factor in CETA; and (2) a general process for determining eligible energy transformation projects. Ecology intends to finalize its rules at the end of 2020.

2. TECHNOLOGY CHANGES

Convergence of Delivery System Planning and Resource Planning

Traditionally, the focus of an integrated resource planning process has been to determine the lowest reasonable cost mix of demand- and supply-side resources needed to meet the total projected load and peak needs of its customers with an adequate reserve margin. For 33 states, the planning process is prepared under rules or requirements for an IRP and reviewed by state utility commissions. This is the case in Washington.

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

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

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

Washington State's Clean Energy Transformation Act is also driving change.
It recognizes that transforming the state's energy supply requires the modernization of its electricity system and that clean energy action planning must include any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities. Additionally RCW 19.280.100, resulting from House Bill 1126, furthers this connection as energy supply

needs are met through distributed energy resources (DERs). It established a policy that guides how distributed energy resource planning processes are to occur in order to illuminate the interdependencies among customer-sited energy and capacity resources.

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

Historically, the two planning processes have occurred on separate timelines. However, DERs installed in sufficient quantity to solve delivery system needs may change the results in the resource planning process, so coordinating the two benefits both processes and analyses. The confluence of technology, customer adoption, grid integration capability and solution effectiveness will drive the pace of interconnecting the DSP and IRP processes.

Distributed Energy Resources Planning Process

HB1126 was passed by the Washington legislature and became effective July 28, 2019. This Act relates to enabling electric utilities to prepare for the distributed energy future, adding a new section to chapter 19.280 RCW.[2] RCW 19.280.100 codified the legislation verbatim. No further rules, as defined by the Washington Administrative Code, have been developed by the WUTC at this time.

RCW 19.280.100 states that it is the policy of the state of Washington that any distributed energy resources planning process engaged in by an electric utility in the state should accomplish specified activities and considerations.[3]

Through PSE's Smart Grid Technology reporting that was required by WUTC,[4] PSE has been progressing toward planning for and integrating distributed energy resources. The following provides a highlight of how PSE has integrated this policy into its IRP and delivery system planning, recognizing that greater maturity will develop through the next planning cycle.

2 / http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/House/1126.SL.pdf?cite=2019 c 205 § 1
3 / https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.100
4 / https://apps.leg.wa.gov/wac/default.aspx?cite=480-100-505

Statistory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	Appendix M describes PSE's vision including preliminary data gaps and upgrades that include investments or enhancements such as AMI, SCADA and GIS along with planning tools such as geospatial load forecasting. PSE is working with EPRI and peer utilities in the Washington Utility Symposium described in Appendix A. There will be more to learn as larger quantities of DERs are integrated.
RCW 19.280.100. (2) (b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	Appendix M describes monitoring, control and metering upgrades including AMI and ADMS.
RCW 19.280.100. (2) (c) Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	Programs will be identified through the CEIP process and through engagement with the equity advisory group. PSE is pursuing an Alternative Pricing pilot.
RCW 19.280.100. (2) (d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	Appendix E, Conservation Potential Assessment and Demand Response Assessment, includes a forecast of DERs

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	Appendix M, Delivery System 10-Year Plan includes major electric transmission work highlighting non-wires analysis performed for four areas to date. It also discusses pilots in the near term. Further elaboration regarding data gathered, market research, source information and peer reviewed science, will be added as this 10-year plan matures to fully support this RCW subsection. Appendix A, Public Participation, describes the stakeholder work thus far and future plans and coordination with other stakeholder requirements. PSE included a range of costs for integrating distributed energy resources as initial way to consider pessimistic and optimistic scenarios. More work will be done to build out this process.

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources to displace or delay system resources in the integrated resource plan;	Chapter 5, Key Analytic Assumptions describes the DER forecast derived from a non-wires analysis that is included in the IRP which provides resource and delivery system value. Chapter 2, Clean Energy Action Plan, includes DERs from the non-wire analysis. Appendix M, Delivery System 10-Year Plan, describes the investments that will be needed to support and enable DERs identified in the IRP.
RCW 19.280.100. (2) (g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	Chapter 2, Clean Energy Action Plan, describes PSE's focus on cyber-security with grid modernization.
RCW 19.280.100. (2) (h) Include a discussion of lessons learned from the planning cycle and identify process and data improvements planned for the next cycle.	Lessons learned from this planning cycle will be discussed in future IRPs. Appendix M, Delivery System 10-Year Plan, discusses current data gaps that are actively being addressed.
RCW 19.280.100. (3) To ensure that procurement decisions are based on current cost and performance data for distributed energy resources, a utility may procure cost-effective distributed energy resource needs as identified in any distributed energy resources plan through a process that is price-based and technology neutral. Electric utilities should consider using competitive procurements tailored to meet a specific need, which may increase the utility's ability to identify the lowest cost and most efficient means of meeting distribution system needs. If the projected cost of a procurement is more than the calculated system net benefit of the identified distributed energy resources, the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility, may approve a pilot process by which the electric utility will gain a better understanding of the costs and benefits of a distributed energy resource or resources.	Further work will be done through the Clean Energy Implementation Plan

New Fuel Technologies

Renewable Natural Gas

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

RNG usage in both simple- and combined-cycle plants will be explored as a means of providing capacity support, in a less carbon intensive manner, to support the renewable generation required under CETA.

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

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

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. Because of RNG's significantly higher cost, the very limited availability of sources and the unique nature of each individual project, RNG is not suitable for hypothetical analysis. The benefits of RNG are measured primarily in its carbon reduction benefits, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Due to the very competitive RNG development market, PSE is not prepared to analyze specific RNG projects in a public environment. Individual projects will be analyzed and documented as opportunities arise and there is further clarity of the guidelines for incorporation of RNG into PSE's supply portfolio.

In addition, PSE has a current offering called Carbon Balance which provides residential natural gas customers the choice to purchase blocks of carbon offsets for $3 each per month. The program provides customers with a way to reduce their carbon footprint through the purchase of third-party verified carbon offsets from local projects that work to reduce or capture greenhouse gases.

Biodiesel

Biodiesel is defined as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old growth or first-growth forests. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or from dedicated crops. According to Western Washington Clean Cities, there are two facilities in Washington state that make biodiesel, which together can manufacture 100 million gallons of biodiesel a year.[5] Biodiesel may become crucial in the future as a fuel supply for combustion turbines. These units would be the same basic generator as a natural gas combustion turbine, but instead of burning natural gas with petroleum diesel as a backup fuel, the generator would burn renewable natural gas with biodiesel as the backup fuel. This technology may be crucial to maintaining a reliable, renewable electric system during low hydro conditions.

Two primary challenges will need to be addressed for PSE to be able to use these types of combustion turbines. One is the supply-chain limit for biodiesel. Just one 229 MW renewable peaker would require 85 percent of the current estimated production capacity. Clearly, the supply chain would need to be expanded – probably by adding new production lines to existing refineries

2 / See: https://www.pscleanair.org/284/Biodiesel and using dedicated crops. The other challenge is the engineering and design of these peaking units. Biodiesel tends to burn hotter than petroleum diesel and may have higher particulate emissions. Hawaii Electric has reported thermal stress and emission rate challenges with burning biodiesel in existing units designed for conventional diesel. PSE will need to pursue research and development into how combustion turbines can efficiently burn biodiesel as a backup.

Hydrogen

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

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

Hydrogen, or its derivatives, can be used to reduce the GHG content of gas for gas utilities. Renewable hydrogen can be injected into the existing pipeline infrastructure. The amount of hydrogen that can be blended into the pipeline system with natural gas is limited, because hydrogen is less energy dense than current standards for pipeline quality gas. That means a cubic foot of hydrogen has less energy than a cubic foot of natural gas. Pipeline systems are required to maintain heat content within predetermined ranges for safety reasons. Gas-consuming equipment and appliances are designed to use a certain amount of gas per unit of time, so the gas feeding that equipment needs to maintain these standards. Currently, it appears the ratio of hydrogen that could be injected into the system is about 20 percent.

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

A significant challenge for hydrogen is cost. Today, gray hydrogen (hydrogen manufactured with fossil fuel energy) sells for about $2 per kilogram delivered to a few key chemical market hubs, which translates to about $17.6 per MMBtu for natural gas.[6] While green hydrogen may use surplus renewable electricity that may cost less on a dollars per MWh basis, the output of a hydrogen manufacturing facility using only surplus renewable energy will be less, which will drive up the average cost per unit. That is, the region is not expected to have a surplus of baseload renewable energy any time soon, so the manufacturing process cannot be a baseload operation.

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

3. WHOLESALE MARKET CHANGES

Prices, Volatility and Liquidity / August 2020 Supply Event

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

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

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

Market Developments / CAISO EDAM

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

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

4. REGIONAL RESOURCE ADEQUACY

Utilities in the Northwest Power Pool (NWPP) footprint, including PSE, are accelerating retirements of firm generating resources. Firm generators are expected to be replaced by variable renewable energy resources as a result of Washington State's Clean Energy Transformation Act and other states' and utilities' own goals and commitments focused on reducing greenhouse gas emissions. As the resource mix changes, a key challenge will be to ensure that the region maintains adequate levels of firm capacity to reliably serve load. This will require utilities to accurately assess how resources like renewables and energy storage can help maintain system reliability and what other firm generation may be needed to maintain system reliability. Resource planning in the Northwest is currently done on a utility-by-utility basis, typically through integrated resource planning processes. This utility-by-utility planning framework has worked well for the region during times when the region was surplus capacity. As large amounts of firm generators retire and several regional studies point to a capacity deficit in the next decade, utilities have growing concerns about whether the new capacity needed to maintain regional reliability can be procured in a timely manner.

As a result, utilities across the Northwest have partnered to explore a potential regional resource adequacy program. A Northwest resource adequacy program would offer two key benefits: reliability and cost savings. First, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Resource adequacy programs do this by establishing transparent processes to assess, allocate and procure a region's resource needs. Second, a regional resource adequacy program would enable cost savings. By planning for the peak demand of the entire region (the coincident peak demand) instead of each utility's individual (non-coincident) peak demand, a regional approach would produce an overall lower capacity need and therefore a reduced level of investment. Furthermore, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand.

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

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

5. FUTURE DEMAND UNCERTAINTY FACTORS

Electric Vehicles

Electric vehicles (EV) are rapidly gaining a presence in PSE's service territory and taking hold in every vehicle market. These EVs include light-duty vehicles (LDV), medium-duty vehicles (MDV), or heavy-duty behicles (HDV), both cars and trucks, and they are operated by individuals and as members of fleets. With EVs comes new electric load, which PSE is preparing for by having an EV sales and load forecast performed on its behalf, which was then incorporated into the 2021 IRP Demand Forecast. This load forecast revealed new opportunities to manage this load and improve customer experience, which PSE is investigating through a suite of EV pilot programs.

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

Demand Impacts

The Electric Vehicle Charger Incentive (EVCI) Pilot Program, which went into effect on May 1, 2014, allowed PSE to offer a $500 rebate to customers who purchase their own Level 2 electric vehicle charger.[7] Using data gathered through this pilot, PSE created an "Electric Vehicle Household and Charger Load Profiling" study with a study period set for 12 months ending June 2017. At the time, there were an estimated 13,140 EVs registered in PSE's electric service territory, of which 9,480 were 100 percent battery-operated (BEV) and 3,660 were plug-in hybrid vehicles (PHEV).[8]

The key findings of the study were as follows:

- On a typical weekday, hourly load per Level 2 EV charger varied between 0.1 kW and 0.9 kW while hourly load per Level 1 charger ranged between 0.06 kW and 0.6 kW.[9]
- On a typical weekend day, hourly load per Level 2 charger ranged between 0.08 kW and 0.6 kW while the range of hourly load per Level 1 charger was 0.04 kW to 0.5 kW.

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

- Daily peak of EV charger load occurred mostly in the early evening hours of 6:00PM to 8:00 PM, as does monthly system peak demand.
- Monthly load factor and system coincidence factor of EV charger loads are fairly low for most months. During the study period, all of the monthly load factors were below 0.29 while 8 of 12 monthly system coincidence factors were lower than 0.40. However, the system coincidence factor will become very high if monthly system peak and EV charger peak loads occur on the same day, as happened in March 2017 when the system coincidence factor was 0.91.
- Although the total load of residential EV chargers represents less than 0.7 percent of the residential class load now, it will grow rapidly to take up a significant portion of the residential class load during the next 10 to 15 years. With 250,000 EV's driven by PSE residential customers, the annual peak load of their EV chargers is estimated to be 371 MW, or over 10 percent of the residential class peak.

EVs represent a significant and unpredictable load that can be added anywhere in the system and can be coincident with peak. This presents a problem for distribution at the circuit level as unexpected demand can be rapidly added with no notice.

Influencing the Load

PSE is uniquely situated to design programs that can manage customer charging patterns in a way that mitigates this peak load increase while still maintaining a positive customer experience. In 2017, PSE surveyed customers who had received a rebate for a Level 2 charger as part of PSE's EVCI program. The survey asked – among other things – about the customer's willingness to shift their charging behavior. The results of the survey indicated that the average surveyed EV driver does not schedule a time to charge their vehicle and instead charges that vehicle during peak hours but would be willing to change that if incentivized.

While customers are willing to shift their charging behavior, the question remains as to what exactly the incentive should be. Many factors about the vehicle and its operator's current charging behavior influence the best solution to providing customers a positive experience while successfully managing the EV load. These factors include the vehicle class (LDV, MDV or HDV), the ownership type (individual or fleet), the vehicle type (BEV or PHEV), the level of charging technology used (L1, L2 or DC Fast), and the location of the charger (workplace, single family residential, multifamily residential, and public charging). Right now, PSE is gaining knowledge about each of these factors through a comprehensive suite of pilot programs so that we can devise and implement the best solutions for managing the charging load. These programs are developing electric vehicle infrastructure across PSE's service area, with targeted charging pilots for single family residential, workplace and fleet, multifamily residential and public. In addition, PSE is also operating programs to educate customers on EVs and to improve access to EVs for low income customers. While these programs, except for the single family residential program outlined below, do not have specific load management features, they are helping PSE to understand the type of charging behavior that exists in these use cases so that we can devise tailored solutions that best fit that behavior.

While most of the programs currently operated by PSE are designed to understand charging load, the single family residential pilot program also has a load-shifting component. PSE covered a significant portion of the installation cost for a smart L2 charger in 500 single family homes, then randomly sorted participants into a control group or one of four treatment groups, all of which experiment with different methods of encouraging customers to charge outside of peak hours. The degree to which participants in each group charge off peak will be compared to the control group to identify which method is the most effective in encouraging customers to shift their EV load to times that are more desirable to the utility while still maintaining a positive customer experience. PSE expects to have preliminary results of the load-shifting study in early 2021.

PSE is continuing to explore different mechanisms to manage EV charging and the associated loads through incentives and rates. These efforts will continue with future LDV EV programs and anticipated programs for fleet and commercial customers (MDV and HDV).

Codes and Standards, Energy Efficiency Technology and Electrification

This section will be completed for the final IRP in April 2021.

Distributed Energy Resources

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

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

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

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

5. GAS SUPPLY AND PIPELINE TRANSPORTATION

Risks to Gas Supply

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

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

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

6. PURCHASING VERSUS OWNING ELECTRIC RESOURCES

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan, as well as the acquisition process. The formal Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and build decisions should also be considered when making prudent resource acquisition decisions.

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

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

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

2021 PSE Integrated Resource Plan

5 Key Analytical Assumptions

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

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.

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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

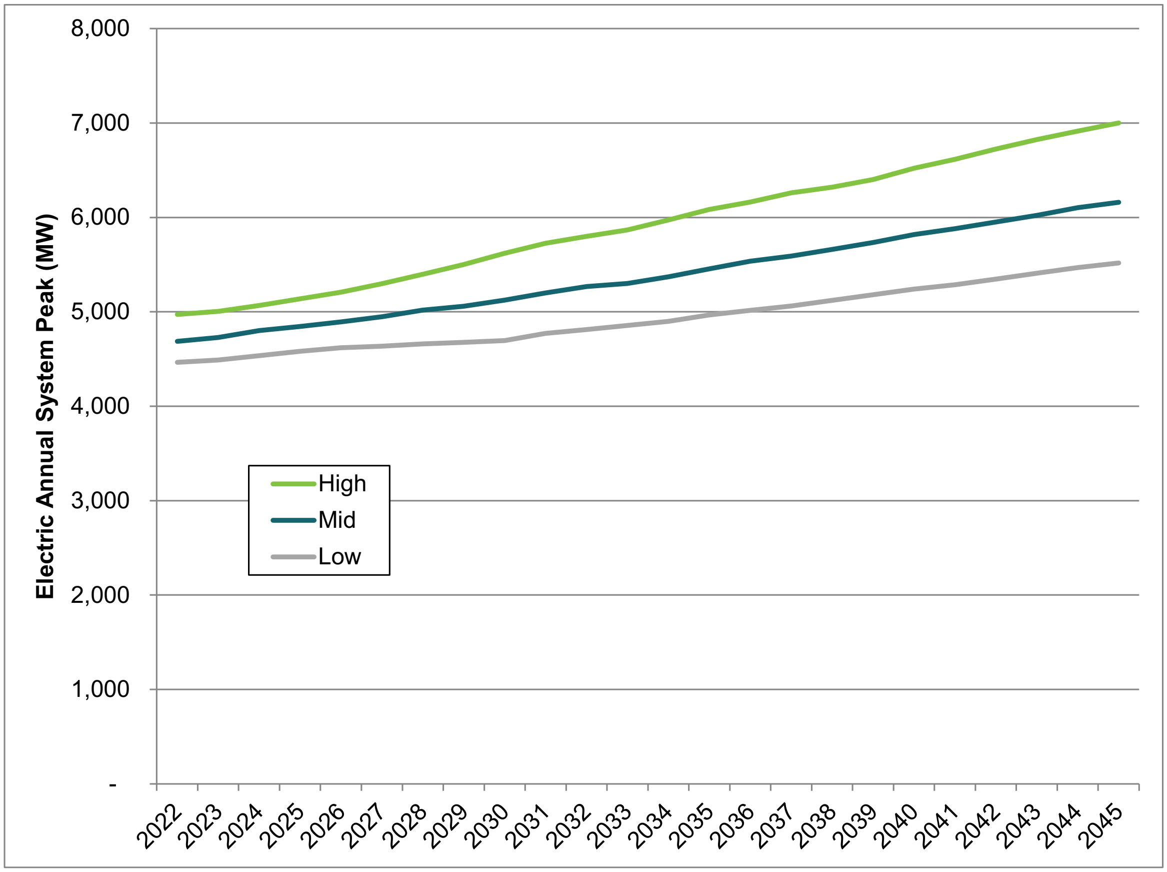
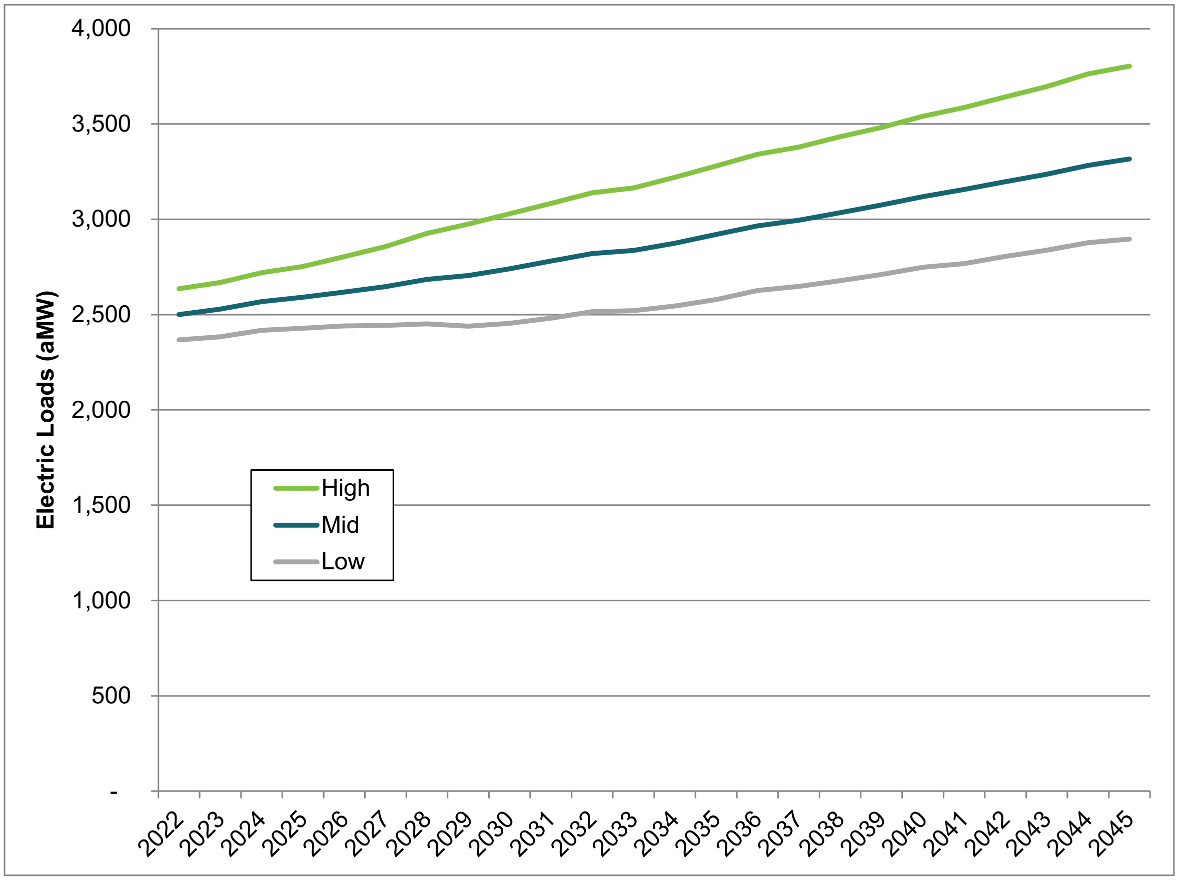


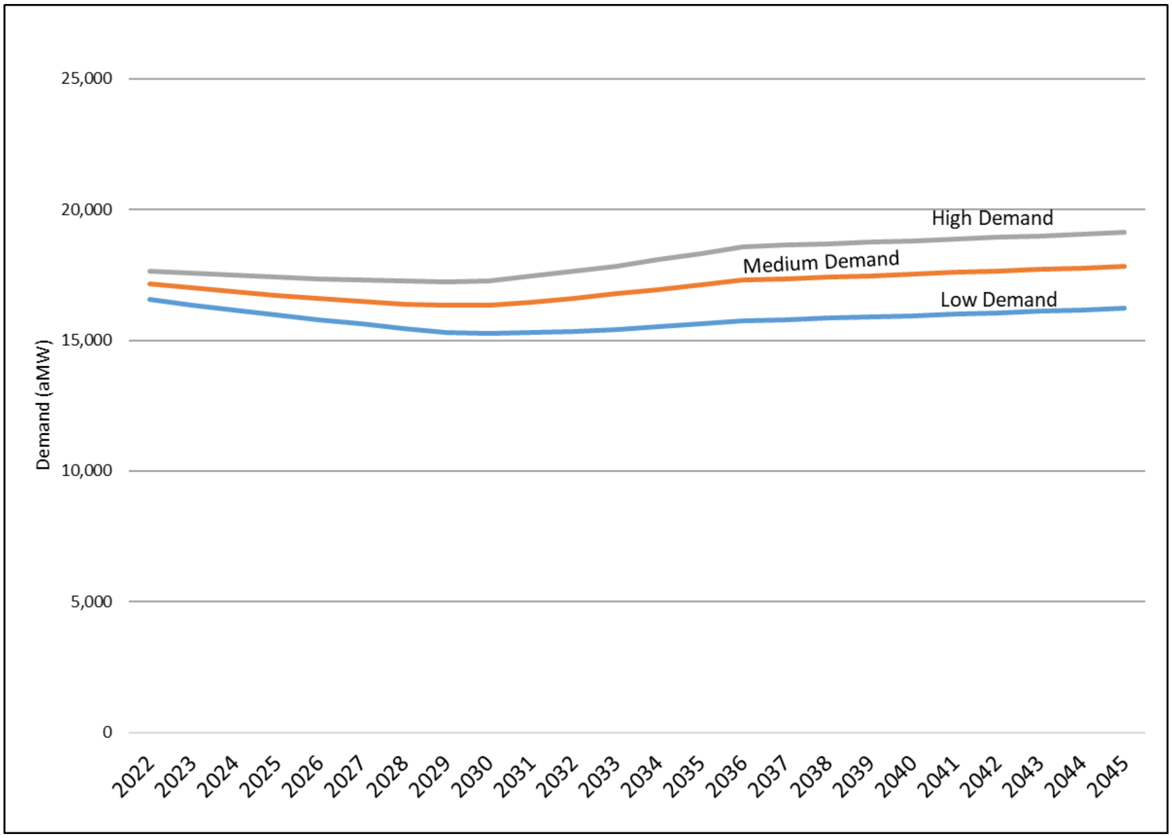
Figure 5-4: 2021 IRP Annual Electric Energy Demand Forecast - Low, Base (Mid) High



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.

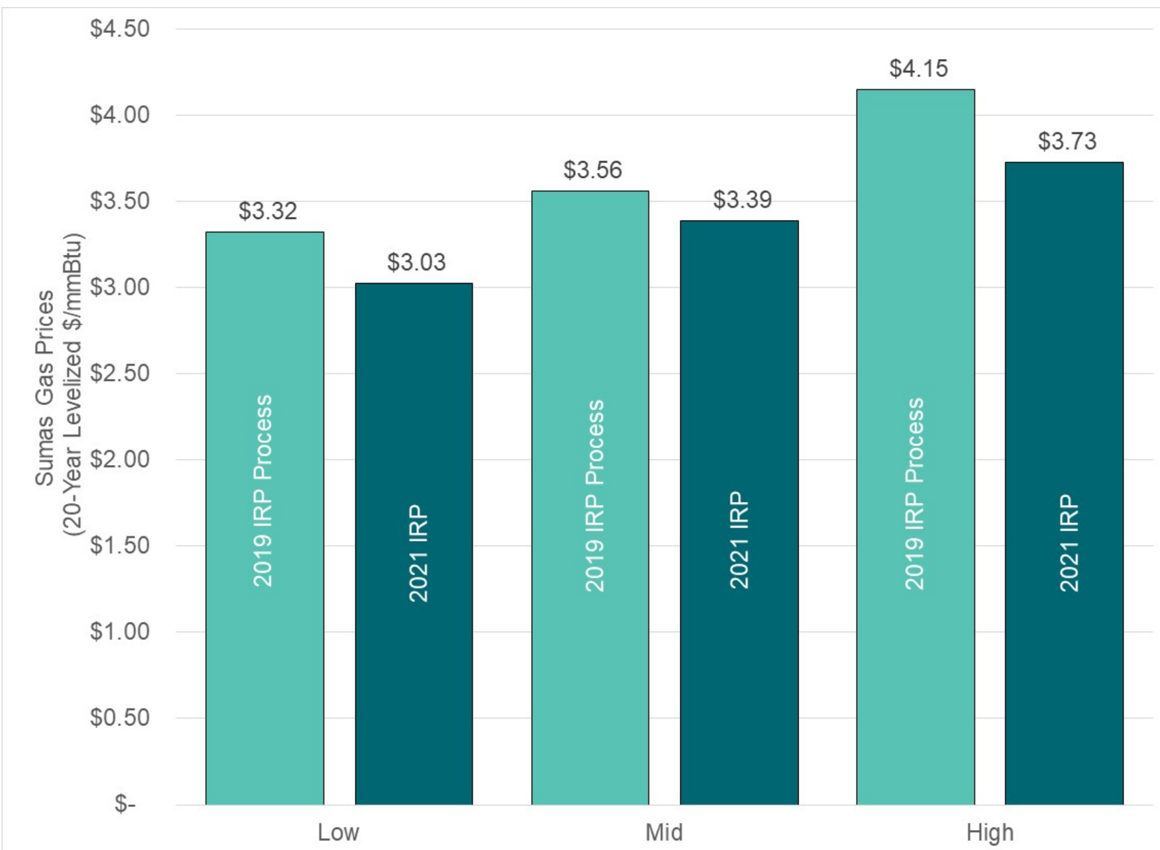
LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends 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.

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)

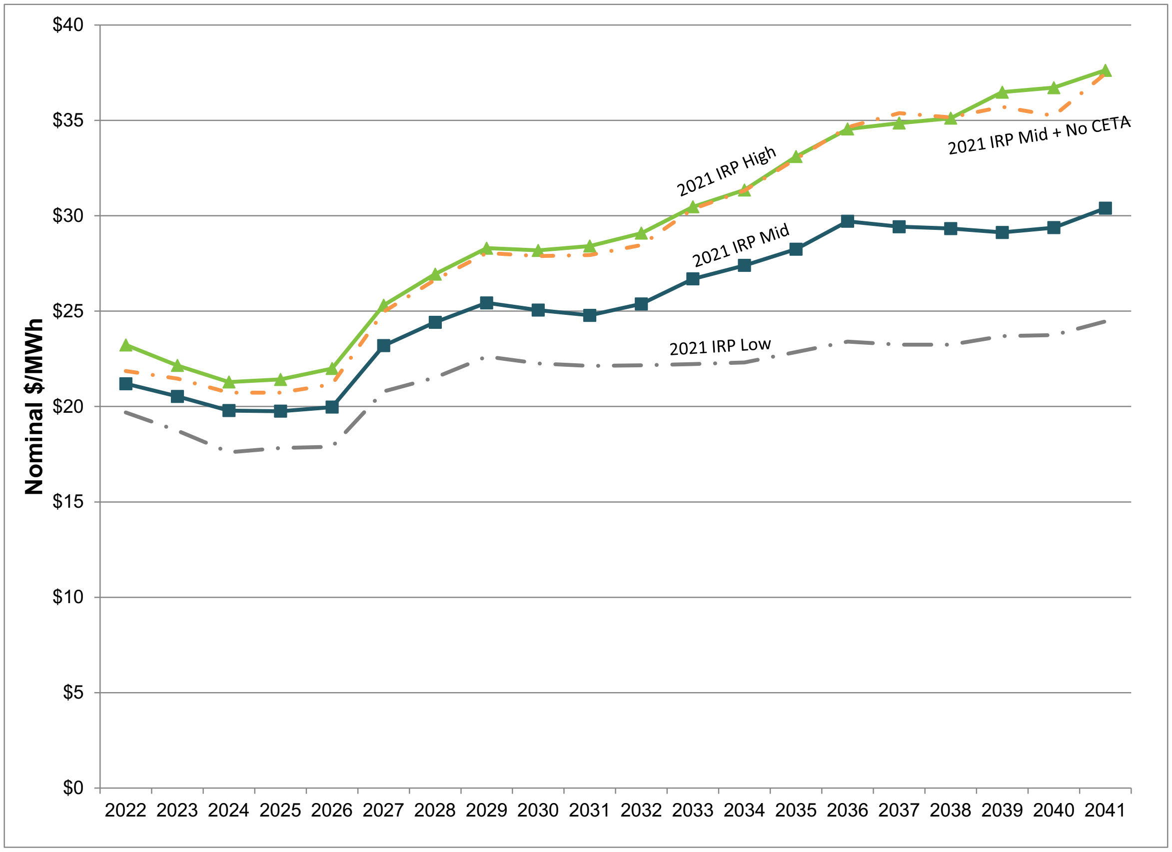
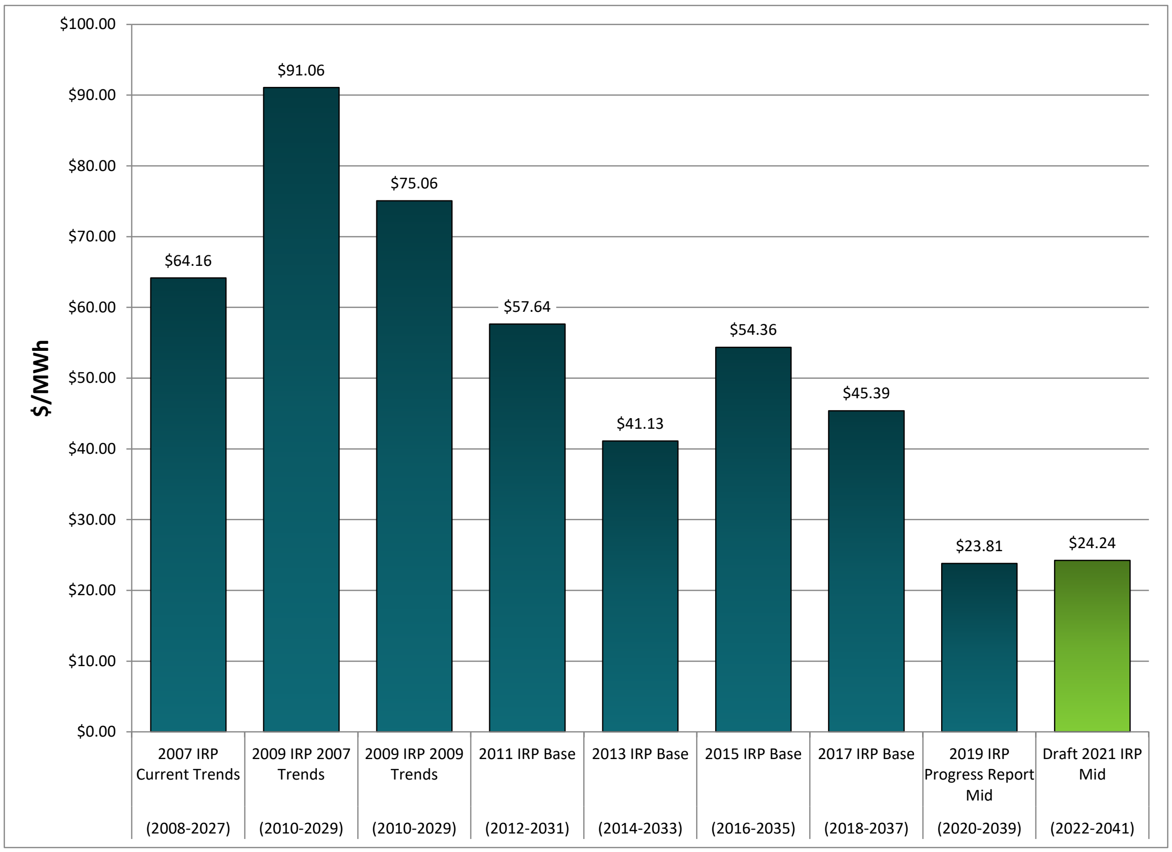


Figure 5-11 below compares the 2021 Mid Scenario power prices to past IRP power prices. In previous IRPs, the downward revisions in forecast power prices corresponded to the downward revisions in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by 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

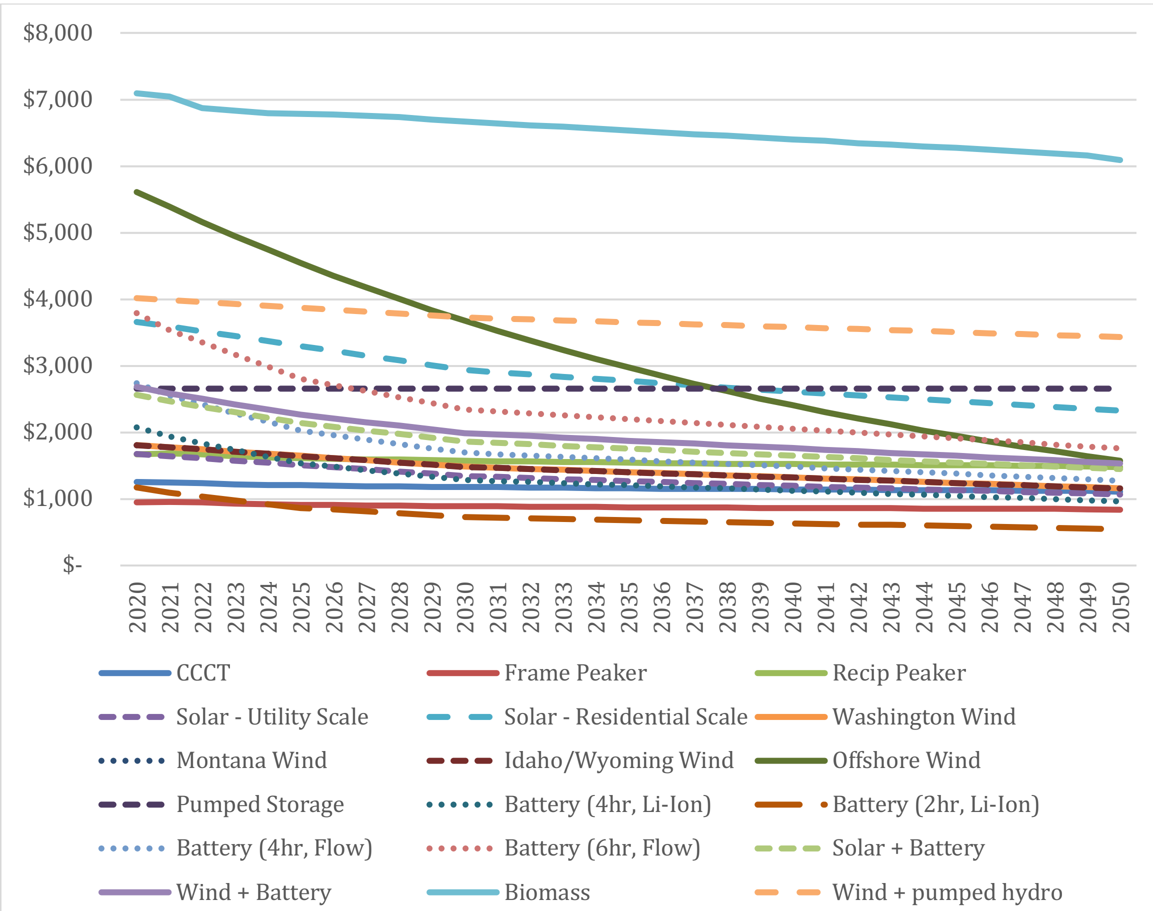
NOTES

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

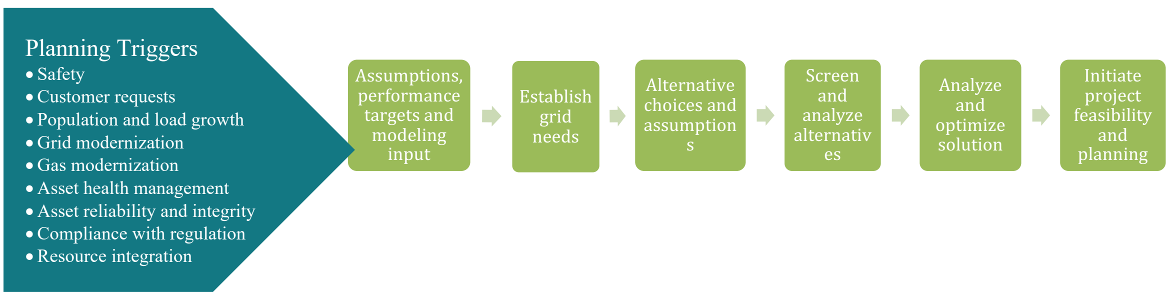
Transmission and Distribution Summary – Planned work to ensure delivery of resources unconstrained	Description (to be completed for final IRP)	Project Phase & Estimated In-service Date	Potential DER Location
Foundational Technology	Advance Metering Infrastructure (AMI) Advanced Distribution Management 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

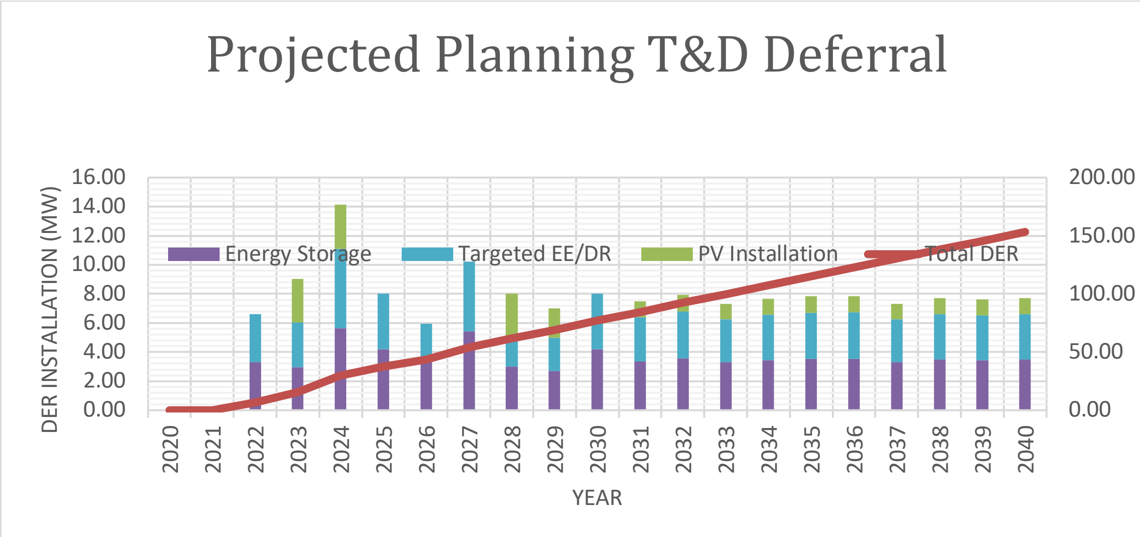


Figure 5-23: 20-year Projected T&D Deferral by Project Type

	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

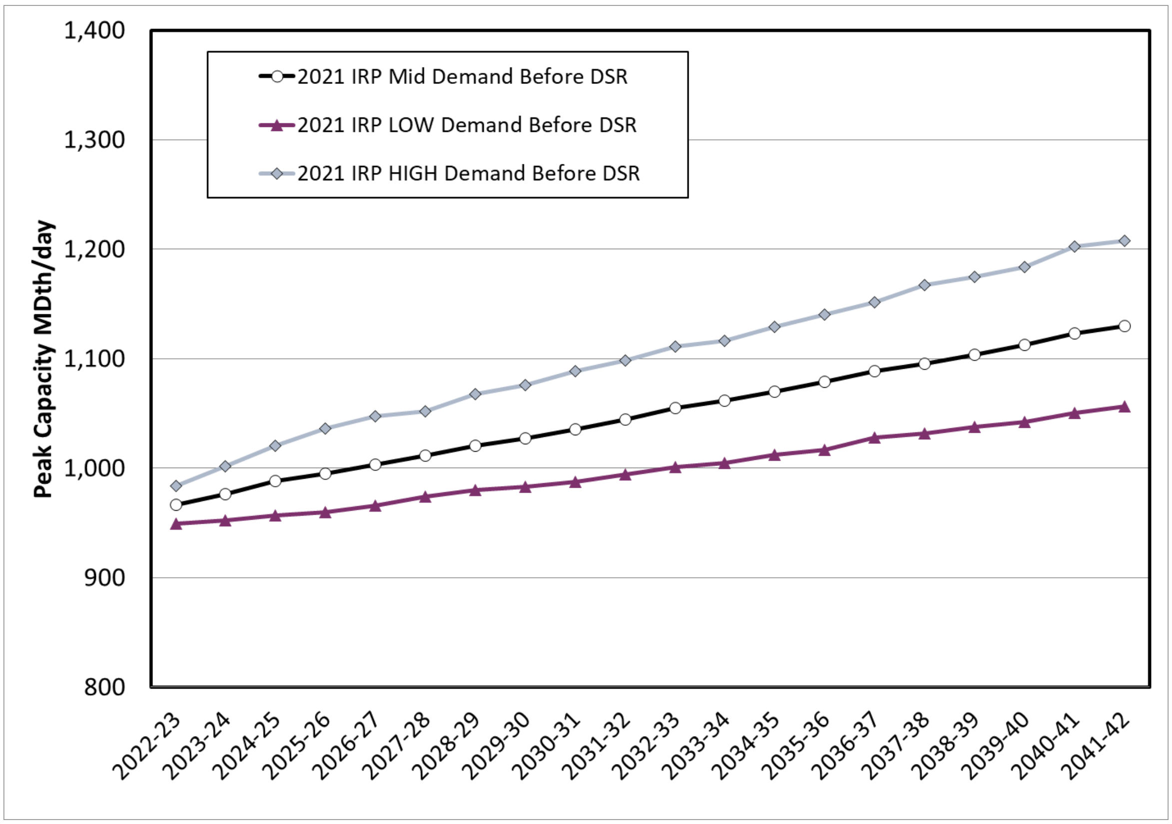
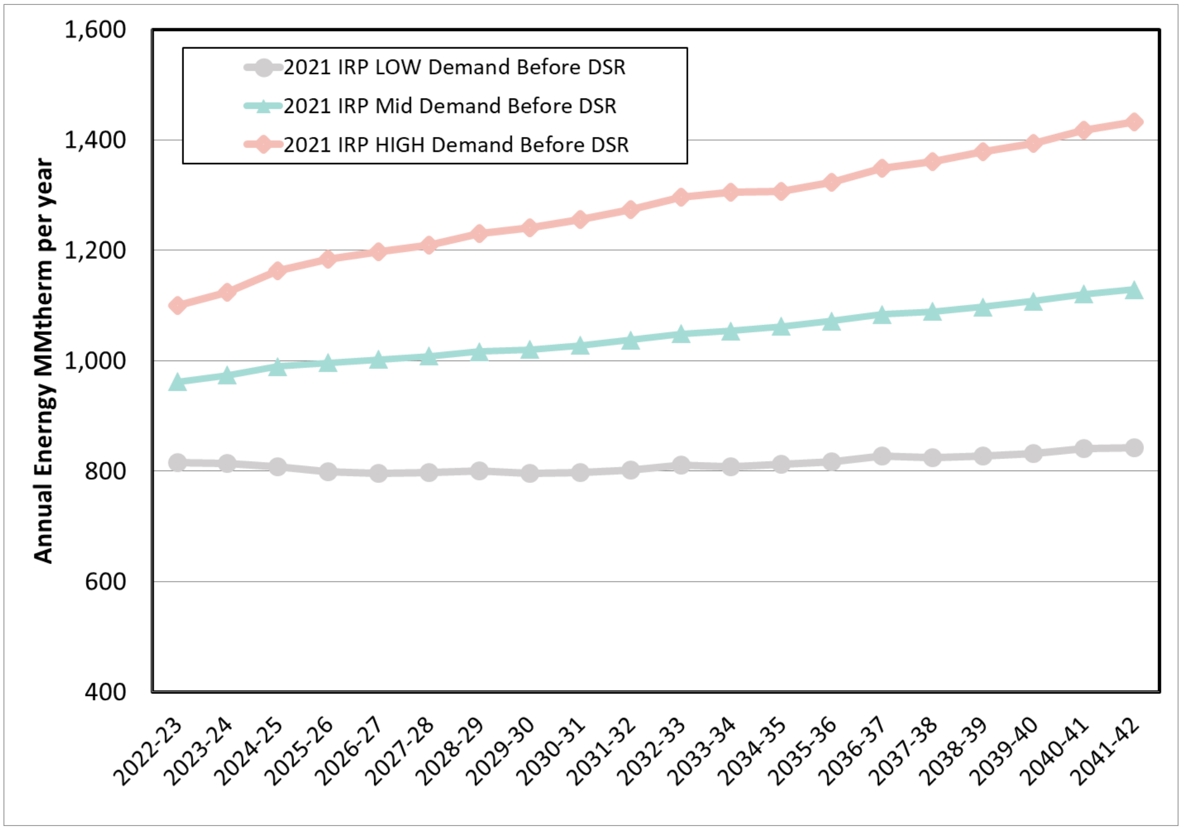


Figure 5-29: 2021 IRP Annual Natural Gas Sales Demand Forecast – Low, Base (Mid), High



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.

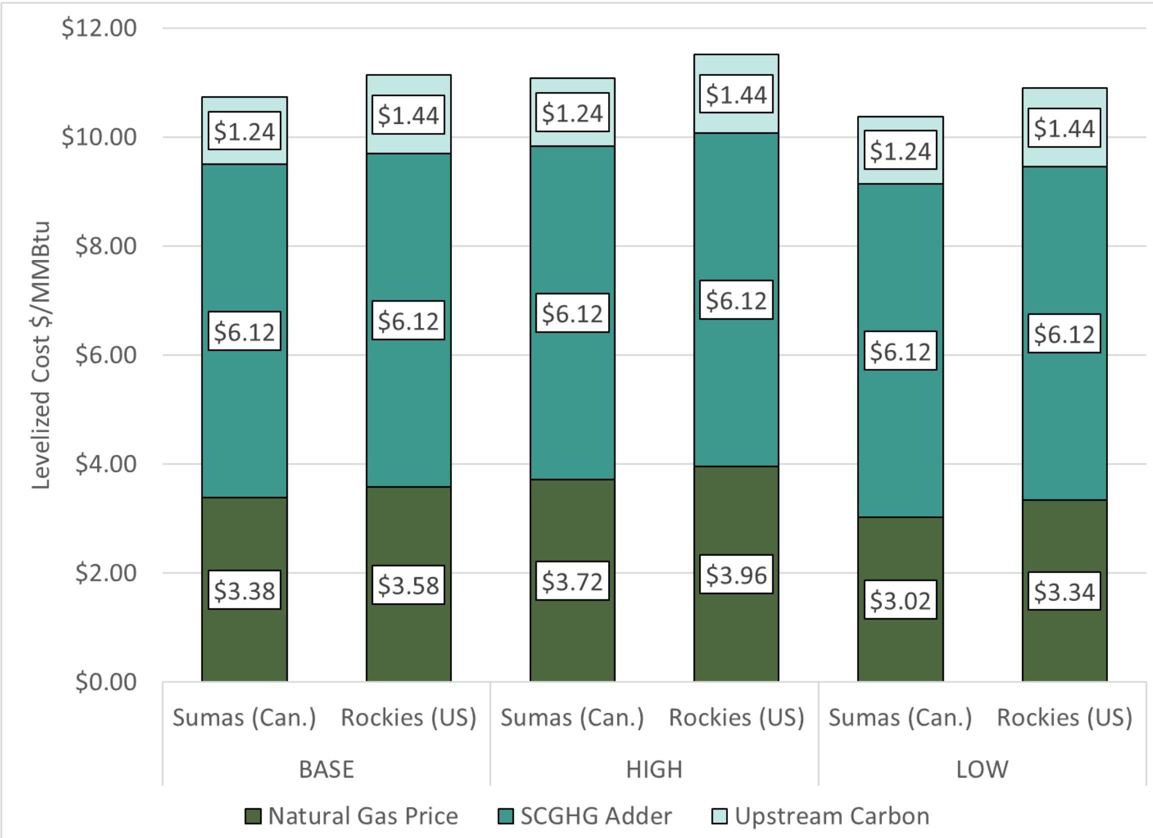
MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

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

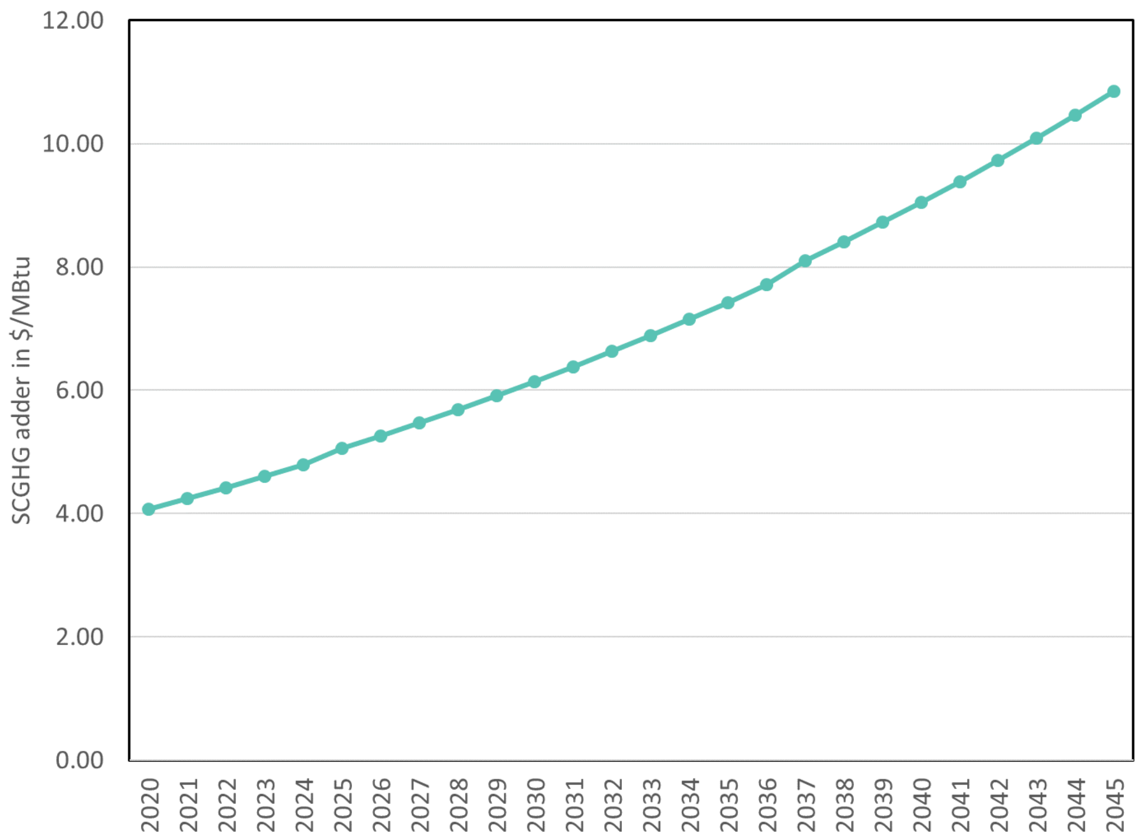


CO_2 Price Inputs

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.

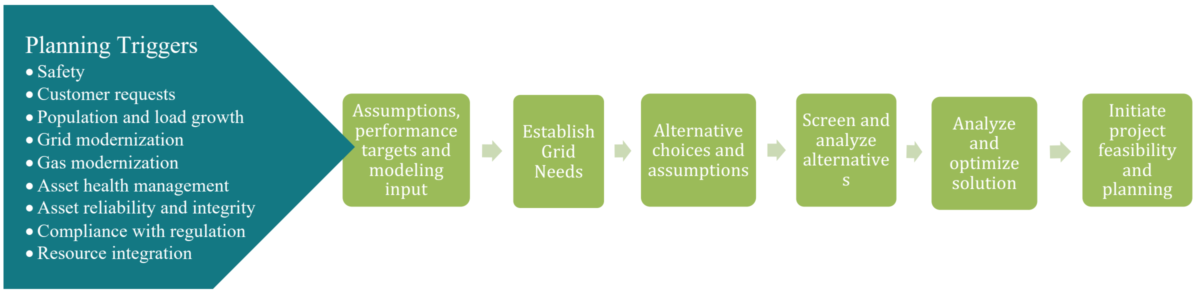
Figure 5-33: Natural Gas Distribution System Planned Work

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.

6 Demand Forecasts

The system-level demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts and peak demand over a 20-year period. These forecasts are designed for use in long-term resource planning and in Delivery System Planning (DSP) needs assessments.

Contents

1. OVERVIEW

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

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

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

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

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

In this IRP, the Base Demand Forecast is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the 30 years ending in 2019.

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

To model a range of potential economic conditions, weather conditions and potential modeling errors in the IRP analysis, PSE also prepares Low and High forecasts in addition to the Base Forecast. The Low Forecast models reduced population and economic growth compared to the Base Forecast; the High Forecast models higher population and economic growth compared to the Base Forecast. For the High and Low Demand Forecasts, historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

CONSERVATION IMPACTS. Demand is reduced significantly when forward projections of additional conservation savings are applied, as shown in Figure 6-1. However, it is necessary to start with forecasts that do not already include forward projections of conservation savings in order to identify the most cost-effective amount of conservation to include in the resource plan.

