GENERIC RESOURCE ALTERNATIVES

APPENDIX D

PUGET SOUND ENERGY

Contents

1. Introduction

Generic resources are theoretical electric generating resources used to develop Puget Sound Energy's (PSE) long-term capacity expansion planning model. As electric generating and storage technologies evolve, assumptions change. We update generic resource assumptions, including cost, operating, and availability, to align with the most recent and industry-reliable data for each Integrated Resource Plan (IRP). This appendix is a catalog of the supply-side — before the meter — generic resource alternatives we considered in the 2023 Electric Progress Report (2023 Electric Report).

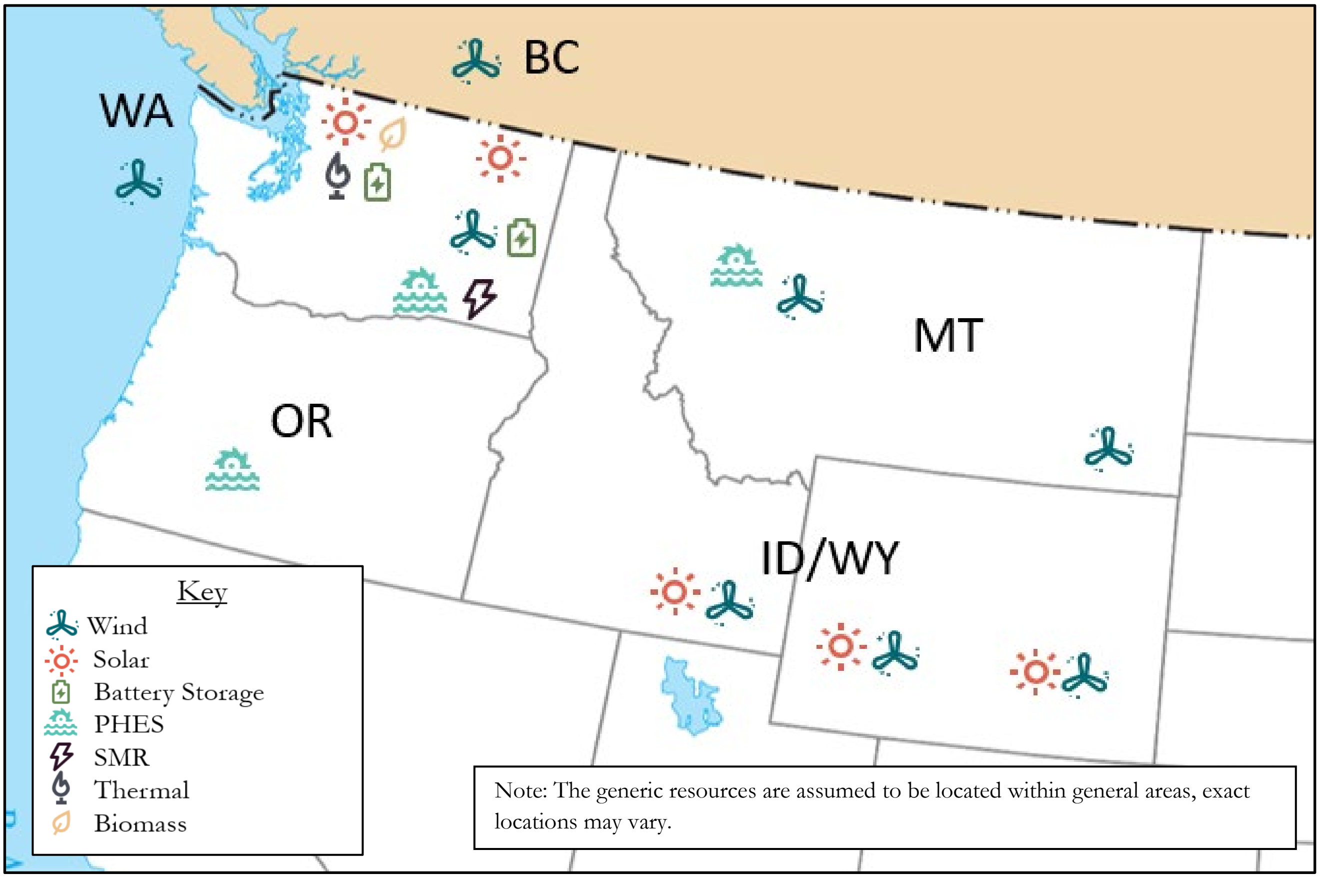
➔ We describe our planning models in Appendix G: Electric Price Models.

Here we describe mature technologies and new ways to generate power, including those commercially viable in the near- and mid-term. We explain the technologies available and the corresponding assumptions we adopted in our long-term capacity expansion model for each resource type. We primarily focused on updating cost assumptions in this report. Conversely, operating assumptions are generally consistent with the 2021 IRP, with some notable exceptions, such as operating life and reliable capacity assumptions. We present the data sources we consulted in Sections 1.1 and 1.2.

Although generic resources are not associated with a specific location, geography can heavily influence assumptions. Therefore, each of our generic resources is region-specific (we modeled Washington wind and Montana wind as separate generic resources) to best capture realistic future costs and operating characteristics in the modeling process. Figure D.1 presents the assumed geographic locations of the various generic resource alternatives we analyzed for this report.

➔ We also analyzed demand-side — after the meter — resources to help meet resource needs and discussed these in Appendix E: Conservation Potential Assessment.