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

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

2021 IRP Base Forecast at End of Forecast Period	Before Additional DSR	After Additional DSR
Electric Energy Demand (aMW) (2045)	3,316	*To be provided in final draft*
Electric Peak Demand (MW) (2045)	6,159	*To be provided in final draft*
Natural Gas Energy Demand (Mdth) (2041)	112,918	*To be provided in final draft*
Natural Gas Peak Demand (Mdth) (2041)	1,130	*To be provided in final draft*

2. ELECTRIC DEMAND FORECAST

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

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

Electric Energy Demand

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

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

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

Figure 6-2: Electric Energy Demand Forecast before Additional DSR
Base, High and Low Scenarios (aMW)

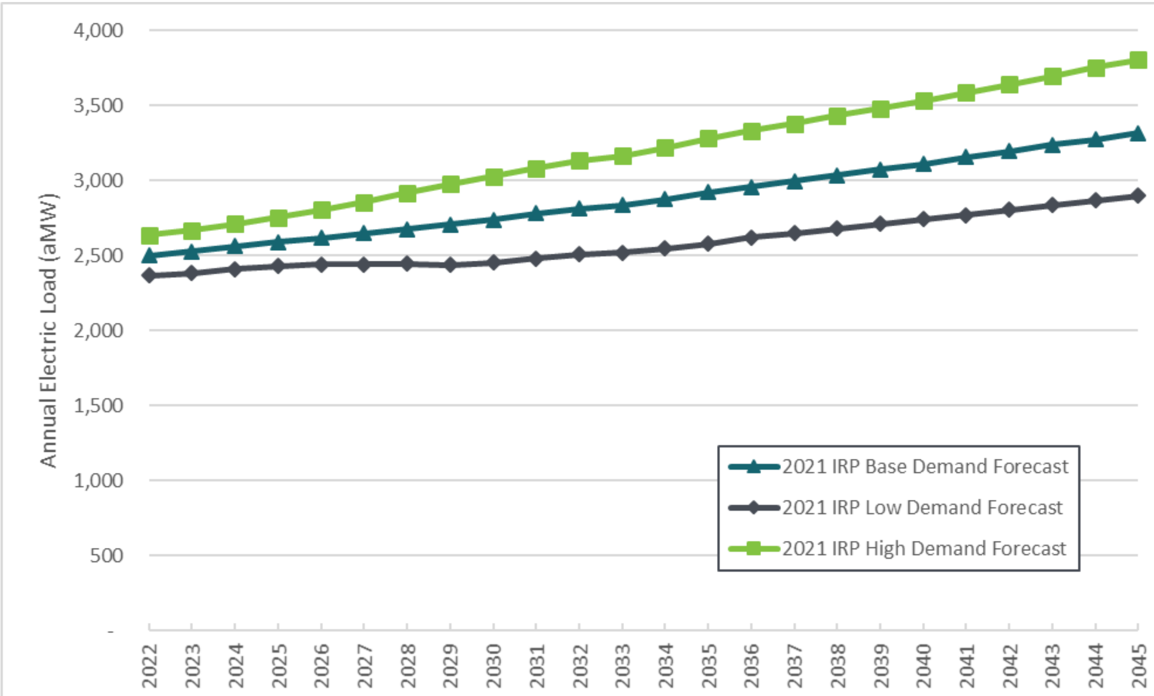


Figure 6-3: Electric Energy Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios

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

Electric Peak Demand

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

Winter Electric Peak Demand

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

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

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

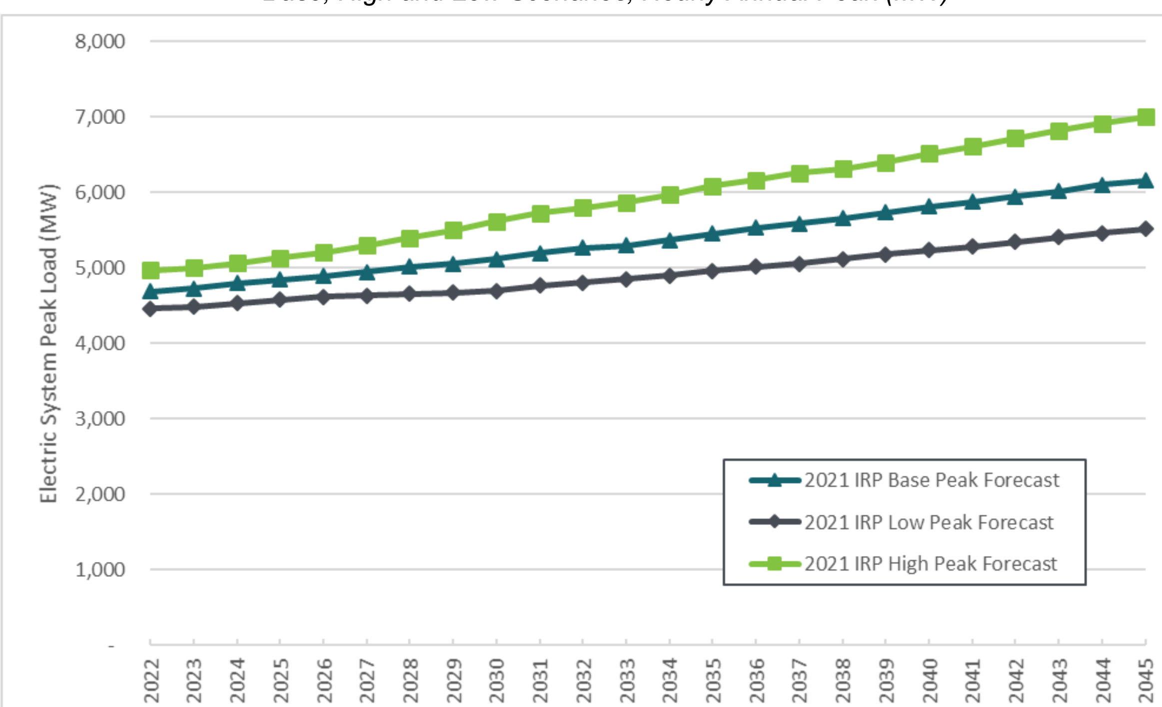
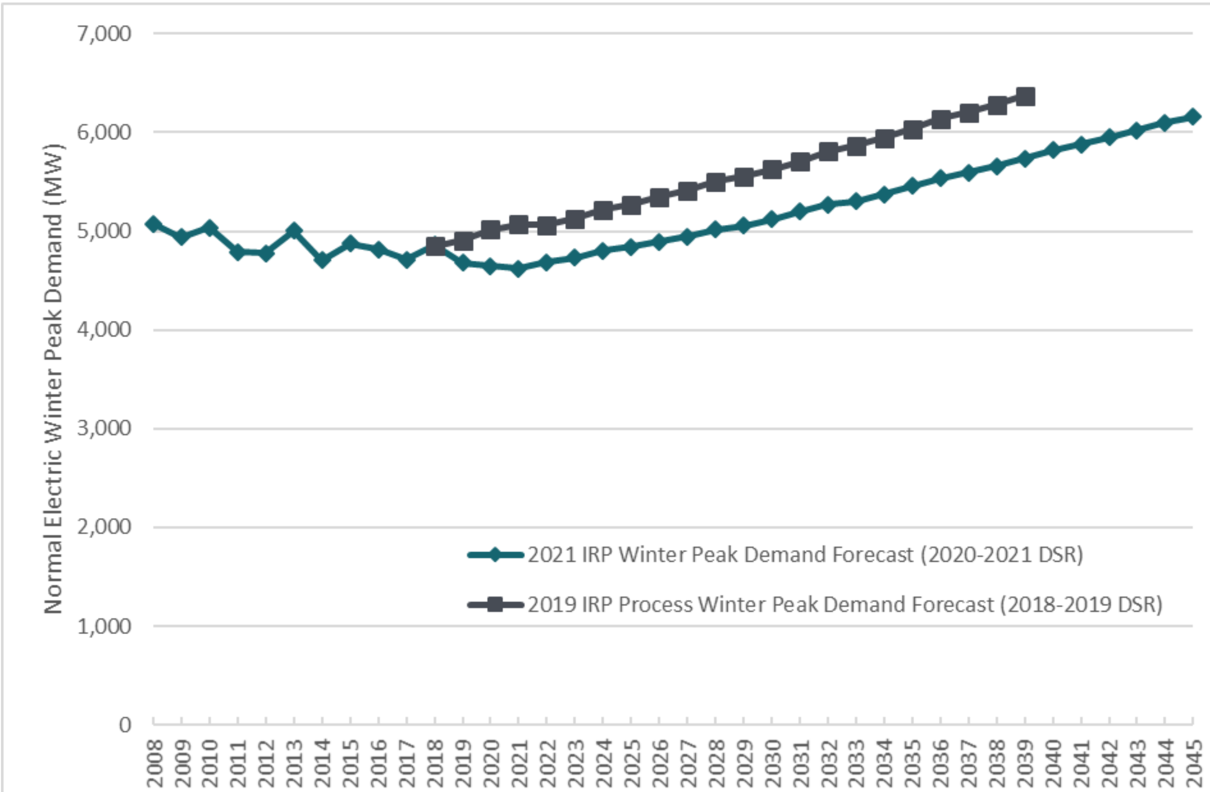


Figure 6-5: Winter Electric Peak Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (MW)

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

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

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



Summer Electric Peak Demand

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

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

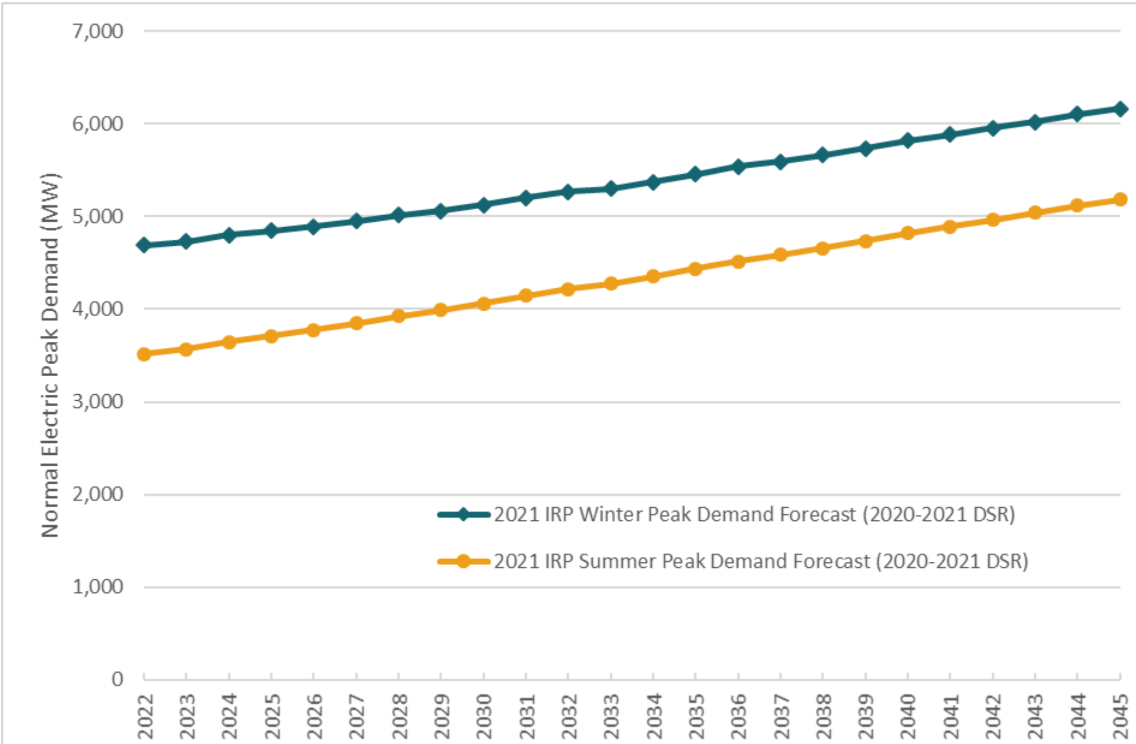


Illustration of Conservation Impacts

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

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

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

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

- *Effect on total system demand – To be provided in final draft.*
- *Effect on average annual growth – To be provided in final draft.*

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

- Effect on system peak – *To be provided in final draft.*
- Effect on peak demand – *To be provided in final draft.*

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

To be provided in in final draft.

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

To be provided final draft.

Details of Electric Forecast

Electric Customer Counts

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

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

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

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

Electric Demand by Class

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

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

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

Electric Use per Customer

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

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

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

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

Electric Customer Count and Energy Demand Share by Class

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

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

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

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

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

3. NATURAL GAS DEMAND FORECAST

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

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

Natural Gas Energy Demand

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

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

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

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

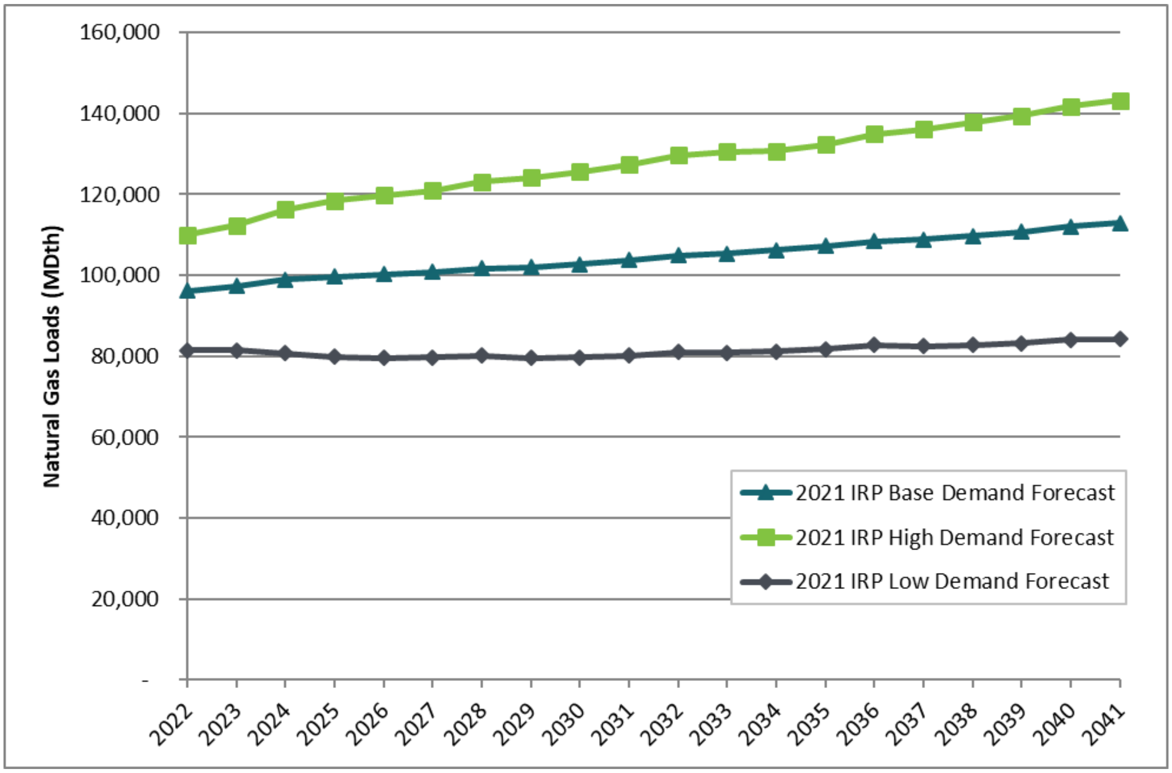


Figure 6-16: Natural Gas Energy Demand Forecast before Additional DSR (Table) Base, High and Low Scenarios without Transport (MDth)

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

Natural Gas Peak Demand

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

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

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

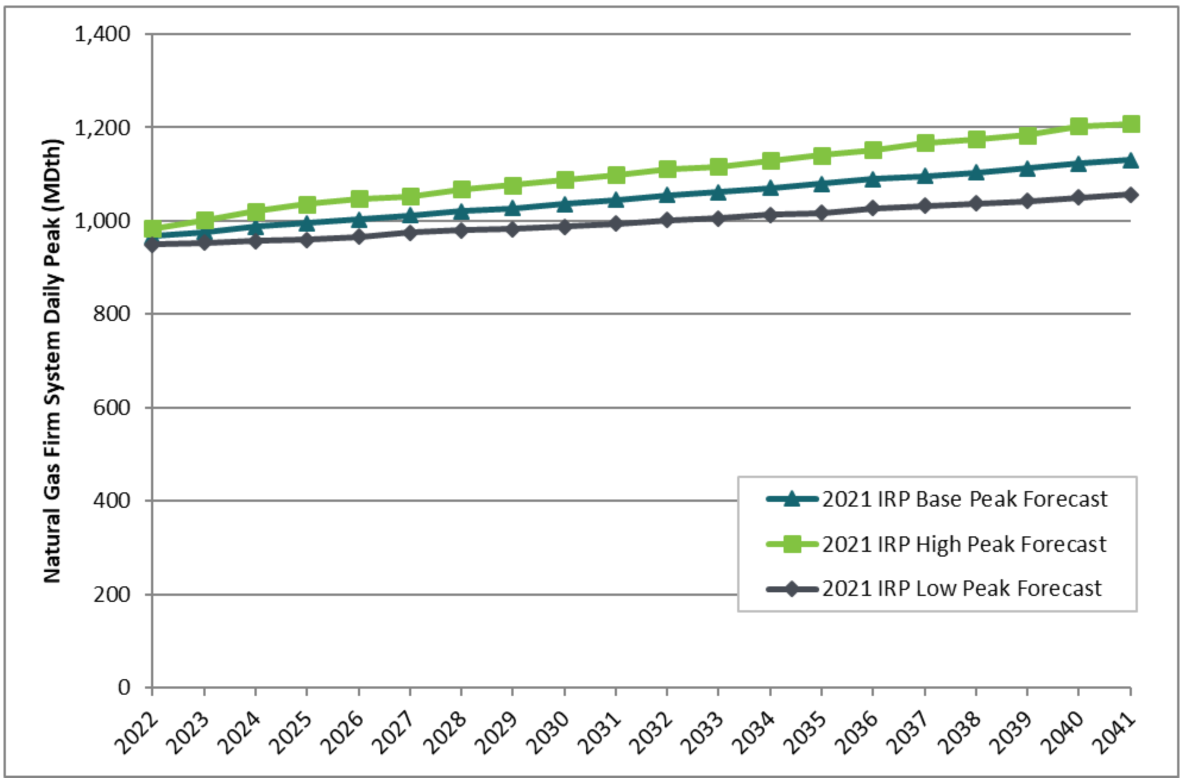


Figure 6-18: Natural Gas Peak Day Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios (13 Degrees, MDth)

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

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

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

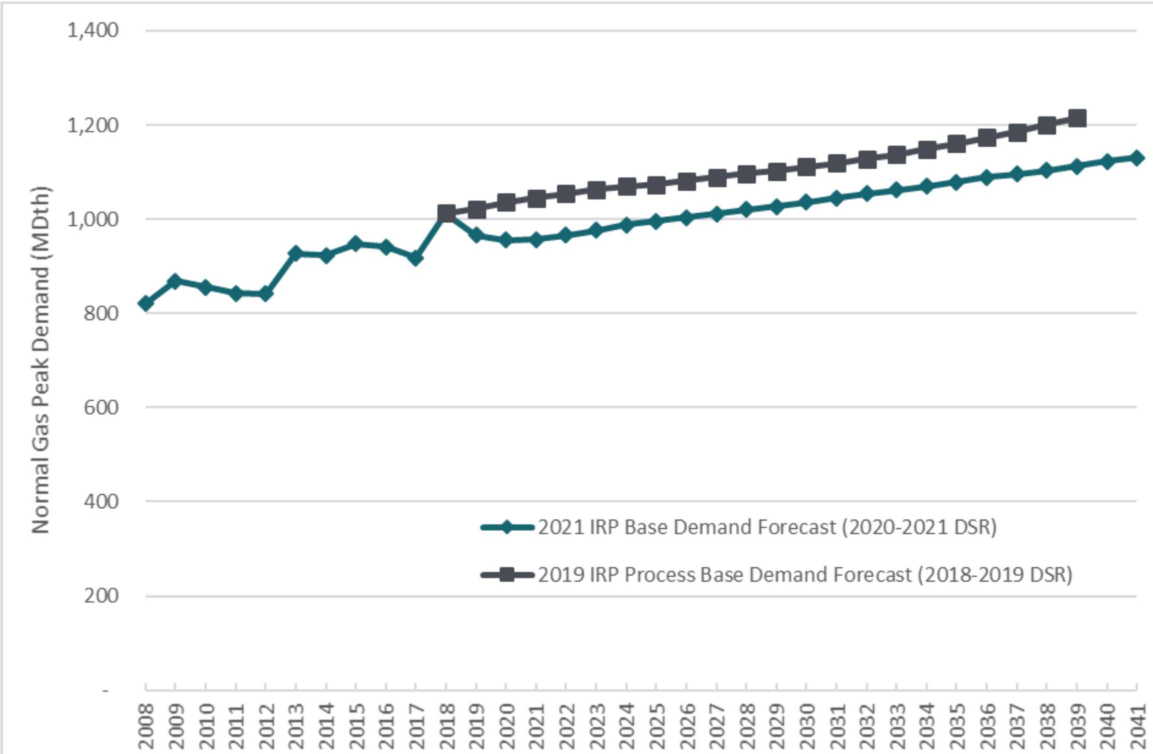


Illustration of Conservation Impacts

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

When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Effect on gas energy demand (without transport but including losses) – *To be provided in final draft.*
- Effect on gas design system peak – *To be provided in final draft.*

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

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

To be provided in final draft.

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

To be provided in in final draft.

Details of Natural Gas Forecast

Gas Customer Counts

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

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

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

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

Gas Use per Customer

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

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

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

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

Gas Demand by Class

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

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

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

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

Gas Customer Count and Energy Demand Share by Class

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

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

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

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

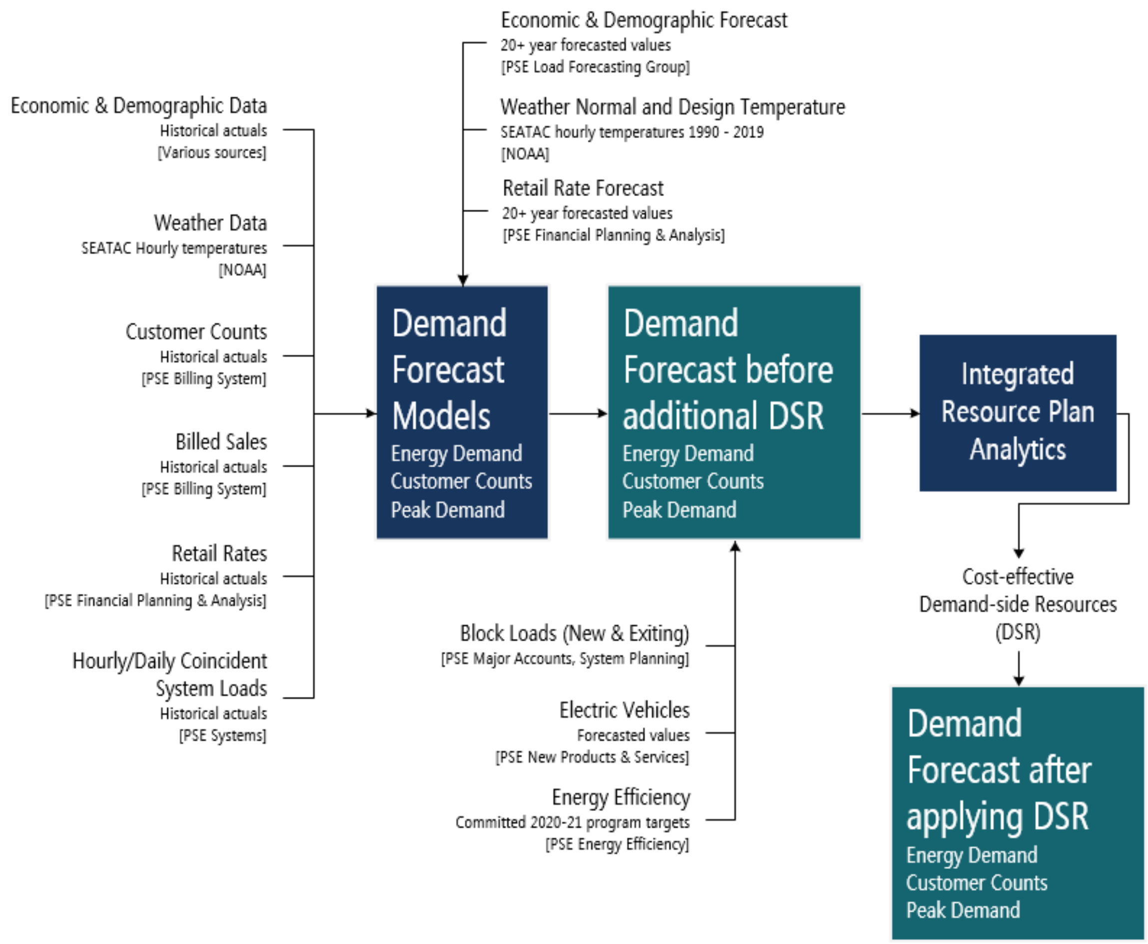
NATURAL GAS DEMAND SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2041**
Residential	53.2%	55.0%
Commercial	23.7%	25.7%
Industrial	2.0%	1.5%
Interruptible	2.2%	0.7%
Transport	18.7%	16.9%
Losses	0.2%	0.2%

4. METHODOLOGY

Forecasting Process

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

Figure 6-27: PSE Demand Forecasting Process



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

- Electric customer classes include residential, commercial, industrial, streetlights, resale and transport (customers purchasing their power not from PSE but from third-party suppliers).

- Natural gas customer classes include firm (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible (commercial and industrial), and transport (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Transport Customers

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

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

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

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

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

High and Low Scenarios

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

- The natural gas high and low scenarios were modelled using 250 stochastic simulations.
- The electric high and low scenarios were created with an additional 60 simulations, to make a total of 310 stochastic simulations, because electric vehicle loads were also varied. The electric modelling also varied the seasonal design peak temperature.

These simulations reflect variations in key regional economic and demographic variables such as population, employment and income. These simulations also vary the equation coefficients around the standard error of the coefficient to include potential model coefficient errors. In the electric scenarios, EV assumptions were held constant in 250 scenarios, a high EV forecast was applied to 30 scenarios and a low EV forecast was applied to the last 30. The high and low EV forecasts were derived using usage assumptions from the high and low EV scenarios in the Pacific Northwest National Lab's *Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid* (July 2020) report.

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

The high and low scenarios are run in the AURORA model to examine how a portfolio would change with high and low growth. A detailed description of the high and low scenarios is available in Chapter 5, Key Analytical Assumptions. The 310 electric stochastic scenarios are run in the AURORA portfolio model to test the robustness of the portfolio under various conditions. The 250 natural gas stochastic scenarios are run in Sendout. In the final draft of the IRP, detailed descriptions of the stochastics will be available in Chapter 8, Electric Analysis, and Chapter 9, Natural Gas Analysis.

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

Resource Adequacy Model Inputs

In addition to the stochastics used to create the high and the low scenarios, PSE also develops 88 electric demand draws for the resource adequacy (RA) model. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2017 is represented in the 88 demand draws. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. RA demand draws were created for the hydro years of 2027 to 2028 and 2031 to 2032.

Additionally, the RA model examines adequacy in each hour of a given future year; therefore, the RA model inputs are scaled to hourly demand using the hourly demand model, described in detail in Chapter 7, Resource Adequacy Analysis. To account for growth in electric vehicles, each of the 88 hourly demand forecasts was first created without electric vehicle demand. Then the hourly forecast of electric vehicle demand was added to each demand forecast, to create the final 88 hourly demand forecasts.

> > > See Chapter 7, Resource Adequacy Analysis *and* ***Appendix F, Demand Forecasting Models****, for detailed discussions of the hourly model.*

Temperature Sensitivity

PSE committed to run a future temperature sensitivity as part of the IRP. To that end, PSE provided three options to the IRP stakeholders and asked them to select one of the options for further analysis. The three options used different future temperature assumptions, representing a wide range of future outcomes. PSE then ran a sensitivity based on the option chosen.

The three temperature sensitivities presented to the IRP stakeholders as options were:

1. **15-year normal temperature**: PSE currently uses a 30-year normal for the base demand forecast. That is, the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. This normal weather is held constant into the future. The 15-year normal would instead use the most recent 15 years of weather data to create average monthly weather and that weather would be held constant into the future. This option has the least amount of warming in the future.
2. **Historical trended temperature**: PSE contracted with Itron to examine the historic warming trend in temperatures at Sea-Tac Airport. The warming trend at Sea-Tac was determined to be linear over time at 0.4 degrees Fahrenheit warming per decade. This warming trend was then projected linearly into the future. A detailed write up of this analysis is presented in Appendix L, Temperature Trends Study.
3. **Council climate model**: A recent project by Bonneville Power Administration, U.S. Army Corps of Engineers, and the Bureau of Reclamation produced downscaled climate models for the Northwest region. The Northwest Power and Conservation Council has been working with three of these models. Each of these models is on the Representative Concentration Pathway of 8.5, which some would argue is a “business as usual” pathway, while others would argue that this is a more extreme climate warming scenario. The three models showed different amounts of warming over time. PSE presented and proposed as an option the model in the middle amount of warming with 0.9 degrees Fahrenheit warming per decade.

Figure 6-29 below further describes the three future temperature options that IRP stakeholders chose from for this sensitivity.

Figure 6-29: Attributes of Temperature Sensitivity Options Compared to the Base Demand Forecast Temperatures Used

	Future Weather in Base Demand Model	Temperature Sensitivity Option 1	Temperature Sensitivity Option 2	Temperature Sensitivity Option 3
Description	30-year normal temperature	15-year normal temperature	Historical temperature trend (developed by Itron)	Council climate model
General Modelling Approach	Industry standard approach of using last 30 years of data to create flat projected temperature	Same methodology as 30-year normal, but using last 15 years of data	Uses historical warming trend to forecast future warming	Global Climate Model down-scaled to Pacific Northwest region
Weather Station Used	Sea-Tac	Sea-Tac	Sea-Tac	Sea-Tac
Historical Sea-Tac Weather Used	Last 30 years	Last 15 years	Data back to 1950 to develop a trend, 30-year normal used to define the starting point for the trend	Uses historic year of 1987 to map forecasted daily min and max temperatures to hourly temperatures
Global Climate Model, down-scaling method, and Representative Climate Pathway (RCP) assumed	NA	NA	NA, results similar to RCP 4.5	CCSM4_BCSD (Community Climate Systems Model v4: Bias Corrected Spatial Disaggregation and RCP 8.5)
Energy Demand Modelling Approach	Uses last 30 years of data to create flat projected temperature for future	Uses last 15 years of data to create flat projected temperature for future	Uses historical trend to forecast warming in the future. Uses the middle of the last 30 years of weather as a starting point for weather trend.	Draw a trend line through the future temperatures to get warming per year. Uses the middle of the last 30 years of weather as a starting point for weather trend.
Average Warming in the Forecast Period for Energy Demand Modelling	0^{o} F per decade	0^{o} F per decade	0.4^{o} F per decade	0.9^{o} F per decade

To incorporate the future temperature options into the demand forecast they first had to be converted into heating degree days (HDDs) and cooling degree days (CDDs). Heating and cooling degree days are a measure of how much heating or cooling is expected to be done by electric or natural gas appliances in a given month. Additional information on how to calculate heating and cooling degree days and how they factor into the demand forecast can be found in Appendix F, Demand Forecasting Models.

Figures 6-30 and 6-31 show the resulting heating degree days and cooling degree days from the three temperatures scenarios presented to the stakeholders compared to the current 30 year normal weather approach.

Figure 6-30: Annual Heating Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast

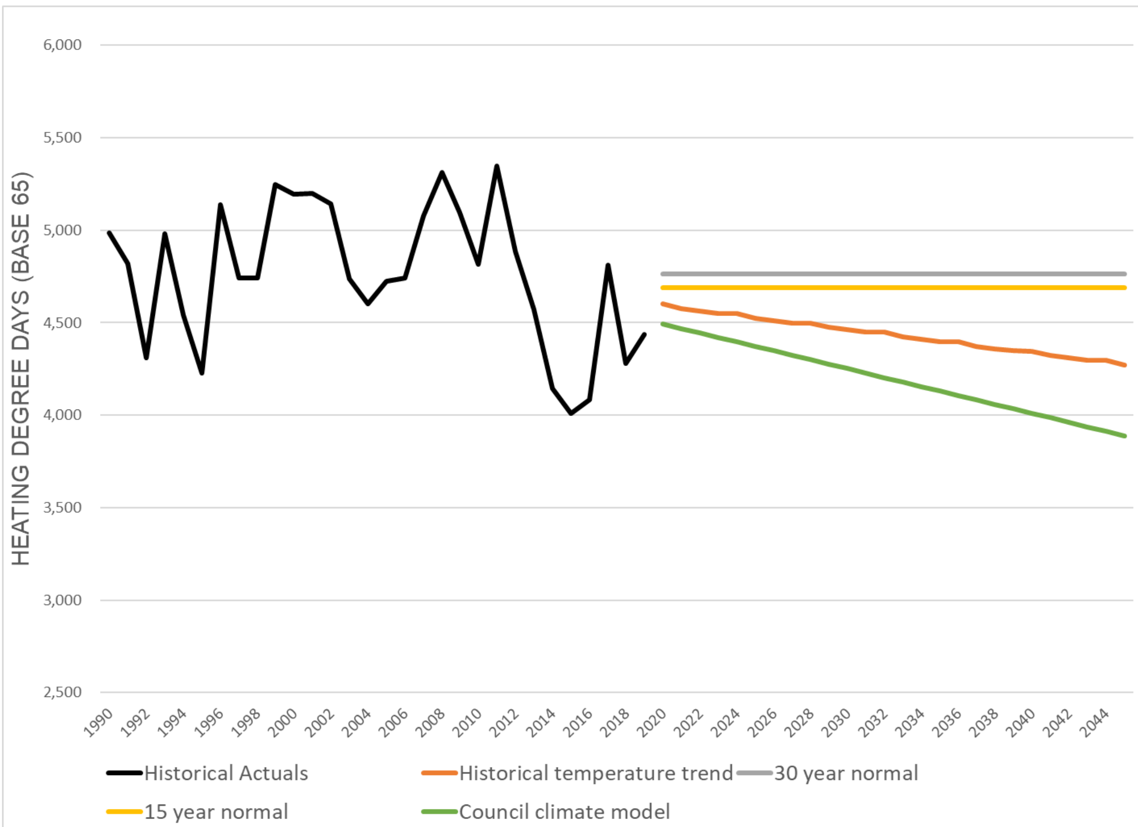
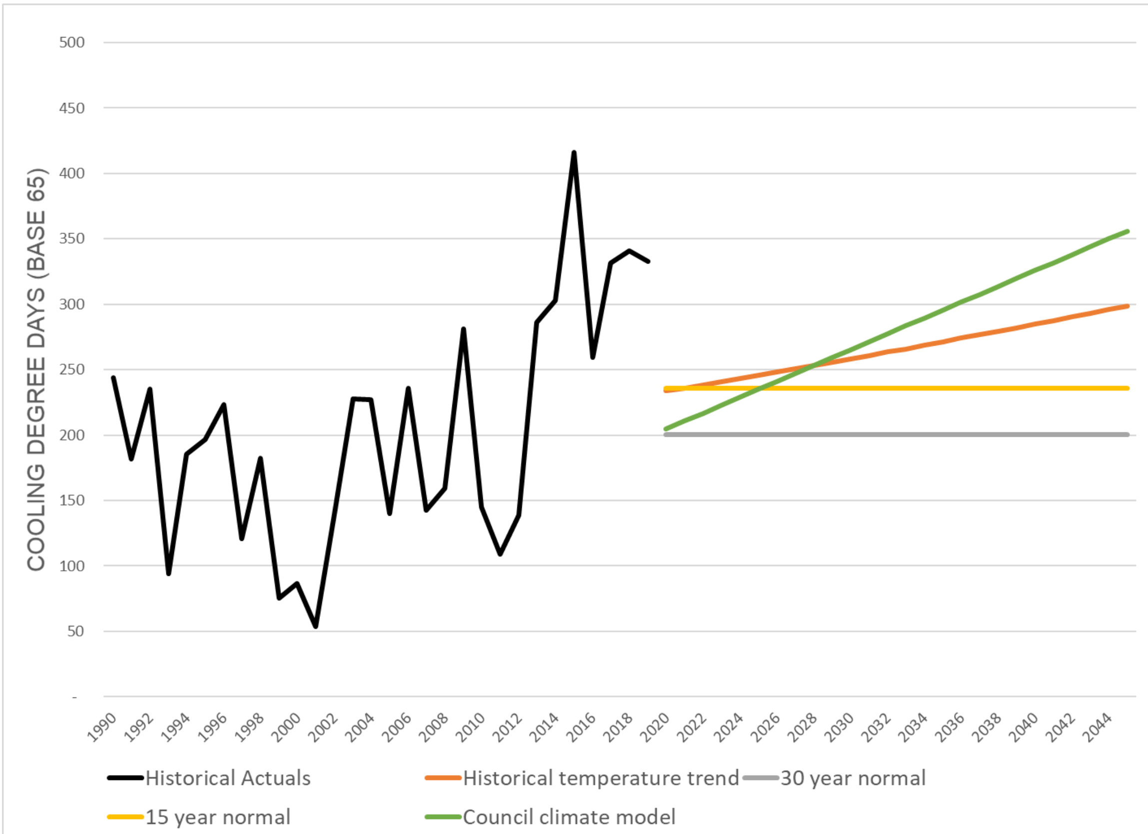


Figure 6-31: Annual Cooling Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast



Through the sensitivity prioritization process, stakeholders selected temperature sensitivity Option 3, which is based on the Northwest Power and Conservation Council climate model that assumes 0.9 degrees Fahrenheit warming per decade. Figures 6-32 and 6-33 compare the IRP base electric and natural gas demand forecasts with the forecasts that result from using this future temperature assumption.

Figure 6-32: Base Electric Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast (aMW)

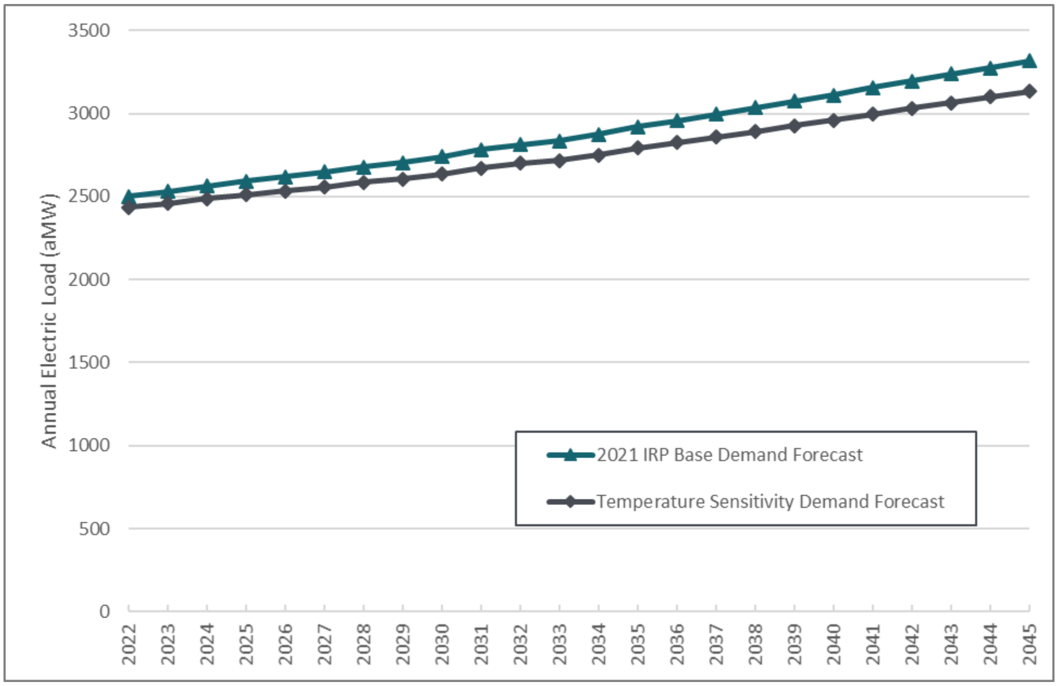
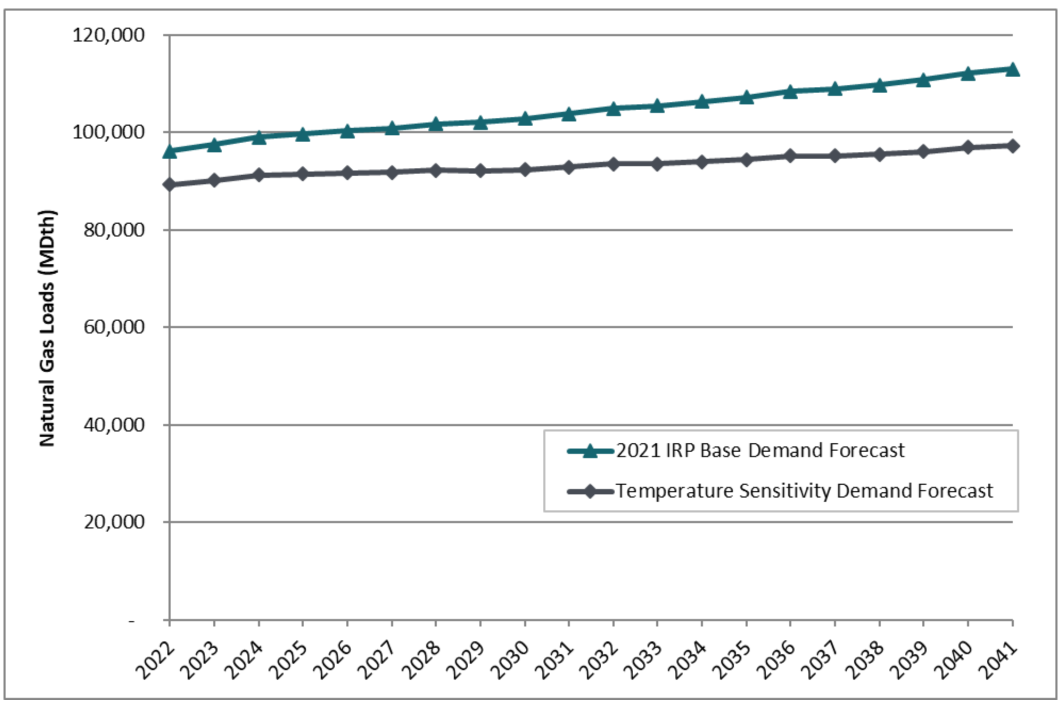


Figure 6-33: Base Natural Gas Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast, without Transport Load (MDth)



Updates to Inputs and Equations

Updates to the demand forecast inputs and equations made since the 2019 IRP Process are summarized below.

POPULATION FORECAST. In previous IRPs, PSE has used Moody's forecast of U.S. population along with the economic and demographic model to forecast population in the electric and natural gas service areas. This has been under-forecasting population growth in the Puget Sound Area. In the 2021 IRP, population forecast is built up from county population forecasts that the Washington Employment Security Department (WA ESD) publishes. This better aligns the electric and natural gas forecasts of residential customers with population growth. Therefore, as population growth slows in the later part of the forecast period, the residential customer counts also slow.

ELECTRIC COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES. To better model the different segments of the electric commercial and industrial classes, the classes were broken out into smaller segments, including small/medium, large, high voltage, and commercial lighting. Customer counts and use per customer were modeled for each segment individually, then added up to create the total customer counts and energy demand for each class.

SUMMER PEAK MODELLING. The electric peak model was updated to include an index of air conditioning (AC) saturation in lieu of a linear trend as a proxy of past and future AC adoption. The AC index is created by using PSE's historical Residential Characteristics Survey ("RCS") data points and calibrating to the U.S. Energy Information Administration (EIA) trend (West Region). The model driver was adopted to better track the non-linear nature of historical and future AC adoption.

MODELING SOFTWARE UPDATE. PSE transferred the demand forecast model from the Eviews application to energy forecasting software developed by Itron. The transition to Itron software enables PSE to manage the forecast input and output data in a database format (rather than separate Excel spreadsheets) and is modular in nature, organizing the forecasting steps in a consistent fashion across models. The modeling approach and methodology has not materially changed with this transition.

5. KEY ASSUMPTIONS

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

Economic Growth

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

National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, PSE's IRP forecast begins with assumptions about what is happening in the broader U.S. economy. We rely on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. The May 2020 Moody's forecast was used for this IRP.

The Moody's forecast calls for:

- A drop in employment and a sharp rise in unemployment in the second quarter of 2020 due to the Covid-19 pandemic. Unemployment stays above 6 percent until the first quarter of 2022, and is above 5 percent until the first quarter of 2023.
- After 2023 Moody's predicts the economy grows modestly as the U.S. population growth rate slows in the long term.
- U.S. GDP to continue to grow over the forecast period with 2.2 percent average annual growth from 2022 to 2045. This growth rate is higher compared to the Moody's forecast used in the 2019 IRP Process, which projected 2.0 percent average annual growth, but some of this growth is from the projected recovery from Covid-19.
- Average annual population growth of 0.4 percent for 2022-2045. This is down from the 0.6 percent growth rate Moody's forecast in the 2019 IRP Process for 2020-2039.

However, this IRP did not use Moody's population projections because PSE's regional projections based on Moody's U.S. forecasts were consistently under-forecasting population growth in the electric and natural gas service areas. Instead, PSE used the Washington State Employment Security Department (WA ESD) population projections by county for the electric and natural gas service areas.

Moody's identified possible risks that could affect the accuracy of this forecast:[5]

- The Moody's forecast assumes that Covid-19 infections peak in May 2020 and begin to abate in July 2020. There is a downside risk if additional outbreaks occur, which are possible until a vaccine is widely available.
- Re-imposition of social distancing and forced business closures could derail any recovery that the economy has made.
- Moody's assumes that government and lawmakers provide monetary and fiscal responses to the pandemic to stabilize financial markets. The timing and size of this response is critical for determining the shape of the recovery.
- Changes to the economies of other global powers could affect the U.S. economy, especially as the demand for goods and services changes with the pandemic.
- Retaliations to U.S. tariffs could cause lower U.S. and global growth.

Regional Economic Outlook

PSE prepares regional economic and demographic forecasts using econometric models based on historical economic data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

PSE's service area covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula. PSE serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties.

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

5 / Moody's Analytics (2020, May) Forecast Risks. Precis U.S. Macro. Volume 25 Number 2.

Electric Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2021 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate of 0.6 percent between 2022 and 2045, which is the same as the annual growth rate forecasted in the 2019 IRP Process.
- Local employers are expected to create about 310,000 total jobs between 2022 and 2045, mainly driven by growth in the commercial sector, compared to about 257,000 jobs forecasted in the 2019 IRP Process.
- Manufacturing employment is expected to decline by 0.1 percent annually on average between 2022 and 2045 due to the outsourcing of manufacturing processes to lower wage or less expensive states or countries, and due to the continuing trend of capital investments that create productivity increases.
- An inflow of 975,000 new residents (by birth or migration) is expected to increase the local area population to 5.3 million by 2045, for an average annual growth rate of 0.9 percent. This growth rate is not constant over time, and the population growth rate is expected to be higher in the near term and lower in the long term. However, on average, this growth rate is higher than the 2019 IRP Process forecast, which projected an average annual population growth of 0.6 percent that would have resulted in 4.6 million electric service area residents by 2039. The 2021 forecast has a different growth rate because the population forecast in this IRP is based on the WA ESD forecast of population instead of Moody's population forecast.

Local economists at Western Washington University have identified possible risks to the regional economy:[65]

- It is unknown when the Covid-19 vaccine will achieve widespread immunity.
- Employers are taking on debt to make ends meet when their customers are spending less.
- Unforeseen layoffs from struggling businesses could slow economic recovery.
- Political and social unrest will have unknown effects on the economy.
- Lingering US-China tension could affect the economy.

5 / Western Washington University Center of Economic and Business Research (2020, June) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 2.
6 / Western Washington University Center of Economic and Business Research (2020, March) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 1.

HIGH SCENARIO OUTLOOK. For the Electric High Demand Forecast scenario, population grows by 1.1 percent annually from 2022 to 2045, and employment grows by 0.8 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Electric Low Demand Forecast scenario, population grows by 0.7 percent annually from 2022 to 2045. Employment grows 0.3 percent annually from 2022 to 2045.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 6-34 and 6-35.

Figure 6-34: Population Growth, Electric Service Counties

2021 IRP POPULATION GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,334	4,482	4,715	4,936	5,134	5,310	0.9%
2021 IRP High Demand Forecast	4,398	4,609	4,902	5,158	5,398	5,609	1.1%
2021 IRP Low Demand Forecast	4,267	4,363	4,536	4,723	4,869	4,989	0.7%

Figure 6-35: Employment Growth, Electric Service Counties

2021 IRP EMPLOYMENT GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	2,172	2,268	2,327	2,385	2,436	2,482	0.6%
2021 IRP High Demand Forecast	2,365	2,488	2,562	2,669	2,744	2,814	0.8%
2021 IRP Low Demand Forecast	1,996	2,047	2,088	2,103	2,145	2,159	0.3%

Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Gas Demand Forecast scenario, population grows by 1.0 percent annually from 4.5 million people in 2022 to 5.45 million people by 2041. Employment is expected to grow by 1.2 percent annually from 2022 to 2041.

HIGH SCENARIO OUTLOOK. For the High Gas Demand Forecast scenario, population grows by 1.2 percent annually from 2022 to 2041, and employment grows by 2.1 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Gas Demand Forecast scenario, population grows 0.8 percent annually from 2022 to 2041, and employment grows 0.2 percent annually.

The Base, High and Low population and employment forecasts for PSE's gas sales service area are compared in Figures 6-36 and 6-37.

Figure 6-36: Population Growth, Gas Service Counties

2021 IRP POPULATION GROWTH, GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	4,542	4,703	4,953	5,197	5,452	1.0%
2021 IRP High Demand Forecast	4,619	4,842	5,159	5,437	5,766	1.2%
2021 IRP Low Demand Forecast	4,461	4,575	4,769	4,955	5,146	0.8%

Figure 6-37: Employment Growth, Gas Service Counties

2021 IRP EMPLOYMENT GROWTH, GAS SERVICE COUNTIES (1,000s)						
Scenario	2022	2025	2030	2035	2041	AARG 2022-2041
2021 IRP Base Demand Forecast	2,225	2,368	2,497	2,628	2,780	1.2%
2021 IRP High Demand Forecast	2,478	2,748	3,043	3,257	3,655	2.1%
2021 IRP Low Demand Forecast	1,975	1,987	1,989	2,022	2,042	0.2%

Other Assumptions

Weather

For the IRP Base Demand scenario, the energy demand forecast is based on normal weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The 2021 IRP forecast methodology, as described in this chapter and Appendix F, Demand Forecasting Models, employs various thresholds of heating and cooling "degree days," consistent with industry practices. Employing monthly degree days helps estimate the amount of weather-sensitive demand in the service area. PSE rolls forward the 30-year period employed in each IRP to capture recent climate conditions. To create the High and Low Demand Forecasts historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

In this IRP, PSE is including a temperature sensitivity that explores how changing heating and cooling degree days could affect loads in the future as the climate warms. This sensitivity is described in detail in Chapter 5, Key Analytical Assumptions.

Additionally, PSE is following and participating in the regional efforts of the Northwest Power and Conservation Council to include climate change in its planning process. These efforts include both forecasting future temperatures as well as considering secondary effects of climate change on population and economic growth. Future IRPs will incorporate climate change impacts as regionally accepted information becomes available.

Covid-19 Adjustments

In early March 2020, the Covid-19 pandemic reached the Puget Sound region in earnest. The governor issued a "Stay Home, Stay Healthy" order on March 23 that had immediate impacts on the local economy. The typical historic economic assumptions were not able to capture all of the immediate impacts to the demand forecast, so additional assumptions and adjustments were made to reflect the impacts of Covid-19.

The IRP demand forecast used the Moody's May 2020 economic forecast, including the economic and epidemiological assumptions about the severity of the disease and its effects on the economy. This Moody's forecast assumed that the new infections would abate in July 2020 and did not include a second wave of infections. PSE tracked the observed effects on each customer class. Additionally, PSE assessed the potential impacts on the commercial class by building type, since some sectors of the economy were hit harder than others. Adjustments from these additional analyses were aligned with the epidemiological assumptions made by Moody's in the May 2020 forecast. These adjustments were made to demand in the forecast for year 2020.

After 2020, no additional adjustments were made to the demand forecast. Effects of Covid-19 were incorporated into the demand forecast using the macroeconomic variables. The result is a slow recovery over the following few years and a recovered economy by 2024, with lingering effects of the recession persisting thorough out the remainder of the forecast.

Loss Factors

The electric loss factor is 6.8 percent, compared to 7.1 percent in the 2019 IRP Process. The gas loss factor in this IRP is 0.2 percent, which is the same loss factor as the 2019 IRP Process.

Block Load Additions

Beyond typical economic change, the demand forecast also takes into account known major demand additions and deletions that would not be accounted for though typical load growth in the forecast. The majority of these additions are from major infrastructure projects. These additions to the forecast are called block loads and they use information provided by PSE's system planners. The adjustments to non-transport customers add 91.1 MW of connected demand by 2025 for the electric system as a whole. These block loads are included in the commercial class, and King County has the majority of the additions.

The gas forecast includes block loads of 0.1 MDth per day and are included in the industrial class.

Schedule Switching

In addition to block loads, PSE accounts for customers that switch between rate schedules. Customers that purchase their own electricity or natural gas are called transportation customers and they rely on PSE for distribution services. Because PSE is not responsible for acquiring supply resources for electric or gas transportation customers, in the IRP they are removed from the forecast before supply-side resource need is determined.

Interruptible Loads

PSE has 152 electric interruptible customers; six of these are commercial and industrial customers and 146 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 14 MW of coincident peak demand. Since this 14 MW is so small compared to PSE's peak demand, and PSE has not typically curtailed customers on these interruptible schedules during a normal peak event, it was included in the firm demand forecast.

For a number of gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was assumed when forecasting peak gas demand.

Electric Vehicles

An electric vehicle (EV) forecast was created for PSE by Guidehouse in early 2020. The forecast assumes 74,000 customer-owned light duty EVs on the road in PSE's service area in 2022, increasing to 962,000 EVs in 2045. Annual energy sales from new electric vehicles total 83,000 MWh in 2022 and 1,960,000 MWh in 2045. Initially, 81 percent of this charging is assumed to occur on residential accounts, while the remaining 19 percent is assumed to occur through commercial accounts. During the forecast period this percentage changes as charging at commercial locations becomes more widely available, resulting in 56 percent charging on residential accounts and 44 percent charging on commercial accounts in 2045. Electric vehicles are an emerging technology, thus PSE anticipates this forecast will be revised on an ongoing basis in the future. The additional demand by electric vehicles grows to an 8 percent share of total peak demand by 2045, before including cost-effective DSR identified in the 2021 IRP. Figure 6-38 below shows the December evening peak demand and annual average energy demand from new electric vehicles. Figure 6-39 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Figure 6-38: Electric Vehicle Peak Demand and Average Energy Demand from New Vehicles (aMW, MW)

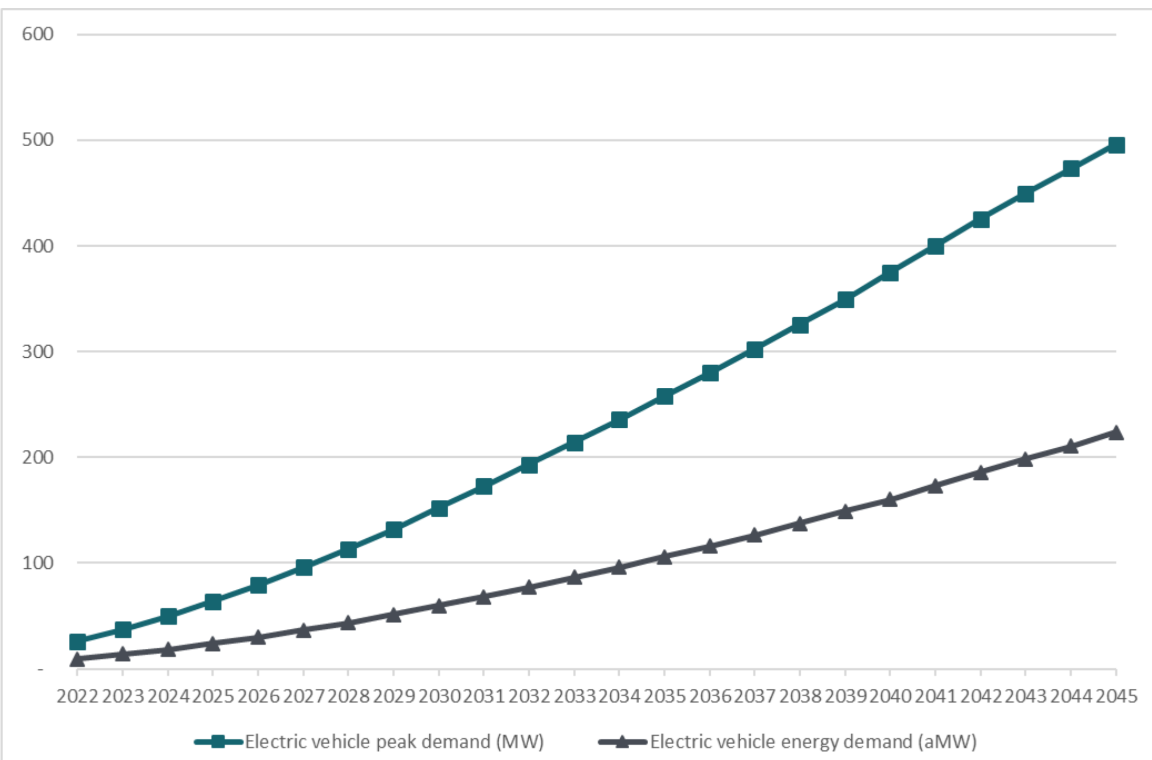
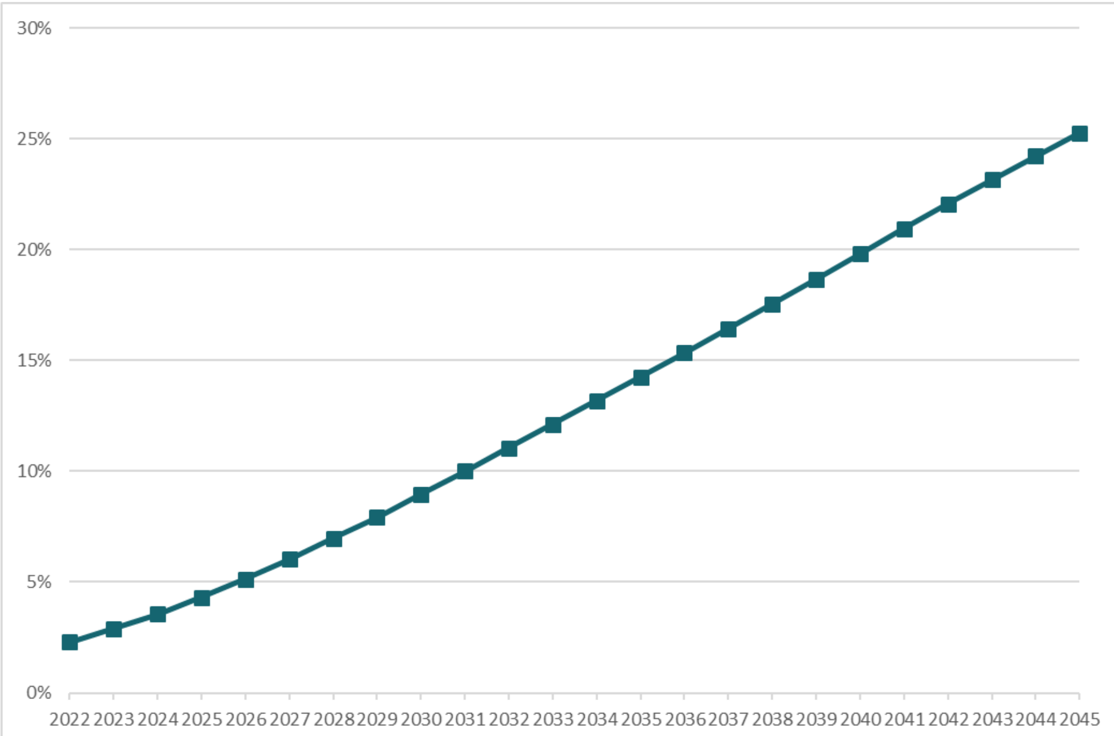


Figure 6-39: Electric Vehicles as a Percent of Purchased Vehicles



Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2021 IRP Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2022, this adds 365 MDth to the forecast. This demand is expected to grow at an average annual rate of 3.5 percent, based on the Annual Energy Outlook 2019 published by the U.S. Department of Energy.

Retail Rates

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

Distributed Generation

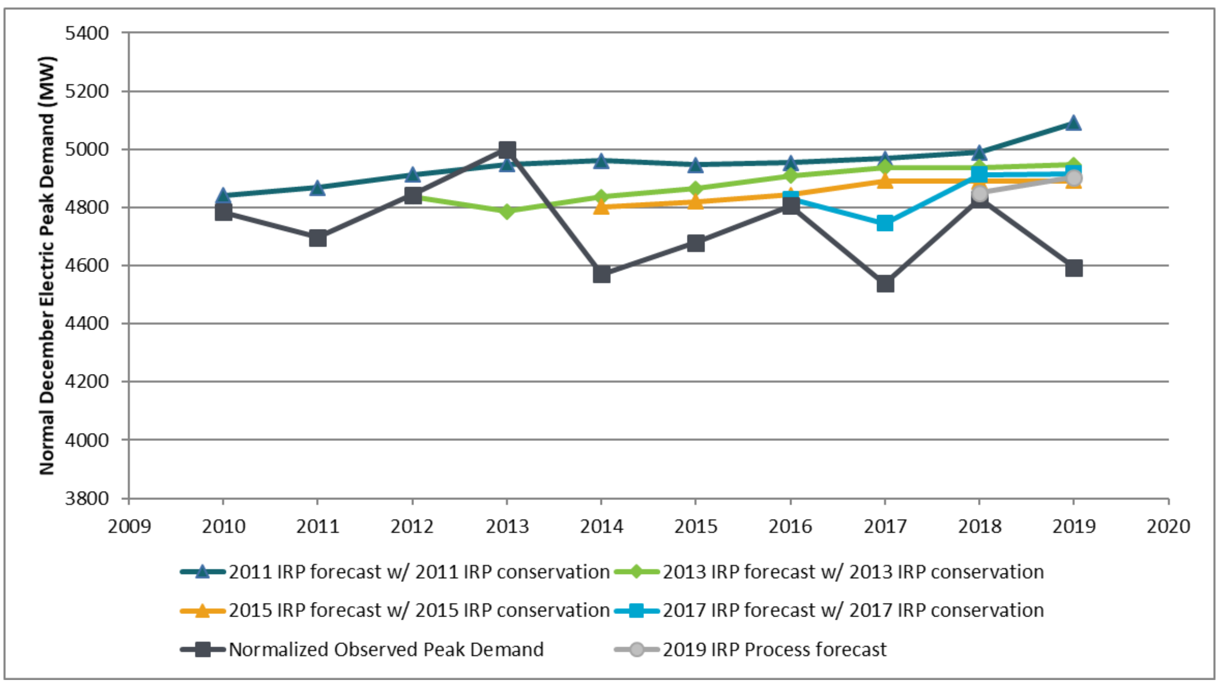
Distributed generation, including customer-level generation via solar panels, was not included in the demand forecast; this energy production is captured in the IRP modeling process as a demand-side resource. A description is included in the Appendix E, Conservation Potential Assessment and Demand Response Assessment.

6. RETROSPECTIVE OF PREVIOUS DEMAND FORECASTS

IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6-40 compares the 2011, 2013, 2015, 2017 and 2019 IRP Process electric Base Scenario peak demand forecasts after DSR with normalized[7] actual observations. The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed. The percent difference of normalized actual values compared to each IRP forecast is presented for each year in Figure 6-41.

Figure 6-40: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



7 / *Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.*

Figure 6-41: Observed Electric Peak Demand and Difference from Previous IRP Forecasts

ELECTRIC DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	2011 IRP	2013 IRP	2015 IRP	2017 IRP	2019 IRP Process
2010	1.2%				
2011	3.6%				
2012	1.5%	-0.1%			
2013	-1.0%	-4.3%			
2014	8.5%	5.8%	5.1%		
2015	5.7%	4.0%	3.0%		
2016	3.1%	2.1%	0.8%	0.5%	
2017	9.5%	8.8%	7.8%	4.6%	
2018	3.3%	2.3%	1.2%	1.7%	0.5%
2019	10.8%	7.7%	6.5%	7.1%	6.8%

Similarly, weather normalized actual gas peak demand is compared to the gas peak forecasts after conservation from the 2011, 2013, 2015, 2017 IRPs and the 2019 IRP Process in Figures 6-42 and 6-43.

Figure 6-42: Observed Weather Normalized Gas Peak Demand Compared to Previous IRP Forecasts of Gas Peak Demand

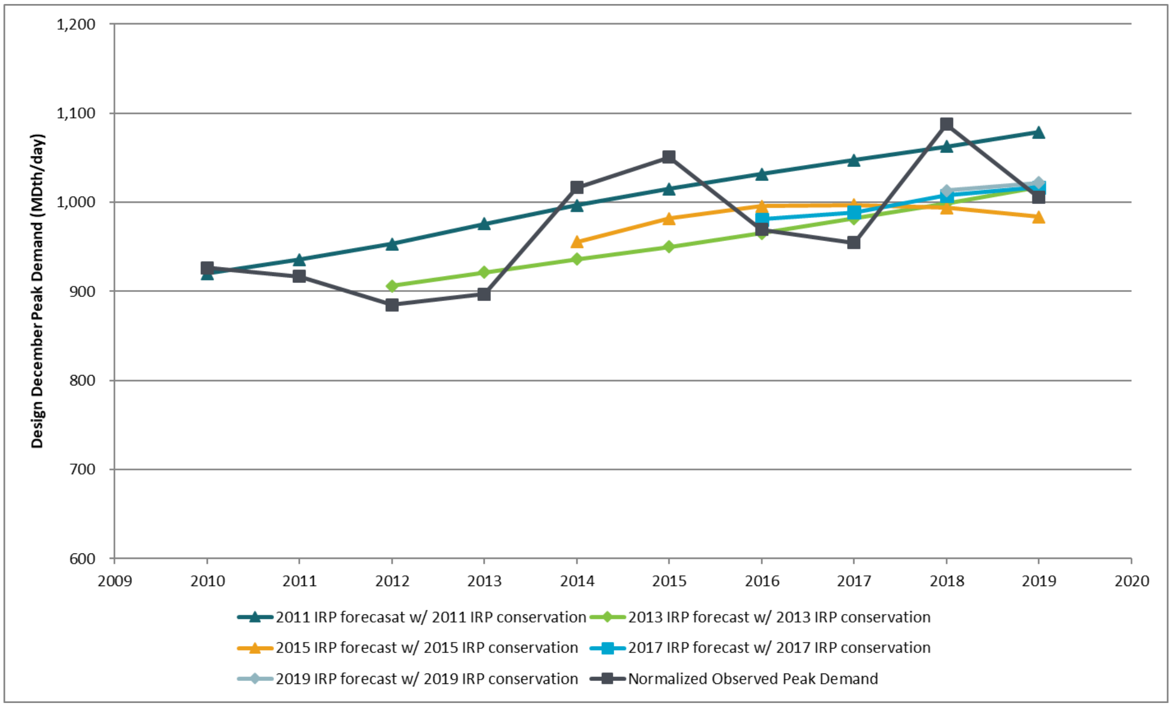


Figure 6-43: Observed Gas Peak Demand and Difference from Previous IRP Forecasts

GAS DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**	**2019 IRP Process**
2010	-0.7%				
2011	2.0%				
2012	7.8%	2.4%			
2013	8.8%	2.7%			
2014	-2.0%	-7.9%	-5.6%		
2015	-3.4%	-9.6%	-6.1%		
2016	6.4%	-0.4%	3.2%	1.2%	
2017	9.7%	2.8%	5.0%	3.6%	
2018	-2.3%	-8.2%	-8.2%	-7.4%	-6.9%
2019	7.3%	1.1%	-1.7%	1.1%	1.6%

Reasons for Forecast Variance

As explained throughout this chapter, the IRP peak demand forecasts are based on forecasts of key demand drivers that include expected economic and demographic behavior, conservation, customer usage and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. These differences are explained below.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare the Moody's forecasts of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP Process with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP Process, forecasts of housing starts are no longer used as a driver in the demand forecast; instead, forecasts of population based on WA ESD data are now used to forecast population in PSE's service territories. The Moody's forecast of housing starts and population from May 2020 are included in the two charts below for comparison

Additionally, while the Moody's forecast used in the 2019 IRP Process did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects from the Covid-19 pandemic. Therefore, Moody's forecasts used prior to the 2021 IRP have likely over-estimated economic growth in 2020 and the following few years. It is likely that we will not know the full extent of the pandemic's repercussions on the economy and energy demand during this IRP cycle.

Figure 6-44: Moody's Forecasts of U.S. Housing Starts Compared to Actual Housing Starts

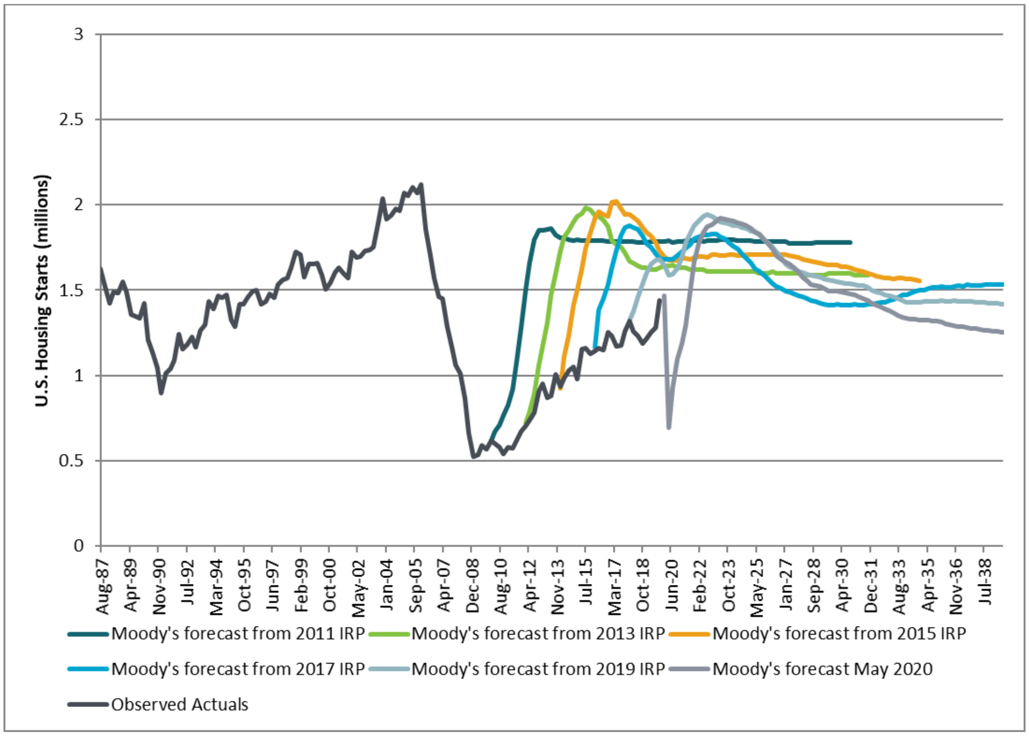
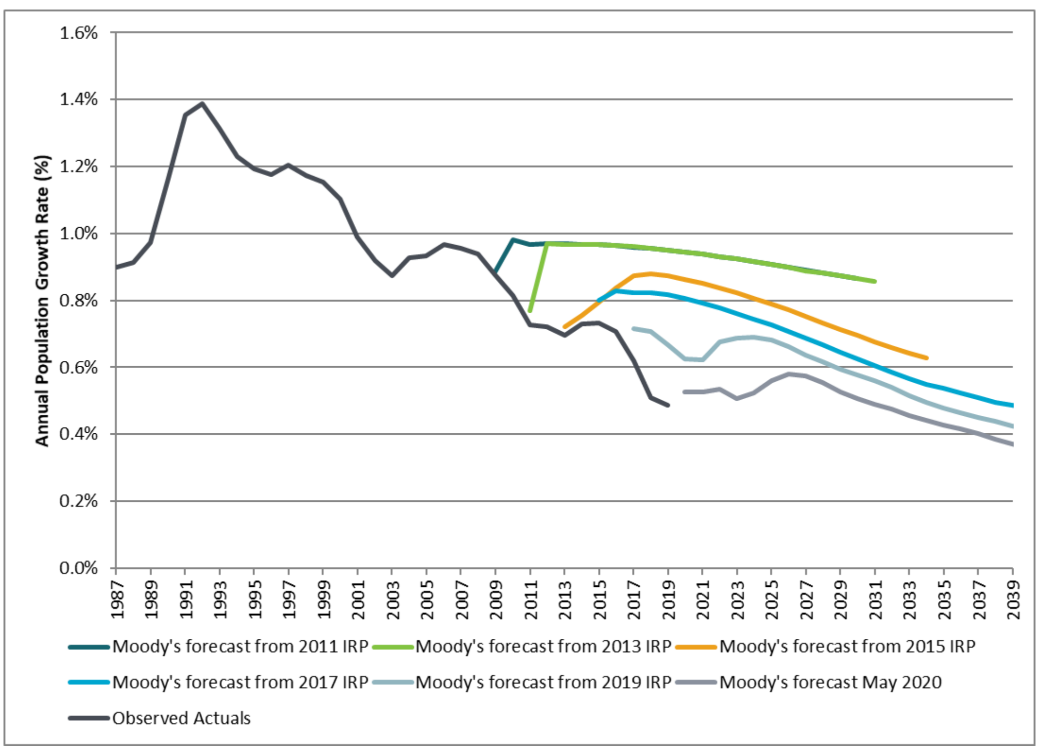


Figure 6-45: Moody's Forecasts of U.S. Population Growth Compared to Actual Population Growth



Conservation and Customer Usage

The comparison in Figure 6-40 of weather normalized peak observations to the IRP peak demand forecasts after conservation assumes that the forecasted conservation will be implemented. However, consumers can adopt energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted. Additionally, conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.

Also, due to the Global Settlement from the 2013 General Rate Case (GRC) PSE and the 2017 GRC PSE decisions accelerate electric and natural gas conservation, respectively, by 5 percent each year. This is additional conservation that is not taken into account in this comparison of IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. For each IRP, the normal weather assumption is updated by rolling off two older years of data and incorporating two new years of weather data into the 30-year average. Over time, normal heating degree days have been declining and normal cooling degree days have been increasing. As temperatures change over time, the forecast of demand with normal weather changes.

Additionally, over time our customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, gas peaks in 2010, 2013, 2016, and 2017 fell on weekends. Gas peaks in 2010, 2012, and 2015 fell on New Year's Eve and the gas peak in 2019 fell on Boxing Day (the day after Christmas). Additionally, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend, in 2015 it fell on New Year's Eve, and in 2019 it fell on the day after Christmas. Usage on these days is likely to be different than usage on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, we would expect those forecasts to be higher than the actual peak demand.

7 Resource Adequacy Analysis

This appendix provides an overview of PSE's resource adequacy modeling framework and how it aligns with other regional resource adequacy analyses.

Contents

1. OVERVIEW

The energy supply industry is in a state of transition as major decarbonization policies are implemented in most states. Significant amounts of coal-fired generation is being retired, and new intermittent, renewable generation is being constructed. These changes will cause PSE and other utilities to significantly change how they plan, especially with regard to resource adequacy. To maintain confidence in the wholesale market and ensure that sufficient resources are installed and committed, PSE, along with Northwest Power Pool members, is designing and implementing a regional resource adequacy program. The detailed design phase of the resource adequacy program is under way, with completion expected in mid-2021. As more details are understood, PSE will begin the evaluation of various resource adequacy elements in the resource adequacy analysis included in the 2021 IRP. At this time, the regional resource adequacy program has not been contemplated or included in the analysis described in this chapter.

In the past, relying on short-term wholesale capacity markets has been a very cost-effective strategy for customers. This strategy also avoided building significant amounts of new baseload natural gas generation that might have created significant stranded cost concerns under the new policies. Recent experience shows that while wholesale electricity prices remain low, on average, in the Pacific Northwest, the region is starting to experience periods of high wholesale electricity prices and low short-term market liquidity.

PSE is in the process of completing a supporting analysis to evaluate the availability of short-term market purchases for peak capacity. At the time of this writing, that analysis is not yet complete; it will be provided in the final IRP in addition to the resource adequacy analysis described here. It is important that PSE continue to closely monitor the region's projected winter season load/resource balance and any changes in the liquidity of the short-term market, and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

2. 2021 IRP RESOURCE ADEQUACY ANALYSIS

Resource adequacy planning is used to ensure that all of PSE customer's load obligations are reliably met by building sufficient generating capacity, or acquiring sufficient capacity through contracts, to be able to meet customer demand with appropriate planning margins and operating reserves. The planning margin and operating reserves refer to capacity above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events with minimal interruption of service. Unexpected events can be variations in temperature, hydro and wind generation, equipment failure, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Reliability requires that the full range of potential demand conditions are met even if the potential of experiencing those conditions is relatively low.

The physical characteristics of the electric grid are very complex, so for planning purposes, a 5 percent loss of load probability (LOLP) reliability metric is used to assess the physical resource adequacy risk. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulations. Therefore, the likelihood of capacity being lower than load at any time in the year cannot exceed 5 percent. The 5 percent LOLP is consistent with the resource adequacy metric used by the Northwest Power and Conservation Council (NPCC).

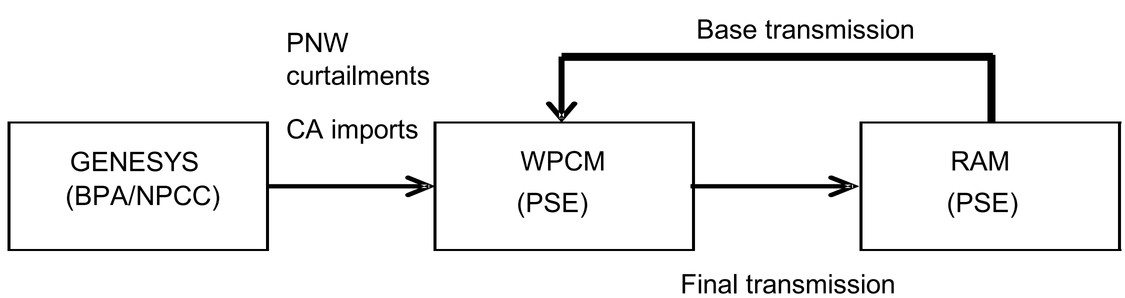
Quantifying the peak capacity contribution of a renewable and energy limited resource (its effective load carrying capacity, or ELCC) is an important part of the analysis. ELCC is calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP target reliability metric constant. In this way, we can identify the capacity contribution of different resources such as wind, solar and hydro. Energy-limited resources such as batteries and demand response programs use a similar methodology, but use expected unserved energy (EUE) as the resource adequacy metric. EUE is used instead of LOLP for energy-limited resources because it better captures adequacy impacts of longer duration which may deplete energy storages.

Resource Adequacy Modeling Approach

PSE's Resource Adequacy Model (RAM) is used to analyze load/resource conditions for PSE's power system. Since PSE relies on significant amounts of wholesale power purchases to meet peak need, the analysis must include evaluation of potential curtailments to regional power supplies. To accomplish this, the RAM integrates two other analyses into its results: 1) the GENESYS model developed by the NPCC and BPA, which analyzes regional level load/resource conditions, and 2) the Wholesale Purchase Curtailment Model (WPCM), developed by PSE, which analyzes the specific effects of regional curtailments on PSE's system. This allows us to evaluate PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

Figure 7-1 illustrates how the inputs and outputs of these models were linked. The outputs of the GENESYS Model provide inputs for both the WPCM Model and the RAM/LOLP Model. The RAM/LOLP Model and WPCM models are used iteratively, with the final output of the RAM/LOLP model used in the next WPCM modelling run.

Figure 7-1: Market Reliability Analysis Modeling Tools



The GENESYS Model

The GENESYS model was developed by the NPCC and BPA to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions, and as of the 2023 assessment, 88 years of temperature conditions. For the 2021 IRP, PSE started with the GENESYS model from the NPCC power supply adequacy assessment for 2023. When combined with thermal plant forced outages, the mean expected time to repair those units, variable wind plant generation, and available imports of power from outside the region, the model determines the PNW's overall hourly capacity surplus or deficit in 7,040 multi-scenario "simulations." Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[1]

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) utilizing both forward and short-term purchases.

Since the GENESYS model was set for a 2023 assessment, PSE made some updates to capture regional load/resource changes in order to run the model for 2027 and 2031. The updates include:

1. Coal plant retirements

Figure 7-2: Coal Plant Retirements Modeled

Plant	Year Retired in Model
Hardin	2018
Colstrip 1 & 2	2019
Boardman	2020
Centralia 1	2020
N Valmy 1	2021
N Valmy 2	2025
Centralia 2	2025
Jim Bridger 1	2023
Jim Bridger 2	2028
Colstrip 3&4	2025

2. Increased the demand forecast using the escalation rate from 2023 to 2027 and 2031
3. Added planned resources from PSE's portfolio: Skookumchuck Wind and Lund Hill solar.

1 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the GENESYS model. A PNW load-curtailment event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

The Wholesale Purchase Curtailment Model (WPCM)

During a PNW-wide load-curtailment event, there is not enough physical power supply available in the region (including available imports from California) for the utilities of the region to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, PSE developed the WPCM as part of the 2015 IRP. The WPCM links regional events to their specific impacts on PSE's system and on PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

The amount of capacity that other load-serving entities in the region purchase in the wholesale marketplace has a direct impact on the amount of capacity that PSE would be able to purchase. Therefore, the WPCM first assembles load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events. For this analysis, PSE used the capacity data contained in BPA's *2018 Pacific Northwest Loads and Resources Study*, the latest BPA study available at the time this resource adequacy analysis was completed.

BPA Loads and Resources Study for 2020–2029

BPA published its *2018 Pacific Northwest Loads and Resources Study* in April 2019. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region.

The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads.

- For 2023, the BPA study forecasts an overall regional winter peak load deficiency of 3,056 MW.
- When BPA's 2023 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 3,056 MW capacity deficit noted above would change to a 344 MW surplus.
- Looking forward to 2029 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2020 winter season peak load deficit of approximately 246 MW to a peak load deficit of approximately 4,891 MW in 2029.
- When BPA's 2029 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in its RAM – the region would transition

from a 2020 winter capacity surplus of 3,054 MW to a peak load deficit of approximately 1,491 MW by 2029.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2023. The BPA forecast indicates, as does the PNUCC study, that the PNW may experience larger winter capacity deficits over time.

> > > BPA's *2018 Pacific Northwest Loads and Resources Study* can be found at: https://www.bpa.gov/p/Generation/White-Book/wb/2018-WBK-Loads-and-Resources-Summary-20190403.pdf

In October 2020, BPA published its *2019 Pacific Northwest Loads and Resources Study*. The study was completed after PSE finalized this resource adequacy analysis, so updated 2019 information could not be incorporated. PSE is reviewing the 2019 BPA study to assess the implications on the analysis.

Allocation Methodology

The WPCM then uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases. In essence, on an hourly basis, the WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases. In some cases, reductions in PSE's initial desired volume of wholesale market purchases could trigger a load-curtailment event in the LOLP portion of RAM.

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.

SPOT MARKET ALLOCATIONS. For spot market capacity allocation, each of the five large utility purchasers is assumed to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation *is not* based on a straight pro-rata allocation, because in actual operations the largest purchaser (which is usually PSE) would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs but the larger purchasers cannot.

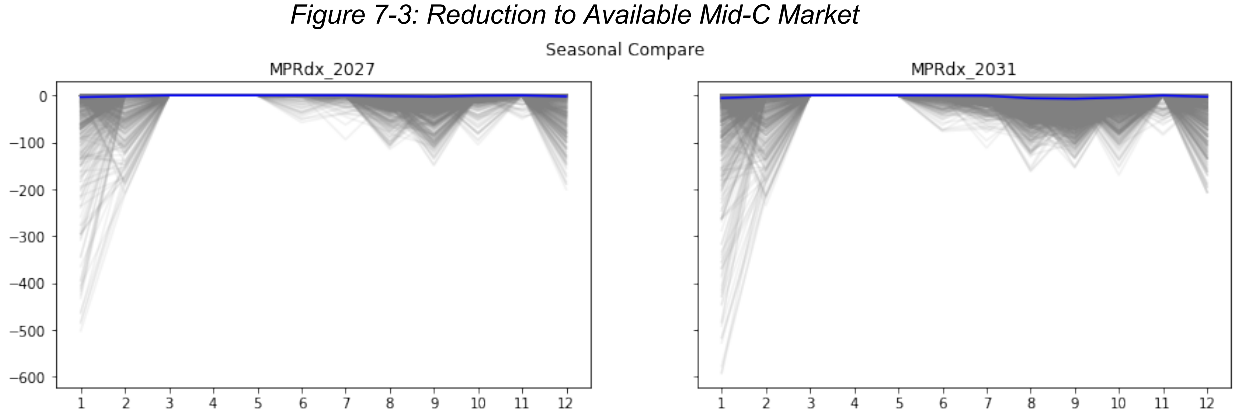
WPCM Outputs

For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-C transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.

Figure 7-3 shows the results of the WPCM. The charts illustrate the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the deficiencies go as high as a 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 7-3: Reduction to Available Mid-C Market



The Resource Adequacy Model (RAM)

PSE's probabilistic Resource Adequacy Model enables PSE to assess the following.

1. To quantify physical supply risks as PSE's portfolio of loads and resources evolves over time.
2. To establish peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin.
3. To quantifying the peak capacity contribution of a renewable and energy limited resource (its effective load carrying capacity, or ELCC)

The RAM allows for the calculation of the following risk metrics.

- **Loss of load probability (LOLP)**, which measures the *likelihood of a load curtailment event occurring* in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s).
- **Expected unserved energy (EUE)**, which measures outage magnitude in MWh and is the *sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations.*
- **Loss of load hours (LOLH)**, which measures outage duration and is *the sum of the hours with load curtailments divided by the number of simulations*.
- **Loss of load expectation (LOLE)**, which measures the *average number of days per year with loss of load* due to system load exceeding available generating capacity.
- **Loss of load events (LOLEV)**, which measures the *average number of loss of load events per year*, of any duration or magnitude, due to system load exceeding available generating capacity.

Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these five risk metrics, once a planning standard has been established.

3. CONSISTENCY WITH REGIONAL RESOURCE ADEQUACY ASSESSMENTS

PSE's reliance on market purchases requires that our resource adequacy modeling also reflect regional adequacy conditions, so consistency with the NPCC's regional GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM.

PSE's RAM operates much like the GENESYS model. Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 7,040 individual simulations; the result of each simulation is PSE's hourly capacity surplus or deficiency. The LOLP, EUE and LOLH for the PSE system are then computed across the 7,040 simulations.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 7,040 simulations made in the NPCC's GENESYS model in terms of temperature and hydro conditions.

The existing resources used by PSE included in this analysis are Mid-Columbia purchase contracts and western Washington hydroelectric resources, several gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. Since Colstrip must be out of PSE's portfolio by 2026, it was assumed to retire on 12/31/2025 and was not included as a resource in either GENESYS nor RAM.

The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

1. **FORCED OUTAGE RATE FOR THERMAL UNITS**. Forced outage refers to a generator failure event, including the time required to complete the repair. The "Frequency Duration" outage method in AURORA is used to model unplanned outages (forced outage) for thermal plants. The Frequency Duration outage method option allows units to fail or return to service at any time step within the simulation, not just at the beginning of a month or a day. The method will employ all or nothing outages for most outages, but will use partial outages at the beginning and end of the outage period. The logic considers each unit's forced outage rate and mean repair time. When the unit has planned maintenance schedule, the model will ignore those hours in the random outage

scheduling. In other words, the hours that planned maintenance occurs is not included in the forced outage rate.

2. **HOURLY SYSTEM LOADS**. Modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 88 temperature years. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2016 is represented in the 88 demand draws. Since the resource adequacy model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. Additionally, the model examines adequacy in each hour of a given future year; therefore, the model inputs are scaled to hourly demand using the hourly demand model.

3. **MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 7,040 combinations of hydro and temperature simulations are consistent with the GENESYS model.

4. **WHOLESALE MARKET PURCHASES.** These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained above. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM. The initial set of hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights is computed as the difference between PSE's maximum import rights less the amount of transmission capability required to import generation from PSE's Wild Horse wind plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports was reduced on the hours when a PNW load-curtailment event is identified in the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

5. **WIND AND SOLAR.** PSE models 250 unique 8,760 hourly profiles, which exhibit the typical wind generation patterns. Since wind and solar are both intermittent resources, one of the goals in developing the generation profile for each wind and solar project considered is to ensure that this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind and solar generation are reflected. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL's) Wind Tool Kit database.[2] Wind speed data was collected from numerous sites within a prescribed radius around a region of interest. Wind speed data was processed with a heuristic wind production model to generate hundreds of possible generation profiles. The 250 profiles which aligned most closely with the average seasonal production of the site, as determined by the average of the entire data set, were selected for use in the RAM. The profiles were then correlated by measurement year. Similarly, solar irradiance data for a given region was obtained from the National Solar Radiation Database[3] and processed with the NREL System Advisory Model to generate production profiles. The 250 solar profiles which were most closely aligned with the annual average production, as determined by the annual average of the entire data set, were selected for use in the RAM. The solar profiles were correlated by measurement year.

2 / https://www.nrel.gov/grid/wind-toolkit.html
3 / https://nsrdb.nrel.gov/

4. OPERATING RESERVES AND PLANNING MARGIN

Operating Reserves

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

CONTINGENCY RESERVES. In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event. The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA).

In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60 minutes, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power, or curtailing load. The RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, should a forced outage at one of PSE's generating plants cause loads to exceed available resources.

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

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts versus real-time values for load, wind and solar generation. The first study was for the year 2025 and includes PSE's current portfolio plus new renewable resources. The second study is for the year 2030 and includes PSE's current portfolio plus generic wind and solar resources to meet the 80% renewable requirement. Figure 7-2 below is a summary of the flex up and flex down requirement given the renewable resources that PSE will balance. Based on the results from the 2019 IRP Process, we estimate that PSE will balance almost 2,400 MW of wind and 1,400 MW of solar by 2030 to meet CETA goals.

Figure 7-4: Balancing Reserve Requirements

Case	Capacity of PSE-balanced Wind (MW)	Capacity of PSE-balanced solar (MW)	Average Annual Flex up (MW)	Average Annual Flex down (MW)	99th percentile of forecast error (flex up cap)	1st percentile of forecast error (flex down cap)
2025 Case	875	-	141	146	190	196
2030 Case	2,375	1,400	492	503	695	749

This table is a summary of the flexible ramp requirements. RAM uses the hourly flex up and flex down requirements for each study year.

Planning Margin

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin is defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of reliable service to customers under peak load conditions. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads) / Normal Peak Loads,

> Where Generation Capacity (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model. This generation capacity includes existing and incremental capacity required to meet the reliability standard.

The planning margin framework allows for the derivation of multiple reliability/risk metrics such as the likelihood (i.e., LOLP), magnitude (i.e., EUE) and duration (i.e., LOLH) of supply-driven customer outages. Those metrics can then be used to quantify the relative capacity contributions of different resource types towards meeting PSE's firm peak loads. These include thermal resources, variable-energy resources such as wind, wholesale market purchases, and energy limited resources such as energy storage, demand response and backup fuel capacity.

In this IRP, PSE continues to utilize the LOLP metric to determine its capacity planning margin and establishes the 5 percent LOLP level used by the NPCC as adequate for the region. This value is obtained by running the 7,040 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using "perfect" capacity, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

5. 2021 IRP RAM INPUT UPDATES

The following key updates to the RAM inputs were made:

1. The load forecast was updated to reflect the 2021 IRP demand forecast assumptions.
2. The hourly draws of the existing PSE wind fleet and new wind resources were based on NREL wind data set of 250 stochastic simulations.
3. The hourly draws of existing PSE solar resources and new solar resources were based on NREL solar data set of 250 stochastic simulations.
4. Colstrip Units 3 & 4 and Centralia were removed.
5. New resources from the 2018 RFP were added.
6. The balancing reserve requirements were updated to include new 2025 and 2030 study results.

YEARS MODELED. The 2021 IRP time horizon starts in 2022, so PSE modeled a 5-year and a 10-year resource adequacy assessment. The first assessment is the 5-year assessment for the period of October 2027 – September 2028. The second assessment is the 10-year assessment for the period of October 2031 – September 2032. The modeled year follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact for the analysis. This is consistent with the NPCC's GENESYS model. If PSE modeled the calendar year, it would break up the winter season (November – February).

PSE also updated the 2023 forecasts from the 2018 NPCC Resource Adequacy Assessment in the RAM model. Since PSE is running the years 2027 and 2031, the GENESYS model was updated from 2023 to match the years 2027 and 2031. This was done by updating the demand forecast using the Council's demand escalation, updating plant retirements such as Colstrip and Centralia, and including new resources from PSE's portfolio (Skookumchuck and Lund Hill).

Impacts of Input Revisions to Incremental Capacity Needed to Meet 5 Percent LOLP

Study Year 2027

The incremental impact of each modeling update on the capacity need for the study year 2027 is documented in Figure 7-5. The starting point is the 2019 IRP Process capacity need with Colstrip Units 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-5: Impact of Key Input Revisions for 2027

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2027 - Sep 2028
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1&2	1,026	1,867
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2027-2028	960	
	Updated balancing reserves for 2025 Case	918	
	Updated transmission assumptions - Add 50 MW BPA contract - Goldendale firm transmission	982	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP Load Forecast for October 2027 – September 2028		1,334
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,273
	Updated Lund Hill generation to NREL data		1,291
	Add Golden Hills		1,161
	Add new RFP resource		1,018
	Demand Forecast - fixed some errors in March - updated A/C saturation to align with 2021 IRP demand forecast		887
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to be in AC		881
	Fixed correlations for wind and solar data		907

Figure 7-6 summarizes the resulting metrics when the LOLP meets the 5 percent standard.

Figure 7-6: Reliability Metrics at 5% LOLP for 2027

Metric	Base System – no added resources	System at 5% LOLP – add 907 MW
LOLP	68.84%	4.99%
EUE	5,059 MWh	430 MWh
LOLH	11.06 hours/year	0.83 hours/year
LOLE	12.58 days/year	0.12 days/year
LOLEV	2.49 events/year	0.14 events/year

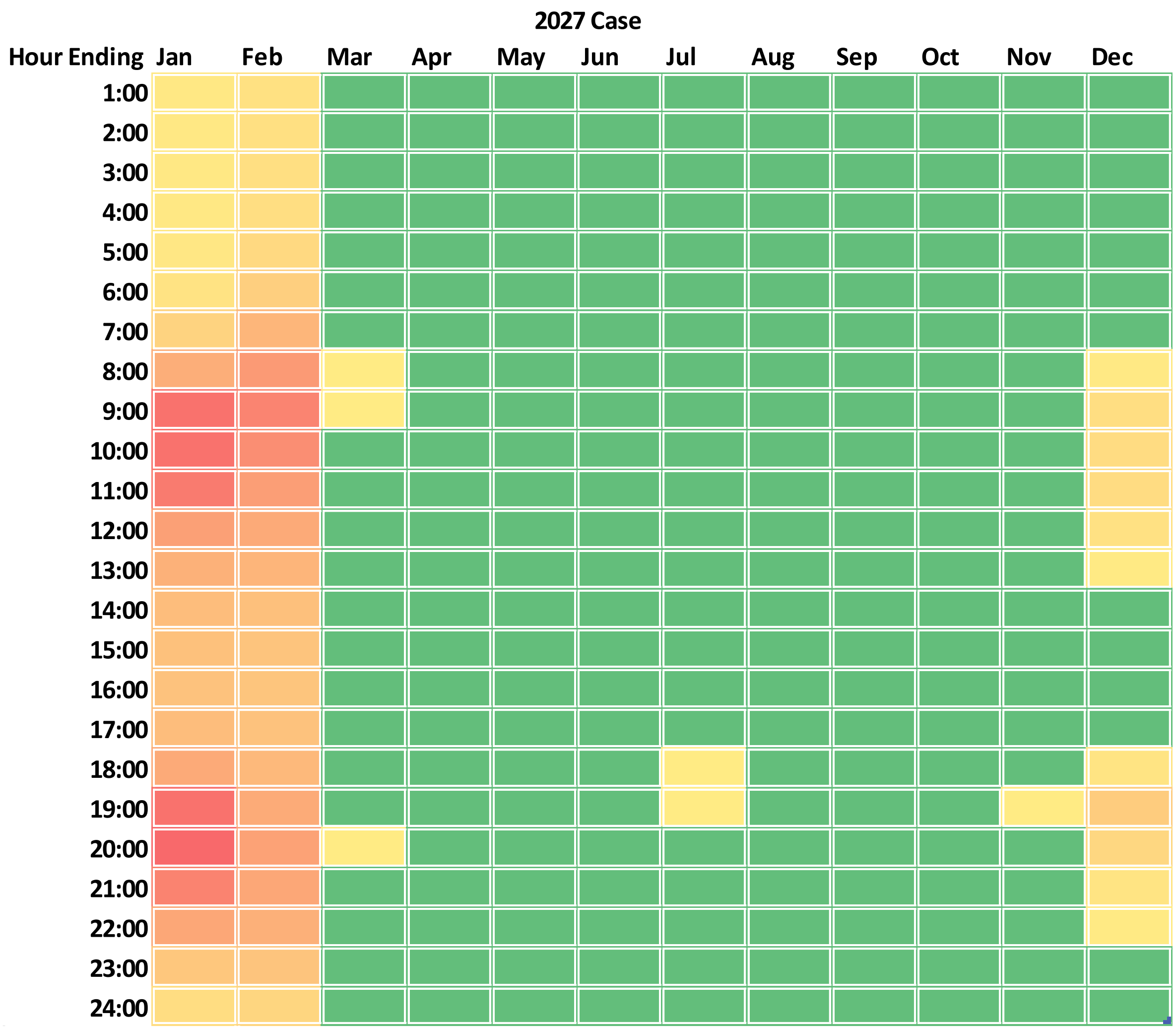
A loss of load event can be caused by many factors, which may include temperature, demand, hydro conditions, plant forced outages, and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. Figure 7-7 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February. However, this is the first time that we are seeing events occur in the summer, even though they affect few hours (about 0.04 percent of total hours). Given this result, PSE is still strongly winter peaking; we do not see this changing but will continue to monitor the summer events.

Figure 7-7: Hours of Loss of Load across 7,040 Simulations for 2027

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	4,846	2,893
2	3,296	2,553
3	10	5
4	-	-
5	-	-
6	10	-
7	3	2
8	-	-
9	-	-
10	-	-
11	5	1
12	474	275

Figure 7-8 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-8: Loss of Load Hours for 2027



Study Year 2031

The incremental impact of each modeling update on the capacity need for the study year 2031 is documented in Figure 7-9. The starting point is the 2019 IRP Process capacity need with Colstrip 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-9: Impact of Key Input Revisions for 2031

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2031 - Sep 2032
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1&2	1,026	2,217
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2031-2032	956	
	Updated balancing reserves for 2030 case	1,071	
	Updated transmission assumptions - Add 50 MW BPA contract - Goldendale firm transmission	1,134	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP demand forecast for October 2027 – September 2028		1,635
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,581
	Updated Lund Hill generation to NREL data		1,596
	Add Golden Hills		1,469
	Add new RFP resource		1,326
	Demand Forecast - fixed some errors in March - updated A/C saturation to align with 2021 IRP demand forecast		1,344
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to be in AC		1,361
	Fixed correlations for wind and solar data		1,381

Figure 7-10 summarizes the resulting metrics when the LOLP meets the 5 percent standard.

Figure 7-10: Reliability Metrics at 5% LOLP for 2031

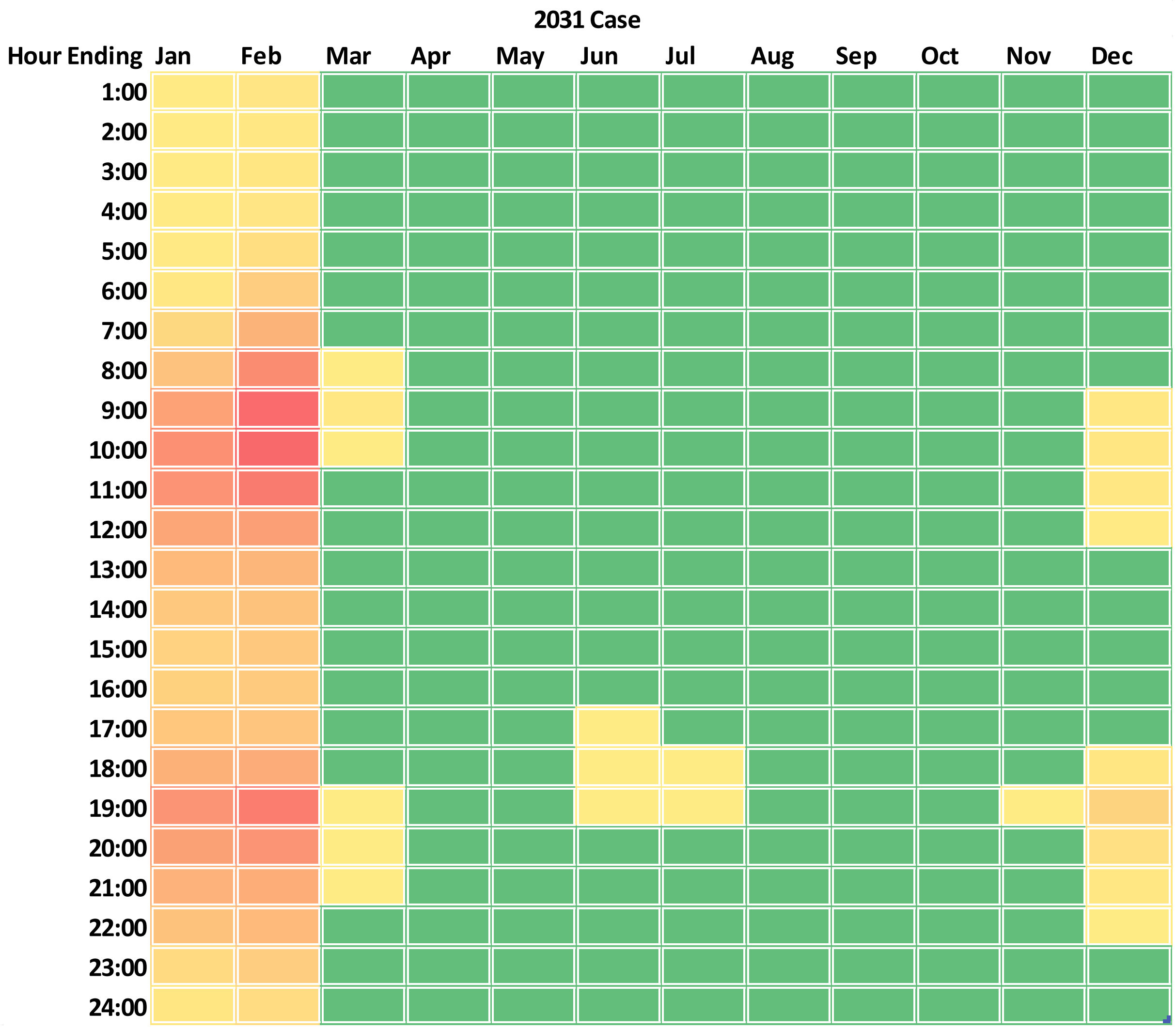
Metric	Base System – no added resources	System at 5% LOLP – add 1361 MW
LOLP	98.45%	5.00%
EUE	19,243 MWh	419 MWh
LOLH	51.90 hours/year	0.86 hours/year
LOLE	11.25 days/year	0.12 days/year
LOLEV	13.80 events/year	0.17 events/year

Figure 7-11 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February.

Figure 7-11: Hours of Loss of Load across 7,040 Simulations for 2031

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	*3,860*	*2,387*
2	*4,267*	*3,365*
3	*40*	*14*
4	-	-
5	-	-
6	*12*	*5*
7	*4*	*2*
8	*4*	-
9	-	-
10	-	-
11	*9*	*1*
12	*325*	*160*

Figure 7-12: Loss of Load Hours for 2031



6. RESOURCE NEED

Planning Margin Calculation

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. Using the LOLP methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031. The planning margin is used as an input into the AURORA portfolio capacity expansion model. It is simply a calculation used as an input into the model to make sure that the expansion model targets 907 MW of new capacity in 2027 and 1,381 MW in 2031. The planning margin calculation for the 2021 IRP is summarized in Figure 7-13.

Figure 7-13: 2021 IRP Planning Margin Calculation

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	907 MW	1,381 MW
Total Resources Peak Capacity Contribution	3,591 MW	3,599 MW
Short-term Market Purchases	1,471 MW	1,473 MW
Generation Capacity	5,969 MW	6,453 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	20.7%	24.2%

The total capacity contribution from resources has been updated based on the 2021 IRP ELCC. The section below is the update to the peak capacity contribution of existing resources.

Peak Capacity Credit of Resources

The effective load carrying capability (ELCC) of a resource represents the peak capacity credit assigned to that resource. It is calculated in RAM since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of perfect capacity that would yield the same level of reliability. For resources such as a wind, solar, or other energy-limited resources such as batteries and demand response programs, the ELCC is expressed as a percentage of the equivalent perfect capacity.

The ELCC value of any resource, however, is also dependent on the reliability metric being used for evaluating the peak contribution of that resource. This is a function of the characteristics of the resource being evaluated, and more importantly, what each of the reliability metrics is counting. For example, a variable energy resource such as wind or solar with unlimited energy may show different ELCC values depending on which reliability metric is being used – LOLP or EUE. For example, LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occurred within each draw, and it ignores the duration and magnitude of the deficit events. EUE sums up all deficit MW hours across events and draws regardless of their duration and frequency, expressed as average over the number of draws. In this study, we utilize LOLP as the reliability metric in estimating the ELCC of wind, solar and market purchases. However, we use EUE to determine the ELCC of energy-limited resources such as batteries and demand response, because LOLP is not able to distinguish the ELCC of batteries and demand response programs with different durations and call frequencies.

HYDRO RESOURCES CAPACITY CREDITS. The estimated peak contribution of hydro resources was modeled in the RAM. We only modeled the ELCC contribution of PSE owned hydro, Baker River Projects and Snoqualmie Falls. The peak capacity contribution of the Mid-C hydro is based on the Pacific Northwest Coordination Agreement (PNCA) final regulation and represents PSE's contractual capacity less losses, encroachment and Canadian Entitlement.

Figure 7-14: Peak Capacity Credit for Hydro Resources Based on 5% LOLP Relative to Perfect Capacity

Hydro Resources	2021 IRP Year 2027 (MW)	2021 IRP Year 2031 (MW)
Upper Baker Units 1 and 2	90	90
Lower Baker Units 3 and 4	82	79
Snoqualmie Falls	38	37

Figure 7-15: Peak Capacity Credit for Mid-C Hydro Resources

Based on Contractual Capacity Less Losses, Encroachment and Canadian Entitlement

Hydro Resources	2021 IRP Year 2027 (MW)	2021 IRP Year 2031 (MW)
Priest Rapids	5	5
Rock Island	121.2	121.2
Rocky Reach	313	313
Wanapum	6.1	6.1
Wells	115	115

THERMAL (NATURAL GAS) RESOURCES CAPACITY CREDITS. The peak capacity contribution of natural gas resources is different than other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need is at 23 degrees F, the capacity of natural gas plants is set to the available capacity of the natural gas turbine at 23 degrees F.

Figure 7-16: Peak Capacity Credit for Natural Gas Resources

THERMAL RESOURCES	2021 IRP peak capacity credit based on 23 degrees (MW)
Sumas	137
Encogen	182
Ferndale	266
Goldendale	315
Mint Farm	320
Frederickson CC	134
Whitehorn 2 & 3	168
Frederickson 1 & 2	168
Fredonia 1 & 2	234
Fredonia 3 & 4	126
Generic 1x0 F-Class Dual Fuel Combustion Turbine	237
Generic 1x1 F-Class Combined Cycle	367
Generic 12x0 18 MW Class RICE	219

WIND AND SOLAR CAPACITY CREDITS. In order to implement the ELCC approach for wind and solar in the RAM, the wind and solar projects were added into the RAM incrementally to determine the reduction in the plant's peaking capacity needed to achieve the 5 percent LOLP level. The wind project's peak capacity credit is the ratio of the change in perfect capacity with and without the incremental wind capacity. The order in which the existing and prospective wind projects were added in the model follows the timeline of when these wind projects were acquired or about to be acquired by PSE: 1) Hopkins Ridge Wind, 2) Wild Horse Wind, 3) Klondike Wind, 4) Lower Snake River Wind, 5) Skookumchuck Wind, 6) Lund Hill Solar, 7) Golden Hills Wind, 8) New RFP Resource, and finally 9) a generic wind or solar resource. Figure 7-17 below shows the estimated peak capacity credit or ELCC of the wind resources included in this IRP.

Figure 7-17: Peak Capacity Credit for Wind and Solar Resources
Based on 5% LOLP Relative to Perfect Capacity

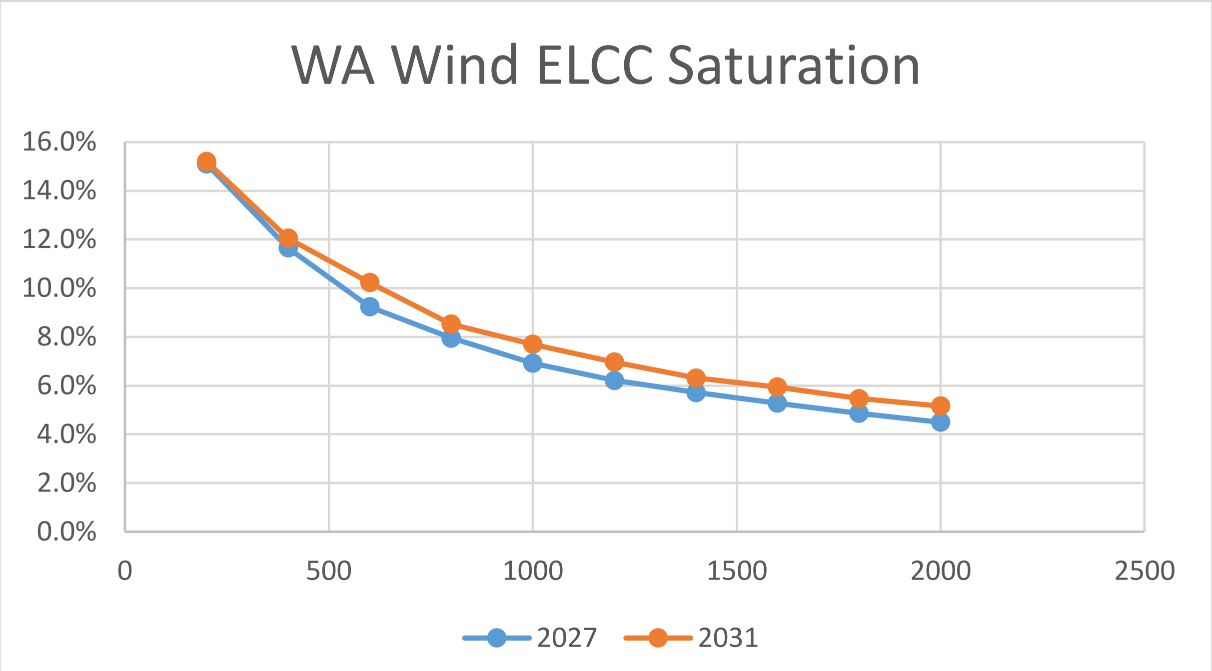
WIND AND SOLAR RESOURCES	2021 IRP Year 2027	2021 IRP Year 2031
Existing Wind	9.6%	11.2%
Skookumchuck Wind	29.9%	32.8%
Lund Hill Solar	8.3%	7.5%
Golden Hills Wind	60.5%	56.3%
Generic MT East Wind1	41.4%	45.8%
Generic MT East Wind2	21.8%	23.9%
Generic MT Central Wind	30.1%	31.3%
Generic WY East Wind	40.0%	41.1%
Generic WY West Wind	27.6%	29.4%
Generic ID Wind	24.2%	27.4%
Generic Offshore Wind	48.4%	46.6%
Generic WA East Wind[1]	17.8%	15.4%
Generic WY East Solar	6.3%	5.4%
Generic WY West Solar	6.0%	5.8%
Generic ID Solar	3.4%	4.3%
Generic WA East Solar[1]	4.0%	3.6%
Generic WA West Solar – Utility scale	1.2%	1.8%
Generic WA West Solar – DER Roof	1.6%	2.4%
Generic WA West Solar – DER Ground	1.2%	1.8%

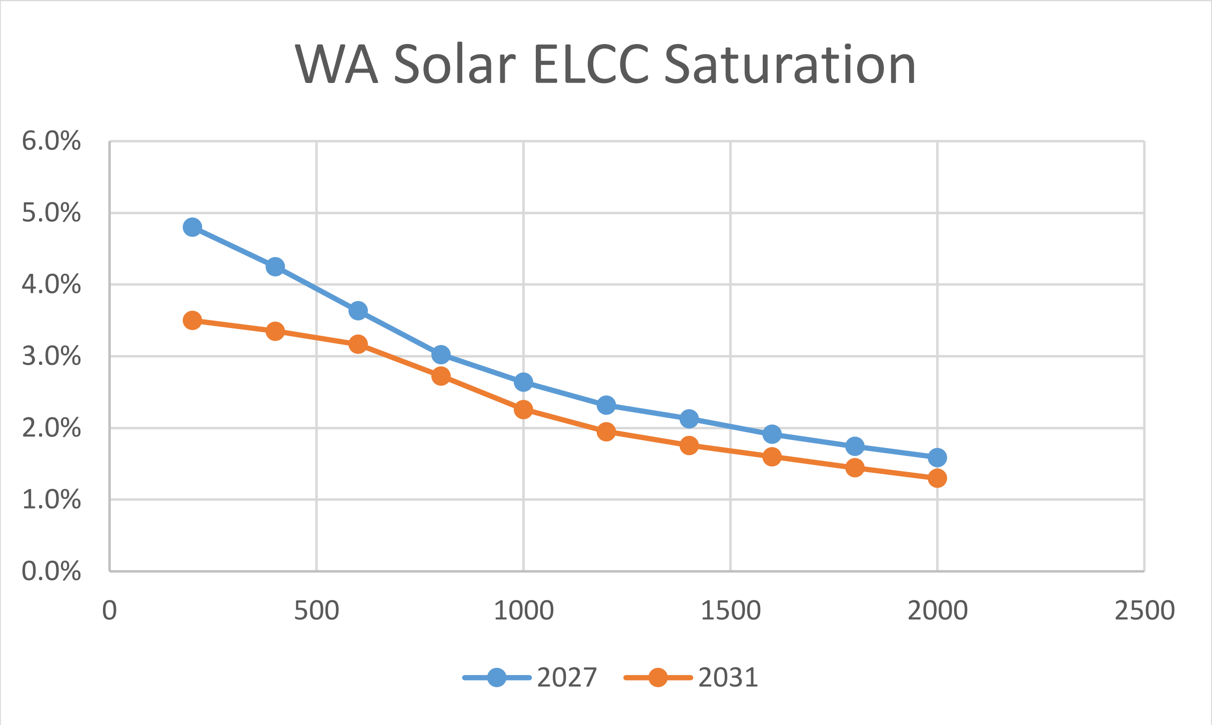
NOTES

1. This ELCC is for the first 100 MW of the resource, the saturation curve for up to 2,000 MW is shown below.

ELCC saturation curves. The peak capacity credit in Figure 7-17 above is for the first 100 MW of installed nameplate capacity for Washington Wind and Solar. Figure 7-18 below is the ELCC for the next 200 MW and then the next 200 MW after that and so on. The Figure shows a decreasing ELCC as more wind or solar is added to the same region.

Figure 7-18: Saturation curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty.

As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit or ELCC of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19. The low peak capacity contribution for energy is because these are short duration resources. As shown in figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events.

Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	2021 IRP Year 2027	2021 IRP Year 2031
Lithium-ion, 2 hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-lin, 4 hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4 hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6 hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8 hr, 80% RT efficiency	100	37.2%	43.8%

HYBRID RESOURCES CAPACITY CREDIT. The capacity contribution of a solar plus battery storage resource is also estimated using EUE. This combination of resources was not analyzed in the 2019 IRP Process. The estimated peak contribution of a solar plus battery storage resource is shown in Figure 7-20.

Figure 7-20: Peak Capacity Credit for Hybrid Resource Based on EUE at 5% LOLP

SOLAR + BATTERY RESOURCE	Capacity (MW)	2021 IRP 2027	2021 IRP 2031
Generic WA Solar, Lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	15.4%
Generic WA Wind, Lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	23.0%
Generic MT East Wind, Pumped Storage, 8 hr, 80% RT efficiency	200	54.3%	57.7%

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response program is also estimated using EUE, since this resource is also energy limited like storage resources. The same methodology was used as for storage resources. The estimated peak capacity contribution of demand response is shown in Figure 7-21.

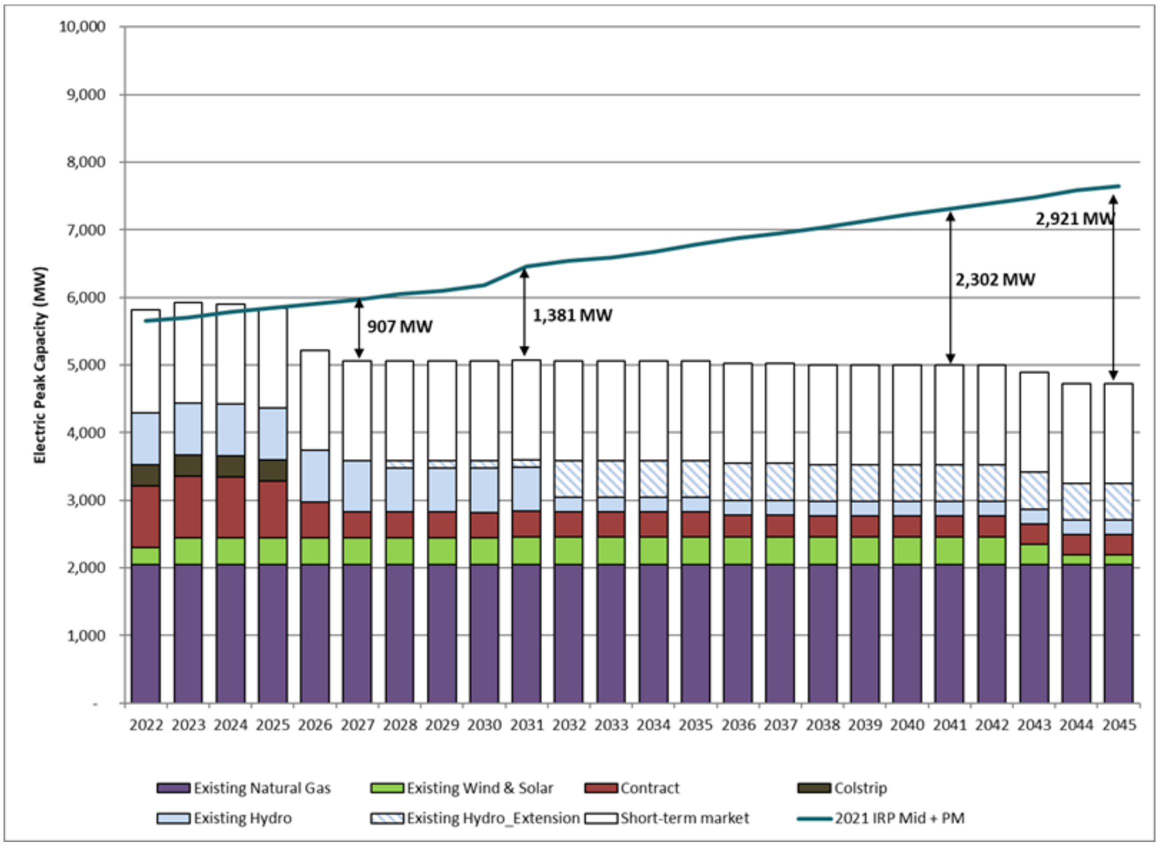
Figure 7-21: Peak Capacity Credit for Demand Response

DEMAND RESPONSE	Capacity (MW)	2021 IRP 2027	2021 IRP 2031
Demand Response, 3 hr duration, 6 hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4 hr duration, 6 hr delay, 10 calls per year	100	32.0%	37.4%

Peak Capacity Need

Figure 7-22 shows the peak capacity need for the mid demand forecast modeled in this IRP. Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW by 2027 and 1,381 MW in 2031.

Figure 7-22: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



8

Electric Analysis

This chapter presents the results of the electric analysis

Contents

1. ANALYSIS OVERVIEW

The electric analysis in the 2021 IRP followed the six-step process outlined below. Steps 1, 3, and 4 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Establish Resource Need

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

- Chapter 7 presents the resource adequacy analysis.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 5 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 6 presents the 2021 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Analyze Alternatives and Portfolios Using Deterministic and Stochastic Risk Analysis

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

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

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

4. Analyze Results

Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions for the draft preferred portfolio.

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

5. Develop Resource Plan

Chapter 3 describes the reasoning behind the strategy chosen for this preferred portfolio.

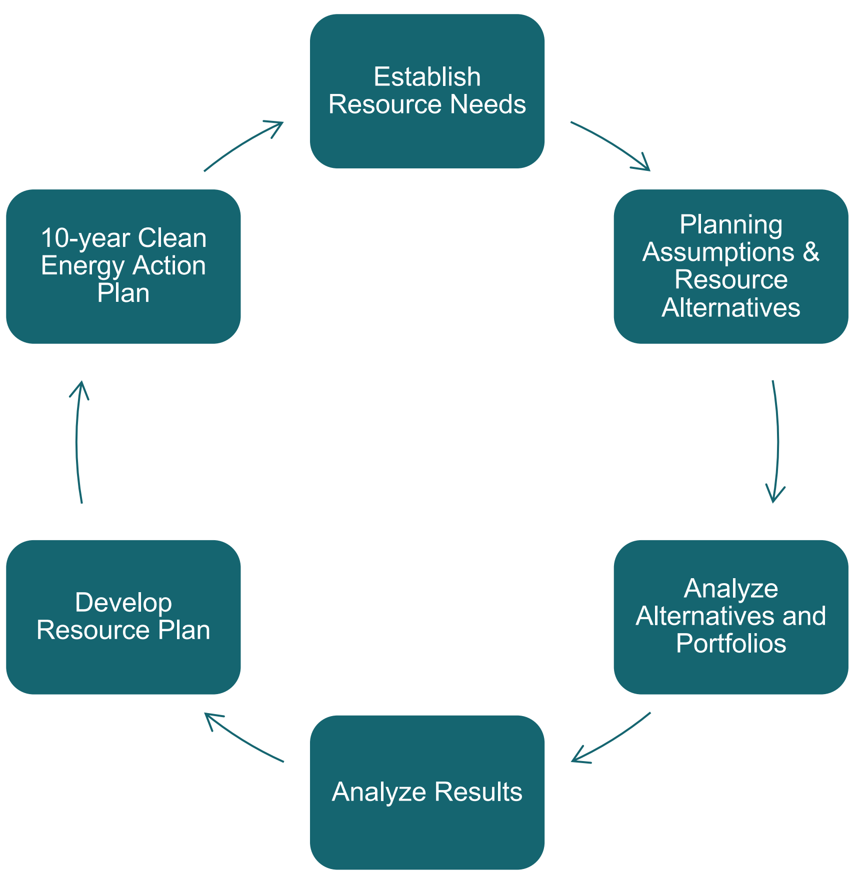
6. Create the 10-year Clean Energy Action Plan

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the Action Plan and the 10-Year Clean Energy Action Plan.

- The Action Plan is presented in the Executive Summary, Chapter 1.
- The 10-year Clean Energy Action Plan is presented in Chapter 2.

Figure 8-1 illustrates this process.

Figure 8-1: 2021 IRP Process



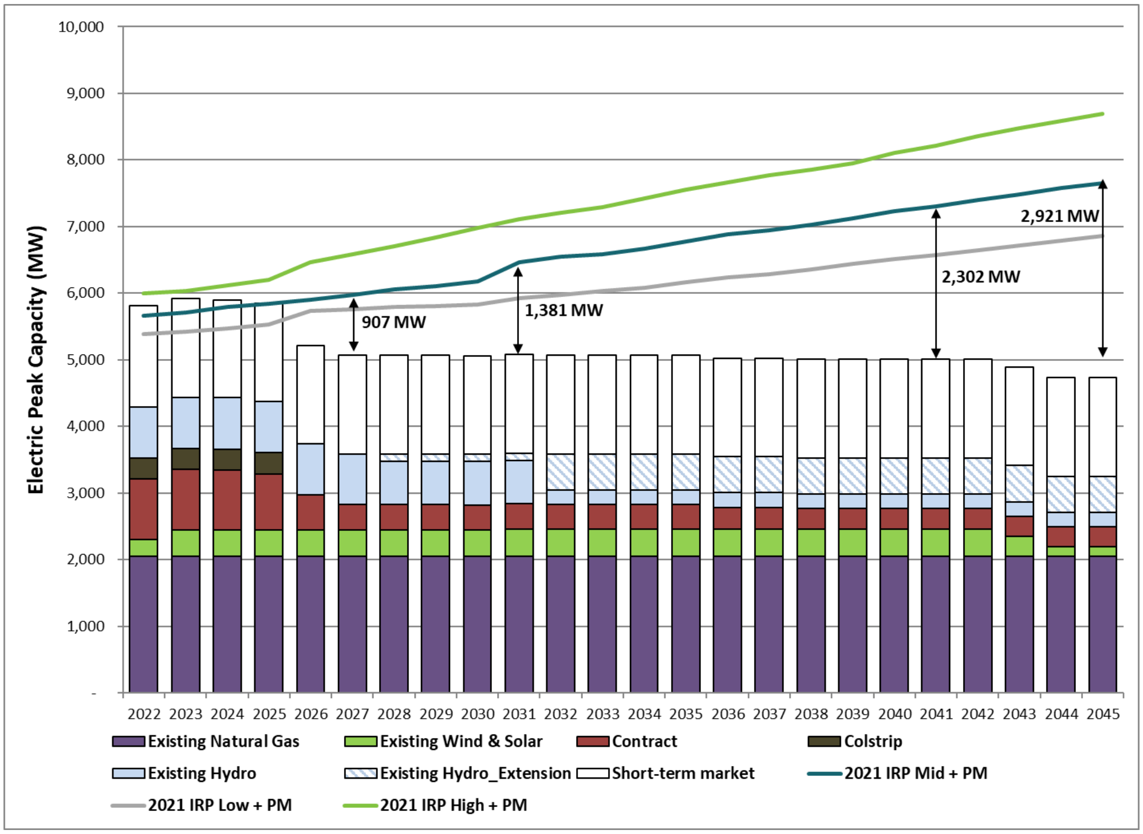
2. RESOURCE NEED

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: (1) peak hour capacity for resource adequacy, i.e. does PSE have the amount of capacity available in each hour to meet customer's electricity needs; (2) hourly energy, i.e. does PSE have enough energy available in each hour to meet customer's electricity needs; and (3) renewable energy, i.e. does PSE have enough renewable and non-emitting resources to meet the clean energy transformation targets.

Peak Capacity Need

Figure 8-2 shows the peak capacity need for the mid demand forecast modeled in this IRP (mid demand refers to the 2021 IRP Base Demand Forecast described in Chapter 6). Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW in 2027 and 1,381 MW in 2031. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis. The physical characteristics of the electric grid are very complex, so for planning purposes we simplify physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model (RAM). The RAM analysis produces reliability metrics that allow us to assess physical resource adequacy risk; these include LOLP (loss of load probability), EUE (expected unserved energy) and LOLH (loss of load hours). We can simplify physical resource need in this way because PSE is much less hydro-dependent than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If PSE were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources or contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons.

Figure 8-2: Electric Peak Capacity Need
(physical reliability need, peak hour need compared with existing resources)



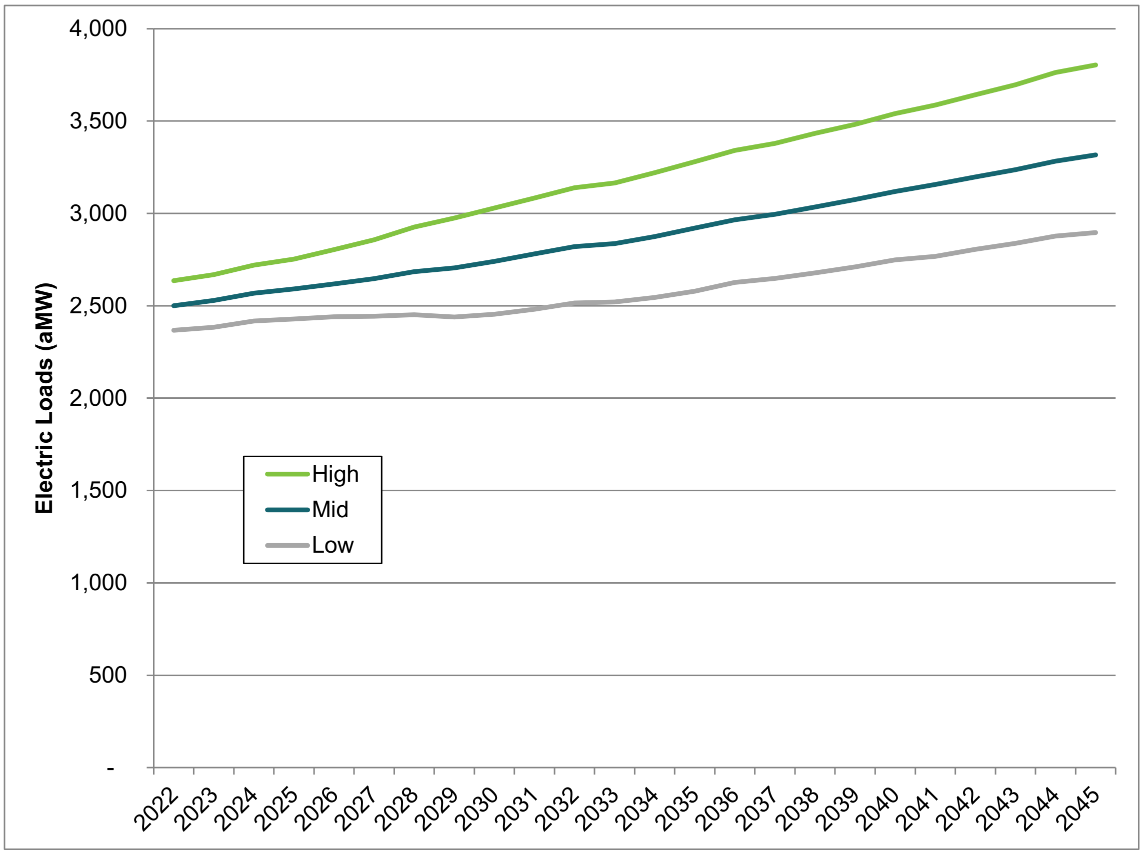
Energy Need

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

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

Figure 8-3 illustrates the company's energy position across the planning horizon, based on the energy demand forecast for the Mid, High and Low Scenarios. The Mid Demand Scenario starts at 2,500 aMW in 2022 and grows to 2,740 aMW by 2030 and 3,316 aMW by 2045.

Figure 8-3: Annual Demand Forecast



Renewable Need

Washington State has two renewable energy requirements. The first is a renewable portfolio standard (RPS) which requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. Under the statute (RCW 19.285), PSE must meet 15 percent of retail sales with renewable resources by 2020. PSE has sufficient qualifying renewable resources to meet RPS requirements until 2023, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades to existing hydro plants.

The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. The difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can be used to meet the requirements.

Washington State's RPS and renewable energy requirements calculate the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, when MWh sales decrease, so does the amount of renewables needed. Achieving demand-side resource targets has precisely this effect. Demand-side resources decrease sales volumes, which then decreases the amount of renewable resources needed.

Figure 8-4 below shows the calculation for the 80 percent renewable requirement in 2030 to meet CETA. Demand-side resources are optimized in the portfolio and will provide a further reduction to the need shown in the last line of the table. Under normal hydro conditions and without the addition of new renewable/non-emitting resources, PSE will meet 40 percent of sales with renewable resources in 2022.

Figure 8-4: Calculation of 2021 IRP Renewable Need for 2030

	MWh
2030 Estimated Sales before Conservation[1]	24,004,160
Conservation: Codes & Standards, Solar PV	(774,387)
Line Losses	(1,579,625)
Load Reducing Customer Programs & PURPA	(1,243,449)
Sales Net of Conservation and Customer Programs	20,406,699
80% of Estimated Net Sales	16,325,360
Existing Non-emitting Resources[2]	(8,691,268)
Need for New Renewable/Non-emitting Resources	7,634,092

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022
2. Assumes normal hydro conditions and P50 wind and solar

Figure 8-5 below illustrates the renewable energy need before any demand-side resources for both RCW 19.285 and CETA based on the mid demand forecast.

Figure 8-5: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements

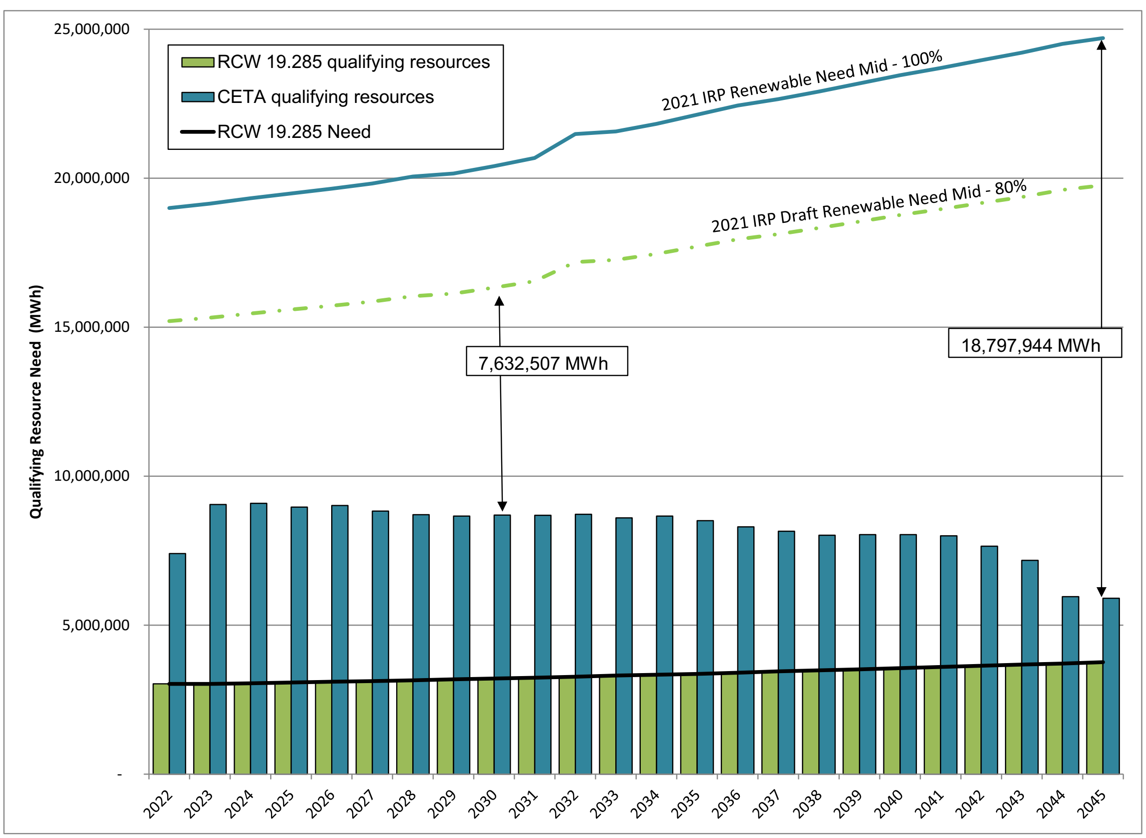
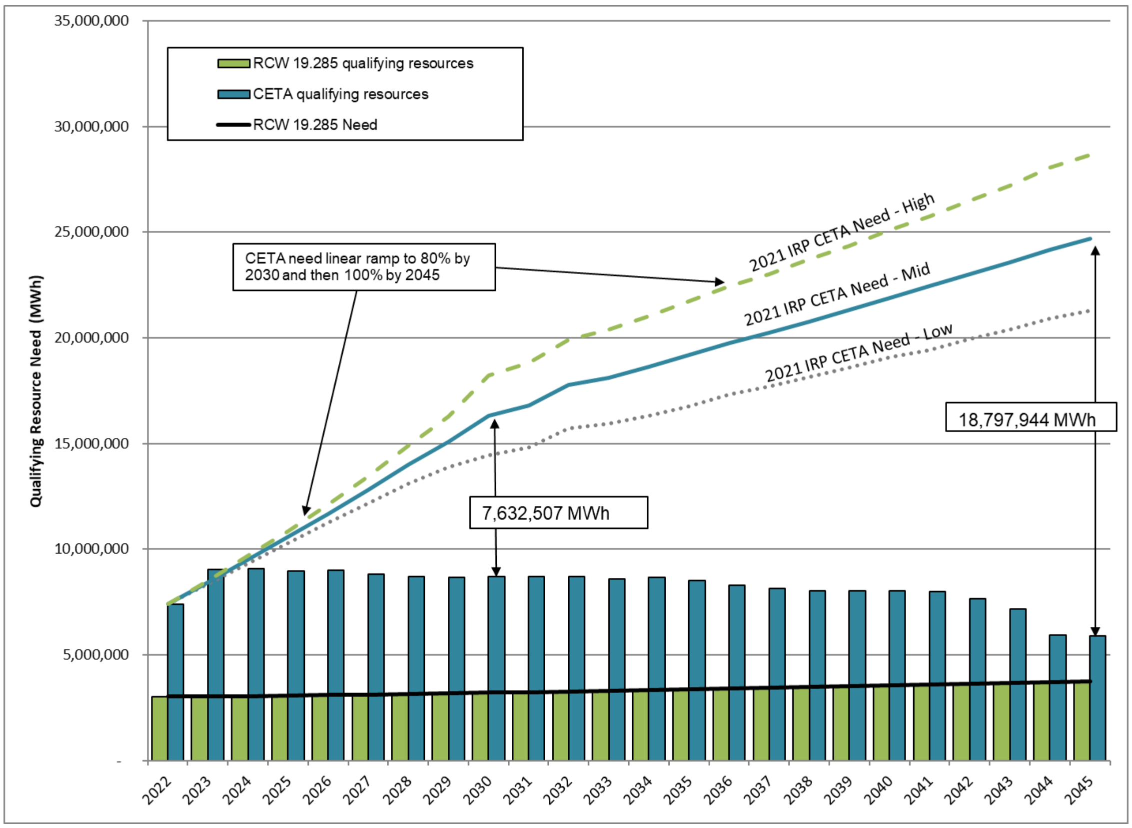


Figure 8-6 below assumes a linear ramp for CETA clean energy standards to reach the 80 percent target in 2030 and the 100 percent target in 2045. The linear ramp is needed to ensure that the portfolio model is gradually adding resources to meet clean energy targets, rather than waiting until the final year before a goal must be achieved. The linear ramp starts in 2022, as the IRP assumes all new resources are self-builds that will take at least two years before becoming operational. Since the IRP analysis starts in 2022, the earliest a resource can be built is 2024.

Figure 8-6: Renewable Need and Linear Ramp for CETA



3. ASSUMPTIONS AND ALTERNATIVES

The scenarios and sensitivities used in the electric analysis are summarized here for convenience.[1]

Scenarios and Sensitivities

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

1 / Chapter 5 presents the scenarios and sensitivities developed for this IRP analysis and discusses in detail the key assumptions used to create them, including customer demand, natural gas prices, possible carbon dioxide (CO_2) prices, resource costs (both demand-side and supply-side) and power prices. Appendix D presents a detailed discussion of existing electric resources and resource alternatives.

Fig 8-8: 2021 IRP Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**Alternatives Analyzed**
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast, mid electric price forecast
2	Low	Low gas price, low demand forecast, low electric price forecast
3	High	High gas price, high demand forecast, high electric price forecast
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced 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		
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.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**Alternatives Analyzed**
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.
EMISSIONS 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	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.
LOAD SENSITIVITIES		
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 PORTFOLIOS		
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 Peaking Capacity	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.

4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.[2]

Deterministic Portfolio Optimization Analysis

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

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

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

Stochastic Risk Analysis

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

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

For this purpose, we take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 250 draws[3] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can evaluate the risk associated with each portfolio. The stochastic analysis will be completed for the final IRP and has not been included in this draft.

3 / Each of the 250 simulations is for the 24-year IRP forecasting period, 2022 through 2045.

5. KEY FINDINGS

The quantitative results produced by this extensive analytical and statistical evaluation led to key findings summarized in the following pages.

Economic Scenarios

1. **Mid Scenario:** *Renewable Need:* In the Mid Scenario, the renewable need is met annually across the planning horizon. Wyoming and Montana wind are the first wind resources added in 2025 and 2026, because their generation profile is well-matched to PSE's load profile. However, these resources are limited by transmission. On the other hand, WA wind is added consistently through the planning time horizon starting in 2028 since there are no transmission constraints imposed on wind resources in the Mid Scenario. In terms of conservation savings, a total of 1,497 MW nameplate of DSR resources were added to the portfolio by 2045.

   Peak Need: With the retirement of Centralia and the removal of Colstrip 3&4 in 2025 as part of CETA compliance, 474 MW of peaking capacity resources are added to the portfolio in 2026.

   Energy need: The hourly energy need is met in the Mid Scenario. Energy is provided by conservation and new and existing renewable resources. However, the use of existing non-renewable resources decline overtime.

2. **Low Scenario:** Lower energy demand, lower natural gas and power price are reflected in the Low scenario. Portfolio additions are similar to the Mid Scenario, but with less resources added by 2045. The total nameplate capacity addition by 2045 is 6,589 MW, a reduction of 1,977 MW from the Mid Scenario. There are less DSR resources added to the portfolio for a total of 1,301 MW nameplate capacity by 2045.

3. **High Scenario**: In the High Scenario, there is higher customer growth, with the higher energy demand reflected in the higher natural gas and power price. More resources are added due to the higher peak capacity and renewable energy need. The total nameplate capacity addition by 2045 is 10,429 MW, an increase of 1,863 MW from the Mid Scenario. DSR savings are higher in this portfolio for a total of 1,536 MW nameplate capacity by 2045.

Portfolio Sensitivities

Future Market Availability

A. **Renewable Overgeneration Test:** Prohibiting sales to the Mid-C market reduces renewable overgeneration by shifting 1,600 MW nameplate of new Washington wind capacity into an additional 510 MW of biomass capacity and 525 MW of battery capacity. However, total portfolio costs increase significantly. In the later years of this portfolio, batteries serve as the primary source of peak energy, being charged by market purchases in excess of demand during off-peak hours.

B. **Market Reliance:** This sensitivity will be evaluated for the final IRP.

Transmission Constraints and Build Limitations

C. **"Distributed" Transmission/Build Constraints - Tier 2:** Tier 2[4] transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon as compared to the Mid Scenario. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. The model pairs these distributed solar resources with battery storage projects to better serve load when the sun is not shining. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

D. **Transmission/Build Constraints – Time-delayed (Option 2):** This sensitivity will be evaluated for the final IRP.

E. **Firm Transmission as a Percentage of Resource Nameplate:** In general, cost savings from reduced firm transmission sensitivities are marginal and likely not a viable method of reducing portfolio costs. Wind resources show the least cost benefit in transmission reduction sensitivities due to the significant portion of time wind resources generate power at or near nameplate capacity (i.e., rated power). Solar resources, which typically spend less time at rated power, show increased cost benefit relative to wind resources, but the cost benefit is still unlikely to prove valuable in resource portfolios.

Conservation Alternatives

4 / Transmission alternatives were divided into four tiers that express increasing levels of constraint. These tiers are described in Chapter 5, Key Assumptions.

F. 6-Year Conservation Ramp Rate: This sensitivity will be evaluated for the final IRP.

G. Non-energy Impacts: This sensitivity will be evaluated for the final IRP.

H. Social Discount Rate for DSR: This sensitivity will be evaluated for the final IRP.

Social Cost of Greenhouse Gases (SCGHG)

I. Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model: The changes brought on by changing SCGHG to an externality cost are minor. The model optimizes dispatch of existing gas plants to minimize cost, while newly acquired peaking capacity is largely unused. The sensitivity resulted in more peaking capacity being built than the Mid Scenario, but the average capacity factors of the newly built plants averages to 0.3 percent by 2045.

J. SCGHG as an Externality Cost in the Portfolio Model and Hourly Dispatch: This sensitivity will be evaluated for the final IRP.

K. AR5 Upstream Emissions: This sensitivity will be evaluated for the final IRP.

L. SCGHG as a Fixed Cost Plus a Federal CO_2 Tax: This sensitivity will be evaluated for the final IRP.

Emissions Reduction

M. Alternative Fuel for Peakers: This sensitivity will be evaluated for the final IRP.

N. 100% Renewable by 2030 : In this sensitivity, the 24-year levelized portfolio costs increased by 128 percent for a total of $31.1 billion dollars in revenue requirement. With no access to thermal resources by 2030, a significant amount of batteries totaling 26,100 nameplate MW were built to keep the portfolio balanced. Market access remains important in this sensitivity, as purchases became a resource for meeting energy and peak capacity needs in addition to being a source for charging the batteries.

O. Natural Gas Generation Out by 2045 : In this sensitivity, the 24-year levelized revenue requirement is $33.9 billion dollars, an increase of $20.3 billion dollars or 149 percent. With the retirement of all existing natural gas fired and new peaking capacity resources happening in one year, the portfolio model fails to meet the peak capacity need in 2045.

There is a significant increase in the annual portfolio costs between 2044 and 2045 due to penalties related to violation of CETA constraints in the model. This sensitivity requires further work for the final 2021 IRP.

P. Must-take Energy Storage: Delaying the availability of peaking capacity resources resulted in much earlier addition of storage resources, for a total of 3,775 MW nameplate capacity by 2030. We also see an additional 7 MW nameplate capacity of demand response by 2045 compared to the 121 MW of demand response added in the Mid Scenario portfolio. Peaking capacity resources were still added to the portfolio for a total of 711 MW nameplate capacity compared to 948 MW nameplate capacity in the mid portfolio. In this sensitivity, the 24-year levelized revenue requirement is $29.1 billion dollars, an increase of $15.5 billion dollars or 113 percent.

P2. Must-take Pump Hydro Energy Storage: Without peaking capacity resources and batteries available until 2030, 2,800 MW nameplate capacity of pump hydro energy storage resources were added to the portfolio by 2028 in order to fill the peak capacity needed after the removal of Centralia and Colstrip 3&4. Interestingly, 711 MW nameplate of peaking capacity resources and 1,225 MW nameplate of 2-hr Lithium Ion batteries were added to the portfolio by 2045. For Sensitivity P2, the 24-year levelized revenue requirement is $22.4 billion dollars, an increase of $8.72 billion dollars over the Mid Scenario.

Demand Adjustments

Q. Fuel Switching, Gas to Electric: This sensitivity will be evaluated for the final IRP.

R. Temperature Sensitivity: This sensitivity will be evaluated for the final IRP.

CETA Costs

S. SCGHG Included, No CETA: Without the CETA renewable requirement, the 24-year levelized revenue requirement is $10.1 billion dollars, a $3.6 billion dollars reduction from the mid portfolio. There are no renewable resource addition to the portfolio except for a 350 MW of wind in 2044 needed to maintain compliance with the RPS requirement. A total of 1,513 MW nameplate peaking capacity was added to the portfolio by 2045. There was less conservation selected in this portfolio for a total of 1188 MW of nameplate capacity, a reduction of 319 MW from the mid portfolio.

T. No CETA or SCGHG: Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement is $9.4 billion dollars, a $4.2 billion dollar reduction from the Mid Scenario portfolio. Compared to Sensitivity S, this is a further reduction of $0.7 billion dollars. Similar to Sensitivity S, there are no renewable resource additions to the portfolio except for 350 MW of wind in 2044 needed to maintain compliance with the RPS requirement. Even less conservation is selected in this portfolio for a total of 1,052 MW of nameplate capacity, 455 MW less than in the Mid Scenario portfolio.

U. 2% Cost Threshold: This sensitivity will be evaluated for the final IRP.

Balanced Portfolio

V. Balanced Portfolio: PSE developed a schedule for various resource additions during the planning horizon based on the understanding of the results from other sensitivities. Distributed energy resources and customer programs were set as must-take resources and ramped in over time. The portfolio costs were slightly higher than the Mid Scenario, because distributed solar resources are higher cost than Washington wind and solar east resources, which were found to be the optimal renewable resources following Montana and Wyoming wind resources in the Mid Scenario. In Sensitivity V, the 24-year levelized revenue requirement is $14.37 billion dollars, an increase of $0.74 billion dollars or 5 percent over the Mid Scenario.

W. Balanced Portfolio with Alternative Fuel for Peakers: Extending the assumptions from Sensitivity V to include biodiesel as fuel source for new frame peakers resulted in an increase of $0.8 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $14.43 billion dollars, an increase of $0.06 billion dollars from Sensitivity V. Even with the premium on biodiesel fuel prices compared to natural gas price, the model selected the same amount of combustion turbine resources in Sensitivity W compared to the Mid Scenario.

6. ECONOMIC SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all three economic scenarios look very much alike given all the generic resource options. The mix of resources is similar for three scenarios and the amount of resources added increased or decreased based on high and low load forecasts, respectively. Given that the Low economic scenario has a lower demand, the peak need and renewable need are lower so fewer resources are added. In the High economic scenario, more resources are added for a higher peak need and renewable need. Figure 8-7, shows the levelized cost by scenario while Figure 8-8 shows the optimal portfolio builds by scenario.

Figure 8-7: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

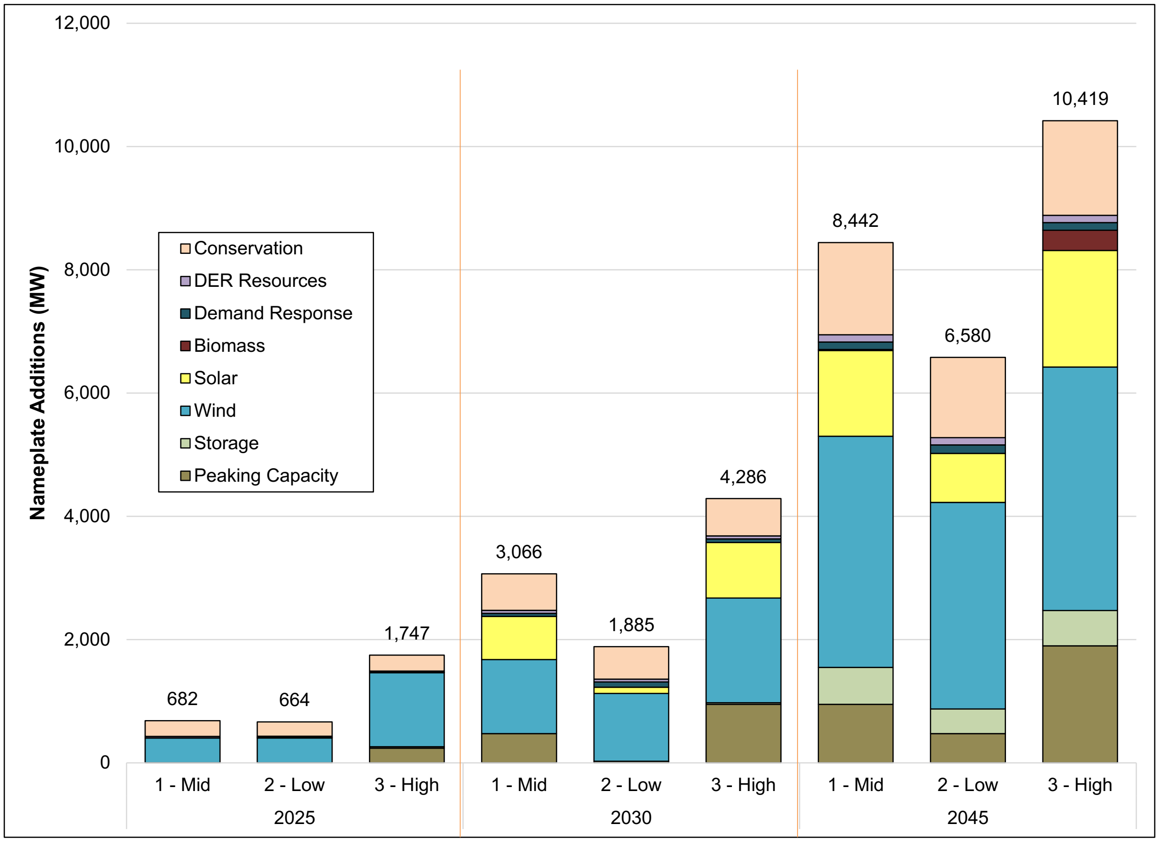
		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
2	Low Scenario	$10.44	$4.47	$14.91	($3.77)
3	High Scenario	$17.18	$6.31	$23.49	$4.82

Figure 8-8: Relative Optimal Portfolio Builds by Scenario
(cumulative nameplate capacity in MW for each resource addition by 2045)

		DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Peaking Capacity	Total
1	Mid	1,497	118	121	15	1,393	3,750	600	948	8,442
2	Low	1,304	118	137	-	797	3,350	400	474	6,580
3	High	1,537	118	122	330	1,891	3,950	575	1,896	10,419

Figure 8-9 below displays the megawatt additions for the deterministic analysis optimal portfolios for all three scenarios in 2025, 2030 and 2045. No new resources are added until 2024. See Appendix N, Electric Analysis, for more detailed information.

Figure 8-9: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Portfolio Emissions

In this section, we present emissions results associated with each sensitivity. Figure 8-10 shows CO_2 emissions for the Mid portfolio and each sensitivity analyzed so far. The chart shows the direct emissions from each portfolio of resources and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. All sensitivities that meet CETA renewable requirements show significant reduction in emissions through the planning horizon. Direct emissions decrease to zero for Sensitivity N, 100% renewables by 2030.

Figure 8-10: CO_2 Emissions by Portfolio

(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)

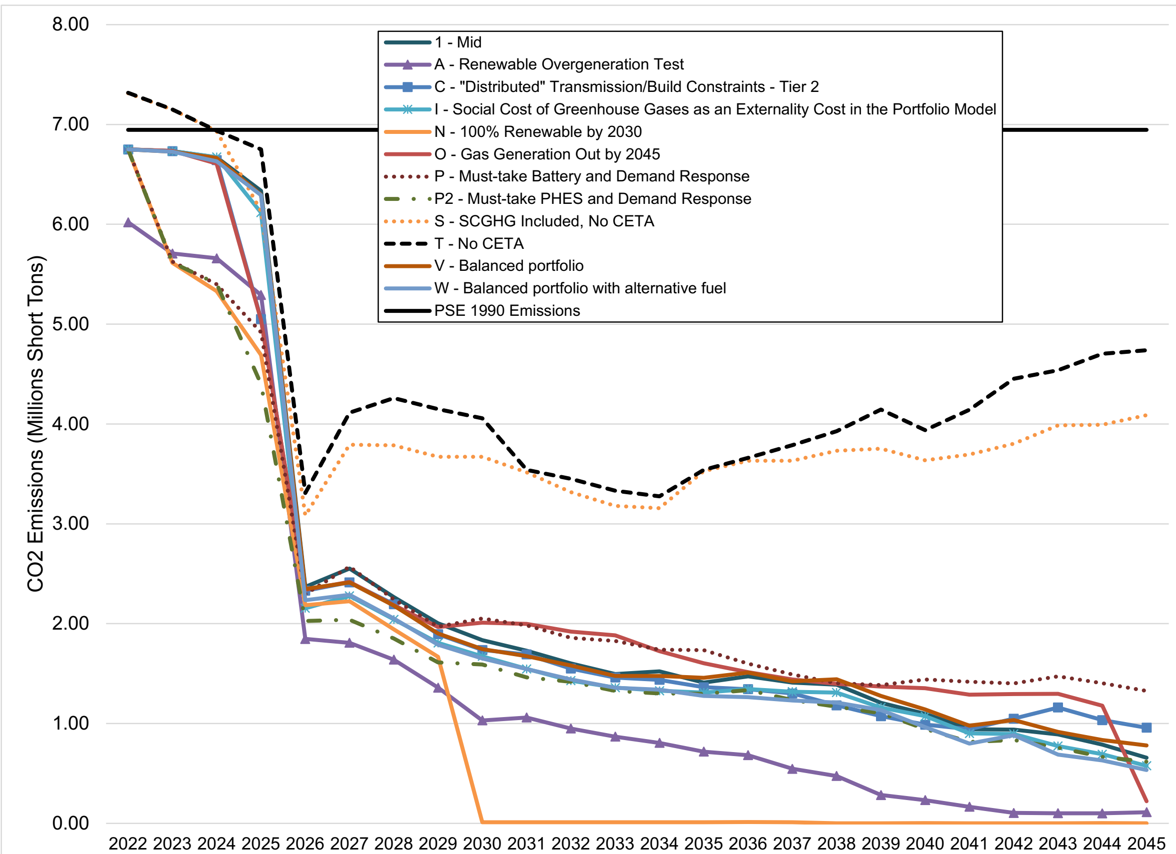
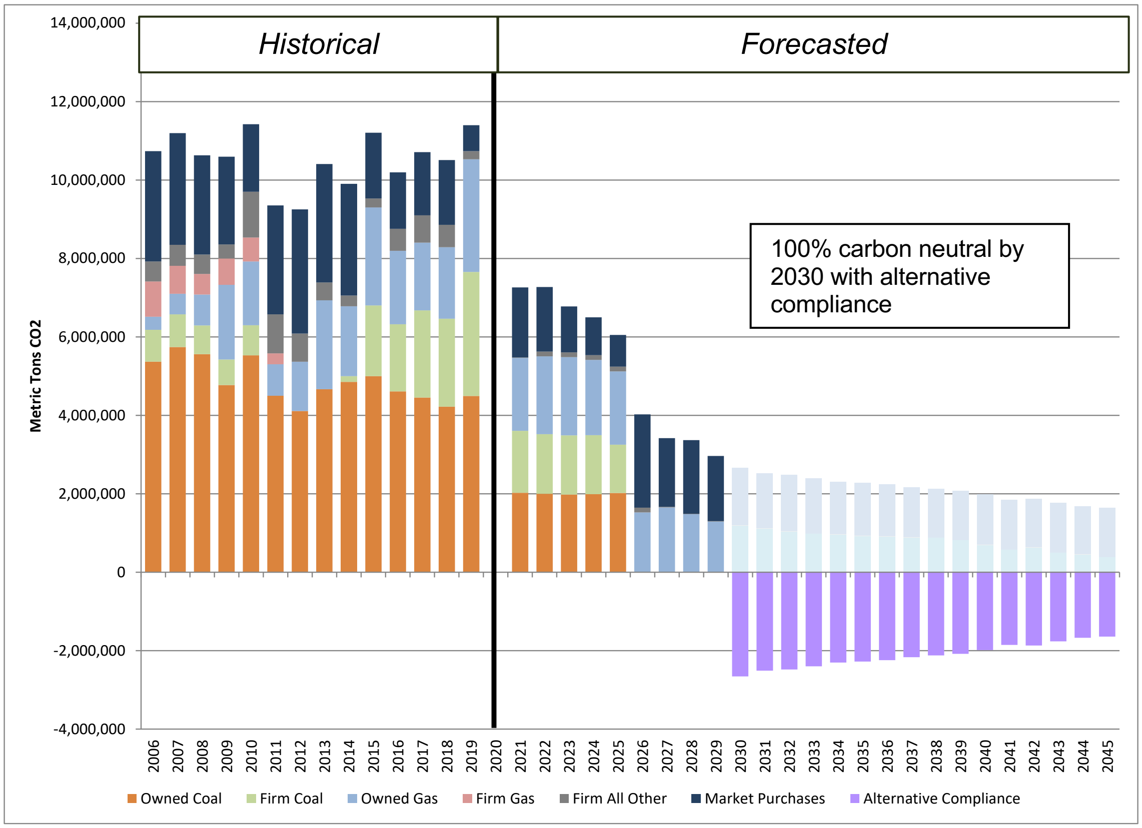


Figure 8-11, below, shows the emissions by resource type for the Mid Scenario portfolio. There is a direct relationship between emissions and the dispatch of thermal plants. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will be further reduced with a lower projected lower economic dispatch of thermal resources as well the exit of Colstrip 3 & 4 and Centralia from PSE portfolio. With the retirement of resources and forecasted drop in dispatch, the total portfolio decreases by over 75 percent from 2019 to 2029. Through alternative compliance mechanisms, the portfolio achieves carbon neutral from 2030 through to 2045.

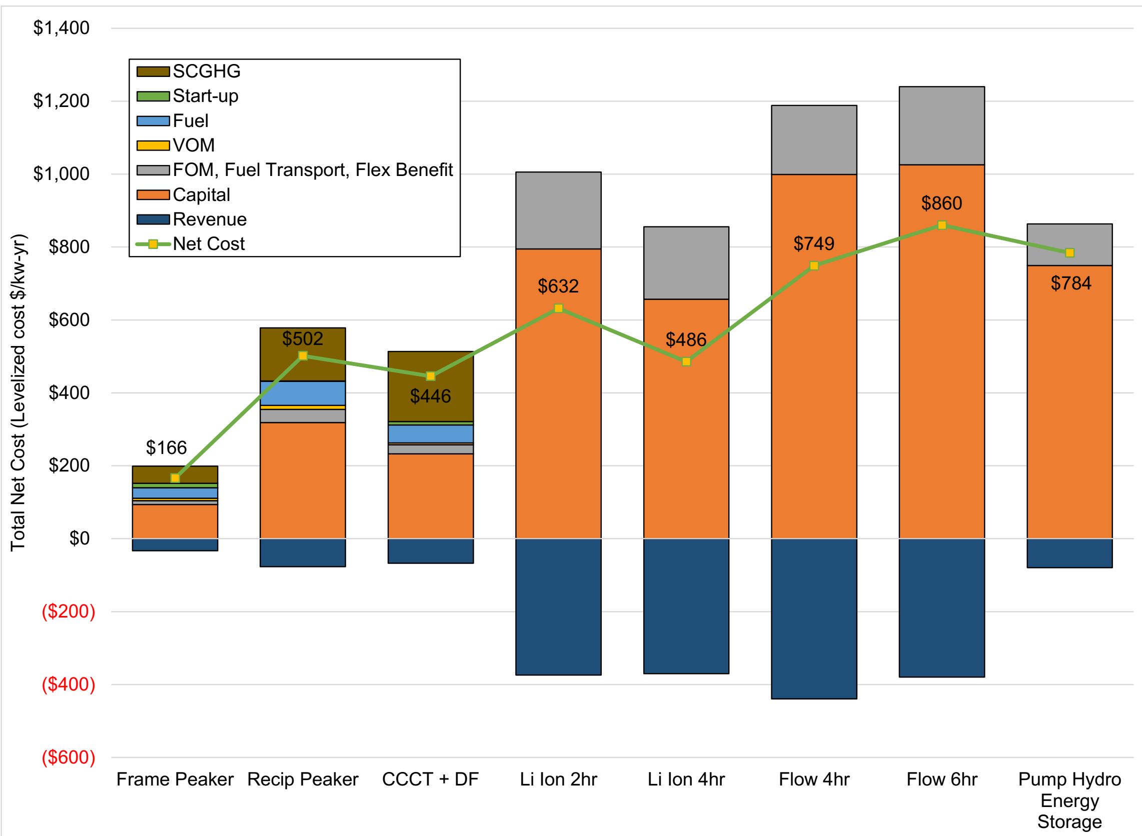
Figure 8-11: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions for the Mid Scenario Portfolio



Levelized Cost of Capacity

Figure 8-12 compares the cost of peakers, baseload gas plants and energy storage resources in the Mid Scenario portfolio. The levelized cost of capacity is based on the peak capacity value. For example, the nameplate of a 2-hour lithium-ion battery is 25 MW, but it has an ELCC of 12.4 percent, so the peak capacity value is 3.1 MW. (The total cost of the lithium-ion battery is divided by 3.1 MW instead of the 25 MW which is why it has a high levelized cost of capacity.) The SCGHG costs are added to the total costs when calculating the levelized cost of capacity of new peakers and baseload gas plants. For frame peakers, the levelized cost of capacity increased from $119 to $166 when SCGHG costs are added.

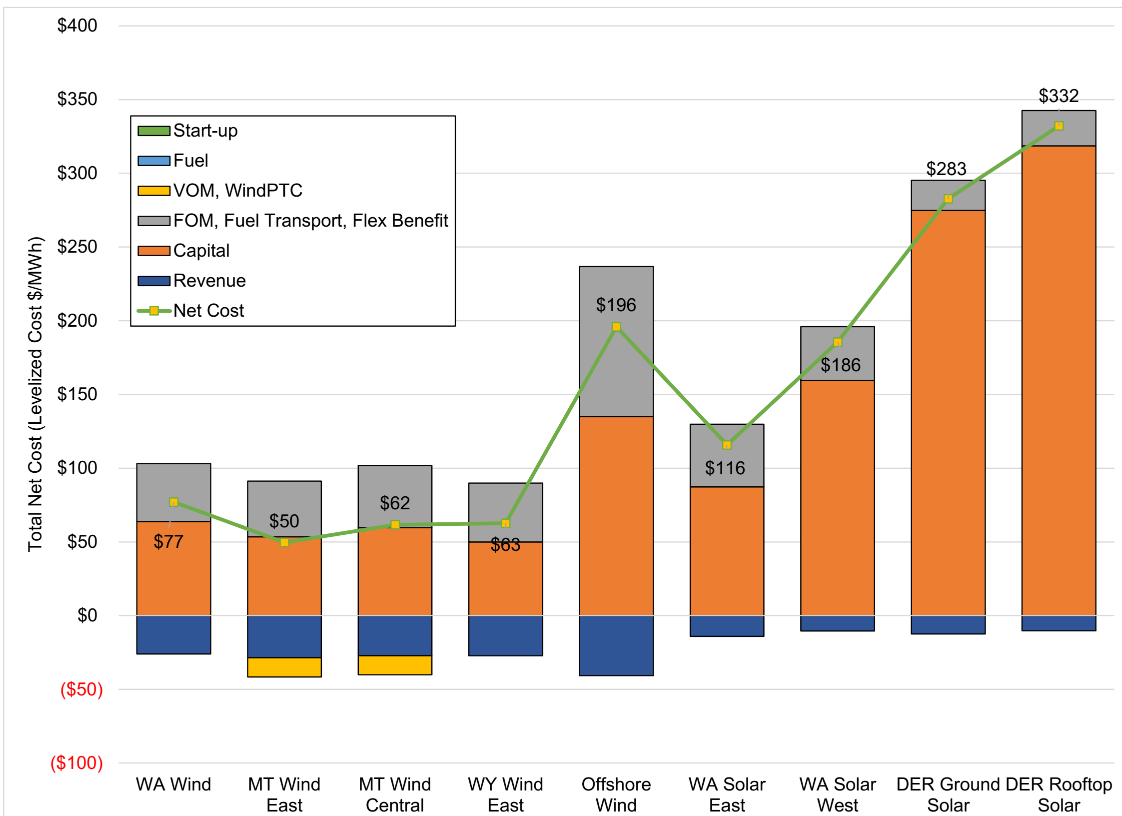
Figure 8-12: Net Cost of Capacity in the Portfolio Model



Levelized Cost of Energy

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources outside of the Pacific Northwest region will be limited. After the Montana and Wyoming wind, costs between eastern Washington wind and solar are very close. Figure 8-13 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resource to meet CETA, followed by eastern Washington wind and solar.

Figure 8-13: Wind and Solar Cost Components



7. SENSITIVITY ANALYSIS RESULTS

Portfolio sensitivity analysis is an important form of risk analysis. It helps us understand how specific assumptions can change the mix of resources in the portfolio and affect portfolio costs. Figures 8-14 and 8-15 illustrate the breakdown of costs and resource builds between the Mid Scenario and the various Sensitivities modeled for this IRP.

Figure 8-14: Relative Optimal Portfolio Costs by Sensitivity
(dollars in billions, NPV including end effects)

		24-Yr Levelized Costs			
	Portfolio	**Revenue Requirement**	**SCGHG Costs**	**Total**	**Change from Mid**
1	Mid Scenario	$13.63	$5.04	$18.68	
A	Renewable Over-generation Test	$15.32	$4.24	$19.57	$0.89
C	"Distributed" Transmission/Build Constraints - Tier 2	$14.53	$5.06	$19.59	$0.91
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	$13.65	$4.78	$18.42	($0.25)
N	100% Renewable by 2030	$31.14	$3.42	$34.56	$15.89
O	Gas Generation Out by 2045	$33.90	$6.24	$40.14	$21.46
P	Must-take Battery and Demand Response	$29.09	$6.06	$35.15	$16.47
P2	Must-take PHES and Demand Response	$22.35	$4.36	$26.71	$8.04
S	SCGHG Included, No CETA	$10.06	$9.01	$19.08	$0.40
T	No CETA	$9.40	$0.00	$9.40	($9.28)
V	Balanced Portfolio	$14.37	$5.06	$19.43	$0.75
W	Balanced Portfolio with Alternative Fuel for Peakers	$14.43	$4.86	$19.30	$0.62

Figure 8-15: Relative Optimal Portfolio Builds by Sensitivity
(cumulative nameplate capacity in MW for each resource addition by 2045)

	Portfolio	DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Peaking Capacity	Total
1	Mid Scenario	1,497	118	121	15	1,393	3,750	600	948	8,442
A	Renewable Overgeneration Test	1,545	692	183	525	1,490	2,150	118	4,165	7,828
C	"Distributed" Transmission/Build Constraints - Tier 2	1,537	3,068	125	105	499	2,715	1,050	948	10,047
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	1,372	118	141	120	1,394	3,450	600	966	8,161
N	100% Renewable by 2030	1,304	118	123	-	1,394	4,050	26,100	-	33,089
O	Gas Generation Out by 2045	1,262	118	130	-	1,397	4,150	18,625	-	25,682
P	Must-take Battery and Demand Response	1,304	118	128	-	1,796	3,750	3,775	711	11,582
P2	Must-take PHES and Demand Response	1,304	118	128	-	1,397	3,950	4,100	711	11,708
S	SCGHG Included, No CETA	1,179	118	155	-	-	350	-	1,513	3,315
T	No CETA	1,042	118	133	-	-	350	-	2,151	3,794
V	Balanced Portfolio	1,658	798	211	60	796	3,750	1,125	948	9,346
W	Balanced Portfolio with Alternative Fuel for Peakers	1,784	798	215	15	697	3,750	750	984	8,993

A. Renewable Over-generation Test

What happens if PSE is unable to sell excess energy to the Mid-C Market?

Baseline: PSE can sell 1500 MW of energy to the Mid-C market at any given hour.

Sensitivity: PSE cannot sell any energy to the Mid-C market at any hour.

Key Findings

Prohibiting sales to the Mid-C market reduces renewable over-generation by shifting 1,600 MW of built Washington wind capacity into an additional 510 MW of biomass capacity and 525 MW of battery capacity. In the later years of this portfolio, batteries serve as the primary source of peak energy, being charged by market purchases in excess of demand during off-peak hours.

Assumptions

This portfolio keeps all underlying assumptions from the Mid Scenario portfolio. The only difference between Sensitivity A and the Mid Scenario is PSE's ability to sell energy to the Mid-C market, which has been removed in Sensitivity A.

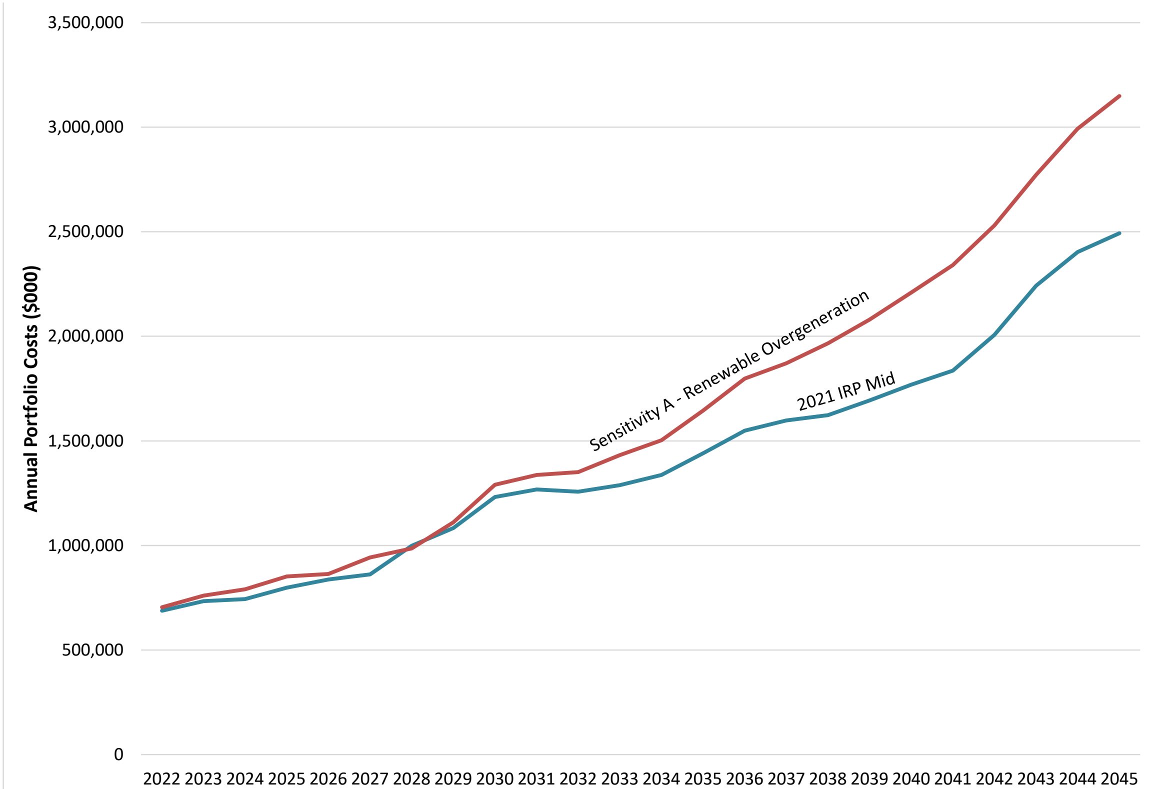
Annual Portfolio Costs

Figures 8-16 and 8-17 illustrate the breakdown of costs between the Mid Scenario and Sensitivity A portfolios. The costs of the portfolio remain similar until the year 2030, where costs begin to diverge. This is driven by the increased builds of biomass and battery resources, which cost more than the Mid Scenario build of Washington wind resources and peaking capacity. Most of these costs are incurred in the later years of the model, which carries less weight in the levelized costs of the portfolio. As a result, total portfolio costs increase less than 5 percent driven mostly by the increased revenue requirement. SCGHG costs come down as the market purchases of the portfolio decrease slightly.

Figure 8-16: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity A

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
A	Renewable Overgeneration test	$15.32	$4.24	$19.57	$0.89

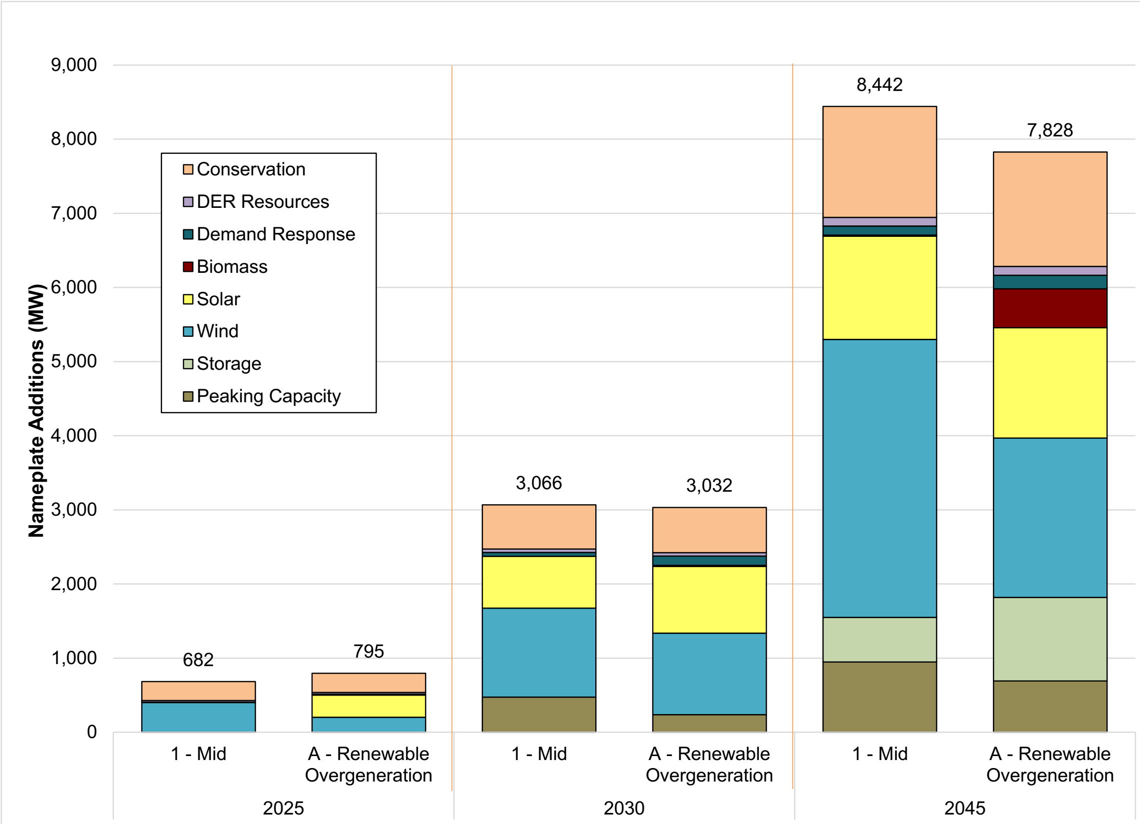
Figure 8-17: Annual Portfolio Costs – Mid Scenario and Sensitivity A



Resource Additions

Figure 8-18 compares the nameplate capacity additions of the Sensitivity A and Mid Scenario portfolios. Sensitivity A builds a similar amount of nameplate capacity as the Mid Scenario, but the distribution of those resources moves away from wind generation and toward biomass and battery storage. Seventy-five percent of the batteries built are 6-hour flow batteries, and no pumped hydro storage is built. Conservation reaches Bundle 12 in this sensitivity. No PSE resources, new or existing, were retired in this sensitivity.

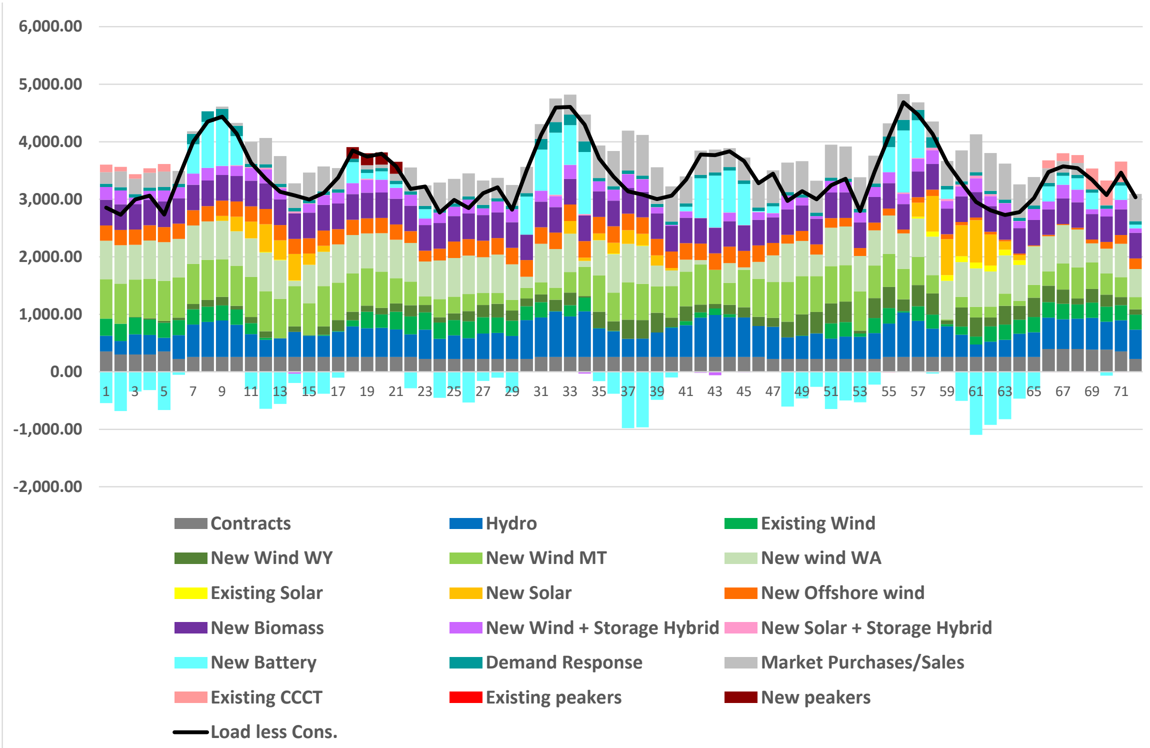
Figure 8-18: Portfolio Additions, Sensitivity A – Renewable Overgeneration



Other Findings

PEAK NEED: In 2045, the peak capacity behavior of the new resources in the sensitivity portfolio become apparent. Figure 8-19 shows the peak demand of 2045 resources in the hourly dispatch model. Battery resources cycle constantly in order to make it through peak demand hours, which is likely driving the selection of 6-hour flow batteries for their longer duration than 4-hour or 2-hour options. To charge these batteries the portfolio relies on market purchases to provide excess energy, as the PSE supply-side resources do not provide enough surplus at these times.

Figure 8-19: 2045 Peak Demand Period of Sensitivity A, December 28-30 2045



The relationship between the market purchases being made by the model and the battery activity can be seen by examining the times at which the market purchases are occurring. Figure 8-20 shows the percentage of hours each month where market purchases are being made by PSE in the year 2045 of the sensitivity. Figure 8-21 shows the percentage of hours each month where market purchases are being made while batteries are being charged or discharged. Market purchases are being made nearly constantly through the winter. When batteries are charging during off-peak hours, these purchases provide the energy for them to charge. When batteries are discharging during peak hours, these purchases help to meet demand.

Figure 8-20: Percentage of Each Month Where Market Purchases are Being Made in Each Hour for Sensitivity A

Purchase	1	2	3	4	5	6	7	8	9	10	11	12
0	81%	89%	84%	27%	0%	0%	16%	58%	90%	68%	63%	87%
1	81%	89%	87%	30%	0%	0%	13%	58%	90%	71%	67%	90%
2	81%	86%	84%	27%	0%	0%	19%	52%	80%	71%	67%	90%
3	81%	89%	84%	23%	0%	0%	19%	52%	80%	71%	63%	87%
4	84%	89%	71%	23%	0%	0%	10%	48%	83%	68%	67%	87%
5	84%	82%	74%	17%	0%	0%	10%	48%	87%	68%	67%	84%
6	84%	68%	68%	20%	0%	0%	19%	77%	83%	61%	67%	74%
7	81%	61%	71%	7%	0%	0%	23%	77%	83%	71%	60%	77%
8	84%	79%	74%	10%	0%	0%	26%	87%	83%	65%	60%	77%
9	84%	79%	68%	7%	0%	3%	23%	87%	80%	68%	57%	87%
10	84%	82%	74%	13%	0%	3%	23%	87%	80%	68%	57%	87%
11	81%	86%	77%	13%	0%	0%	23%	87%	83%	68%	57%	87%
12	81%	86%	77%	27%	3%	0%	16%	84%	80%	65%	57%	94%
13	81%	86%	77%	27%	3%	0%	23%	84%	83%	68%	60%	94%
14	84%	86%	74%	20%	3%	3%	26%	77%	80%	65%	60%	90%
15	84%	82%	77%	13%	3%	3%	13%	77%	80%	68%	67%	94%
16	84%	79%	74%	10%	0%	0%	19%	61%	77%	71%	73%	90%
17	74%	82%	71%	13%	0%	0%	19%	48%	57%	68%	70%	87%
18	77%	82%	68%	20%	0%	3%	23%	45%	60%	65%	63%	84%
19	84%	86%	68%	17%	3%	3%	29%	35%	57%	58%	70%	84%
20	84%	86%	68%	13%	3%	3%	23%	52%	73%	71%	70%	81%
21	81%	89%	77%	17%	3%	3%	29%	58%	90%	68%	67%	90%
22	81%	86%	84%	23%	6%	3%	19%	55%	97%	74%	70%	87%
23	81%	86%	84%	17%	3%	3%	19%	61%	97%	77%	73%	94%
	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average
	82%	83%	76%	18%	1%	1%	20%	65%	81%	68%	65%	87%

Figure 8-21: Percentage of Each Month Where Market Purchases are Being Made in Each Hour While Batteries are Charging and Discharging for Sensitivity A

Charge, Purchase	1	2	3	4	5	6	7	8	9	10	11	12
0	61%	50%	45%	3%	0%	0%	0%	10%	17%	32%	33%	81%
1	71%	57%	48%	7%	0%	0%	0%	13%	27%	35%	43%	84%
2	71%	50%	52%	10%	0%	0%	3%	10%	17%	42%	47%	81%
3	65%	54%	45%	0%	0%	0%	3%	6%	10%	26%	37%	77%
4	84%	86%	35%	3%	0%	0%	0%	3%	3%	13%	67%	87%
5	48%	43%	26%	3%	0%	0%	0%	23%	23%	42%	43%	71%
6	10%	21%	16%	0%	0%	0%	13%	52%	13%	6%	13%	19%
7	6%	7%	29%	0%	0%	0%	23%	71%	70%	26%	7%	10%
8	0%	32%	42%	3%	0%	0%	26%	87%	77%	32%	17%	3%
9	23%	36%	48%	7%	0%	3%	19%	84%	77%	39%	27%	26%
10	39%	57%	55%	13%	0%	3%	19%	87%	73%	55%	23%	45%
11	52%	71%	74%	13%	0%	0%	19%	84%	80%	58%	40%	58%
12	65%	68%	68%	27%	0%	0%	13%	84%	80%	48%	47%	94%
13	71%	79%	77%	27%	0%	0%	23%	81%	77%	55%	47%	81%
14	74%	75%	74%	20%	0%	3%	26%	74%	67%	52%	43%	81%
15	77%	64%	71%	10%	0%	0%	13%	71%	67%	48%	37%	65%
16	26%	43%	48%	3%	0%	0%	13%	45%	67%	13%	3%	16%
17	3%	11%	0%	0%	0%	0%	10%	10%	3%	3%	0%	3%
18	0%	7%	0%	0%	0%	0%	0%	0%	0%	3%	3%	13%
19	0%	4%	0%	0%	0%	0%	3%	0%	0%	3%	7%	6%
20	6%	25%	6%	0%	0%	0%	0%	3%	3%	6%	17%	13%
21	45%	46%	10%	0%	3%	0%	0%	6%	13%	23%	37%	71%
22	16%	21%	42%	3%	3%	0%	3%	6%	23%	58%	13%	23%
23	58%	32%	32%	0%	0%	0%	3%	6%	13%	19%	27%	58%
	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average
	40%	43%	39%	6%	0%	0%	10%	38%	38%	31%	28%	49%

Discharge, Purchase	1	2	3	4	5	6	7	8	9	10	11	12
0	10%	29%	35%	23%	0%	0%	13%	48%	70%	35%	23%	3%
1	3%	25%	32%	20%	0%	0%	10%	45%	60%	35%	20%	0%
2	6%	25%	26%	13%	0%	0%	16%	42%	63%	29%	20%	10%
3	13%	36%	29%	20%	0%	0%	13%	45%	70%	35%	20%	6%
4	0%	0%	32%	17%	0%	0%	10%	42%	77%	55%	0%	0%
5	29%	29%	48%	13%	0%	0%	3%	23%	50%	23%	17%	10%
6	74%	39%	52%	13%	0%	0%	0%	16%	53%	52%	50%	52%
7	74%	46%	35%	3%	0%	0%	0%	6%	10%	35%	53%	65%
8	84%	43%	32%	3%	0%	0%	0%	0%	3%	19%	37%	74%
9	52%	39%	13%	0%	0%	0%	3%	3%	3%	26%	27%	58%
10	32%	21%	13%	0%	0%	0%	3%	0%	7%	10%	30%	42%
11	23%	14%	3%	0%	0%	0%	3%	3%	3%	10%	10%	13%
12	10%	11%	10%	0%	0%	0%	0%	0%	0%	10%	7%	0%
13	6%	7%	0%	0%	0%	0%	0%	3%	7%	6%	7%	10%
14	10%	7%	0%	0%	3%	0%	0%	3%	3%	10%	13%	10%
15	6%	18%	6%	3%	3%	3%	0%	3%	13%	19%	10%	19%
16	39%	32%	16%	3%	0%	0%	3%	3%	10%	58%	60%	68%
17	71%	71%	68%	13%	0%	0%	6%	26%	43%	65%	70%	84%
18	77%	75%	58%	17%	0%	3%	13%	45%	60%	58%	57%	71%
19	81%	82%	68%	13%	0%	3%	23%	35%	57%	48%	60%	77%
20	68%	61%	61%	10%	3%	3%	23%	48%	70%	58%	47%	52%
21	32%	43%	65%	17%	0%	3%	29%	52%	77%	39%	30%	19%
22	58%	64%	39%	20%	3%	3%	13%	48%	63%	13%	57%	65%
23	6%	46%	45%	17%	0%	3%	13%	52%	80%	55%	37%	26%
	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average
	36%	36%	33%	10%	1%	1%	8%	25%	40%	33%	32%	35%

Removing access to market sales eliminates an economic incentive for PSE to over-generate renewable energy, and does not allow the model to count sold energy towards CETA goals. As a result, renewable overgeneration is reduced in the model. This portfolio builds 1,600 MW less of Washington wind capacity and 255 MW less of peaking capacity. That capacity is redistributed to an additional 510 MW of biomass and 525 MW of battery resources in order to manage peak needs in the winter months. Market purchases in excess of load become an integral part of the portfolio for charging batteries during the later years in order to meet peak demand.

RENEWABLE OVERGENERATION. Eliminating market sales reduced renewable over-generation in the portfolio as a result of the decreased wind resources in Washington. Figure 8-22 compares the amount of renewable overgeneration in the Mid Scenario and Sensitivity A.

Figure 8-22: Renewable Over-generation – Mid Scenario and Sensitivity A

	2030			2045		
Portfolio	Hours of Over-generation	MWh of Over-generation	% of total load with conservation	Hours of Over-generation	MWh of Over-generation	% of total load with conservation
Mid Scenario	1,226	286,296	1.4%	4307	3,262,871	14.6%
Sensitivity A	1,322	65,054	0.3%	391	14,698	0.06%

These results indicate that the elimination of market sales was effective at curbing over-generation of renewable resources. In the Mid Scenario portfolio, renewable overgeneration can provide value through sales. Without the ability to sell excess energy, the model can only curtail that production or use it to charge battery resources. Once the battery resources are at capacity, there is no option left but to curtail the energy. By 2045 in the sensitivity, renewable overgeneration is effectively eliminated and CETA is met without including the sale of energy to the Mid-C market.

Next Steps

The Mid Scenario portfolio overbuilds renewable resources in order to meet CETA while counting the sales of renewable energy to Mid-C towards CETA goals. Sensitivity A effectively steers the portfolio away from the CETA counting problem, but leans heavily on market purchases and biomass capacity. The amount of biomass and market purchases used in this sensitivity are unlikely to be available in reality, and further investigation is needed into the behavior of the portfolio when market availability is limited.

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

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

> **Baseline:** The baseline assumes the transmission constraints described by Tier 0. PSE's system is subject to few transmission constraints including 1500 MW toMid-C market purchases and build limitations for Montana, Idaho and Wyoming based resources.
> **Sensitivity:** Sensitivity C assumes the transmission constraints described by Tier 2. PSE's system is subject to more restrictive transmission constraints, including those described in the baseline plus build limitations for eastern, southern and western Washington-based resources.

Key Findings

Tier 2 transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon as compared to Mid Scenario portfolio. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. The model pairs these distributed solar resources with battery storage projects to better serve load when the sun is not shining. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

Assumptions

Sensitivity C assumes transmission capacity outside of PSE's service territory will be limited to 3,070 MW. Figure 8-23 summarizes the Tier 2 transmission capacity assumptions for each resource group region. (A complete description of the four transmission tiers and resource group regions is provided in Chapter 5.)

Figure 8-23: Sensitivity C Transmission Constraints – Tier 2

Resource Group Region	Tier 2
PSE territory	unconstrained
Eastern Washington	675
Central Washington	625
Western Washington	100
Southern Washington/Gorge	705
Montana	565
Idaho / Wyoming	400
TOTAL	3,070

In addition to the transmission constraints described in Tier 2, several additional constraints were incorporated into the optimization to encourage realistic resource selections:

- Biomass cogeneration facilities were limited to 105 MW given the limited number of pulp and timber mills located within Washington state.
- Utility-scale, western Washington solar projects were limited to 500 MW. PSE's transmission system west of the Cascades would require significant upgrades to accommodate an additional transmission load of greater than 500 MW. Furthermore, given the large amount of land needed, siting and permitting of large-scale solar projects west of the Cascades is known to be difficult.
- The forecast of customer-owned, residential solar projects was adjusted to reflect increased adoption of residential solar. The forecast matches the Conservation Potential Assessment Low-cost, Business-As-Usual residential solar adoption rate. This assumption aligns with a portfolio focused on distributed energy resources.
- Build limitations on ground-mounted and rooftop distributed solar were lifted to encourage a focus on distributed resource selection.

Portfolio Costs

Compared to the Mid Scenario portfolio, the Sensitivity C portfolio is more expensive over the modeling time horizon as shown in Figure 8-24. Increased generic resource revenue requirements are the major driver of the increased portfolio cost. Distributed solar resources cost substantially more to install than utility-scale solar resources, resulting in increased generic resource revenue requirements.

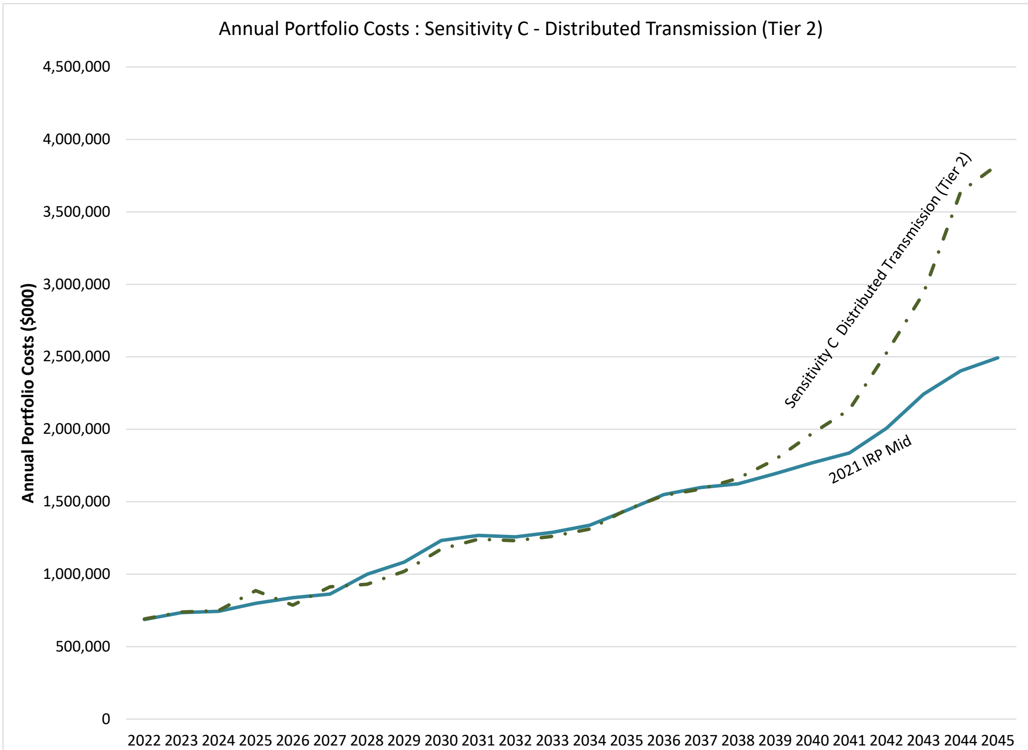
SCGHG costs are within $16 million between the Mid Scenario and Sensitivity C portfolios over the 24-year time horizon. In Sensitivity C, existing gas plants and new peaking capacity contribute more emissions in later years, but early retirement of Colstrip Unit 3 in 2024 significantly reduces near-term emission costs.

Figure 8-24: Portfolio Cost Comparison – Mid Scenario and Sensitivity C

		24-Yr Levelized Costs			
	Portfolio	**Revenue Requirement**	**SCGHG Costs**	**Total**	**Change from Mid**
1	**Mid Scenario**	$13.63	$5.04	$18.68	
C	**Distributed – Transmission/Build Constraints Tier 2**	$14.53	$5.06	$19.59	$0.91

Until year 2038, the Mid Scenario and Sensitivity C portfolios project similar annual revenue requirements as shown in Figure 8-25. After year 2038, Sensitivity C exhausts all available transmission outside of PSE's service territory and is forced to select more costly distributed solar resources, resulting in a sharp increase in annual revenue requirement in the later years.

Figure 8-25: Annual Portfolio Costs – Mid Scenario and Sensitivity C



Resource Additions

Sensitivity C is marked by a transition from utility-scale wind and solar resources in central, eastern and southern Washington to distributed solar resources within the PSE service territory. Given that the effective load carrying capability of distributed solar resources is low, battery storage resources are added to the portfolio to meet load during peak hours. Biomass resources within PSE service territory are added to help accommodate base load and meet CETA energy targets. New peaking capacity resource additions remain unchanged from the Mid Scenario. Colstrip Unit 3 is economically retired in 2024, one year ahead of its planned retirement date in 2025.

Sensitivity C selects conservation Bundle 11, equating to 1,537 MW of conservation by year 2045. This is more conservation than was selected in the Mid Scenario, which selected Bundle 10. The increased conservation is attributed to the increased resource costs of distributed solar resources.

These resource build decisions are summarized in Figures 8-26 and 8-27.

Figure 8-26: Portfolio Additions, Sensitivity C – Distributed Transmission Tier 2

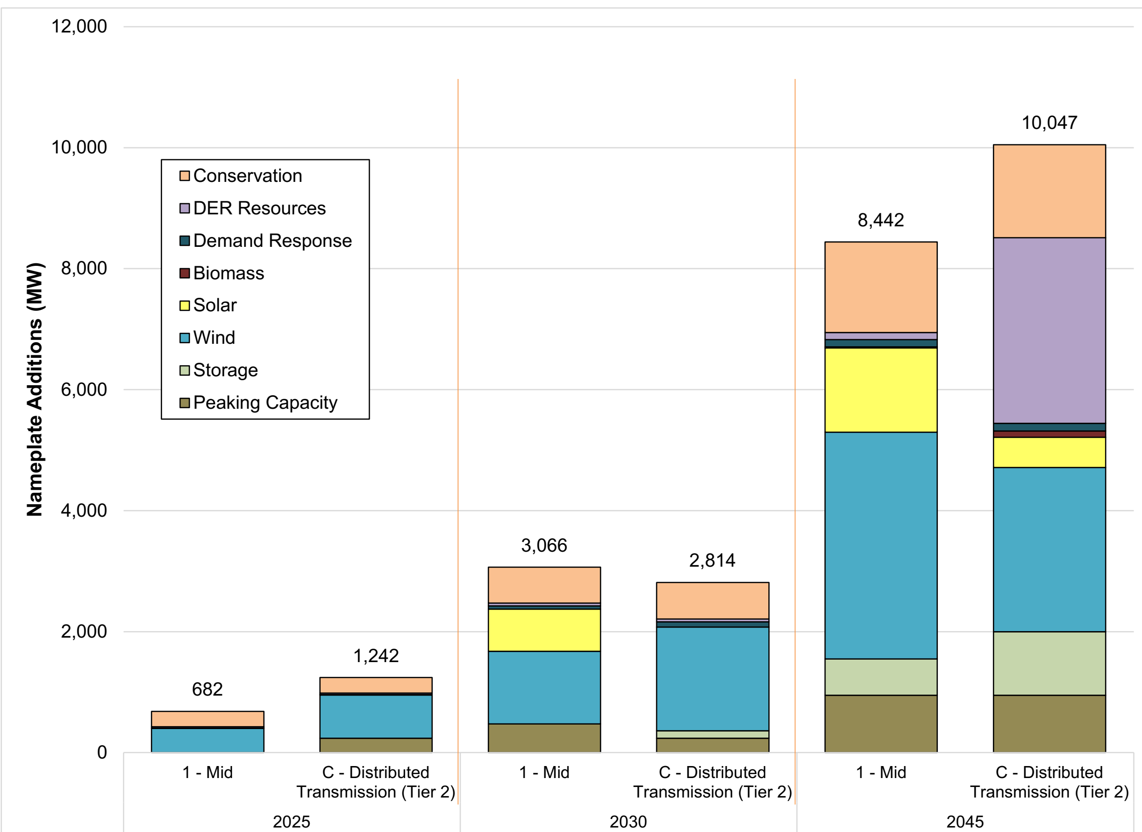


Figure 8-27: Portfolio Additions by 2045, Sensitivity C – Distributed Transmission Tier 2

Resource Additions by 2045	Mid	Sensitivity C - Distributed Transmission (Tier 2)
Conservation	1,497 MW	1,537 MW
DER Resources	118 MW	3,068 MW
Demand Response	121 MW	125 MW
Renewable Resources	5,158 MW	3,319 MW
Biomass	15 MW	105 MW
Solar	1,393 MW	499 MW
Wind	3,750 MW	2,715 MW
Storage	600 MW	1,050 MW
Peaking Capacity	948 MW	948 MW

Other Findings

Distributed energy resources (DERs) are capable of meeting a significant portion of load as shown in Figure 8-28. DERs contribute approximately 14 percent of total energy load in 2045. However, DERs are a poor resource for providing peak capacity need, with an effective load carrying capability (ELCC) of less than 2 percent. This means that other resources are needed to provide capacity during peak need events. Sensitivity C selected peaking capacity resources to meet this need. The same quantity of peaking resource capacity was added to Sensitivity C as was added to the Mid Scenario portfolio, but in Sensitivity C the peaking capacity resources were dispatched more often. This results in increased emissions for Sensitivity C in the later years of the modeling horizon. In 2045, the Mid Scenario generated 0.66 million tons of greenhouse gases (GHGs), while Sensitivity C generated 0.96 million tons of GHGs. Figure 8-29 compares the emissions from the Mid Scenario and Sensitivity D portfolios in millions short tons.

Figure 8-28: Annual Energy Production by Resource Type (aggregated) – Sensitivity *C*

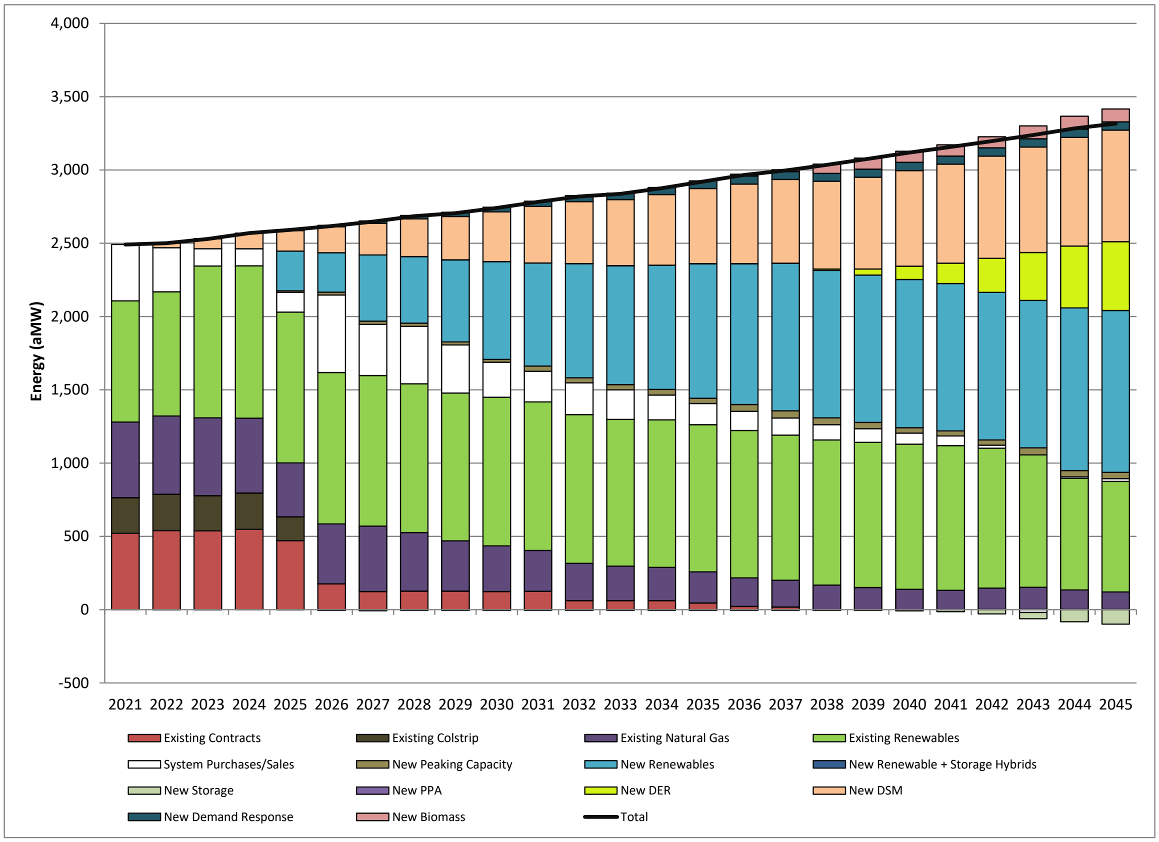
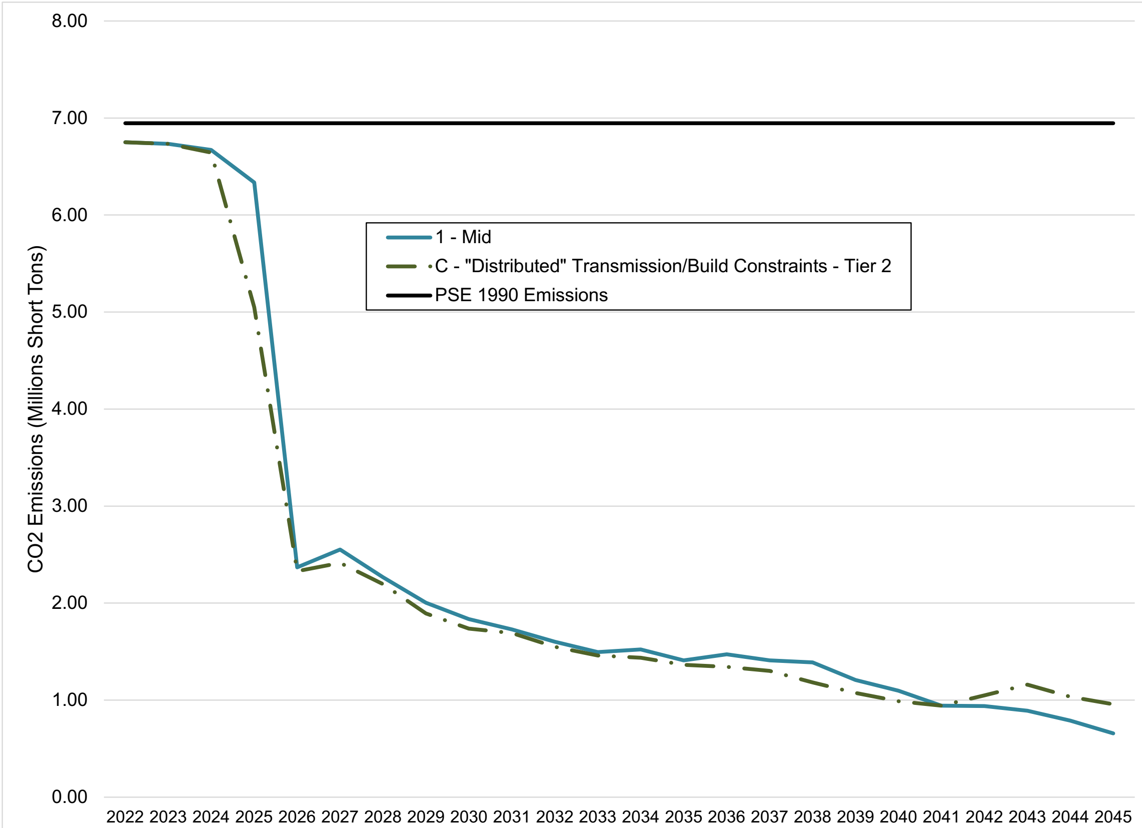


Figure 8-29: Portfolio Emissions – Mid Scenario and Sensitivity C



E. Firm Transmission as a Percentage of Resource Nameplate

What would be the impact on portfolio costs when the capacity of firm transmission purchased with new resources was less than the nameplate capacity of the generating resource?

Baseline: New Resources are acquired with transmission capacity equal to their nameplate capacity.
Sensitivity: New resources are acquired with less transmission capacity than nameplate capacity.

Key Findings

In general, cost savings from reduced firm transmission sensitivities are marginal and likely not a viable method to reduce portfolio costs. Wind resources show the least cost benefit in transmission reduction sensitivities due to the significant portion of time wind resource generate power at or near nameplate capacity (i.e., rated power). Solar resources, which typically spend less time at rated power, show increased cost benefit relative to wind resources, but the cost benefit is still unlikely to prove valuable in resource portfolios.

Assumptions

This sensitivity examines the trade-off in the cost of firm transmission against the replacement cost of power lost to transmission curtailment. The trade-off was calculated for the following generic resource alternatives: Washington wind, Montana wind east, Montana wind central, Wyoming wind east, Wyoming wind west, Idaho wind, utility-scale Washington solar east, utility-scale Wyoming solar east, utility-scale Wyoming solar west and utility-scale Idaho solar. The annual transmission cost for each resource was calculated from the fixed transmission cost (provided in Figure 5-25 in Chapter 5) times the nameplate capacity of the resource. The transmission-curtailed energy was calculated as the sum of all hours where the resource production exceeded the reduced transmission limit. For example, a 100 MW wind farm operating at rated power with 10 percent reduced transmission will curtail 10 MWh for a one-hour period (100 MW x 1 h – 100 MW x (1-0.10) x 1 h = 10 MWh). The replacement cost of transmission-curtailed energy was assumed to be equal to the levelized cost of power for the given resource. PSE acknowledges that these assumptions present a “worst-case scenario” analysis, where it is assumed that all power produced can be used (i.e. production equals demand) and that no short-term transmission may be purchased to supplement long-term firm transmission. While not a comprehensive analysis, this assessment provides a reasonable estimate of potential costs and benefits attributable to reduced transmission sensitivities.

Wind Results

Figure 8-30 shows the trade-off for 200 MW, generic wind resources modeled in the 2021 IRP at various degrees of transmission under-build. Points greater than zero on this plot indicate reduced transmission scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (i.e., 100 percent), therefore at 100 percent, there is no benefit or cost. All wind resources indicate a maximum benefit at transmission capacity equal to 97.5 percent of resource nameplate. This is because wind farms typically produce 0 to 3 percent less power than nameplate due to internal electrical line losses. After this point, the trade-off quickly drops below zero, representing a cost. This is because wind resources often produce rated power. Figure 8-31 shows a typical histogram for a wind resource, where the plurality of the generation time is at or above 95 percent net capacity factor. Therefore, most often, when the wind farm is generating power, it is likely to be using all available transmission.

Figure 8-30: Trade-off as a Function of Transmission Under-build Degree for 200 MW Wind Resources

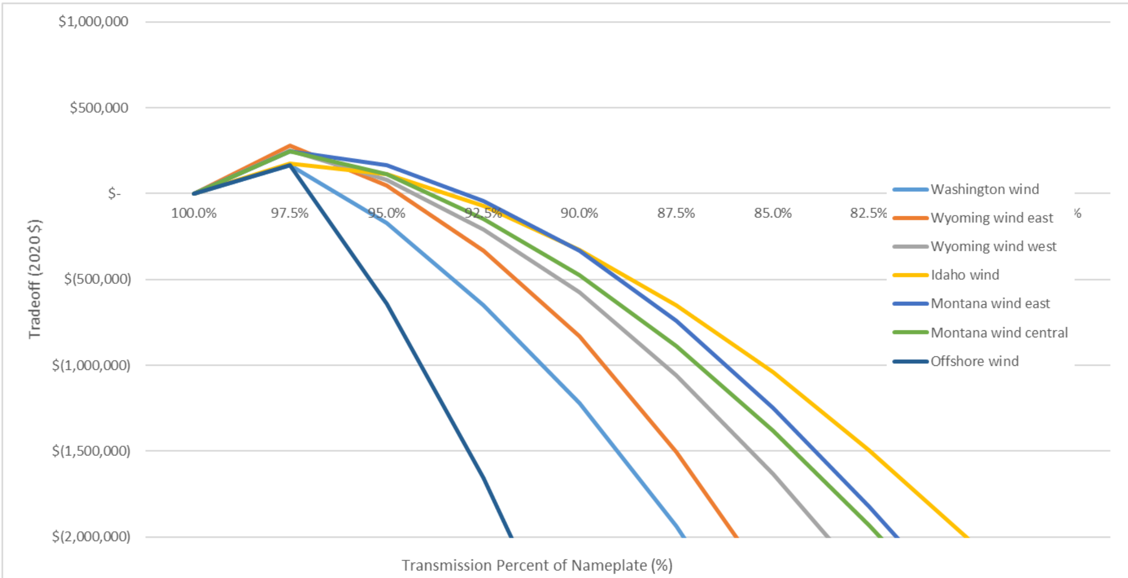
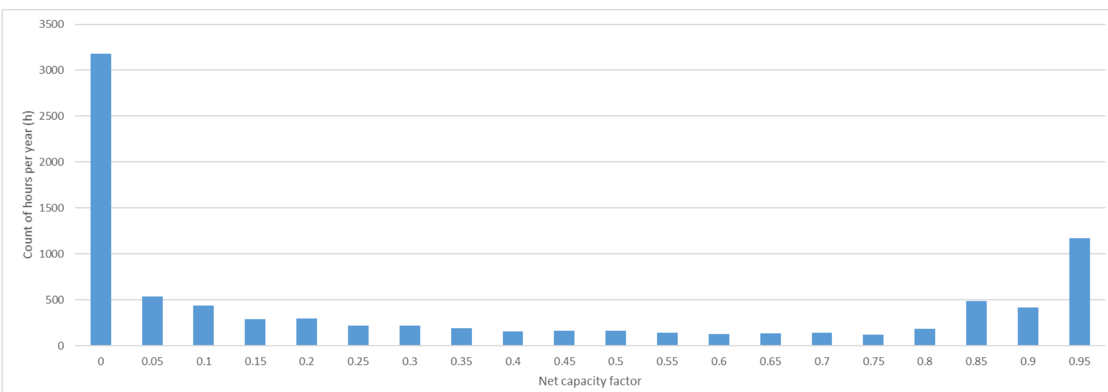


Figure 8-31: Net Capacity Factor Distribution of a Typical Wind Resource



For a 200 MW wind facility, the maximum cost benefit ranges from $165,000 to $281,000 per year depending on the resource location. While these are potentially material cost savings, PSE does not believe incorporation of a 97.5 percent transmission under-build would result in material changes in the portfolio assessment. These costs are relatively small compared to overall capital and transmission costs and all wind resources would gain roughly the same cost benefit.

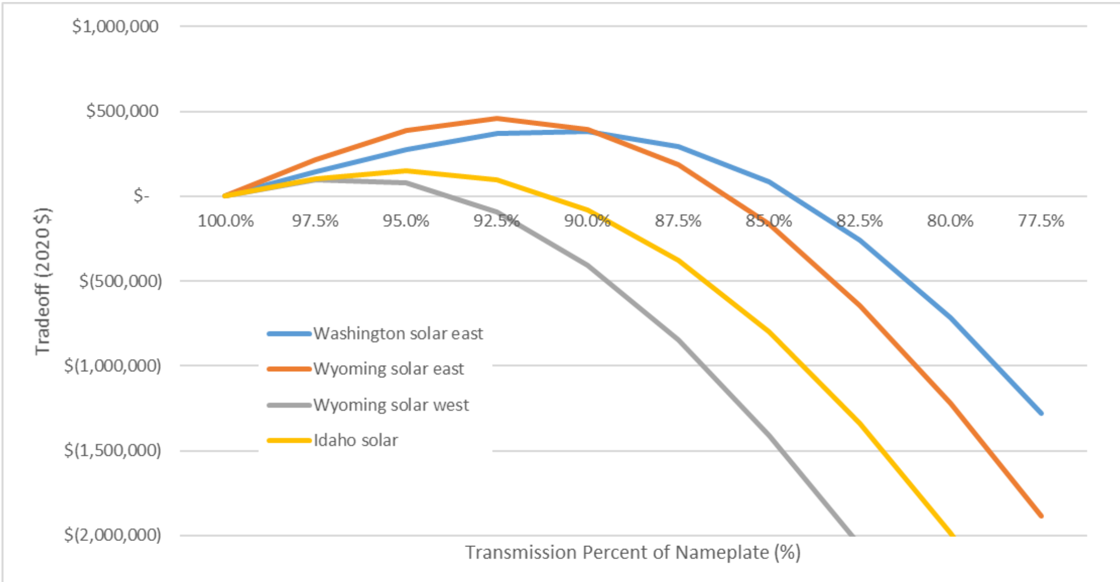
Decisions to purchase less firm transmission than nameplate capacity are more appropriate during the resource acquisition process, as opposed to the IRP planning process.

Furthermore, limiting output capacity from a resource would also reduce the effective load carrying capacity of the resource. Peaking capacity is a key consideration for PSE's portfolio and firm transmission under-build would only increase the amount of resources added to meet peak need.

Solar Results

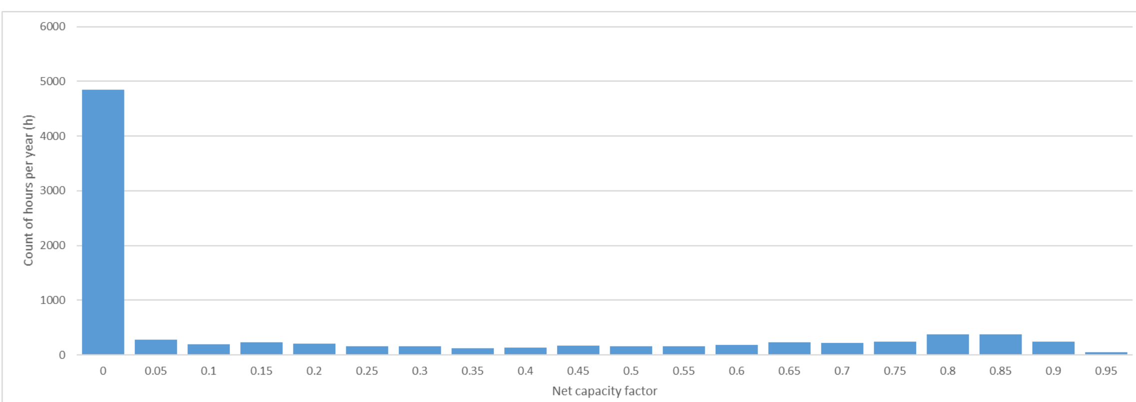
Figure 8:32 shows the trade-off for 200 MW of generic solar resources modeled in the 2021 IRP at various degrees of transmission reduction. Points greater than zero on this plot indicate transmission reduction scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (i.e., 100 percent), therefore at 100 percent, there is no benefit or cost. Solar resources indicate a maximum benefit at transmission capacity between 97.5 percent and 90.0 percent of resource nameplate. This is because solar farms have a more variable distribution of power production at high capacity factors, giving each solar resource a unique trade-off cost profile. However, as discussed in the wind results above, solar farms also produce most power at higher hourly capacity factors Figure 8-33 shows a typical histogram for a solar resource, where the plurality of the generation time is at or above 80 percent hourly capacity factor.

Figure 8-32: Trade-off as a Function of Transmission Under-build Degree for 200 MW Solar Resources



For a 200 MW solar facility, the maximum benefit ranges from $97,000 to $460,000 per year depending on the resource location. Similar to the wind farm results presented above, solar resources do show some benefit, however, PSE does not feel these benefits would add materially to the IRP portfolio development process. This assessment may provide more benefit in resource acquisition decisions.

Figure 8-33: Net Capacity Factor Distribution of a Typical Solar Resource

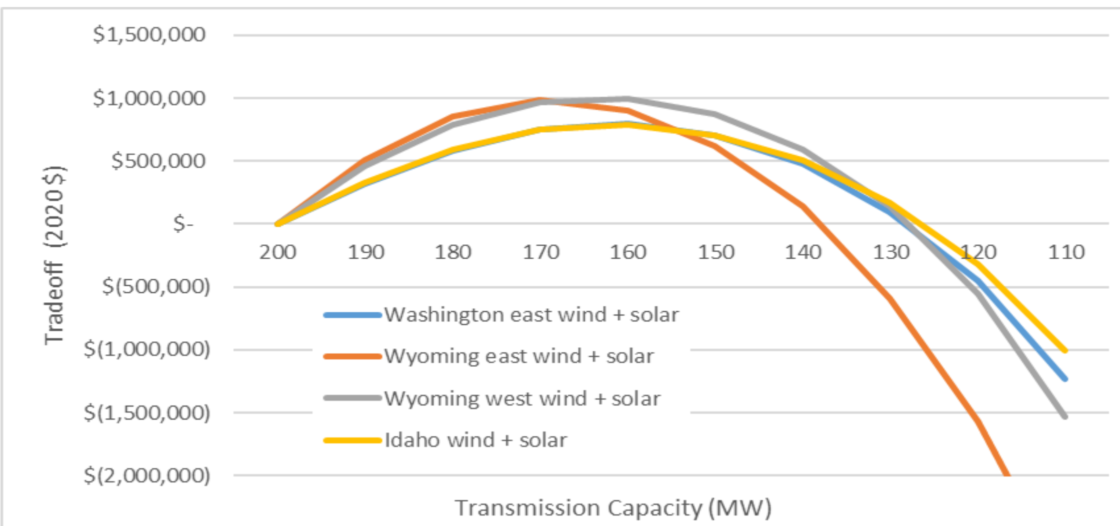


Next Steps

In addition to the reduced transmission sensitivities described above, PSE also took an initial look at co-locating a wind and solar resource with shared, limited transmission capacity. A complementary relationship appears to exist between the resource pairs assessed. First, wind resources with higher winter time production may benefit from co-location with solar resources which have greater production in the summer months. Second, wind resources with higher overnight production may benefit from co-location with solar resources which, by nature, only produce power during the day. Cost savings may be realized by optimizing the amount of transmission to better match the average seasonal and diurnal production of the co-located resources, as opposed to securing firm transmission for both resources individually.

Figure 8-34 shows the possible trade-off of co-locating a 100 MW wind farm with a 100 MW solar farm at various locations. The maximum cost benefit ranges from $784,000 to $999,000 per year depending on resource location. PSE intends to examine co-located resources in more detail in future IRP cycles.

Figure 8-34: Trade-off as a Function of Transmission Capacity for Co-located 100 MW Wind and 100 MW Solar Resources



I. SCGHG as an Externality Cost in the Portfolio Model Only

How would the LTCE model build if SCGHG was implemented as an externality cost instead of a planning adder?

> **Baseline:** SCGHG is implemented as a planning adder in the Long-term Capacity Expansion Model (LTCE), and not used in the hourly dispatch.
> **Sensitivity:** SCGHG is implemented as an externality cost in the LTCE model, and not used in the hourly dispatch.

Key Findings

The changes brought on by changing SCGHG to an externality cost are minor. The model optimizes the dispatch of existing gas plants to minimize costs, while newly acquired peaking capacity is largely unused. The sensitivity resulted in more peaking capacity being built than in the Mid Scenario portfolio, but the average capacity factors of the newly built plants averages to 0.3 percent by 2045.

Assumptions

In the Mid Scenario portfolio, SCGHG is included as a planning adder (fixed cost) to emitting resources in the LTCE model. In this sensitivity, the SCGHG is applied as an externality cost (variable cost) in the LTCE model. The SCGHG is not applied in the hourly dispatch model for either portfolio. Both portfolio use the mid electric price forecast with the SCGHG as an adder for market purchases.

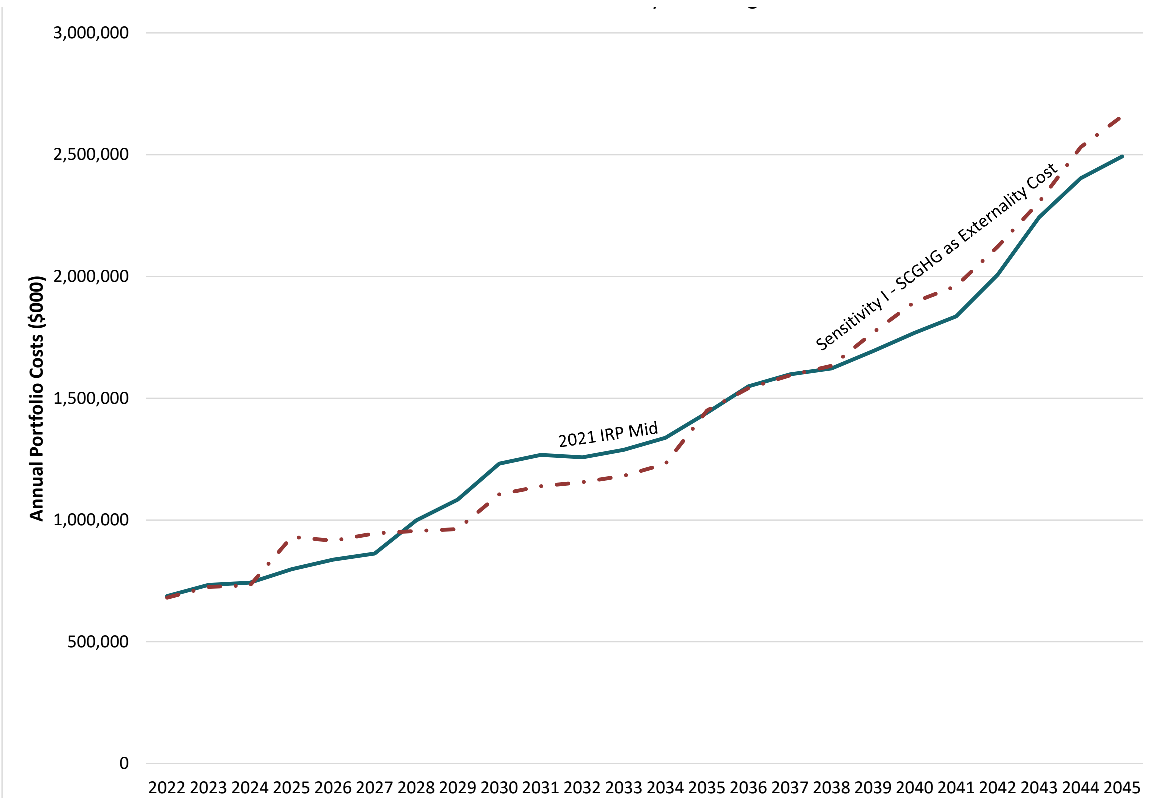
Portfolio Costs

Figure 8-35 and 8-36 illustrate the breakdown of costs between the Mid Scenario and Sensitivity I portfolios. The costs of the portfolio remain similar throughout the time horizon of the model, with Sensitivity I reaching a higher annual cost in 2045 as a result of increased biomass builds that begin to enter the portfolio in 2036. Overall, the cost differences between these portfolios are minor, with Sensitivity I purchasing slightly more expensive resources in the later years.

Figure 8-35: 24-year Levelized Costs – Mid and Sensitivity I portfolios

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
I	SCGHG as Externality Cost	$13.65	$4.78	$18.42	($0.25)

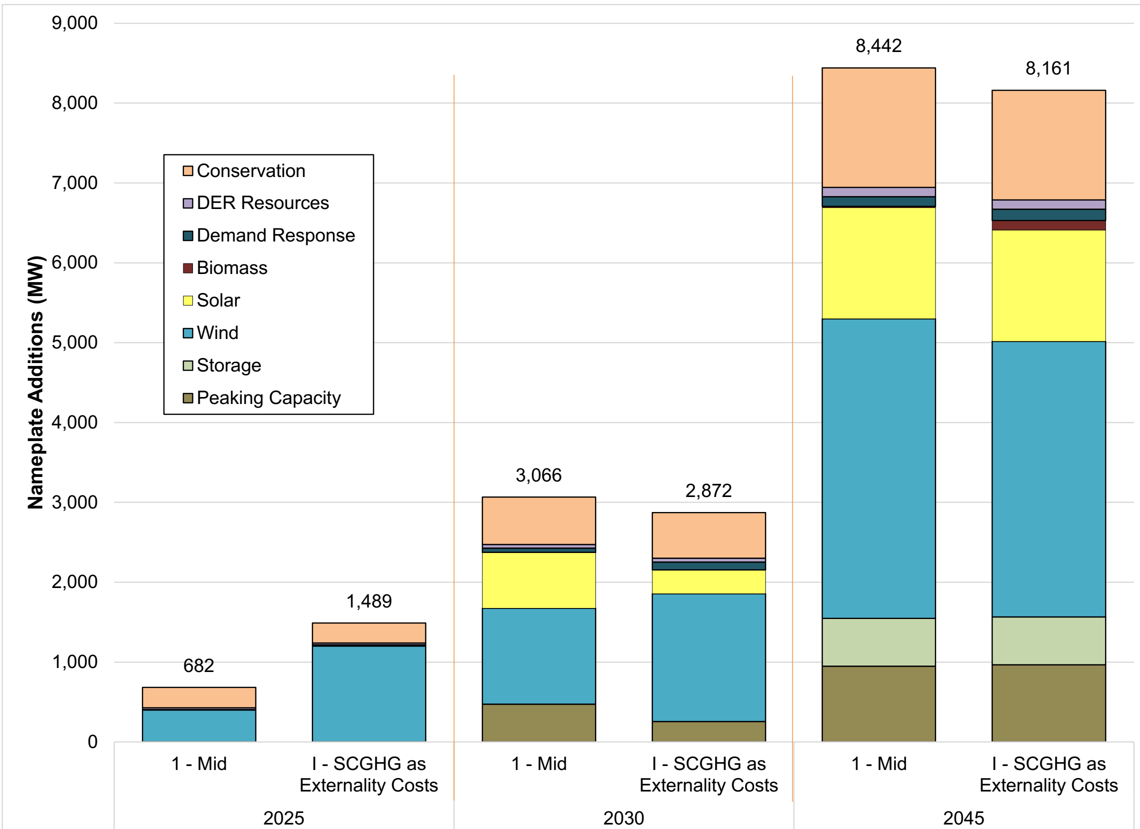
Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity I



Resource Additions

Figure 8-37 compares the nameplate capacity additions of the Sensitivity I and Mid Scenario portfolios. The model in Sensitivity I builds a large amount of Washington wind capacity in 2025 as the retirements of Colstrip and Centralia take place. However, the total Washington wind resources added to the Sensitivity I is lower by 300 MW nameplate capacity compared to the Mid Scenario. Unique to Sensitivity I is the addition of 250 MW of Wind + Battery capacity by 2045. Beyond this change in wind resource selection, by 2045 the amount of intermittent renewable resources is roughly equivalent in nameplate capacity to the Mid Scenario portfolio. Biomass is gradually added to the Sensitivity I portfolio between the years 2036 and 2045 as the model strives to reach CETA and capacity requirements without burning natural gas. Battery builds reach the same total capacity but with a different mix of resources, with 70 percent of the capacity coming from 6-hour flow batteries and the other 30 percent comprised of 4-hour flow, 4-hour lithium-ion and 2-hour lithium-ion batteries. In the Mid Scenario, the portfolio builds 50 percent of 6-hour flow batteries and 50 percent of 4-hour lithium-ion batteries.

Figure 8-37: Portfolio Additions, Sensitivity I – SCGHG as Externality Cost



Other Findings

Peaking capacity is gradually added to the portfolio starting in the year 2026 in order to meet peak need after the retirements of Colstrip and Centralia. Peaking resource additions track with the increases of peak need, as shown in Figure 8-38. In the Sensitivity I portfolio, the new additions of peaking capacity are dispatching less than in the Mid Scenario portfolio by the year 2045, but existing plants are dispatching more. New peaking capacity averages a capacity factor of 0.3 percent in Sensitivity I while new peaking capacity in the Mid Scenario has an average capacity factor of 3.19 percent. Existing gas plants see an increase from an average capacity factor of 3.2 percent to 4.2 percent. The model has optimized around existing natural gas plants, but still requires additional peaking capacity.

The reduced usage of new peaking capacity leads to an overall decrease in the emissions from resources in the portfolio. Figure 8-39 shows the emissions of the Sensitivity I portfolio, where PSE is producing below two million short tons of emissions in the year 2045. The portfolio does begin to lean more on market purchases, which have a CETA-specified emission rate of 0.437 metric tons of CO_2 per MWh.

Figure 8-39: Sensitivity I – Portfolio Peak Capacity Needs

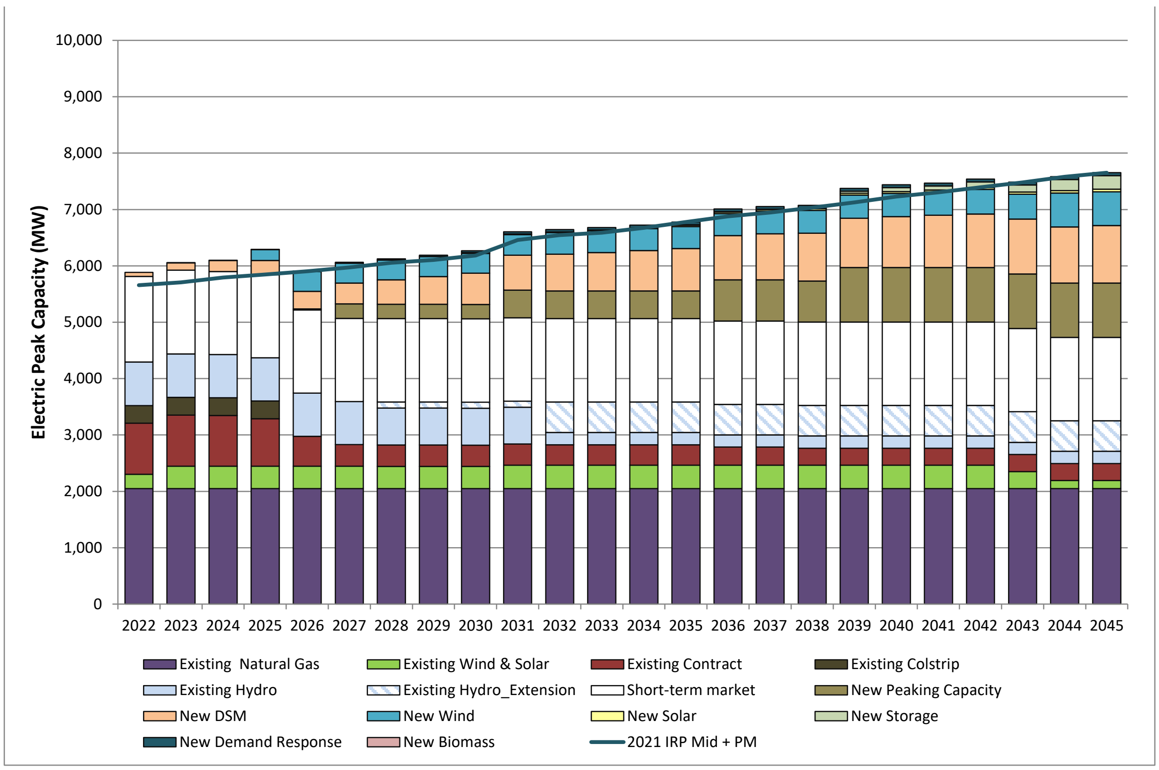


Figure 8-39: Sensitivity I – Emissions

N: 100% Renewable by 2030

What is the cost difference between the mid portfolio and a portfolio with an alternate CETA target of 100% renewable by 2030?

> **Baseline:** 80% of sales must be met by non-emitting/renewable resources by 2030; The remaining 20% is met through alternative compliance.
> **Sensitivity:** 100% of sales must be met by non-emitting/renewable resources by 2030.

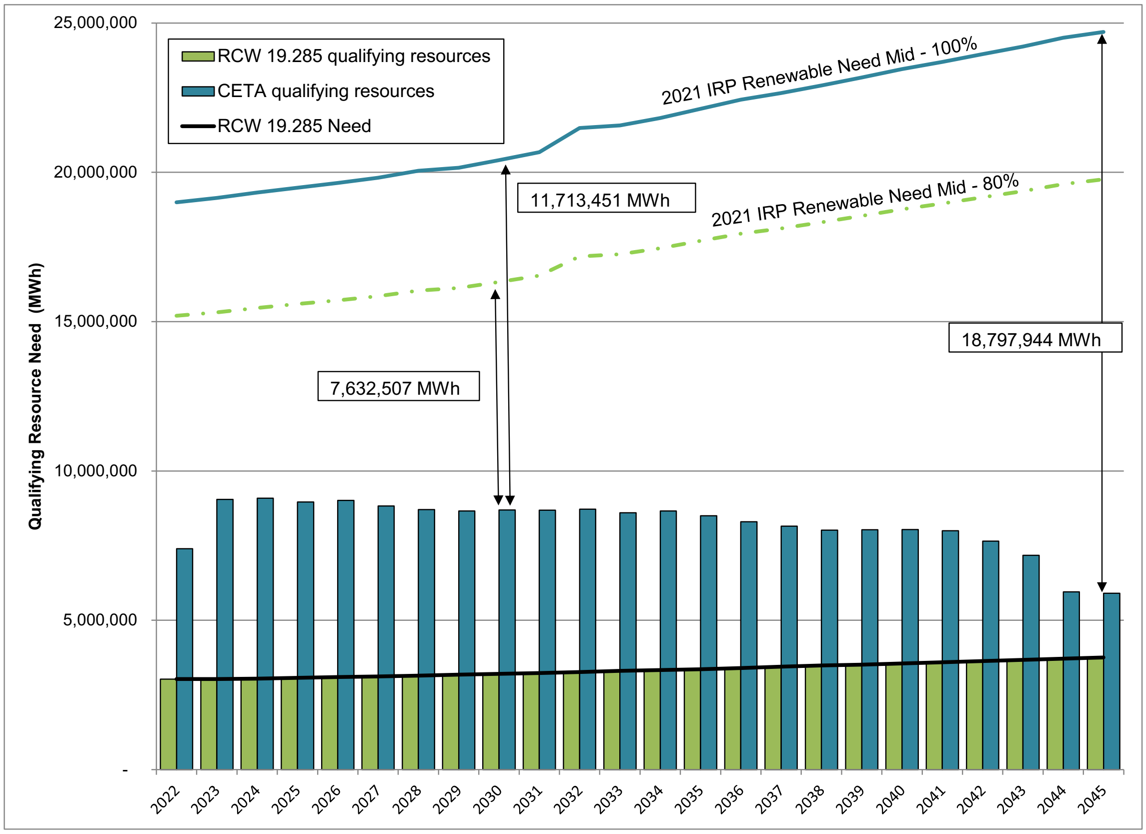
Key Findings

In this sensitivity, the 24-year levelized portfolio costs increased by 128 percent for a total of $31.1 billion dollars in revenue requirement. With no access to thermal resources by 2030, a significant amount of batteries totaling 26,100 nameplate MW were built to keep the portfolio balanced. Market access remains important in this sensitivity as purchases became a resource for meeting energy and peak capacity needs, in addition to being a source for charging the batteries.

Assumptions

In the Mid Scenario portfolio, 80 percent of sales are met by non-emitting/renewable resources by 2030, ramping up to 100 percent by 2045. Existing thermal plants continue to be in operation unless economically retired by the model. New peaking capacity resources remain an option for new resource selection. In order for the Mid Scenario portfolio to be 100 percent greenhouse neutral by 2030, an estimate for alternative compliance costs is calculated starting in 2030 through 2044. In this sensitivity, all existing thermal plants are retired by 2030 regardless of economic viability. New peaking capacity resources are also removed for new resource selection. The CETA target is adjusted to 100 percent renewable by 2030. This means increasing the renewable energy target from 7.6 million MWhs in 2030 to 11.7 million MWhs, an increase of 4.1 million MWhs in renewable need.

Figure 8-40: Renewable Targets in the Mid Scenario and Sensitivity N Portfolio



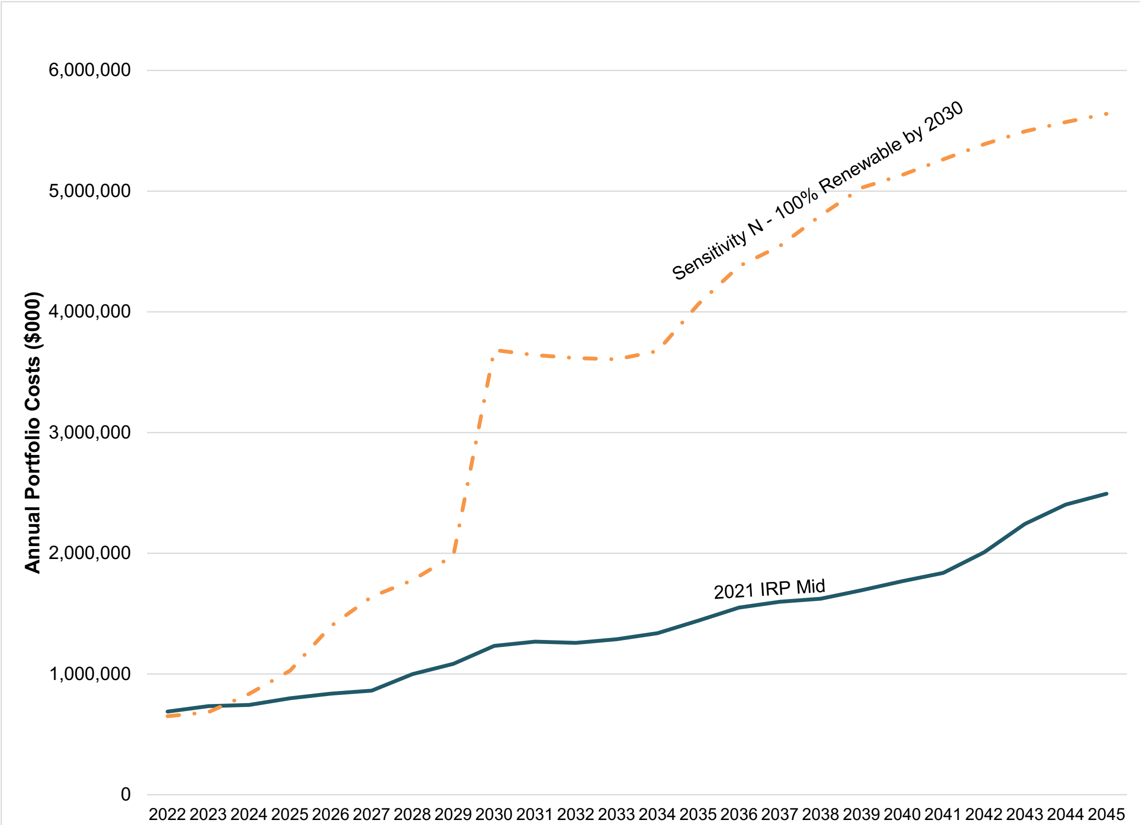
Portfolio Costs

Figures 8-41 and 8-42 illustrate the breakdown of costs between the Mid Scenario and Sensitivity N portfolios. The increase in costs for Sensitivity N is attributed to the increase in the overall resource builds, particularly for storage resources.

Figure 8-41: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity N

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
N	100% Renewable by 2030	$31.14	$3.42	$34.56	$15.89

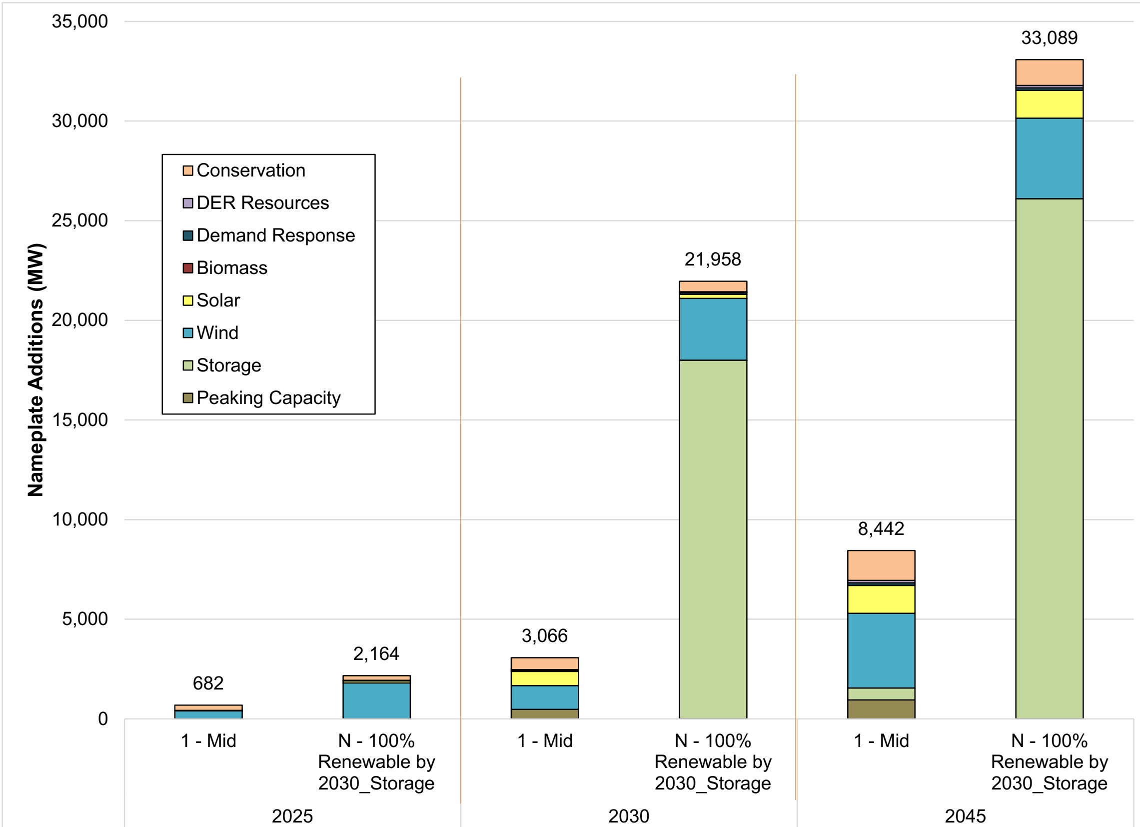
Figure 8-42: Annual Portfolio Costs – Mid Scenario and Sensitivity N



Resource Additions

Figure 8-43 compares the nameplate capacity additions of the Sensitivity N and Mid Scenario portfolios. The model in Sensitivity N builds a large amount of wind capacity in 2025 as the retirements of Colstrip and Centralia take place, but also to meet the higher CETA renewable need. By 2030, a total of 3,100 MW nameplate capacity of wind has been added in this sensitivity compared to 1,200 nameplate capacity of wind in the Mid Scenario portfolio. A total of 18,000 MW of 2-hour lithium-ion battery storage is also added to the portfolio by 2030, replacing the entire fleet of PSE's existing thermal resources. At the end of the planning period, we continue to see an increase in 2-hour lithium-ion battery storage with a total of 26,100 MW nameplate capacity.

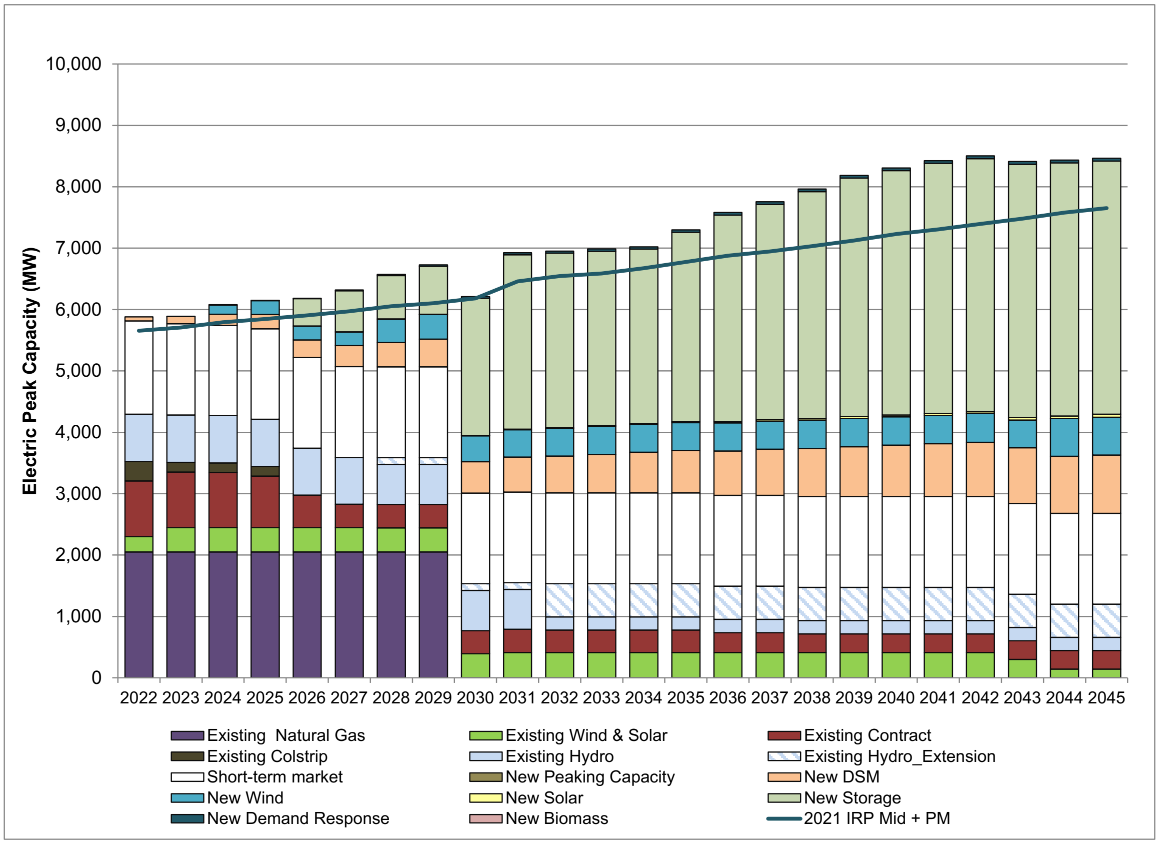
Figure 8-43: Portfolio Additions, Sensitivity N – 100% Renewable by 2030



Other Findings

PEAK CAPACITY. Peak capacity contribution from PSE's existing thermal resources is approximately 2,000 MW. For Sensitivity N, the replacement peak capacity contribution is made up of a mix of new 2-hour lithium-ion batteries, wind and solar resources. Figure 8-44 shows an overbuild of new resources compared to the peak capacity need except for year 2030, when existing thermal resources are removed from the portfolio.

Figure 8-44: Sensitivity N – Portfolio Peak Capacity Needs



STORAGE OPTIONS. PSE ran four portfolios for Sensitivity N, adjusting the size of the storage options in order to get insight into the impact on portfolio costs and to improve model run time. The results and discussion for Sensitivity N are based on N2 in Figure 8-45 below.

Figure 8-45: Sensitivity N – Storage Options

		24-yr Levelized Cost ($ Billions)
Storage Option	**Results**	**Revenue Requirement**
N1. 25 MW Batteries, 25 Pump Hydro Storage	Peak capacity need not met	N/A
N2. 300 MW Batteries, 500 MW Pump Hydro Storage	26,100 MW of 2hr Li-Ion	$31.14
N3. 500 MW Pump Hydro Storage Only	19,500 MW of PHES	$53.81
N4. 100 MW Batteries, 100 MW Pump Hydro Storage	22,000 MW of 2-hr Li-Ion; 4,300 MW of 4-hr Li-Ion	$34.89

O: Gas Generation Out by 2045

What is the cost difference between the mid portfolio and a portfolio that has no gas fired generation resources by 2045?

Baseline: No planned retirements of existing gas fired generation resources; however, the model allows for economic retirement.
Sensitivity: All existing gas fired resources including new peaking capacity resources must be retired by 2045.

Key Findings

In this sensitivity, the 24-year levelized revenue requirement is $33.9 billion dollars, an increase of $20.3 billion dollars or 149 percent compared to the Mid Scenario portfolio. With the retirement of all existing gas-fired and new peaking capacity resources happening in one year, the portfolio model fails to meet the peak capacity need in 2045. There is a huge spike in annual portfolio costs between 2044 and 2045 due to penalties related to violation of model constraints. This sensitivity requires further work for the final 2021 IRP.

Assumptions

In the Mid Scenario portfolio, existing gas-fired generation resources remain in operation unless economically retired by the model. Generic peaking capacity resources are available as a new resource and have an operating life of 30 years. In this sensitivity, all existing gas-fired generation resources are retired by 2045 regardless of economic viability. Generic peaking capacity resources are available as a new resource but are expected to retire by 2045.

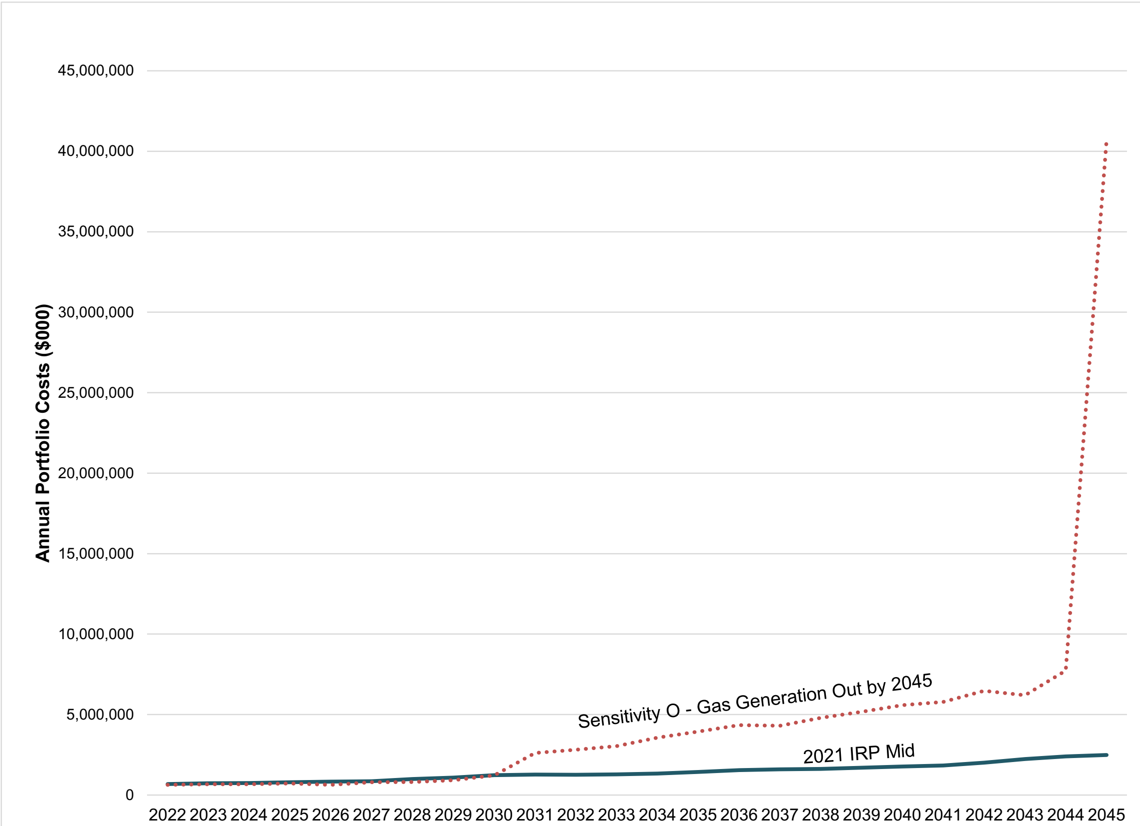
Portfolio Costs

Figures 8-46 and 8-47 illustrate the breakdown of costs between the Mid Scenario and Sensitivity N portfolios. The increase in costs for Sensitivity O is attributed to the increase in the overall resource builds and violations related to the peak capacity requirements for 2045.

Figure 8-46: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity O

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
O	Gas Generation out by 2045	$33.90	$6.24	$40.14	$21.46

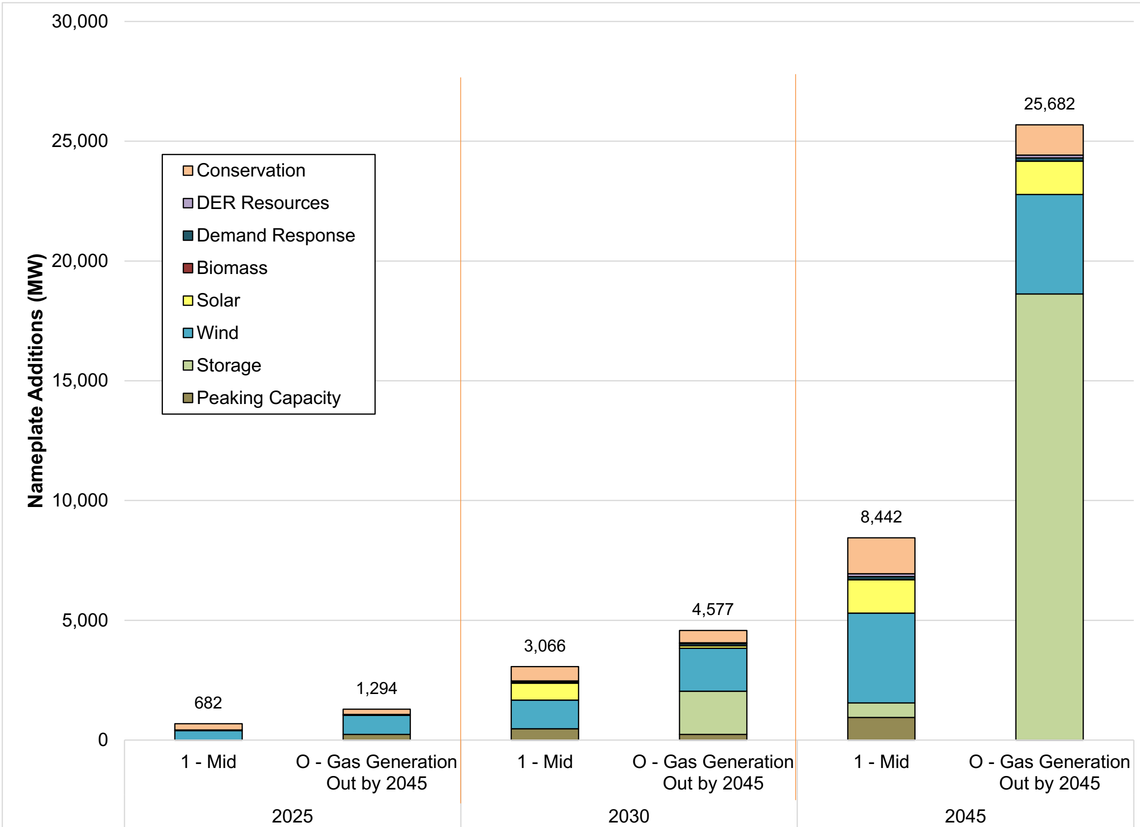
Figure 8-47: Annual Portfolio Costs – Mid Scenario and Sensitivity O



Resource Additions

Figure 8-48 shows a comparison between the nameplate capacity additions of Sensitivity O and the Mid Scenario portfolios. The model in Sensitivity O builds 237 MW of peaking capacity resources as the retirements of Colstrip and Centralia take place, but do not build anymore beyond that. Between 2026 and 2030, 1,800 MW of storage resources are added to the portfolio, and an additional 16,825 MW by 2045. However, there are still not enough resource additions available to meet the peak capacity need for 2045.

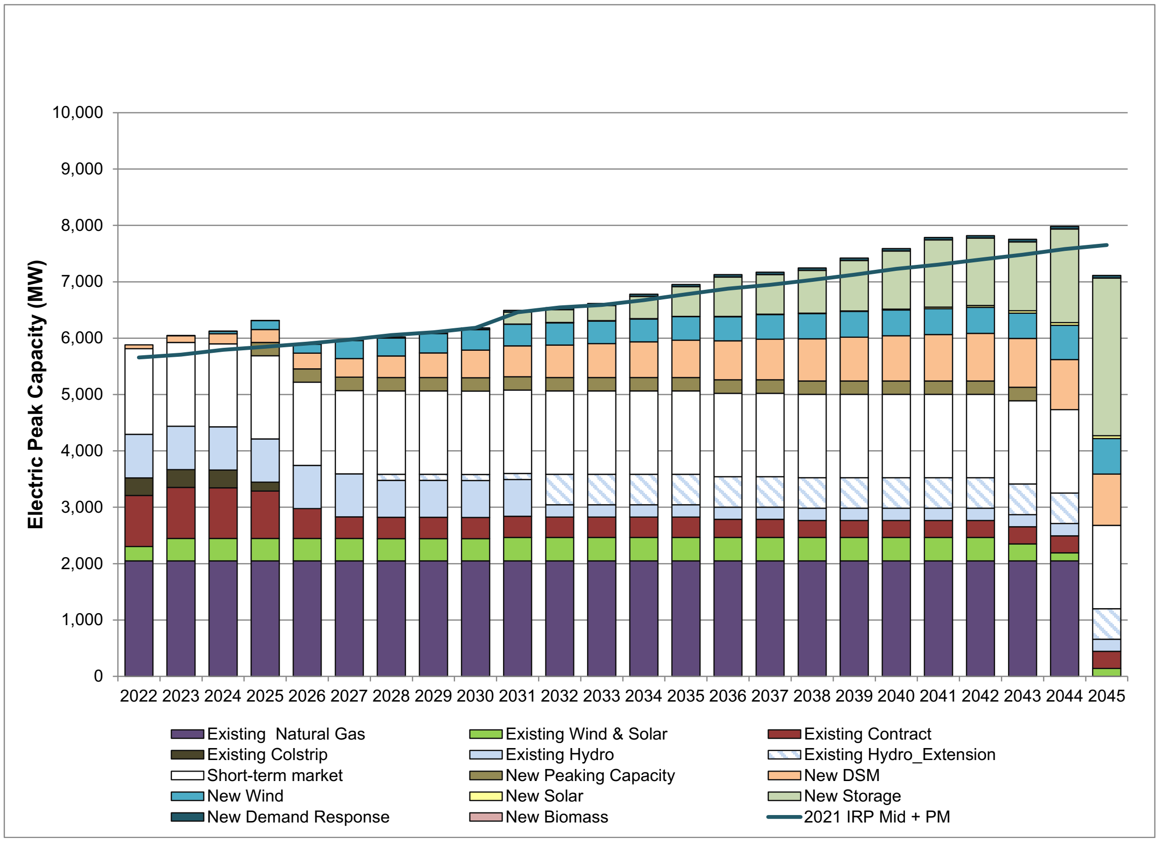
Figure 8-48: Portfolio Additions – Mid Scenario and Sensitivity O



Other Findings

PEAK CAPACITY. Absent of gas-fired generation by 2045, the portfolio fails to meet the peak capacity need at the end of the planning horizon and requires further work for the final IRP. Figure 8-49 shows the peak capacity contribution of existing and new resources compared to the peak capacity need.

Figure 8-49: Sensitivity O – Portfolio Peak Capacity Needs



P: Must-take Battery and P2 Must-take Pumped Hydro Energy Storage

What is the cost difference between the Mid Scenario portfolio and a portfolio where storage resources and demand response programs are selected prior to any peaking capacity resources?

Baseline: Peaking capacity resources are available as early as 2025**.**

Sensitivity P: First eligible year for peaking capacity resources is 2030.

Sensitivity P2: Same as P; Pump hydro energy storage resources are available as early as 2023. First year availability of batteries is moved to 2030 from 2023.

Key Findings

Sensitivity P: Delaying the availability of peaking capacity resources resulted in much earlier addition of battery storage resources, for a total of 3,775 MW nameplate capacity by 2030. We also see an additional 7 MW nameplate capacity of demand response by 2045 compared to the Mid Scenario portfolio. Peaking capacity resources were still added to the portfolio for a total of 711 MW nameplate capacity compared to 948 MW nameplate capacity in the Mid Scenario portfolio. In Sensitivity P, the 24-year levelized revenue requirement is $29.1 billion dollars, an increase of $15.5 billion dollars or 113 percent over the Mid Scenario.

Sensitivity P2: Without peaking capacity resources and batteries available until 2030, 2,800 MW nameplate capacity of pump hydro energy storage resources were added to the portfolio by 2028 in order to fill the peak capacity needed after the removal of Centralia and Colstrip 3&4. Interestingly, 711 MW nameplate of peaking capacity resources and 1,225 MW nameplate of 2-hr Lithium Ion batteries were added to the portfolio by 2045. For Sensitivity P2, the 24-year levelized revenue requirement is $22.4 billion dollars, an increase of $8.72 billion dollars over the Mid Scenario.

Assumptions

In the Mid Scenario portfolio, peaking capacity resources are available as early as 2025. In this sensitivities P and P2, peaking capacity resources are available much later, in 2030. This forces the model to optimize its resource selection between batteries and demand response to keep the portfolio balanced prior to the availability of peaking capacity resources. To better understand the impact of limited storage options, only pump hydro energy storage resources are available for selection in Sensitivity P2 starting in 2023. Lithium Ion and Flow batteries are not available until 2030 in Sensitivity P2.

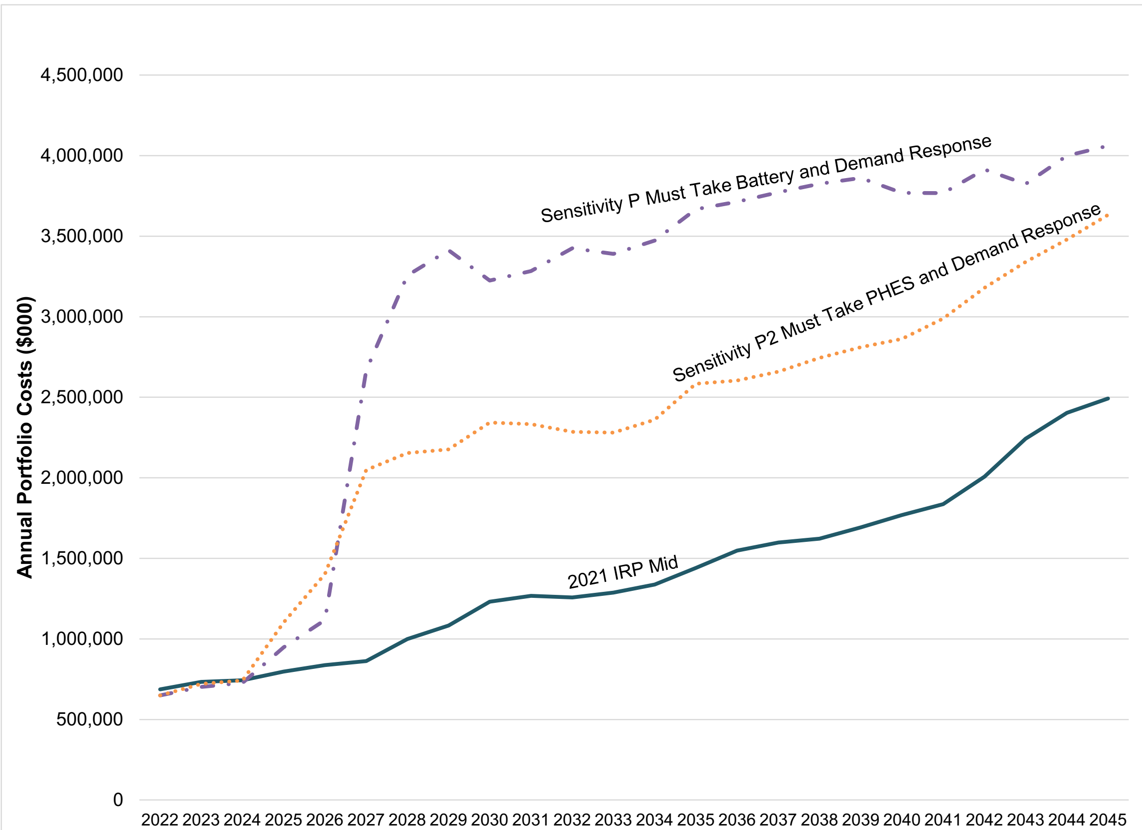
Portfolio Costs

Figures 8-50 and 8-51 illustrate the breakdown of costs between the Mid Scenario and Sensitivity P and P2 portfolios. The annual portfolio costs are significantly higher for both Sensitivities P and P2 compared to the Mid Scenario. Storage resources and Demand Response programs are more expensive options compared to peaking capacity resources. Both sensitivities added over 3,000 MW more nameplate capacity of new resources compared to the Mid Scenario, resulting in higher portfolio costs. A significant amount of batteries and pump hydro energy storage was added to both portfolios between 2025 and 2030 and resulted in the spike in the annual portfolio costs.

Figure 8-50: 20 and 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities P and P2

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
P	Must-take Battery	$29.09	$6.06	$35.15	$16.47
P2	Must-take Pumped Hydro Storage	$22.35	$4.36	$26.71	$8.04

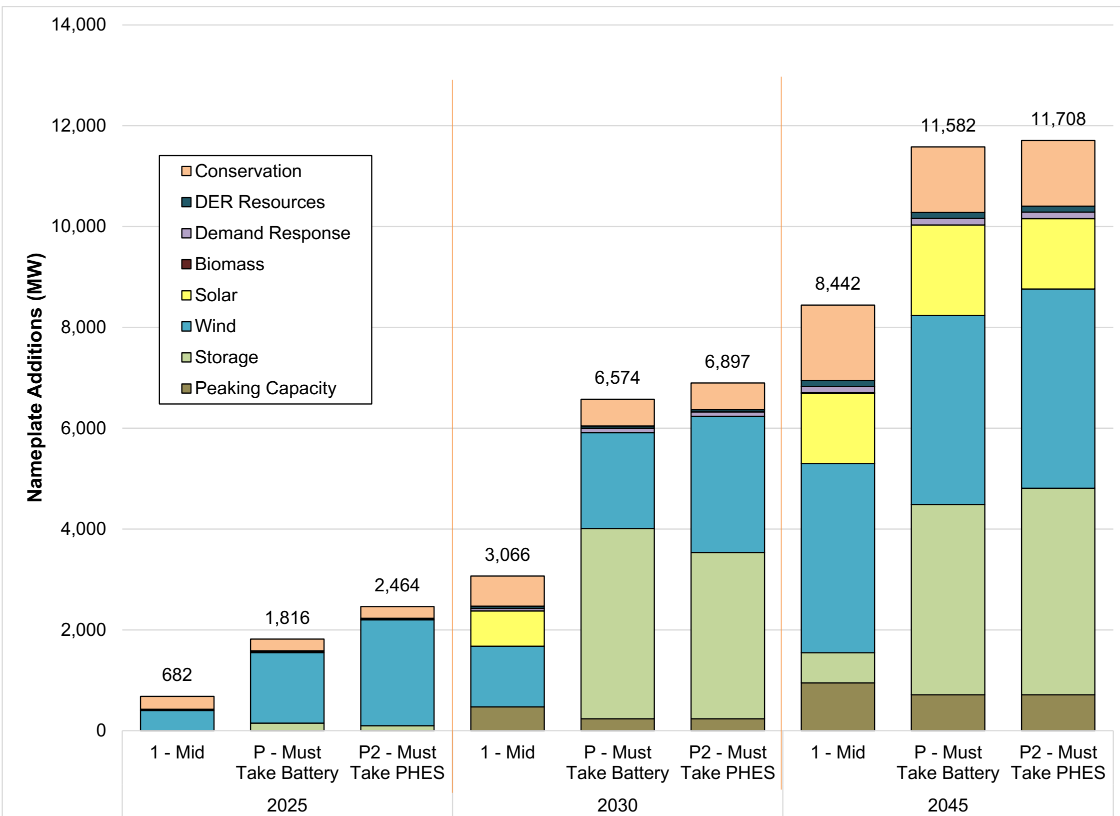
Figure 8-51: Annual Portfolio Costs – Mid Scenario and Sensitivities P and P2



Resource Additions

Figure 8-52 compares the nameplate capacity additions of Sensitivity P and P2 and the Mid Scenario portfolios. In the Mid Scenario portfolio, 474 MW of peaking capacity resources were added in 2026 as the retirements of Colstrip and Centralia take place. In Sensitivity P, batteries are selected to meet that peak need. With 2-hour lithium-ion batteries having a 12.4 percent ELCC, it will take about 3,800 MW nameplate capacity of batteries to replace those peaking capacity resources. In this sensitivity, the model selected 3,775 MW of 2-hour lithium-ion batteries to make up for the difference left unserved by new peaking capacity resources. We see similar resource additions for Sensitivity P2 with the only difference being the addition of pumped hydro energy storage instead of batteries.

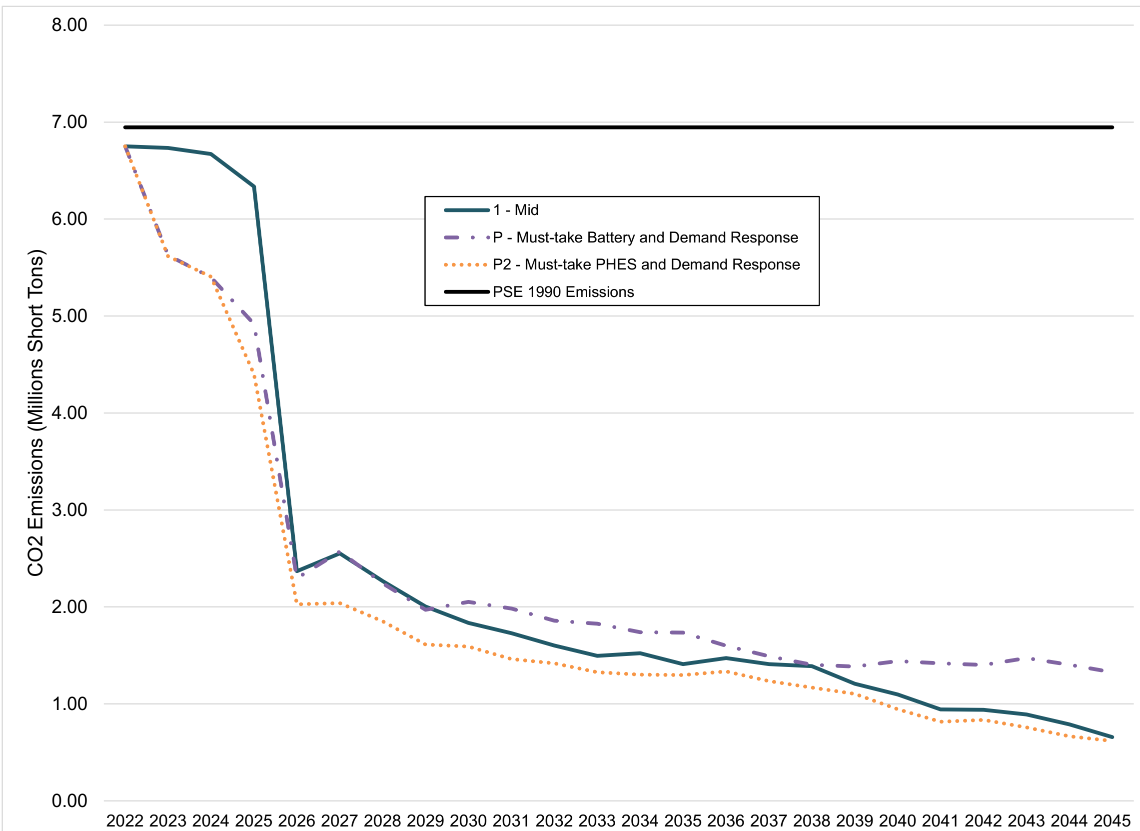
Figure 8-52: Portfolio Additions – Mid Scenario and Sensitivities P and P2



Other Findings

EMISSIONS. Delaying the addition of peaking capacity resources results in slightly higher dispatch of existing thermal plants as seen Sensitivity P. Slightly lower direct emissions from existing and new thermal plants are seen in Sensitivity P2 compared to the Mid Scenario. Figure 8-53 compares the emissions from the Mid Scenario and Sensitivities P and P2 portfolios in millions short tons.

Figure 8-53: Portfolio Emissions – Mid Scenario and Sensitivities P and P2



S. SCGHG Cost Included, No CETA, and

T. No CETA

What is the cost difference between the mid portfolio and a portfolio with the CETA requirement and Social Cost of Greenhouse gas?

Baseline: SCGHG for thermal resources as a fixed cost adder and the CETA requirement is included in the model.
Sensitivity S: There is no CETA renewable requirement. SCGHG costs as a fixed cost adder is included for thermal plants.
Sensitivity T: There is no CETA renewable requirement and SCGHG costs are not included in the model.

Key Findings

Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement for Sensitivity T is $9.4 billion dollars, $4.2 billion dollars less than the Mid Scenario portfolio. Compared to Sensitivity S, the 24-year levelized revenue requirement for Sensitivity T is lower by $0.7 billion dollars. Similar to Sensitivity S, there are no renewable resource additions to the portfolio except for 350 MW of wind in 2044 needed to maintain compliance with the RPS requirement. There are less conservation resources selected in both Sensitivities S and T compared to the Mid Scenario.

Assumptions

In the Mid Scenario portfolio, 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance. The Social Cost of Greenhouse Gases is included as a fixed O&M cost for thermal resources during resource selection. In Sensitivity T, there is no CETA renewable requirement and SCGHG costs are not included in the model. Absent the CETA renewable requirement, the 15 percent of sales RPS requirement under RCW 19.285 is applied in this sensitivity. For Sensitivity S, only the SCGHG costs are included in the mode.l

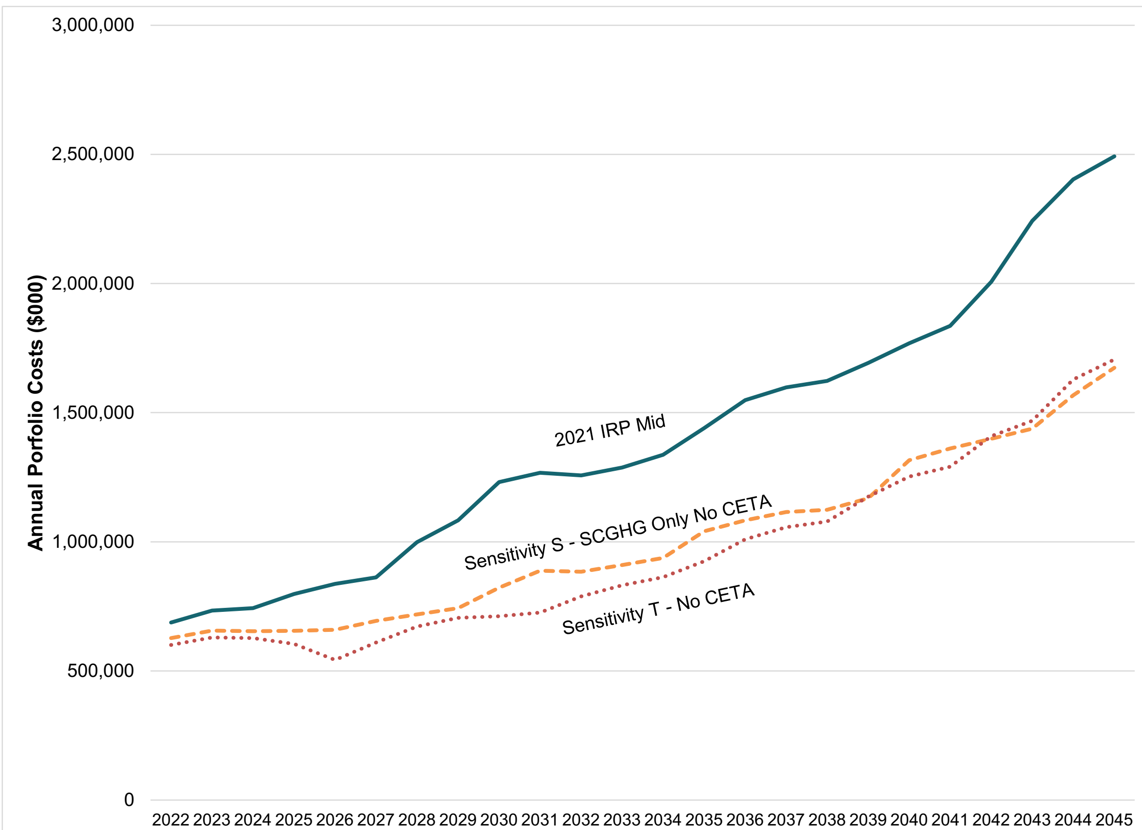
Portfolio Costs

Figures 8-54 and 8-55 illustrate the breakdown of costs between the Mid Scenario, Sensitivity S and Sensitivity T portfolios. The reduction in conservation resources drives the costs even lower for Sensitivity T compared to Sensitivity S.

*Figure 8-54: 24-year Levelized Portfolio Costs –
Mid Scenario, Sensitivity S and Sensitivity T*

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
S	SCGHG Included, No CETA	$10.06	$9.01	$19.08	$0.40
T	No CETA	$9.40	-	$9.40	($9.28)

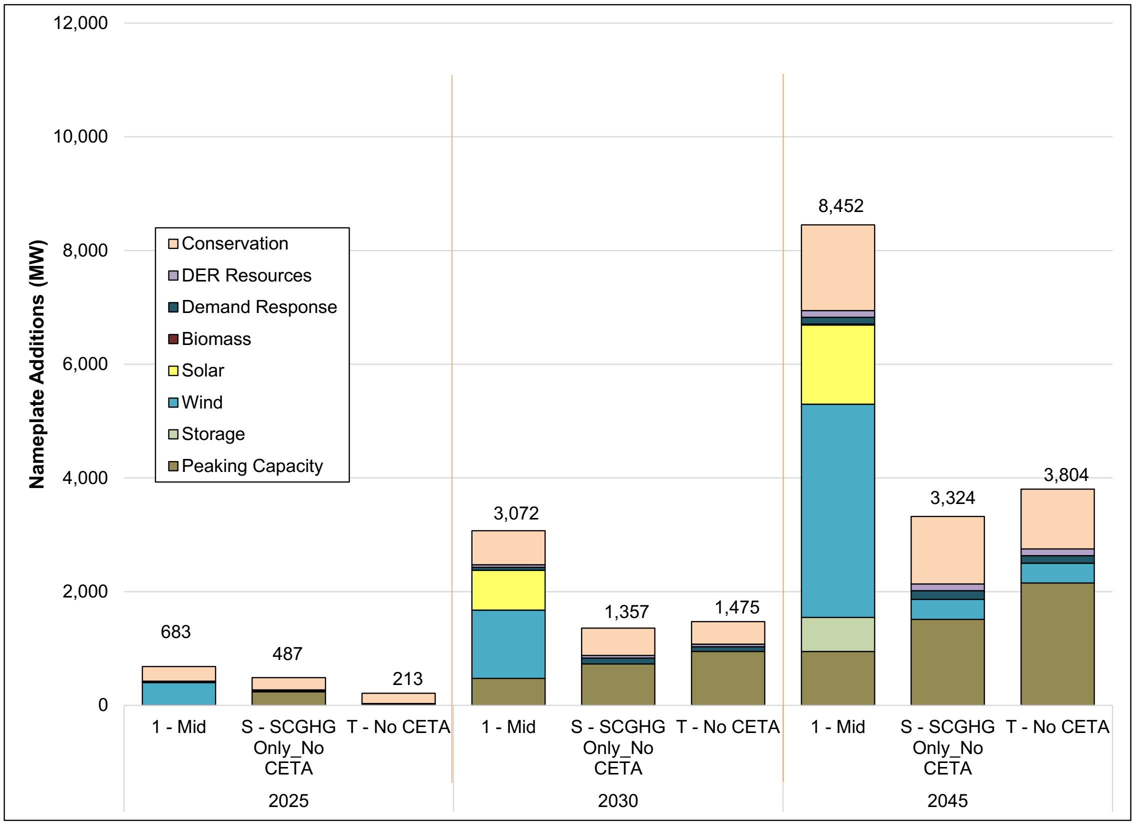
Figure 8-55: Annual Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T



Resource Additions

Figure 8-56 compares the nameplate capacity additions of the Sensitivity S, T and Mid Scenario portfolios. Similar to Sensitivity S, there is no incentive to add renewable resources to the portfolio except for compliance to RCW 19.285. Without SCGHG as a fixed cost adder, even more peaking capacity resources are added for a total 2,151 MW of nameplate capacity by 2045.

Figure 8-56: Portfolio Additions – Mid Scenario, Sensitivity S and Sensitivity T



V. Balanced Portfolio, and

W. Balanced Portfolio with Alternative Fuel

These sensitivities are performed in order to compare the Mid Scenario with a portfolio that gives increased consideration to distributed energy resources. The portfolio was developed from analysis of sensitivity results and lessons were applied in developing the inputs for this sensitivity. The electric capacity expansion model is set to optimize the total portfolio cost and as we notice, delaying new builds till the end does lower cost. This is because all the resources have a declining cost curve over time, so it is more beneficial to wait till the last minute in order to optimize the resource costs. This is not always possible to wait till end to add a lot of resources. When looking at sensitivity C, transmission build constraints, the model waits till the end to add a significant amount of distributed resources. This portfolio takes those distributed resources and ramps them over time starting in 2025 instead of waiting till the last 5-10 years of the portfolio along with adding more customer programs to meet CETA requirements.

Baseline: New resources are acquired when cost effective and needed, conservation and DR measures are acquired when cost-effective.
Sensitivity V: 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 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

Sensitivity W: Same as Sensitivity V above, with the addition of biodiesel as fuel source for new frame peaker resources.

Key Findings

Sensitivity V: Ramping in forced resource additions versus economic resource model selection resulted in higher portfolio costs in Sensitivity V compared to the Mid Scenario. Distributed solar resources are higher cost than Washington wind and Washington solar east resources, which were found to be the optimal renewable resources following Montana and Wyoming wind resources in the Mid Scenario. In Sensitivity V, the 24-year levelized revenue requirement is $14.37 billion dollars, an increase of $0.74 billion dollars or 5 percent over the Mid Scenario.

Sensitivity W: Extending the assumptions from Sensitivity V to include biodiesel as fuel source for new frame peakers resulted in an increase of $0.8 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $14.43 billion dollars, an increase of $0.06 billion dollars from Sensitivity V. Even with the premium on biodiesel fuel prices compared to natural gas price, the model selected the same amount of frame peaker resources in Sensitivity W compared to the Mid Scenario.

Assumptions

Sensitivity V assumes greater investment in distributed energy resources, load reducing resources (i.e. Green Direct) and conservation measures to create a portfolio with greater balance between large, central power plants and small, distributed resources. Investments in these resources are modeled as forced acquisitions. These forced acquisitions include:

- Addition of 50 MW of distributed, ground-mounted solar in the year 2025.
- Annual addition of 30 MW of distributed, rooftop solar from the year 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Addition of all demand response programs with a cost less than $300/kw-yr.
- Annual addition of 25 MW of 2hr Lithium-Ion battery storage from the year 2025 to 2031 for a total of 175 MW of nameplate capacity.
- An adjusted forecast of customer-owned, solar projects to reflect increased residential solar adoption. The forecast matches the CPA Low-cost, Business-As-Usual residential solar adoption rate.
- Addition of three new Green Direct programs consisting of 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

PSE has ramped in resource additions in this sensitivity to spread out the acquisition of new resources. Often resource selections made by the optimization model will be grouped together late in the modeling horizon to take advantage of lower costs projected by the cost curves (also known as learning curves). All generic resource options are still available for economic selection by the optimization model.

Building off the assumptions made in Sensitivity V, Sensitivity W also explores the use of alternative fuel for some peaking capacity resources. The sensitivity assumes new frame peakers are fueled with biodiesel instead of natural gas. Existing thermal resources, new CCCT+DF and new recip peakers will continue to be fueled with natural gas throughout the modeling horizon. The market price for biodiesel was estimated from PSE experience and informed by the U.S. Department of Energy Clean Cities Alternative Fuel Price Report, October 2020. PSE has assumed a fixed biodiesel price of $30.53 per million British Thermal Units (MM BTU) over the entire study period.

Portfolio Costs

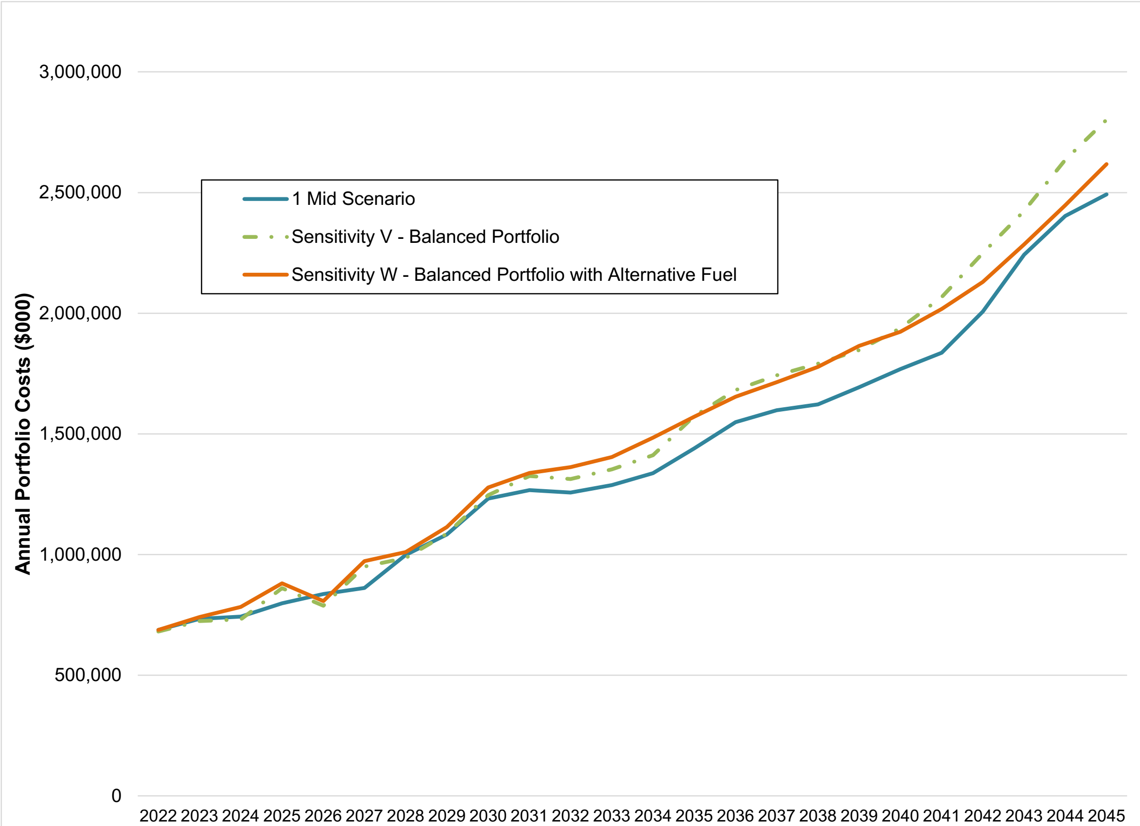
Early investments in high cost resources such as distributed solar and storage result in higher portfolio costs for Sensitivities V and W, as compared to the Mid Scenario. The increased portfolio costs for Sensitivities V and W are driven by the increased revenue requirements of the portfolios as shown in Figure 8-57. SCGHG costs are on par with the Mid Scenario, with Sensitivity V having slightly higher SCGHG costs because of more market purchases and Sensitivity W having slightly lower SCGHG costs because new peaking resources are using an alternative fuel.

Figure 8-57: Portfolio Cost Comparison – Mid Scenario and Sensitivities V and W

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
V	Balanced Portfolio	$14.37	$5.06	$19.43	$0.75
W	Balanced Portfolio with alternative fuel for peakers	$14.43	$4.86	$19.30	$0.62

Annual portfolio costs for the Mid Scenario and Sensitivities V and W are provided in Figure 8-58. Sensitivities V and W ramped in resources throughout the early years of the modeling horizon in an effort to smooth revenue requirement costs. However, these ramped acquisitions had very little impact on the year-to-year portfolio cost.

Figure 8-58: Annual Portfolio Costs – Mid Scenario and Sensitivities V and W



Resource Additions

Resource additions over time for the Mid Scenario and Sensitivities V and W are provided in Figure 8-59. Portfolio builds between the two sensitivities and the Mid Scenario are relatively similar, with a few subtle differences. The capacity of wind resources and peak capacity remains the same between the Mid Scenario and Sensitivities V and W. Wind is a low cost, CETA eligible resource so it is expected that all three portfolios selected the same quantity of wind capacity. Peaking capacity resources are among the lowest cost methods to meet peak demand hours. Therefore it is expected that most portfolios will include some peaking capacity. The same quantity of peaking capacity was selected between Sensitivities V and W. In Sensitivity W, new peaking capacity resources are fueled with biodiesel instead of natural gas. Biodiesel, a renewable resource, and does not have SCGHG cost for that resource. However, biodiesel is also much more expensive than natural gas. It appears, at the current cost projections for biodiesel, the price and the SCGHG of the fuel are offsetting, resulting in similar peaking resource decisions in Sensitivities V and W.

The primary differences between the Mid Scenario and Sensitivities V and W are related to the forced build decisions described in the assumptions section above. Increased DER builds result in less utility-scale solar builds, as these resources fill a similar niche within the portfolio. Increased demand response programs in Sensitivities V and W may also offset some utility-scale solar builds.

More storage is built in both Sensitivities V and W as compared to the Mid Scenario. Both sensitivities ramp in 2hr Lithium Ion battery storage from 2025 to 2031. This storage is useful, particularly paired with the increased DER solar builds in both sensitivities. However, the storage in the Mid Scenario is composed of 4hr Lithium Ion and 6hr Flow battery storage, which is built after year 2040. Sensitivities V and W show similar late year additions of longer duration storage, despite the abundance of 2hr storage added early in the modeling horizon. This shows that longer duration storage is an important component of these portfolios.

Figure 8-59: Portfolio Additions – Mid Scenario and Sensitivities V and W

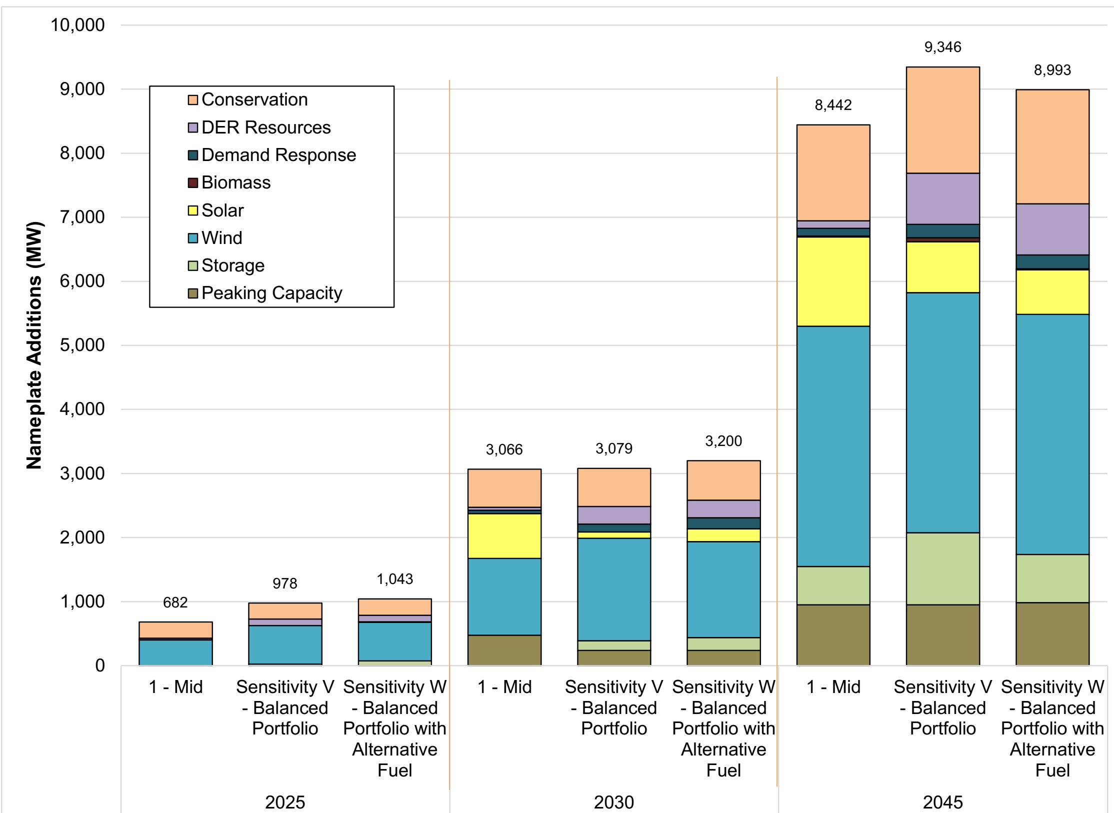


Figure 8-60 provides the final resource builds for Sensitivities V and W as they compare to the Mid Scenario in the year 2045.

Figure 8-60: Portfolio Additions by 2045 – Sensitivities V and W

Resource Additions by 2045	Mid	Sensitivity V - Balanced Portfolio	Sensitivity W - Balanced Portfolio with Alternative Fuel
Conservation	1497 MW	1658 MW	1784 MW
DER Resources	118 MW	798 MW	798 MW
Demand Response	121 MW	211 MW	215 MW
Renewable Resources	5158 MW	4606 MW	4462 MW
Biomass	15 MW	60 MW	15 MW
Solar	1393 MW	796 MW	697 MW
Wind	3750 MW	3750 MW	3750 MW
Energy Storage	600 MW	1125 MW	750 MW
Peaking Capacity	948 MW	948 MW	984 MW

8. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

To be provided in the final IRP.

9 Natural Gas Analysis

This analysis enables PSE to develop valuable foresight about how resource decisions to serve our natural gas customers may unfold over the next 20 years in conditions that depict a wide range of futures.

Contents

1. RESOURCE NEED AND DISCUSSION TOPICS

Resource Need

More than 840,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's natural gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD).[1] Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain fairly constant and use per customer is growing slowly, if at all, so the biggest factor in determining load growth at this time is the increase in customer count.[2]

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2021 IRP Mid Demand Forecast, the 2021 IRP High Demand Forecast and the 2021 IRP Low Demand Forecast.[3]

- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need throughout the study period.
- In the Mid Demand Forecast, the first resource need occurs in the winter of 2031-32.
- In the High Demand Forecast, the first resource need occurs immediately.

Figure 9-1 illustrates natural gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 9-2 shows the resource need surplus/deficit for the Mid Demand Forecast.

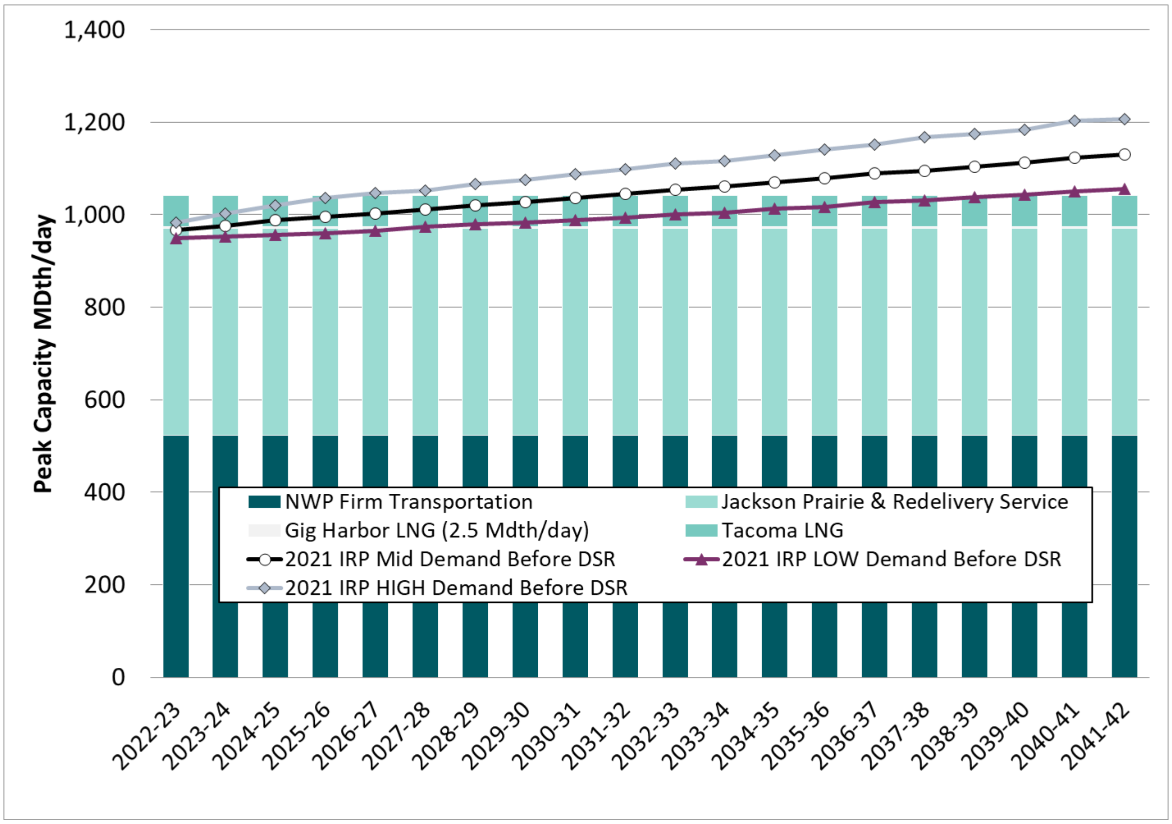
[1] / Heating Degree Days (HDDs) are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD is calculated as 65° less the 13° temperature for the day.

[2] / The 2021 IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.

[3] / The 2021 IRP demand forecasts are discussed in detail in Chapter 6, Demand Forecasts.

In Figure 9-1, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[4] and the bars represent existing resources for delivering gas supply to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[5] The gap between demand and existing resources represents the resource need.

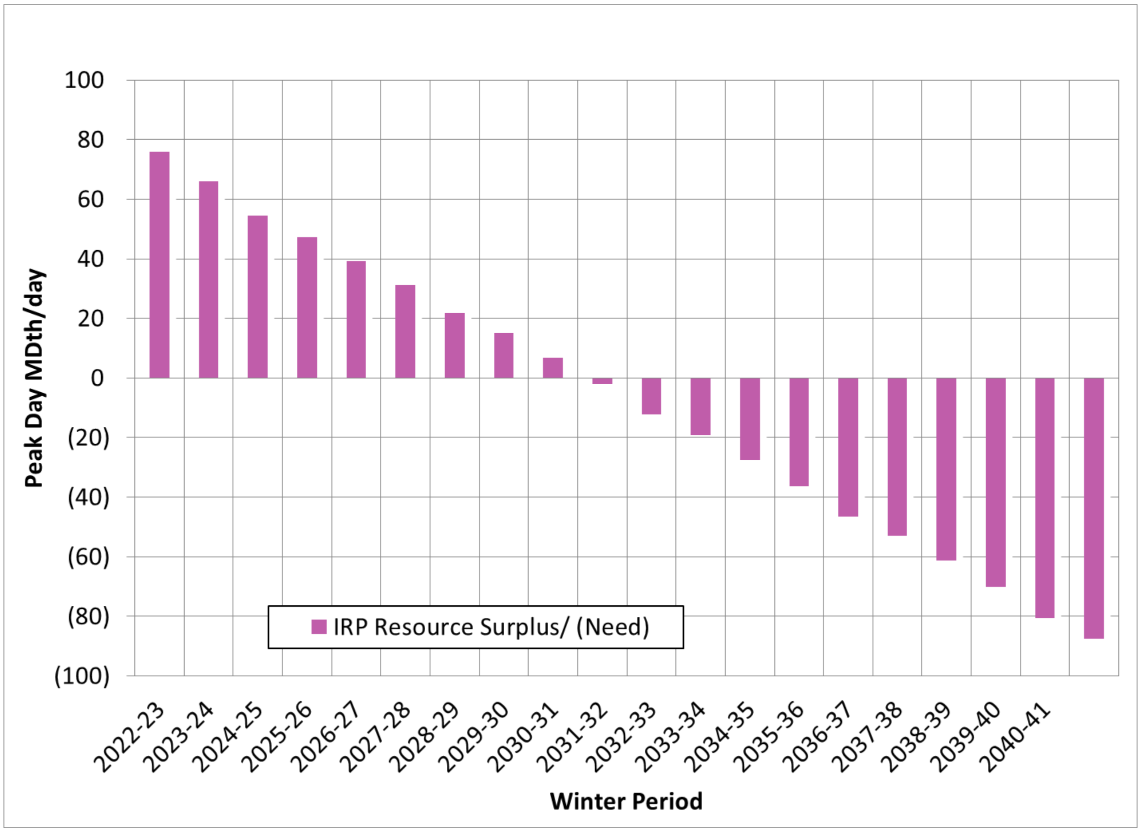
Figure 9-1: Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (Meeting need on the coldest day of the year)



[4] / *One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of additional conservation savings. Therefore the IRP Natural Gas Demand Forecasts include only DSR measures implemented* ***before*** *the study period begins in 2022. These charts and tables are labeled "before DSR."*

[5] / *Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available late in the winter of 2021-22.*

Figure 9-2: Natural Gas Sales Peak Resource Need Surplus/Deficit in Mid Demand Forecast before DSR



Discussion Topics

Infrastructure Reliability

Natural gas transportation and distribution systems are not designed to include the type of redundant capacity that electric distribution systems have because the majority of gas infrastructure is located underground where it is largely insulated from the effects of wind and storm damage. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, PSE builds flexibility and resiliency into the system in four ways.

- **A conservative planning standard.** Since PSE's peak day design standard is based on the coldest temperature on record for our service territory, and since this extreme temperature is not often reached and even more rarely sustained, there is some excess capacity in the system on most days.
- **Diverse transport resources**. PSE has built a transport portfolio that intentionally sources natural gas equally from north and south of our service territory to preserve flexibility in the event of supply disruptions. (Approximately 50 percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south.)
- **Natural gas storage**. Including natural gas storage in the portfolio (via Jackson Prairie, Clay Basin, Gig Harbor LNG, and the soon-to-be-completed Tacoma LNG Project) contributes to flexibility and resiliency in several ways. Storage minimizes the need and costs associated with relying on long haul pipelines to deliver gas on cold days; it allows more natural gas to be purchased in the typically less expensive summer season; and it can furnish natural gas supply in the event of a pipeline disruption.
- **Cooperation with regional entities.** After a 2009 storage interruption, PSE was instrumental in revitalizing the Northwest Mutual Assistance Agreement (NWMAA). Members of the agreement utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest, and they pledge to work together to provide and maintain firm service during emergency conditions and to restore normal service to their customers as quickly as possible after such events occur.

Two incidents illustrate how these strategies work in practice.

A 36-inch pipe on the Westcoast pipeline (Westcoast) between Station 2 and Sumas in central British Columbia (B.C.) ruptured in the early evening of October 9, 2018, shutting off the flow of natural gas from production points in northeast B.C to Sumas for over 30 hours. This resulted in the loss of over 800,000 Dth per day of Sumas supply. Coincidentally, the Jackson Prairie Storage Project was shut down for scheduled maintenance at the time. Coordinating efforts through the Northwest Mutual Assistance Agreement, all the of the natural gas pipelines, utilities, power plant operators and major industrial customers affected worked together to add supply or shed load. Fortis BC, a large downstream utility in southern British Columbia, was able to use some natural gas flowing on its pipeline from Alberta (Southern Crossing), and PSE and other utilities and end-users took steps to reduce natural gas consumption or increase supply from their own on-system storage. These combined efforts prevented a significant loss of pressure in the system, and by 2 p.m. on October 11, 2018 portions of the Westcoast pipeline system were back in service and 38 percent of the normal gas volume from B.C. was flowing. Jackson Prairie personnel worked around the clock to complete the storage facility's planned maintenance ahead of schedule, providing important additional supply to ease the regional situation. Thanks to the combined efforts of Northwest Mutual Assistance participants, the incident lasted less than 48 hours, however, the extensive testing and recertifying required to restore the natural gas flow from B.C. to 100 percent of capacity took over a year. Westcoast was allowed to begin operating its system at 100% by mid-November 2019.

In February, 2019, while Westcoast pipeline was still operating significantly below normal levels, the Jackson Prairie Gas Storage Project suffered a major compressor failure that reduced natural gas deliverability by approximately 250,000 Dth per day. The compressor was repaired and back online in less than 30 days, and the net effect of the outage was a reduction in total available storage withdrawals of only 750,000 Dth. Customers experienced no service interruption, but to compensate for the unavailable storage supplies, PSE and other entities that draw natural gas from the storage facility had to purchase additional flowing supply from the market at a time when supply was low and demand, and therefore prices, were high.

These incidents, while quite rare, demonstrate the resilience of the natural gas transportation and storage system in the region. Despite two major failures, no firm residential or commercial customer was without natural gas, nor was there a loss of electrical service, which is increasingly dependent on the natural gas infrastructure. With PSE's current modeling capabilities, it is not possible to model random outages; however, these recent "real-world" experiences demonstrate that the steps taken by PSE to prepare for occasional infrastructure failure have proven successful.

Supply Adequacy

As noted above, PSE intentionally sources natural gas from both north and south of our service territory to preserve flexibility in the event of supply disruptions. Fifty percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south. At this time, we are monitoring developments on the Westcoast pipeline that serves the Sumas market.

PSE holds firm capacity on Westcoast's system for approximately 50 percent of its needs from British Columbia in order to access natural gas supplies in the production basin in northern British Columbia rather than only at the Sumas market. This strategy provides a level of reliability (physical access to natural gas in the production basin) and an opportunity for pricing diversity, as often there is a significant pricing differential between Station 2 and Sumas that more than offsets the cost of holding the capacity.

When natural gas production in NE B.C. increased substantially due to the shale revolution, a shortage of pipeline capacity leaving the basin developed as producers sought market outlets for the increased production. For the past several years, Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions); so far, the result has been an adequate supply at Sumas in winter months (when the pipeline is in normal operations) and an excess in summer months.

A 2017 Westcoast capacity offering was fully subscribed, and this will drive construction of facilities to provide an additional 105,000 Dth per day of firm capacity on Westcoast and also 94,000 Dth per day of capacity that was previously held back for maintenance and reliability reasons. The new contracts, totaling 199,000 Dth per day, will bring more firm natural gas to the Sumas hub beginning in November 2021

However, between 2024 and 2027, two new large-volume firm industrial loads totaling over 400,000 Dth per day are expected to come online. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand (from both existing and expansion capacity), they will control their own supply and destiny. Much of the firm pipeline capacity that they will use to access their natural gas supply is currently used to provide the adequate and occasionally abundant supplies at the Sumas market hub to other customers. Once the new customers start up their facilities, they will effectively and dramatically reduce the supply available for other customers at Sumas on most days.

PSE is confident that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2021, and that PSE will still be able to compete (on price) to obtain sufficient supplies in peak periods to fill its existing Northwest Pipeline (NWP) capacity, even when the new industrial concerns begin operations. However, PSE is concerned because the increased demand of 400,000 Dth per day is supported by only 199,000 Dth per day of increased capacity, thus placing price pressure on the remaining supplies.

Because there is currently an equilibrium of firm supply and firm demand in peak winter periods and a surplus in summer periods, PSE believes it is not necessary to secure additional firm Westcoast capacity at this time. However, in the future there is the potential for inadequate capacity to bring sufficient supply to Sumas in peak periods. For this reason, the IRP analysis continues to assume that any new long-term Northwest pipeline (NWP) capacity from Sumas used to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast that begins at the supply source in NE B.C. In addition, PSE will consider acquisition of additional Westcoast capacity from Station 2 to Sumas from existing holders, should advantageous opportunities arise.

PSE will continue to monitor developments in the NE B.C. supply and capacity market and to analyze the implications on an ongoing basis.

2. ANALYTIC METHODOLOGY

Analysis of the natural gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing long-term resources. Once need has been identified, a variety of planning tools, optimization analyses and input assumptions help PSE identify the lowest-reasonable-cost portfolio of natural gas resources in a variety of scenarios. Renewal or term extension of existing resources are among the alternatives considered.

Analysis Tools

PSE uses a gas portfolio model (GPM) to analyze natural gas resources for long-term planning and long-term natural gas resource acquisition activities. The current GPM is SENDOUT Version 14.3.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight" – meaning that its theoretical results may not be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them.

***> > > See Appendix I, Natural Gas Analysis Results**, for a more complete description of the SENDOUT gas portfolio model.*

Deterministic Optimization Analysis

PSE developed three natural gas scenarios for this IRP analysis, Mid, High and Low, as shown in Figure 9-3.[6] Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

Figure 9-3: 2021 IRP Natural Gas Analysis Scenarios

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

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

[6] / *Chapter 5, Key Assumptions, describes the scenario inputs in detail.*

PSE also tested five sensitivities in the natural gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect of a single resource, regulation or condition on the portfolio.

Figure 9-4 2021 IRP Natural Gas Portfolio Sensitivities

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

> > > See Appendix I, Natural Gas Analysis Results, *for a detailed presentation of scenario and sensitivity analysis results.*

Natural Gas Peak Day Planning Standard

PSE completed a detailed cost-benefit analysis during the 2005 least cost plan (LCP) that is the basis for the current planning standard. That analysis looked at customers' value of reliability of service with the incremental costs of the resources necessary to provide that reliability at various temperatures. Based on the analysis, PSE determined that it would be appropriate to use the 52 HDD (13ºF) as the peak day planning standard.

PSE has used this planning standard since 2005, including in the 2021 IRP. PSE believes that the planning standard is still appropriate in the current environment for the reasons outlined below.

- The standard is based on reliability and safety. In the gas sector when there is an outage, it triggers a safety protocol that requires service technicians to physically shut off the gas at the appliance before gas service is restored and make another visit to turn on pilot gas lights. Due to the work hours involved, the outages can take days to weeks to restore during a time when the weather is at its coldest and space heating is an essential service. The existing standard has prevented outages over the last 15 years, and while during this time we have not seen temperatures that approach the design peak day temperature, there is no certainty that we will not see this temperature in the near future.
- When seen in the context of other regional gas utility planning standards, the PSE natural gas planning standard is in line with industry best practices. PSE's implied temperature criteria derived from its planning standard places it in the 98th percentile for annual peaks from 1950 to 2019 (see Figure 9-5), similar to other PNW utilities (see Figure 9-6).

Figure 9-5: PSE Planning Standard Implied Temperature Criteria

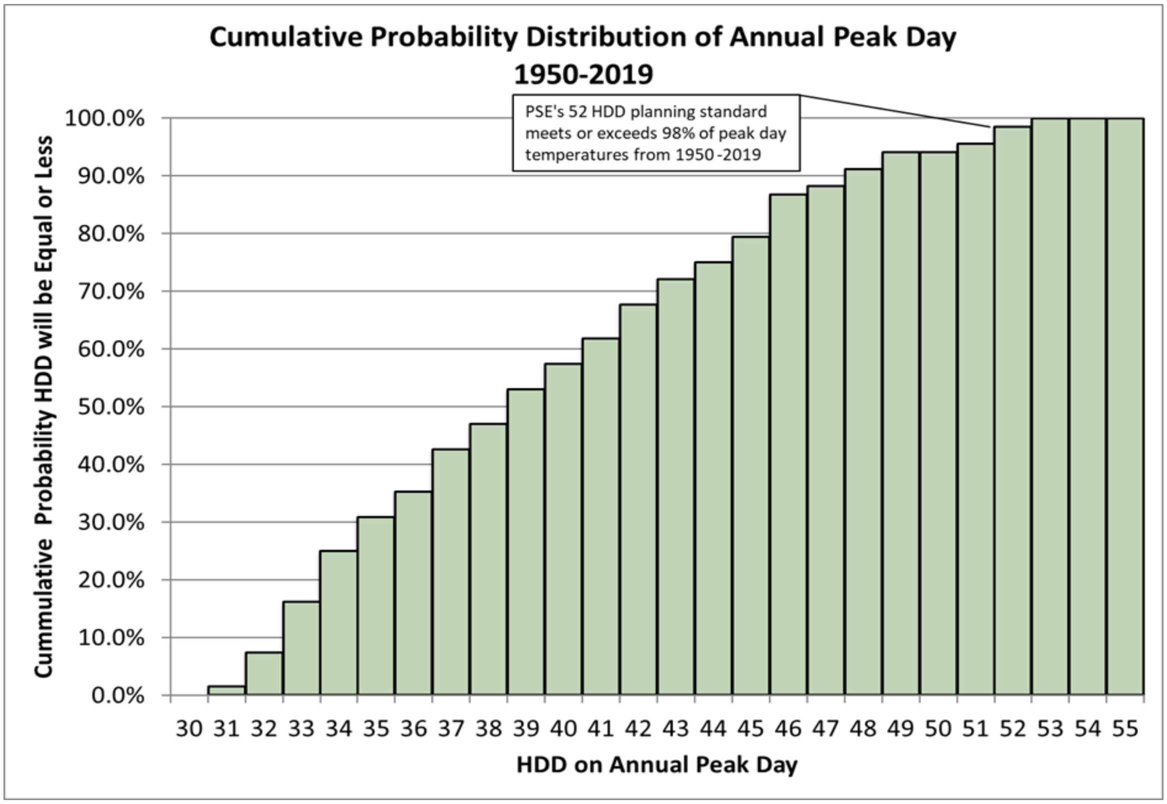


Figure 9-6: Pacific Northwest Gas Utility Planning Standards

PNW Gas Utility	Peak Capacity Design Standard
NW Natural	NW Natural will plan to serve the highest firm sales demand day in any year with 99% certainty: 99th percentile of annual peak days over last 100 years.
Cascade Natural	Coldest day during the past 30 years.
Avista Corp	Adjust the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day.
Fortis NG	1 in 20 years temperature based on annual peak days over last 60 years.
PSE	98th percentile of annual peak days from 1950-2019

Natural gas ignition technology has not changed much in the last 15 years. Penetration of electronic ignition is still very small, so service personnel are still required to relight homes in the event of an outage. The cost of relighting has also increased since the 2005 study due to increased population density and travel times in the region.

The results of the 2021 IRP analysis show that lower demand, which may result from a revised peak day planning standard, will likely not change the resource alternatives needed to serve future loads. Even in the Low Scenario, the gas portfolio model selected the same level of cost-effective conservation as the High Scenario. Thus, revising the planning standard would not change the results of the analysis in the 2021 IRP.

Given that the PSE planning standard is in line with peer gas utilities, has provided a reliable gas system, and will not result in any material change to the resource alternatives chosen in the analysis, PSE believes it is appropriate to use the 52 HDD peak day planning standard in the 2021 IRP. PSE plans to study the impacts of changing the planning standard.

3. EXISTING RESOURCES

Existing natural gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, natural gas supplies and demand-side resources.

Existing Pipeline Capacity

There are two types of pipeline capacity. “Direct-connect” pipelines deliver supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver natural gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity

All natural gas delivered to our distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold nearly one million dekatherms (Dth) of firm capacity with NWP.

- 542,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada (AECO); the Rocky Mountain Basin (Rockies) and the San Juan Basin. This provides valuable flexibility, including the ability to source natural gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity

To transport natural gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

A schematic of the gas pipelines for the Pacific Northwest region is provided in Figure 9-7. For the details of PSE's natural gas sales pipeline capacity, see Figure 9-8.

Figure 9-7: Pacific Northwest Regional Gas Pipeline Map

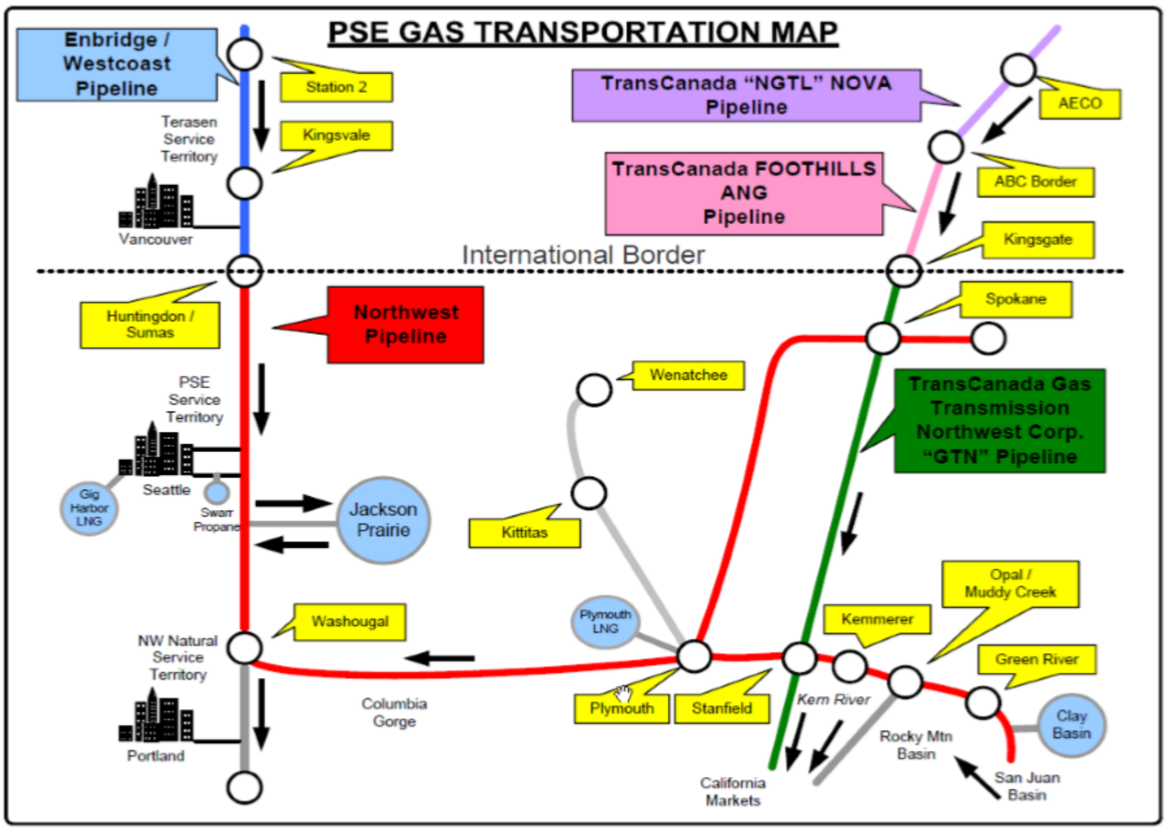


Figure 9-8: Natural Gas Sales - Firm Pipeline Capacity (Dth/day) as of 11/01/2020

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Direct-connect				
NWP/Westcoast Interconnect (Sumas)	1	287,237	135,146	152091
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936
NWP/various in US Rockies & San Juan Basin	1	179,699	52,423	127,276
Total TF-1		**542,872**	**187,569**	**355,303**
NWP/Jackson Prairie Storage Redelivery Service	1,2	447,057	444,184	2,873
Storage Redelivery Service		**447,057**	**444,184**	**2,873**
Total Capacity to City Gate		**989,929**	**631,753**	**358,176**

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Upstream Capacity				
TC-NGTL: from AECO to TC-Foothills Interconnect (A/BC Border)	3	79,744	79,744	-
TC-Foothills: from TC-NGTL to TC-GTN Interconnect (Kingsgate)	3	78,631	78,631	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Spokane)	4	65,392	65,392	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Stanfield)	4,5	11,622	11,622	-
Westcoast: from Station 2 to NWP Interconnect (Sumas)	6,7	135,795	135,795	-
Total Upstream Capacity	**8**	**371,184**	**371,184**	**-**

NOTES

1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.

2. Storage redelivery service (TF-2 or discounted TF-1) is intended only for delivery of storage volumes during the winter heating season, November through March; these annual costs are significantly lower than year-round TF-1 service.

3. Converted to approximate Dth per day from contract stated in gigajoules per day.

4. TC-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.

5. Capacity can alternatively be used to deliver additional volumes to Spokane.

6. Converted to approximate Dth per day from contract stated in cubic meters per day. Westcoast has adjusted the heat content factor upward to reflect the higher Btu gas now normal on its system. The effect is to allow customers to transport more Btu in the same contractual capacity.

7. The Westcoast contracts contain a right of first refusal upon expiration.

8. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

Transportation Types

TF-1

TF-1 transportation contracts are “firm” contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport natural gas every day.

Storage Redelivery Service

PSE holds TF-2 and winter-only discounted TF-1 capacity under various contracts to provide for firm delivery of Jackson Prairie storage withdrawals. These services are restricted to the winter months of November through March and provide for firm receipt only at Jackson Prairie; therefore, the rates on these contracts are substantially lower than regular TF-1 transportation contracts.

Primary Firm, Alternate Firm and Interruptible Capacity

FIRM TRANSPORTATION CAPACITY carries the right, but generally not the obligation (subject to operational flow orders from a pipeline), to transport up to a maximum daily quantity of natural gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported. Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point.

ALTERNATE FIRM CAPACITY occurs when firm shippers have the right to temporarily alter the contractual receipt point, the delivery point and even the flow direction – subject to availability of capacity for that day. This “alternate firm capacity” can be very reliable if the contract is used to flow gas within the primary path; that is, in the contractual direction to or from the primary delivery or receipt point. Alternate firm is much less reliable or predictable if used to flow gas in the opposite direction or “out of path.” While “out of path” alternate firm capacity has higher rights than non-firm, interruptible capacity, it is not considered reliable in most circumstances.

INTERRUPTIBLE CAPACITY on a fully contracted pipeline can become available if a firm shipper does not fully utilize its firm rights on a given day. This unused (interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day. The rate for interruptible capacity is negotiable and typically billed as a variable charge. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport gas on an alternate basis, outside of their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner "within path" or "out of path," along with the ability to create "segmented release" capacity, has resulted in very low non-firm, interruptible volumes on the NWP system.

When capacity is not needed to serve natural gas customers on a given day, PSE may use its firm capacity to transport natural gas from a low-priced basin to a higher-priced location and resell the gas to third parties to recoup a portion of demand charges. When PSE has a surplus of firm capacity and market conditions make such transactions favorable for customers, PSE may release capacity into the capacity release market. The company may also access additional firm capacity from the capacity release market on a temporary or permanent basis when it is available and competitive with other alternatives.

Interruptible service plays a limited role in PSE's resource portfolio because of the flexibility of the company's firm contracts and because it cannot be relied on to meet peak demand.

Existing Storage Resources

Natural gas storage capacity is a significant component of PSE's natural gas sales resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers. Benefits include the following.

- Ready access to an immediate and controllable source of firm natural gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store natural gas during the lower-demand summer season, generally at lower prices, for use during the high-demand winter season.
- Combining storage capacity with firm storage redelivery service transportation allows PSE to contract for less of the more expensive year-round pipeline capacity.
- PSE also uses storage to balance city gate gas receipts from natural gas marketers with the actual loads of our natural gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie Gas Storage Project (Jackson Prairie) in Lewis County, Wash. is an aquifer-driven storage field, located in the market area that is designed to deliver large quantities of natural gas over a relatively short period of time. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long natural gas supply. Figure 9-9 presents details about storage capacity.

Figure 9-9: Natural Gas Sales Storage Resources[1] as of 11/1/2020

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie – PSE Owned	398,667	147,333	8,528,000	N/A
Jackson Prairie – PSE Owned [2]	(50,000)	(18,500)	(500,000)	2023
Net JP Owned	**348,667**	**128,833**	**8,028,000**	
Jackson Prairie – NWP SGS-2F [3]	48,390	20,404	1,181,021	2023
Net Jackson Prairie	**397,057** [5]	**149,237**	**9,209,021**	
Clay Basin [4]	107,356	53,678	12,882,750	2023
Net Clay Basin	**107,356**	**53,678**	**12,882,750**	
Total	**504,413** [6]	**202,915**	**22,091,771**	

NOTES
1. Storage, injection and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.
2. Storage capacity made available to PSE's electric generation portfolio (at market-based price) from PSE natural gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve natural gas sales customers.
3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
4. PSE expects to renew the Clay Basin storage agreements.
5. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio for a total of 447,057 Dth/day.
6. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio.

Jackson Prairie Storage

As shown in Figure 9-9, PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which PSE operates under FERC authorization. PSE owns 398,667 Dth per day of firm storage withdrawal rights and associated storage capacity from Jackson Prairie. Some of this capacity has been made available to PSE's electric portfolio at market rates. The firm withdrawal rights – but not the storage capacity – may be recalled to serve natural gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, PSE has access to 48,390 Dth per day of firm deliverability and associated firm storage capacity through an SGS-2F storage service contract with NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts renew automatically each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core natural gas customers – that is, to meet seasonal load requirements, balance daily load and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores natural gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service.

PSE uses Clay Basin for certain levels of baseload supply and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Natural gas from Clay Basin is delivered to PSE's system (or other markets) using firm NWP TF-1 transportation.

Treatment of Storage Cost

Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. PSE also pays a variable charge for natural gas injected into and withdrawn from Clay Basin. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through the Purchased Gas Adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. The Gig Harbor liquefied natural gas (LNG) satellite storage and the Swarr vaporized propane-air (LP-Air) facility provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these resources typically help to meet extreme peak demand during the coldest hours or days. These resources do not offer the flexibility of other supply sources.

Figure 9-10: Natural Gas Sales Peaking Resources

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Transportation Tariff	Availability
Gig Harbor LNG	2,500	2,500	10,500	On-system	current
Swarr LP-Air [1,2]	30,000	16,680	128,440	On-system	Nov. 2024+
Tacoma LNG [3]	69,300	2,100	538,000	On-system	Mar. 2021
TOTAL	**101,800**	**21,280**	**676,940**		

NOTES
1. Swarr is currently out of service pending upgrades to reliability, safety and compliance systems. It may be considered in resource acquisition analysis for an in-service date of November 2024 or later.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons per minute, it takes 7.7 days to refill, or 16,680 Dth per day.
3. Planned in-service date is Mar. 1, 2021. Withdrawal (vaporization) capacity will rise in the future when the distribution system is upgraded. Such a distribution system upgrade – allowing an increase of 16,000 Dth per day in LNG vaporization – is considered as a potential new resource in this IRP.

Gig Harbor LNG

Located in the Gig Harbor area of the Kitsap Peninsula, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's distribution system. The Gig Harbor plant receives, stores and vaporizes LNG that has been liquefied at other LNG facilities. It represents an incremental supply source, and its 2.5 MDth per day capacity is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows natural gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-Air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE's natural gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering work necessary to upgrade the facility's environmental, safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP in Combination #7 – Swarr LP-Air Upgrade, and is assumed to be available on three years' notice as early as the 2023/24 winter season. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

PSE expects the completion of construction and successful start-up of this LNG peak shaving facility to serve the needs of core natural gas customers as well as regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project will achieve economies of scale that reduce costs for core natural gas customers. This LNG peak-shaving facility is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2021 IRP assumes the project is put into service late in the 2020-21 heating season, providing 69 MDth per day of capacity – 50 MDth per day of vaporization and 19 MDth per day of recalled natural gas supply. The full 85 MDth per day of capacity will become available when additional upgrades to the natural gas distribution system allow vaporization of an additional 16 MDth per day; this additional capacity is assumed to be available as a new resource on three years' notice beginning in the 2024/25 heating season.

Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to natural gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing natural gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta. PSE's pipeline capacity on NWP currently provides for 50 percent of our flowing natural gas supplies to be delivered from north of our service territory and the remaining 50 percent from south of our service territory.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages, operational challenges or high local demands. This separation cycle can last several years, but is often alleviated when additional pipeline infrastructure is constructed. PSE expects generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in transportation costs and forecasted demand increases. The long-term supply pricing scenarios used in this analysis were provided by Wood-Mackenzie, whose North American supply/demand model considers the non-synchronized cyclical nature of growth in production, demand and infrastructure development to forecast monthly pricing in the supply basins accessed by PSE pipeline capacity.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal, Clay Basin and Blanco. Alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TransCanada's Nova (TC-NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (TC-GTN) pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Natural gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. PSE meets average loads with a mix of long-term (more than two years) and short-term (two years or less) supply contracts. Long-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. PSE also contracts for seasonal baseload firm supply, typically for the winter months November through March. Near-term transactions supplement baseload transactions, particularly for the winter months. PSE estimates average load requirements for upcoming months and enters into month-long or multi-month transactions to balance load. Daily positions are balanced using storage from Jackson Prairie, Clay Basin, day-ahead purchases and off-system sales transactions; intra-day positions are balanced using Jackson Prairie. PSE monitors natural gas markets continuously to identify trends and opportunities to fine-tune our contracting, purchasing and storage strategies.

Existing Demand-side Resources

PSE has provided demand-side resources to our customers since 1993.[7] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[8] Through 1998, the programs primarily served residential and low-income customers; in 1999, they were expanded to include commercial and industrial customer facilities. The majority of natural gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

Figure 9-11 shows that energy efficiency measures installed through 2019 have saved a cumulative total of over 5.4 million Dth, which represents a reduction in CO_2 emissions of approximately 324,000 metric tons – more than half of this amount has been achieved since 2010. Savings per year have mostly ranged from 3 to 5 million therms, peaking at just over 6.3 million therms in 2013.

Energy savings targets and the programs to achieve those targets are established every two years. The 2018-2019 biennial program period concluded at the end of 2019. The current program cycle runs from January 1, 2020 through December 31, 2021 and has a two-year energy savings target of approximately 8 million therms. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group.

PSE spent over $17.5 million for natural gas conservation programs in 2019 (the most recent complete program year) compared to $3.2 million in 2005. Spending over that period increased more than 35 percent annually. The low cost of natural gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. PSE is collaborating with regional efforts to find creative ways to make delivery and marketing of natural gas efficiency programs more cost-effective, and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

Figure 9-11 summarizes energy savings and costs for 2018 through 2021.

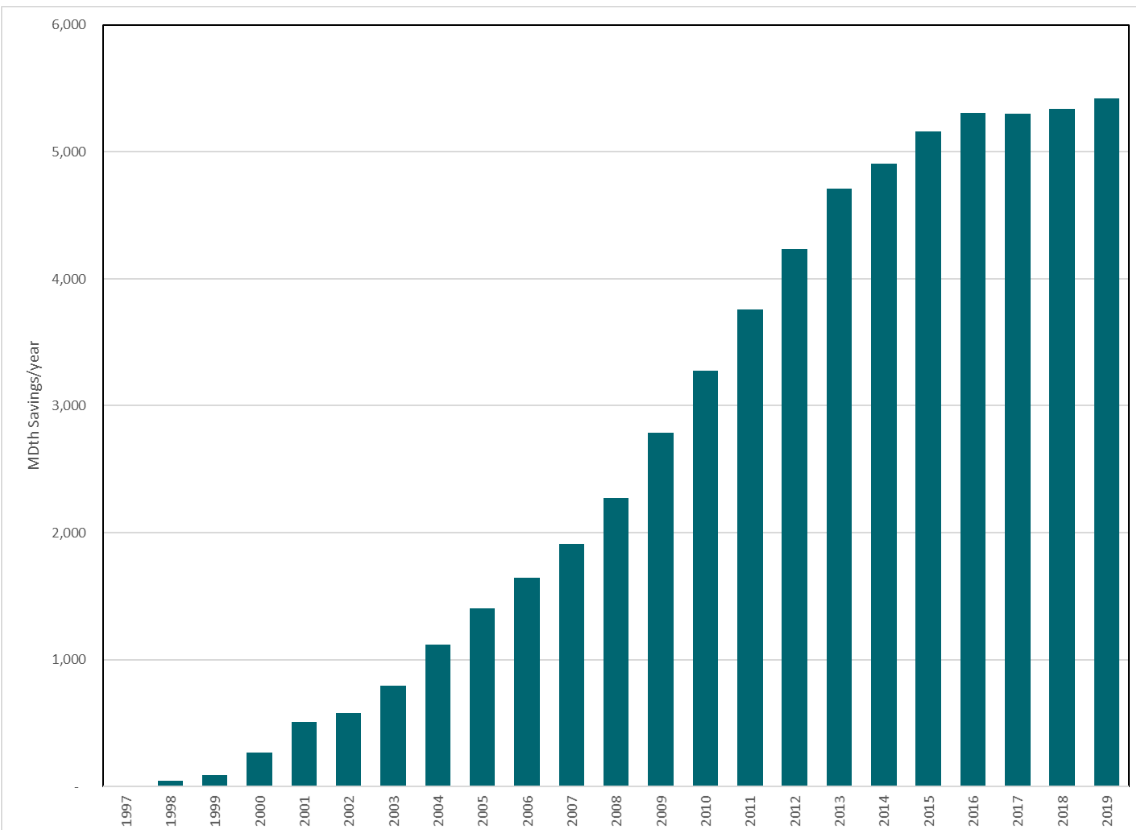
[7] / Demand-side resources, also called conservation, contribute to meeting resource need by reducing demand.

[8] / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 9-11: Natural Gas Sales Energy Efficiency Program Summary, 2018 – 2021
Total Savings and Costs

Program Year	Actual Savings (MDth)	Actual Cost ($ millions)	Target Savings (MDth)	Budget ($ millions)
2018	377.1	15.8	327	15.3
2019	322.8	17.7	314.7	15.9
2020-21			795.3	34.5

Figure 9-12: Cumulative Natural Gas Sales Energy Savings from DSR, 1997 – 2019



4. RESOURCE ALTERNATIVES

The natural gas sales resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

Transporting natural gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and natural gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analysis purposes. These combinations are discussed below and illustrated in Figure 9-13. Note that DSR is a separate alternative discussed later in this chapter.

The following acronyms are used in the descriptions below.

- AECO: the Alberta Energy Company trading hub, also known as Nova Inventory Transfer (NIT)
- LP-Air: liquid propane-air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP: Williams Northwest Pipeline, LLC pipeline
- TC-Foothills: TransCanada-Foothills BC (Zone 8) pipeline
- TC-GTN: TransCanada-Gas Transmission-Northwest pipeline
- TC-NGTL: TransCanada-NOVA Gas Transmission Ltd. pipeline
- Westcoast pipeline: Westcoast Energy Inc. pipeline

Combination # 1 & 1a – NWP Additions + Westcoast [9]

After November 2023, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Natural gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that might be available to be contracted to meet PSE needs from November 2022 to October 2025 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

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

Combination # 3 – Cross Cascades – NWP from AECO

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

[9] / *Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc*

Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

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

Combination # 5 – Plymouth LNG with Firm Delivery

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

Combination # 6 – LNG-related Distribution Upgrade

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

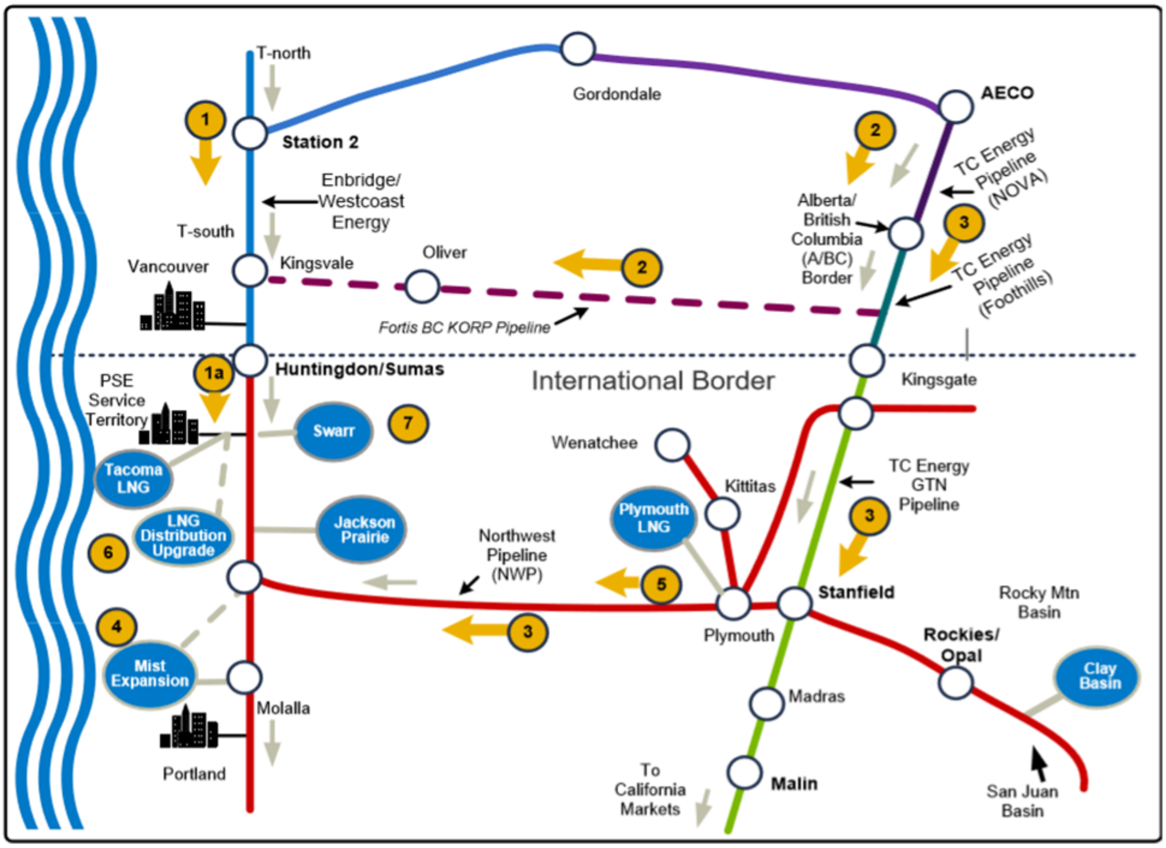
Combination # 7 – Swarr LP-Air Upgrade

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

NOTE: Combinations 2, and 4 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the natural gas sales resource alternatives is depicted in Figure 9-13 below.

Figure 9-13: PSE Gas Transportation Map Showing Supply Alternatives



Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 9-14 below.

Figure 9-14: Direct-connect Pipeline Alternatives Analyzed

Direct-connect Pipeline Alternatives	Description
NWP - Sumas to PSE city gate *(from Combinations 1 & 2)*	Expansions considered in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2025.
NWP – Portland area to PSE city gate *(from Combination 4)*	Expansion considered in conjunction with storage expansion alternatives (Mist storage capacity) assumed available after November 2025.

Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying natural gas at one point and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast (Westcoast Energy's B.C. pipeline), which allows PSE to purchase natural gas at Station 2 rather than Sumas and take advantage of greater supply diversity availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase natural gas directly from suppliers at the very liquid AECO/NIT trading hub and transport it to the existing interconnect with NWP and its proposed Cross-Cascades upgrade on a firm basis. FortisBC and Westcoast have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO/NIT supplies.

Figure 9-15: Upstream Pipeline Alternatives Analyzed

Upstream Pipeline Alternatives	Description
Increase Westcoast Capacity (Station 2 to PSE) *(from Combination 1)*	Acquisition of new Westcoast capacity is considered to increase access to natural gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Madras or Stanfield) *(from Combination 3)*	Acquisition of new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT natural gas to Madras for connection to the TC Cross-Cascades project and a separate northbound upgrade of NWP or to Stanfield for delivery to PSE city gate via the proposed NWP Cross Cascades upgrade. Assumed availability no earlier than November 2025.
Kingsvale-Oliver Reinforcement Project (KORP) *(from Combination 2)*	Expansion of the existing FortisBC Southern Crossing pipeline across southern B.C., enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of new capacity on the TC-NGTL and TC-Foothills pipelines. Available no earlier than November 2025.

The KORP alternative includes PSE participation in an expansion of the existing FortisBC pipeline across southern British Columbia, which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-NGTL and TC-Foothills pipelines, would improve access to the AECO/NIT trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.

Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project, and PSE also contracts for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run. For this IRP, the company considered the following storage alternatives.

Mist Expansion

NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., would consider a potential expansion project to be completed in 2025. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2025, once the Mist upgrade is built. This would also require expansion of NWP's interstate system to PSE's city gate. PSE may be able to acquire discounted winter-only capacity from Mist to PSE's city gate if NWP expands from Sumas to Portland for other shippers, making the use of Mist storage cost-effective. Since this resource is dependent on other parties willingness to contract for an expansion, this resource availability is not in PSE's control.

LNG-related Distribution System Upgrade

This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because natural gas otherwise destined for the Tacoma system is displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

Swarr

The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated while PSE is in the preliminary stages of designing the upgrade to Swarr's environmental, safety and reliability systems and increasing production capacity to 30,000 Dth per day. The facility is assumed to be available on three years' notice for the 2024-25 heating season or beyond.

Figure 9-16: Storage Alternatives Analyzed

Storage Alternatives	Description
Expansion of Mist Storage Facility *(Combination 5)*	Considers the acquisition of expanded Mist storage capacity, based on estimated cost and operational characteristics. Assumes a 20-day supply at full deliverability of up to 100 MDth/day beginning the 2025-26 heating season. (Requires incremental pipeline capacity.)
Distribution upgrade allowing greater utilization of Tacoma LNG *(Combination 7)*	Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG peak-shaving beginning the 2024-25 heating season.
Swarr LP-Air Facility Upgrade *(Combination 8)*	Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2024-25 heating season.
Plymouth LNG contract with NWP firm transportation *(Combination 6)*	Considers acquisition of an existing Plymouth LNG contract and associated firm transportation for 15 MDth/day, beginning April 2023.

Natural Gas Supply Alternatives

Conventional Natural Gas

As described earlier, natural gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate natural gas supplies will be available to support pipeline expansion from northern British Columbia via Westcoast or TC-NGTL,TC-Foothills and TC-GTN or from the Rockies basin via NWP.

Renewable Natural Gas (RNG)

Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

The Washington State legislature passed HB 1257, which became effective in July, 2019, PSE is working with the WUTC and other stakeholders to develop guidelines to implement HB 1257. However, recognizing the competitive nature of the existing RNG market, PSE concluded that there would be an advantage to be a first-mover. To that end, PSE conducted a RFP to determine availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in the first half of 2021. RNG supply not utilized in PSE’s voluntary RNG program(s) will be incorporated into PSE’s supply portfolio, displacing natural gas purchases as provided for in HB 1257.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE’s system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. Because of RNG’s significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for hypothetical analysis. The benefits of RNG are measured primarily in terms of carbon reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Due to the very competitive RNG development market PSE is not prepared to analyze specific RNG projects in a public environment. Individual projects will be analyzed and documented as opportunities arise and there is further clarity on the guidelines for incorporation of RNG into PSE’s supply portfolio.

Demand-side Resource Alternatives

To develop demand-side alternatives for use in the portfolio analysis, PSE first conducts a conservation potential assessment. This study reviews existing and projected building stock and end-use technology saturations to estimate the savings possible through installation of more efficient commercially available technologies. The broadest measure of savings from making these installations (or replacing old technology) is called the technical potential. This represents the total unconstrained savings that could be achieved without considering economic (cost-effectiveness) or market constraints.

The next level of savings is called *achievable* technical potential. This step reduces the unconstrained savings to levels considered achievable when accounting for market barriers. To be consistent with electric measures, the achievability factors for all natural gas retrofit measures was assumed to be 85 percent. Similar to electric measures, all natural gas measures receive a 10 percent conservation credit stemming from the Power Act of 1980. The measures are then organized into a conservation supply curve, from lowest to highest levelized cost.

Next, individual measures on the supply curve are grouped into cost segments called “bundles.” For example, all measures that have a levelized cost of between $2.2 per Dth and $3.0 per Dth may be grouped into a bundle and labeled “Bundle 2.” In the 2019 IRP Process the lower cost bundles were further divided into smaller segments to ensure that some measures included in a larger, marginal bundle don’t get missed.[10] The Codes and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that have been passed but that take effect at a future date. This bundle is always selected in the portfolio, where it effectively represents a reduction in the load forecast.

Figure 9-17 shows the price bundles and corresponding savings volumes in achievable technical potential that were developed for this IRP. The bundles are shown in dollars per therm and the savings for each bundles shown in 2031 and 2041 are in thousand dekatherms per year (MDth/year). These savings were developed using PSE’s weighted average cost of capital (WACC) as the discount rate.

PSE currently seeks to acquire as much cost-effective natural gas demand-side resources as quickly as possible. The acquisition rate or “ramp rate” of natural gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures assume a 10-year ramp rate; in other words, they are acquired during the

[10] / *The $4.5 to $5.5 per Dth and the $5.5 to $7.0 per Dth bundles were divided into four bundles: $4.5 to $5.0, $5.0 to $5.5, $5.5 to $6.2 and $6.2 to $7.0. The narrower ranges allow for a more refined selection of conservation on the supply curve.*

first 10 years of the study period. Acquiring these measures sooner rather than later has been tested in prior IRPs and has consistently been found to reduce portfolio costs.

Figure 9-17: DSR Cost Bundles and Savings Volumes (MDth/year)

	WACC	
	2031	2041
Codes & Standards	725	1,446
Bundle 1: <$0.22	2,393	4,356
Bundle 2: $0.22 to$0.30	2,673	4,672
Bundle 3: $0.30 to $0.45	3,902	7,764
Bundle 4: $0.45 to $0.50	3,932	7,802
Bundle 5: $0.50 to $0.55	3,988	7,898
Bundle 6: $0.55 to $0.62	4,008	7,936
Bundle 7: $0.62 to $0.70	5,112	9,105
Bundle 8: $0.70 to $0.85	5,419	10,093
Bundle 9: $0.85 to $0.95	5,586	10,286
Bundle 10: $0.95 to $1.20	5,812	11,373
Bundle 11: $1.20 to $1.50	7,621	13,341
Bundle 12: >$1.50	10,421	17,051

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment*, for more detail on the measures, assumptions and methodology used to develop DSR potentials.*

In the final step, the gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 9-18 illustrates the methodology described above.

Figure 9-18: General Methodology for Assessing Demand-side Resource Potential

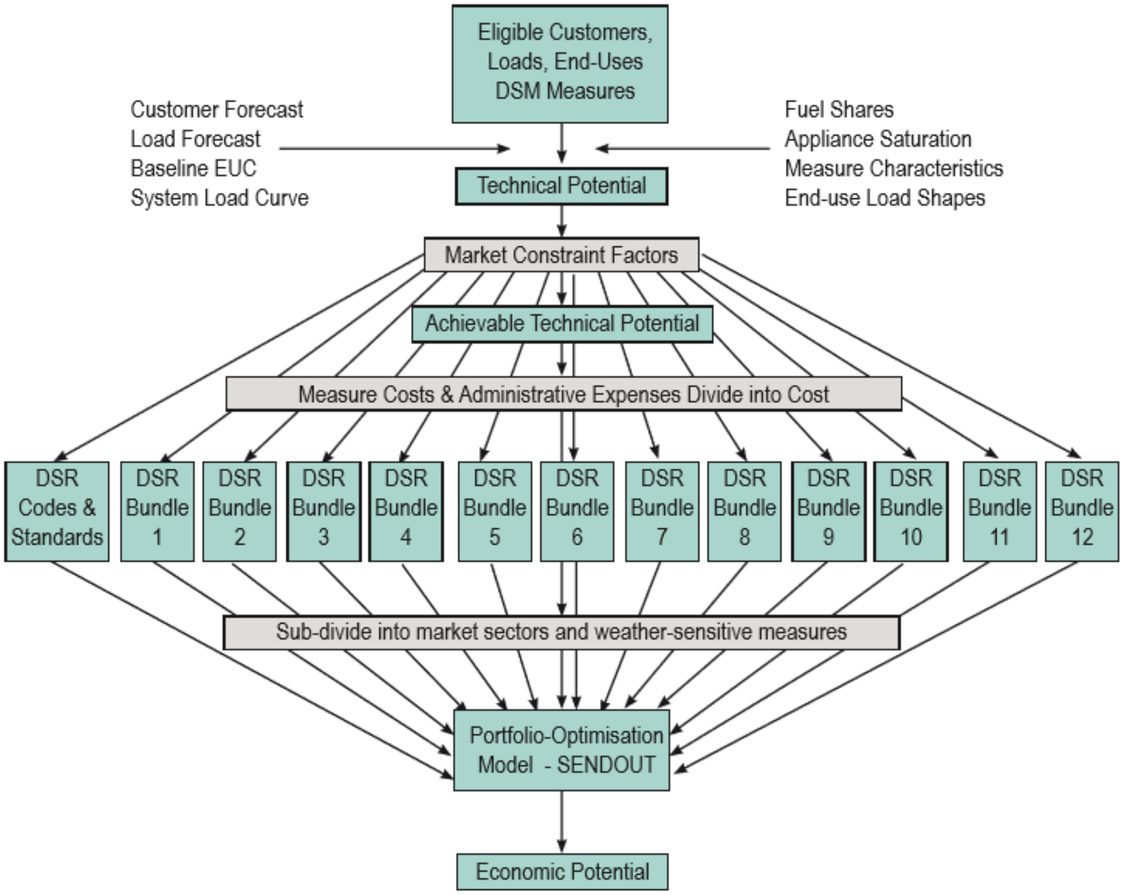


Figure 9-19 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side natural gas resource for a particular scenario.

Figure 9-19: Demand-side Resources – Achievable Technical Potential Bundles

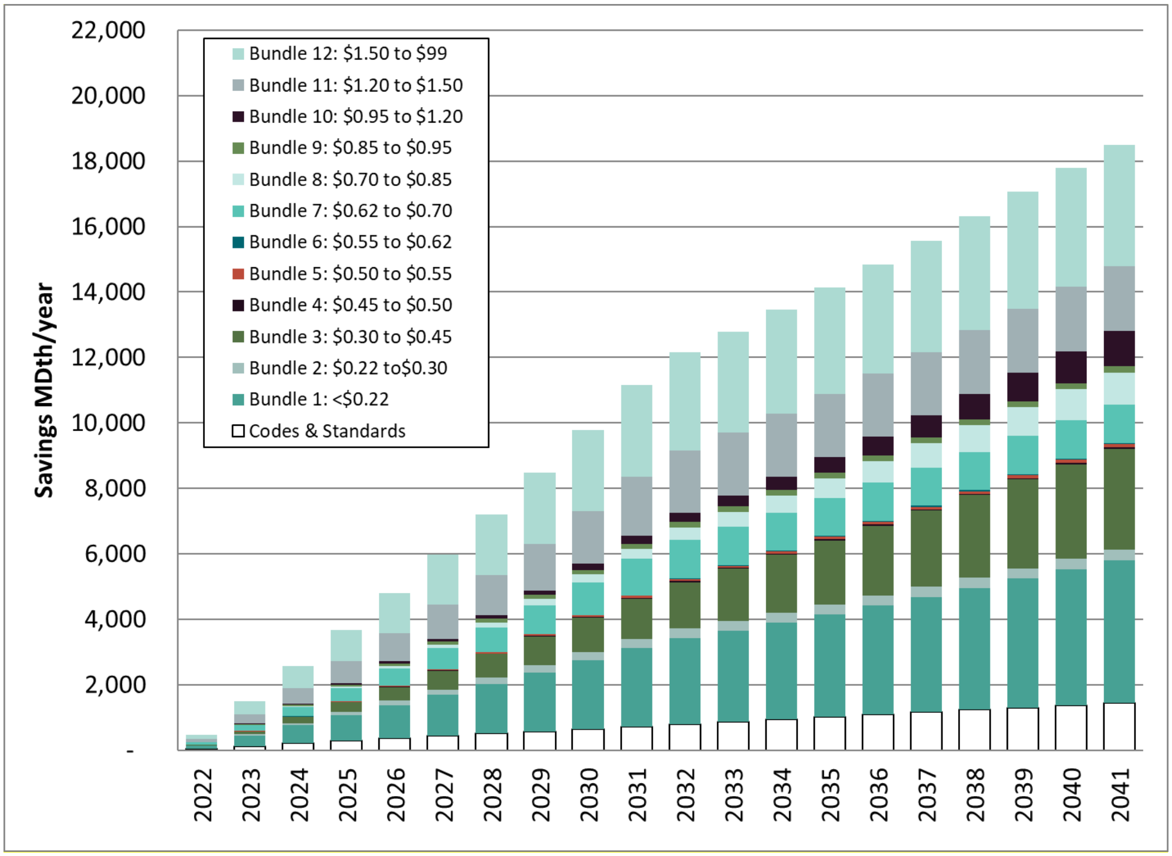
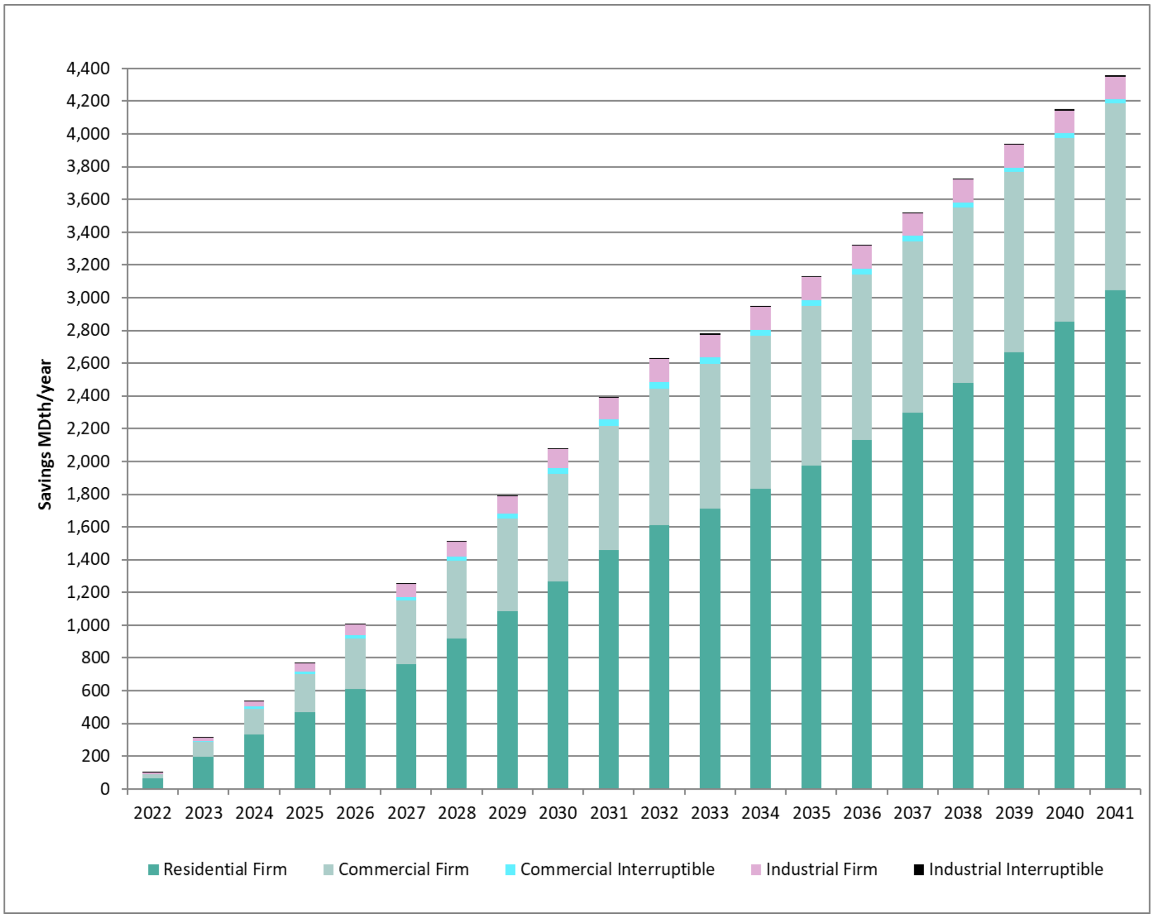


Figure 9-20 shows savings subdivided by customer class This input format is used in the GPM for all bundles in all the IRP scenarios.

Figure 9-20: Savings Formatted for Portfolio Model Input by Customer Class



5. NATURAL GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

1. **In the Mid Scenario, the natural gas sales portfolio is short resources beginning in the winter of 2031/32 and each year after that.** The High Scenario also has a deficit starting in 2026/27 and a growing resource shortfall throughout the study, while in the Low Scenario the portfolio is short beginning 2040/41.
2. **Resource needs are primarily met with demand-side resources in the Mid and Low Scenarios.** The gas portfolio model adds the same amount of demand-side resources in both scenarios. In both cases, it added slightly more DSR than is needed to meet the resource need due to the high total gas costs resulting from the SCGHG and upstream emissions adders.
3. **The High Scenario has a higher need and is short 165 MDth/day on the peak day in 2041.** The gas portfolio model adds the same amount of DSR as in the Mid and Low Scenarios and chooses Plymouth LNG, Swarr and pipeline capacity expansion on Northwest and Westcoast pipelines sourcing gas from Station 2 to meet resource need.
4. **Cost-effective DSR is higher in the 2021 IRP.** The cost-effective bundles in all sectors are higher on the supply curve compared to the 2017 IRP. The increase is due to a significant increase in the quantity of new DSR savings in the supply curve and substantially higher gas costs, which more than offset any reductions due to four more years of conservation implemented since the 2017 IRP, and lower F2020 demand forecast. The result is an overall increase in the cost-effective DSR
5. **Cost-effective DSR is the same in all three scenarios.** The total amount of cost-effective DSR chosen in the Mid, Low and High Scenarios did not change. The primary driving factor appears to be the high total gas cost, which the DSR helps to offset, thereby reducing portfolio cost.
6. **The Swarr LP-Air upgrade project is cost effective in the High Scenario** and is expected to provide 30 MDth per day of peaking capacity effective November 2037.
7. **The Tacoma area distribution system upgrade project was not needed.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.

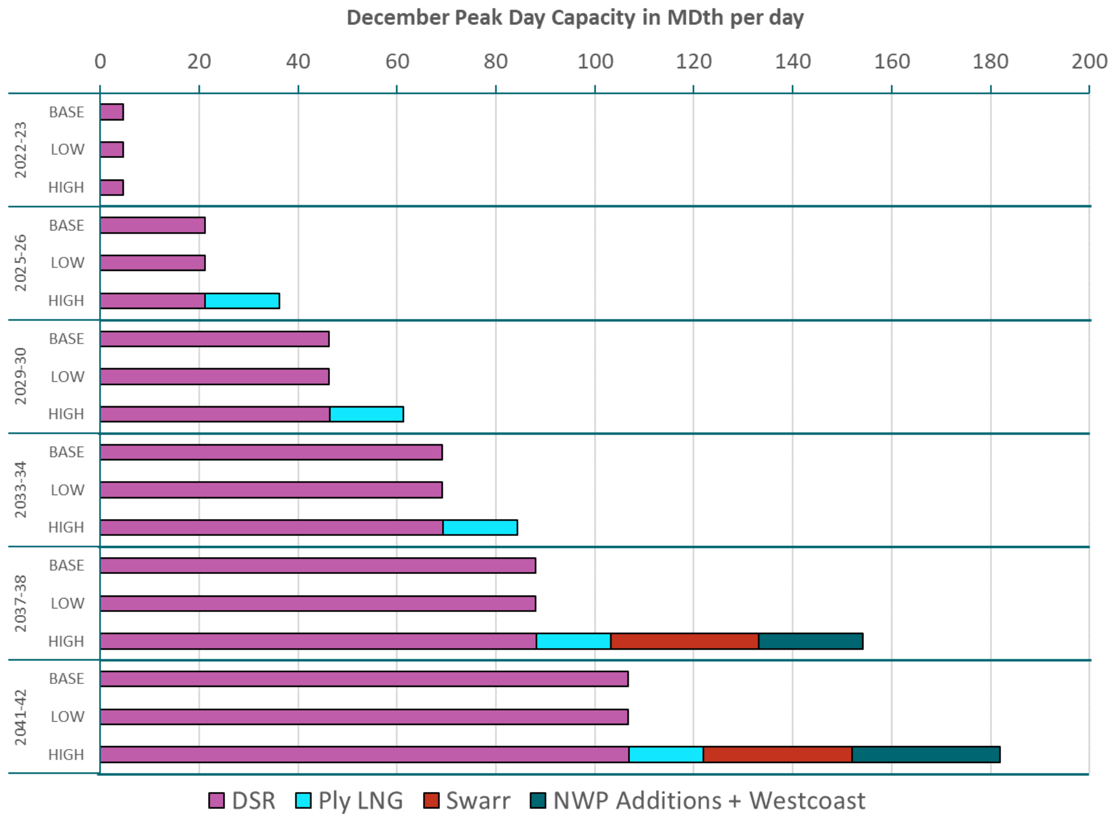
8. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in only the High scenario.** The GPM indicates this pipeline capacity is cost effective starting in 2034/35.
9. **Neither the Cross Cascades TC new pipeline or the Fortis BC KORP project are selected in any scenario.** The resource need is low enough to be satisfied by DSR and thus did not warrant a need for these resources. Additionally, these options present other constraints, such as requiring significant demand by third parties or reliance on other projects and timing outside the control of PSE to become viable.
10. **The Mist Storage project was not selected in any of the Scenarios.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.
11. **The carbon cost assumption was significantly higher in the 2021 IRP compared to the 2017 IRP, and this impacted resource choices.** The levelized cost of carbon adders, which included SCGHG and upstream emissions, was more than double the levelized natural gas commodity price in all three scenarios. This high cost resulted greater volumes of demand-side resources being selected in all three scenarios. The high total gas cost drove the selection of cost-effective DSR in all three scenarios.

Natural Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, natural gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by natural gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature; however, the absolute level of efficiency programs is also affected by the new supply curve and load growth assumptions. Also, the timing of pipeline additions was limited to five-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the three scenarios are illustrated in Figure 9-21 for several winter periods. Combination #1 (NWP plus Westcoast), Combination #5 (Plymouth LNG peaker) and Combination #7 (Swarr LP Plant) are chosen only in High Scenario. The Low and Mid Scenarios both chose only DSR.

Figure 9-21: Natural Gas Resource Additions in 2022/23, 2025/26, 2029/30, 2033/34 and 2041/42 (Peak Capacity – MDth/day)



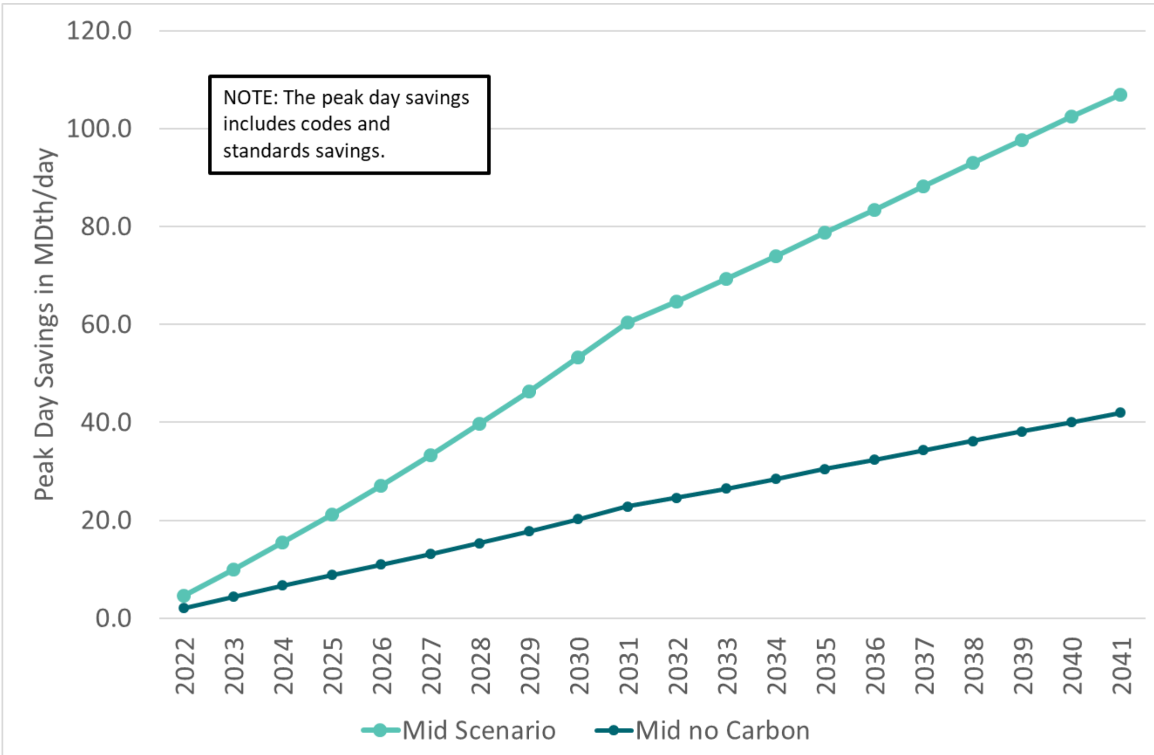
Demand-side Resource Additions

Two categories of demand-side resources are input into the GPM: codes and standards and program measures. Codes and standards is a no-cost bundle that becomes a must-take resource; it essentially functions as a decrement to natural gas demand. Program measures are input as separate cost bundles along the demand-side resource supply curve. The bundles are tested from lowest to highest cost along the supply curve until the system cost is minimized. The incremental bundle that raises the portfolio cost is considered the inflexion point, and the prior cost bundle is determined to be the cost-effective level of demand-side resources.

Carbon costs do impact the amount of cost-effective DSR. Compared to the 2017 IRP, the 2021 IRP carbon costs in the Mid Scenario are significantly higher relative to natural gas prices, which is a function of both declining natural gas prices and higher carbon cost assumptions resulting from carbon legislation passed in the state of Washington in 2019. The carbon legislation requires the inclusion of SCGHG and upstream related carbon emissions. Including these two adders in the price of natural gas results in a total gas cost that is over three times the cost of the natural gas itself. This total gas cost is what is used to make capacity expansion decisions in the GPM, and in these conditions, DSR is preferred in all scenarios since it is a resource that directly offsets the high total gas cost and helps to minimize the portfolio cost.

The sensitivity of DSR to carbon prices is illustrated in Figure 9-22. In the Mid Scenario, when including the carbon adders, cost-effective DSR is 107 MDth per day by 2041/42. This amount is actually more than the resource need in 2041/42 of 88 MDth per day, meaning DSR is being over built by about 19 MDth per day. When the Mid Scenario is run with no carbon adders, using only the natural gas cost, the cost-effective DSR drops to 42 MDth per day. In terms of natural gas supply planning, 42 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the IRP Mid Scenario increases conservation. The carbon adders more than double the cost-effective DSR over the 20-year period.

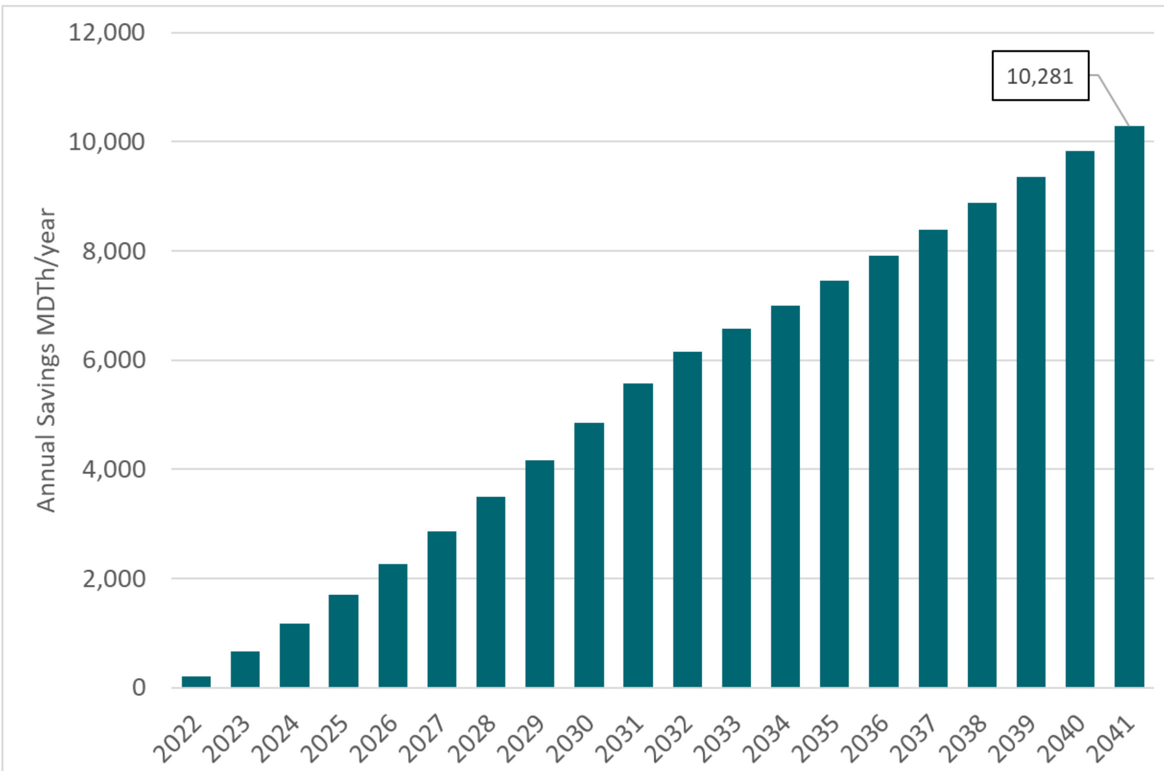
Figure 9-22: Sensitivity of Carbon to Cost-effective Natural Gas Energy Efficiency Savings in the Mid Scenario



DSR is not very sensitive to high avoided costs in the natural gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this resource plan did not vary by scenario.

Energy savings for all three scenarios are shown in Figure 9-23.

Figure 9-23: Cost-Effective Natural Gas Efficiency, Annual Energy Savings for Mid/Low/High Scenario



The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 9-24 and 9-25, below.

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more detail on this analysis.*

Figure 9-24: Natural Gas Sales Cost-effective DSR Bundles by Class and Scenario

Cost-effective Bundles	Mid	Low	High
Residential Firm	9	9	9
Commercial Firm	9	9	9
Commercial Interruptible	6	6	6
Industrial Firm	9	9	9
Industrial Interruptible	9	9	9

Figure 9-25: Natural Gas Sales Cost-effective Annual Savings by Class and Scenario

Savings (MDth/year)	Mid	Low	High
Residential Firm	7,984	7,984	7,984
Commercial Firm	2,093	2,093	2,093
Commercial Interruptible	39	39	39
Industrial Firm	156	156	156
Industrial Interruptible	8	8	8
Total (MDth per year)	**10,281**	**10,281**	**10,281**

Overall, the economic potential of DSR in the 2021 IRP is higher than in the 2017 natural gas sales Mid Scenario, and higher-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 9-26).

The upward shift in overall savings is due to two factors:

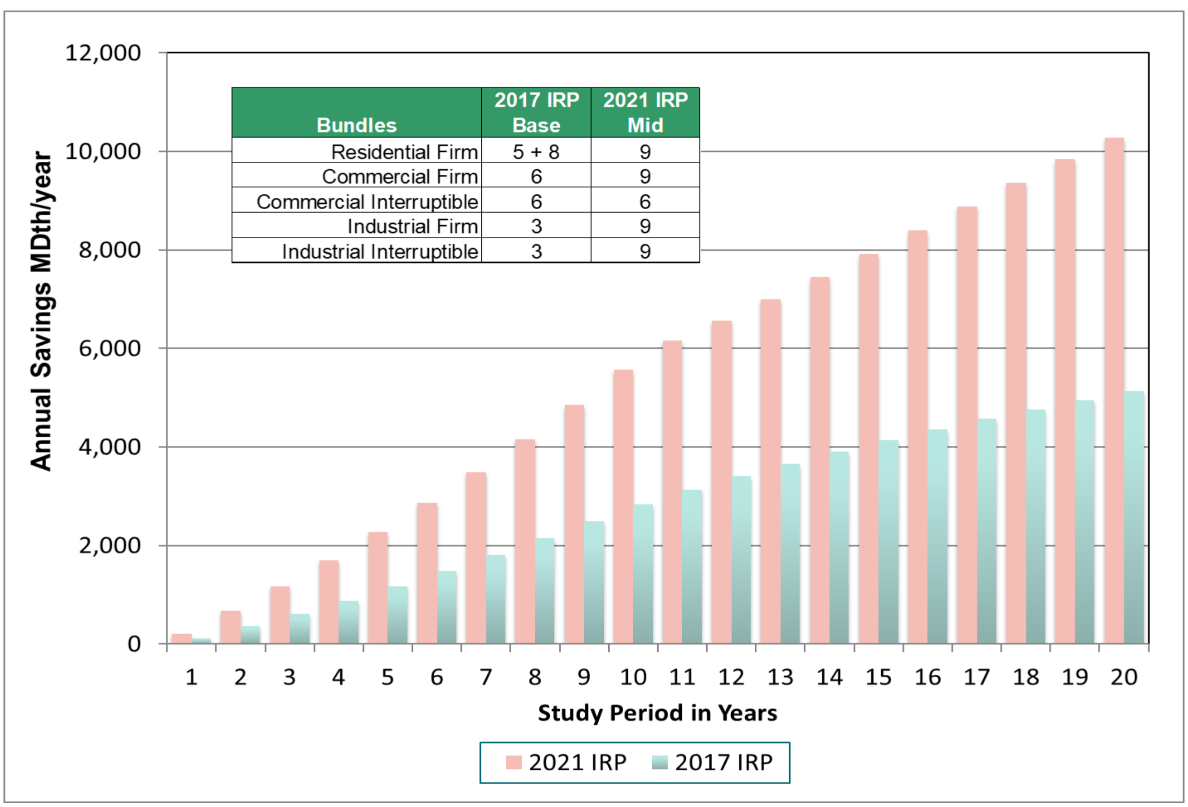
- Higher total natural gas costs that include carbon adders for both end-use and upstream emissions.
- Updates to the measure costs and savings assumptions such that the achievable technical potential was higher and some measures shifted to lower cost effective bundles in the 2021 IRP.

It is notable that the two factors above were a much stronger influence than the following factors, which would have reduced the available DSR under normal circumstances:

- A lower demand forecast in the 2021 IRP than the 2017 IRP
- Four additional years of program implementation will elapse between the 2017 IRP and 2022 when the 2021 IRP study starts, which means that four years of conservation implementation will have reduced the available DSR from the supply curve

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more information on the development of DSR bundles.*

Figure 9-26: Cost-effective Natural Gas Energy Efficiency Savings, 2017 IRP vs 2021 IRP



Bundles	2017 IRP Base	2021 IRP Mid
Residential Firm	5 + 8	9
Commercial Firm	6	9
Commercial Interruptible	6	6
Industrial Firm	3	9
Industrial Interruptible	3	9

Figure 9-27 compares PSE's energy efficiency accomplishments, current targets and the new range of natural gas efficiency potentials determined by the 2021 IRP. In the short term, the 2021 IRP indicates an economic potential savings of 1,192 MDth for the 2022-2023 period for all three scenarios.[11] These two-year program accomplishments and projections show an upward trend, with the 2021 IRP results indicating that the trend is accelerating due to higher avoided costs and more cost-effective saving measures in the supply curve.

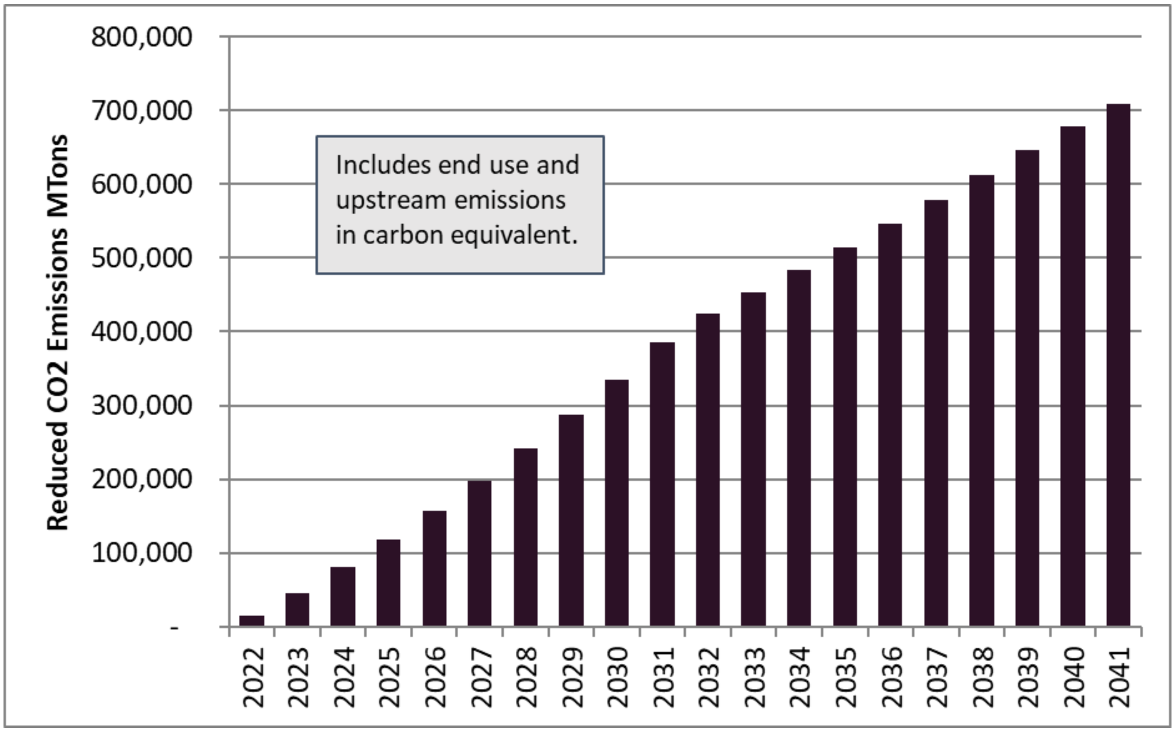
Figure 9-27: Short-term Comparison of Natural Gas Energy Efficiency in MDth

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

Figure 9-28 shows the impact on CO_2 emissions from energy efficiency measures selected in the Mid, Low and High Scenarios.

[11] / *These savings are based on a no-intra year ramping, which is used to set conservation program targets.*

Figure 9-28: CO_2 Emissions Reduction from Energy Efficiency in Mid, Low and High



Scenarios

Peaking Resource Additions

The Swarr LP-Air upgrade project and the Plymouth LNG peaker contract were selected as least cost in only the High Scenario due to the higher resource need created by the higher demand forecast in this scenario.

Pipeline Additions

Pipeline expansion alternatives were made available as early as the 2025/26 winter season, a bit later than the other non-pipeline alternatives were made available. The pipelines were not available earlier due to the lead time needed to develop these resources, but this was not a constraint to the portfolio model. The pipelines were chosen only in the High Scenario, which had a higher resource need due to higher demand. In the High Scenario, the GPM selected 30MDth a day of NWP with Westcoast from Station 2 in the out year.

The other pipeline additions offered in Combinations #2 (KORP) and #3 (Cross Cascades) were not economical in any of the scenarios.

Observation

All of the selected resources (listed here in general order of least cost) – DSR, Plymouth LNG Peaker, Swarr LP-Air, and Northwest + Westcoast pipeline expansion – are within PSE's control (with the exception of the pipeline expansion). The timing of individual projects can be fine-tuned by PSE in response to load growth changes, and none of these projects rely on participation by another contracting party in order to be feasibly implemented.

Complete Picture: Natural Gas Sales Mid Scenario

A complete picture of the Mid Scenario optimal resource portfolio for natural gas sales is presented in graphical and table format in Figures 9-29 and 9-30, respectively.

> > > See Appendix I, Natural Gas Analysis Results, *for additional scenario results.*

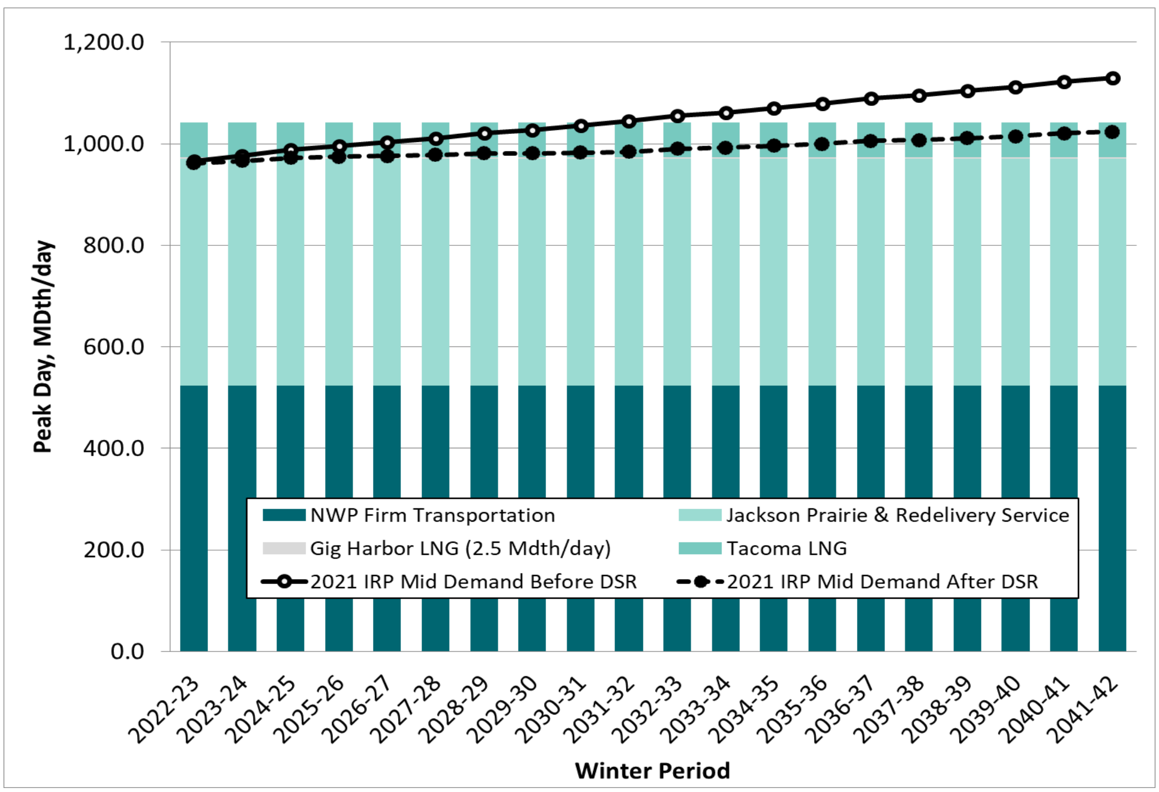


Figure 9-29: Natural Gas Sales Mid Scenario Resource Portfolio

Figure 9-30: Natural Gas Sales Mid Scenario Resource Portfolio (Table)

		Winter Period		
Resource Alternative	**Option**	**2025/26**	**2030/31**	**2041/42**
NWP Additions + Westcoast	#1	-	-	-
KORP	#2	-	-	-
NWP from AECO	#3	-	-	-
Mist Storage	#4	-	-	-
Ply LNG	#5	-	-	-
LNG Tacoma Distr	#6	-	-	-
Swarr	#7	-	-	-
DSR	DSR	21	53	107
Total in MDth/day		**21**	**53**	**107**

Average Annual Portfolio Cost Comparisons

Figure 9-31 should be read with the awareness that its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include forecast rate-base costs related to Jackson Prairie storage, the Tacoma LNG Project and Swarr LP-Air, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 9-31: Average Portfolio Cost of Natural Gas for Gas Sales Scenarios

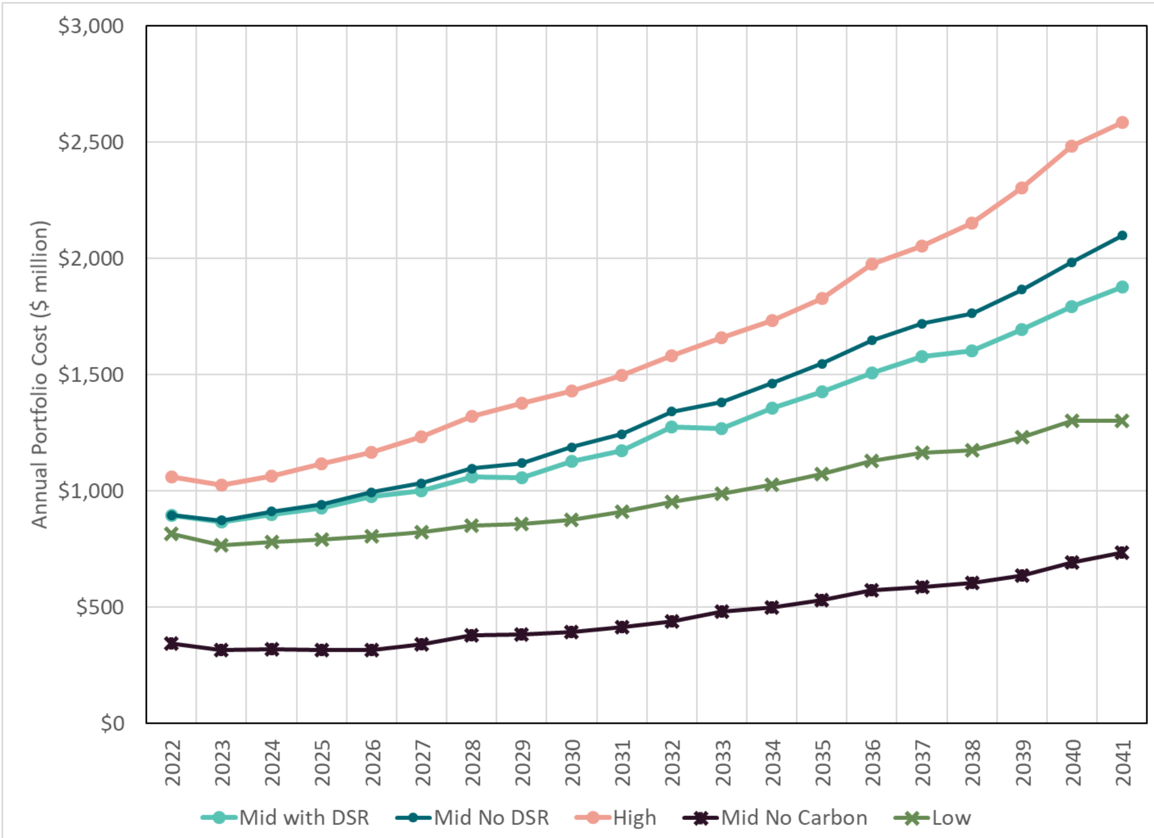


Figure 9-31 shows that average optimized portfolio costs are heavily impacted by natural gas prices and CO_2 cost assumptions included in each scenario.

- The assumed total cost of natural gas supply has the greatest influence on portfolio costs. Natural gas costs were high and relatively close in all three scenarios, and the resulting average portfolio costs were also high and fairly close to each other in comparison to the Mid No Carbon case shown above.
- DSR produces significant savings, as shown by the Mid Scenario with DSR versus the Mid No DSR lines. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Sensitivity Analyses

Five sensitivities were modeled in the natural gas sales analysis for this IRP. Sensitivities start with the Mid Scenario portfolio and change one resource, regulation or condition. This allows PSE to evaluate the impact of a single change on the portfolio.

A. AR5 Upstream Emissions

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

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

This sensitivity results in higher emission rates for both the Canadian and U.S. sourced natural gas. Figure 9-32 shows the emission rates for AR4 and AR5.

Figure 9-32: Upstream Emissions for AR4 and AR5

Sensitivity A	(Canadian Supply) gCO2e/MMBtu	(Domestic Supply) gCO2e/MMBtu
AR4	10,803	12,121
AR5	11,564	13,180

AR5 slightly increased total gas costs (see Figure 9-33), but made no change to the resource mix in the Mid Scenario. The GPM selected the same level of DSR as in the Mid Scenario, but portfolio costs were higher due to the increased upstream emissions adder (see Figure 9-34).

Figure 9-33: Upstream Emission Costs in $/MMBtu AR4 vs. AR5

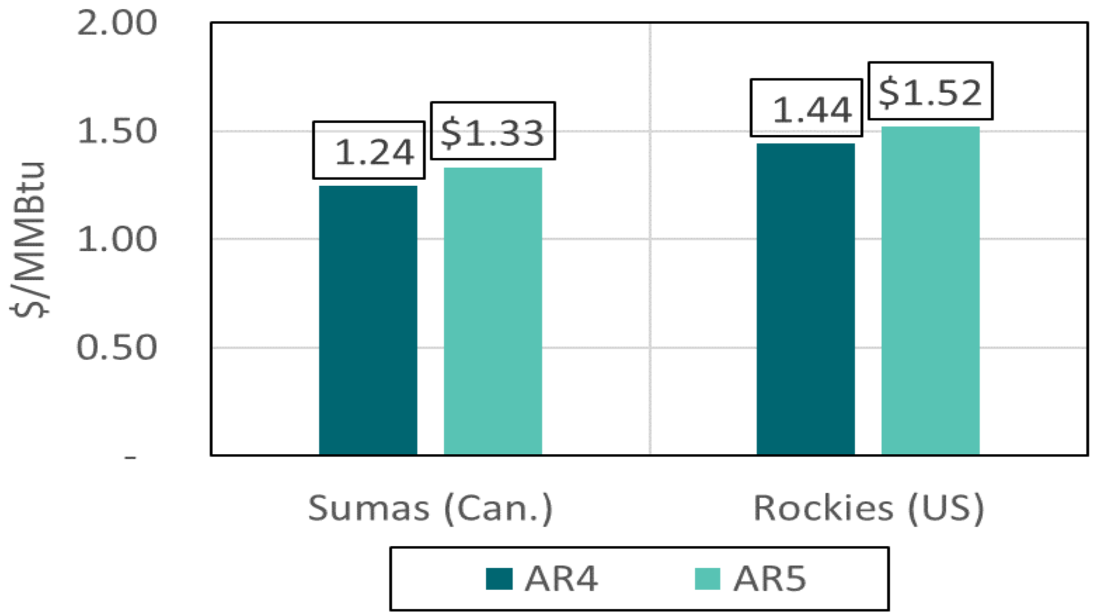


Figure 9-34: NPV for AR5 Portfolio vs. AR4 Portfolio

Sensitivity A	Portfolio NPV, $ billion
Mid Scenario with AR4	$12.660
Mid Scenario with AR5	$12.758

B. 6-Year Conservation Ramp Rate

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

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

The GPM selected the same bundles as in the Mid Scenario, however, the DSR was front-loaded due to the faster ramp rate on the discretionary DSR measures. The overall savings in the 20-year study period did not change (see Figure 9-35), but since the DSR was captured earlier, the NPV of the portfolio was lower (see Figure 9-36)

Figure 9-35: Savings from 6-year Ramp Rate vs. 10-year Ramp Rate

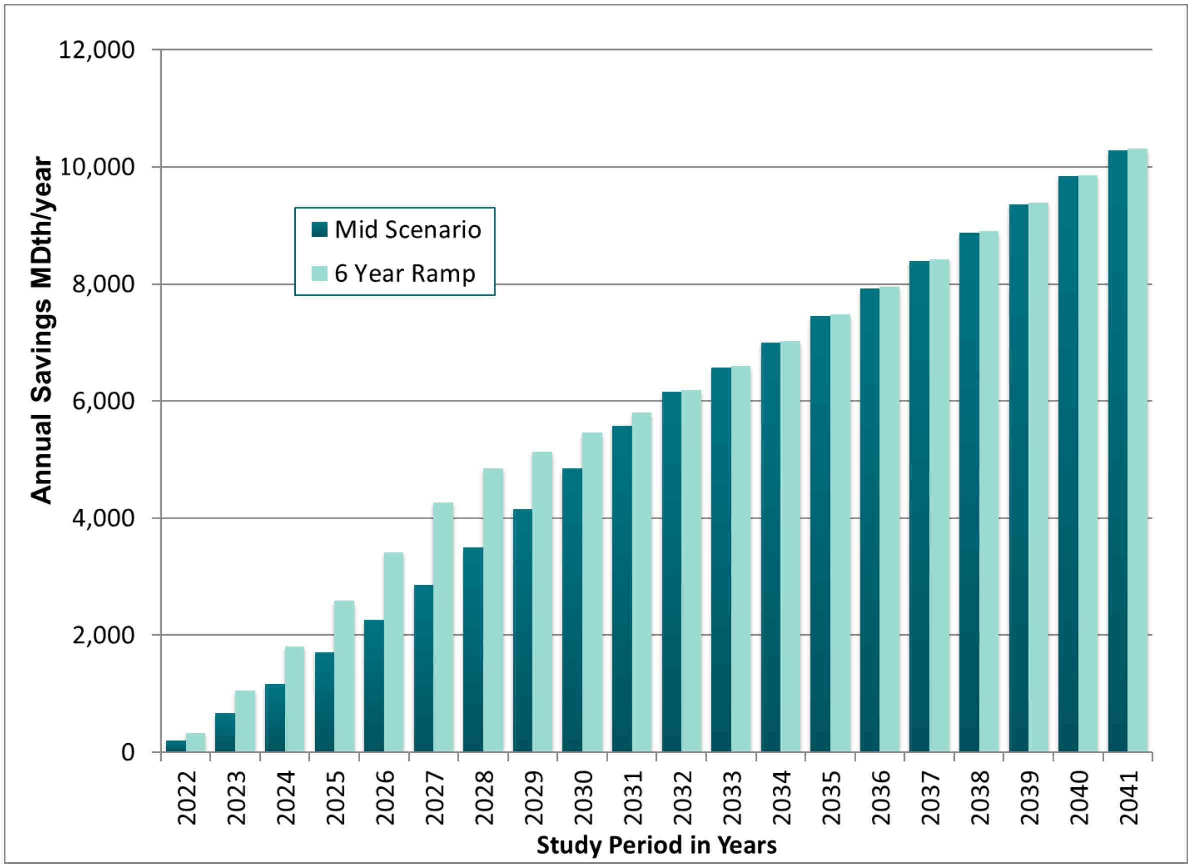


Figure 9-36: NPV for 6-year Ramp Rate vs. 10-year Ramp Rate

Sensitivity B	Portfolio NPV, $ billion
Mid Scenario with 10-year Ramp Rate	$12.660
Mid Scenario with 6-year Ramp Rate	$12.623

C. Social Discount Rate for DSR

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

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

A social discount rate that was lower than PSE's assigned WACC was applied to the demand-side resource alternative in this sensitivity analysis to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as the 2.5 percent nominal discount rate referenced in CETA SCGHG legislation. The 2.5 percent discount rate shifted measures to lower cost points on the conservation supply curve. Since the social discount rate caused the measures to shift to lower cost bundles, the net effect was that cost-effective savings were slightly higher using the social discount rate.

See Figures 9-37 and 9-38 for the DSR savings comparison.

Figure 9-37: Savings by Bundle, 6.8% IRP Mid Scenario Discount Rate vs.

2.5% Social Discount Rate

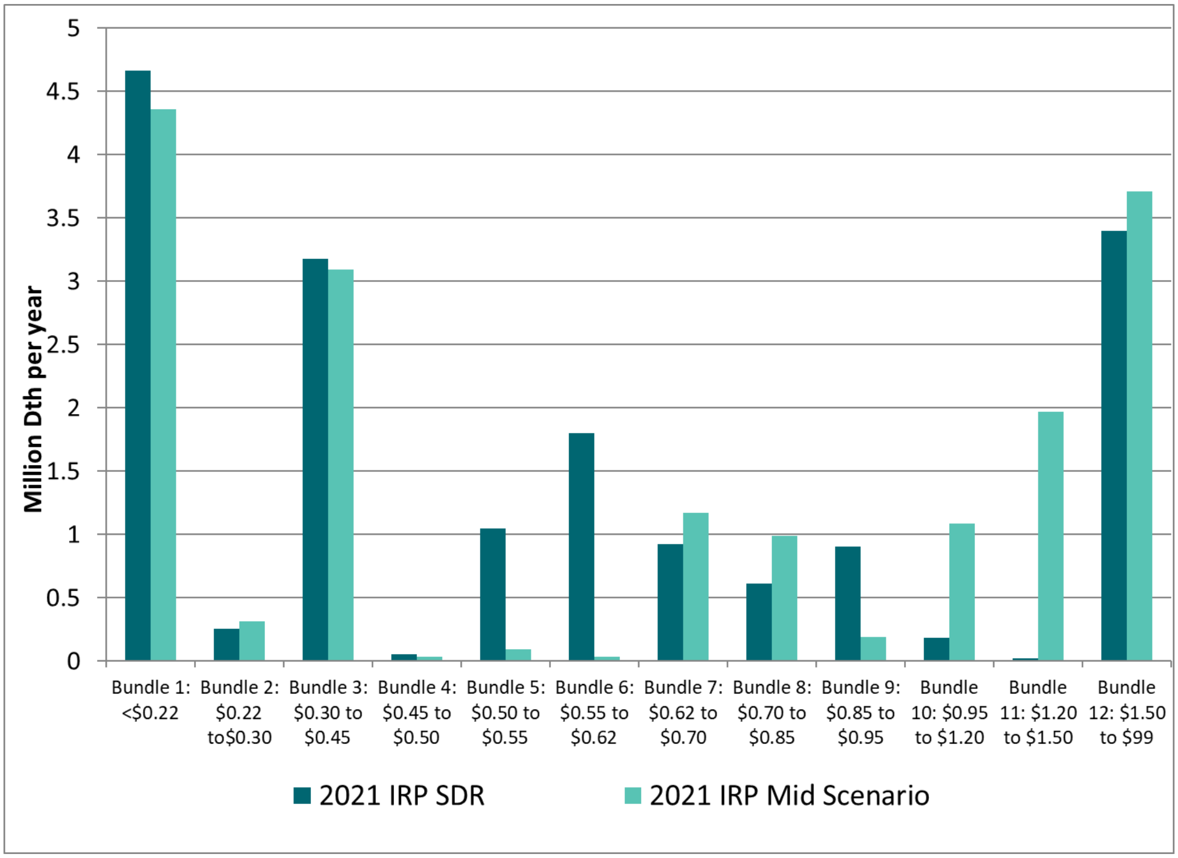


Figure 9-38 Cost-effective Level of Natural Gas DSR,
6.8% Mid Scenario Discount Rate vs.2.5% Social Discount Rate

Sensitivity C Savings (MDth/year)	6.8% Mid Scenario	2.5% Social Discount Rate
Residential Firm	7,984	9,613
Commercial Firm	2,093	2,107
Commercial Interruptible	39	39
Industrial Firm	156	156
Industrial Interruptible	8	8
Total (MDth per year)	10,281	11,923

D. Fuel Switching, Gas to Electric

This sensitivity models accelerated adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity 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 accelerated electrification rate for 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 2021 IRP Mid 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.