Figure D.1: Generic Resource Alternatives Locations



1.1. Cost Assumptions

We sourced the generic resource costs for renewable, energy storage, and thermal resources described in the following pages primarily from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB). We also used input from publicly available data sources, including the U.S. Energy Information Administration (US EIA), Lazard, the Northwest Power and Conservation Council (NPCC), other national laboratories, and other regional IRPs. All cost assumptions are in 2020 dollars, with a 2.5 percent inflation applied through the planning horizon.

➔ Generic resource cost assumptions, including all data sources and averaging assumptions, are available in Appendix H: Electric Analysis and Portfolio Model.

1.2. Operating Characteristics

The following sources informed our generic resource operating characteristics:

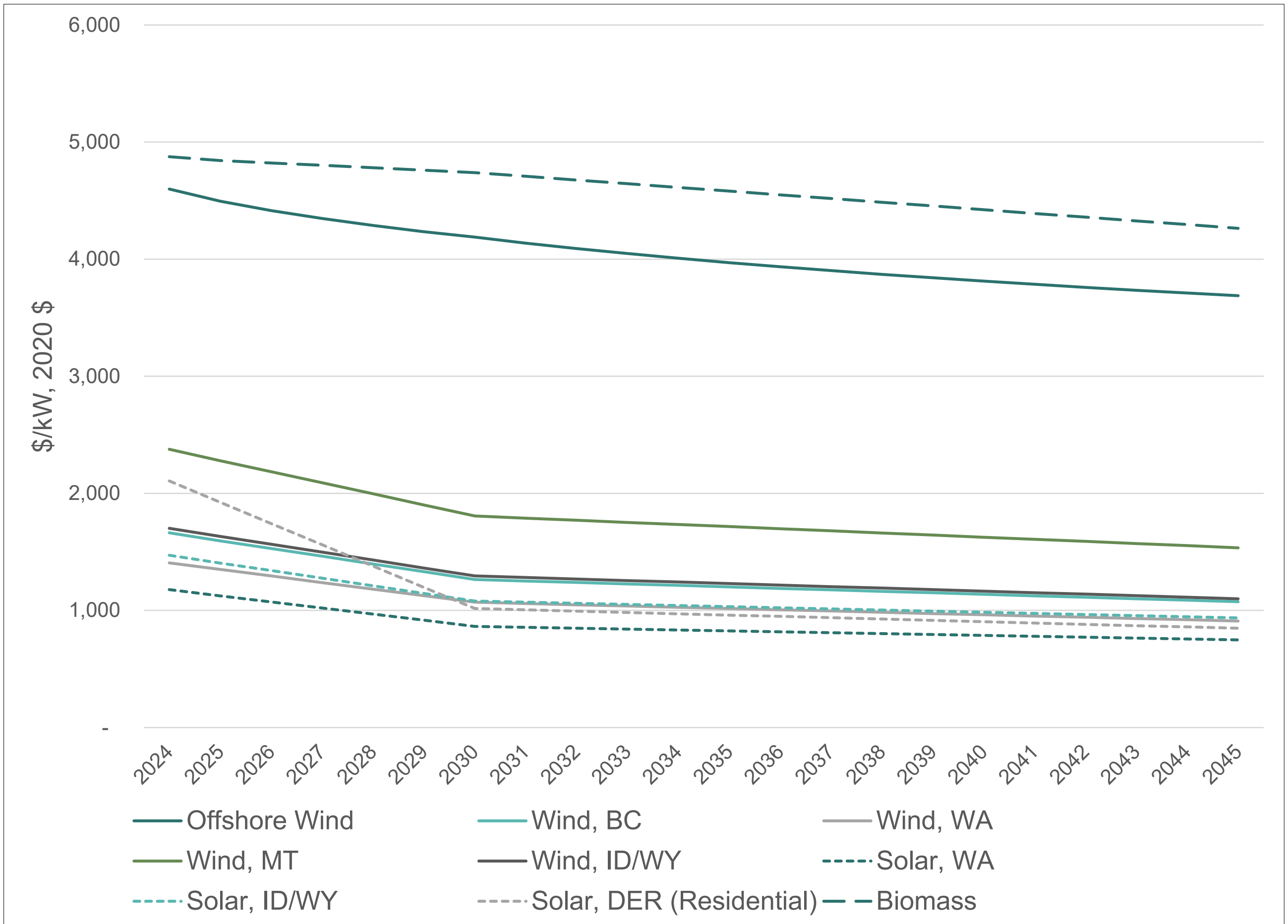
- NREL's 2022 ATB[1]
- PSE's experience in owning, operating, and developing electric-generating resources
- Solar and wind data provided by the consulting firm DNV
- 2019 HDR Generic Resource Costs for Integrated Resource Planning report[2]

2. Renewable and Storage Resource Technologies and Assumptions

We modeled five types of renewable energy resources in this report: biomass, wind, solar, storage, and hybrid technologies. We described these technologies in the following sections and include cost assumptions and commercial availability. Table D.1 through Table D.5 further summarize the technology parameters we modeled. Figure D.2 shows the capital cost curves for each renewable technology through the planning horizon.

1 https://atb.nrel.gov/electricity/2022/index.
2 https://www.pse.com/-/media/PDFs/IRP/2022/03222022/2019_HDR_GenericResourceAssumptionsReport_rev4.pdf?sc_lang=en&modified=20220506194408&hash=E6B1FDDF642DABBE25C1A42AFAB595D2.

Figure D.2: Capital Cost Curves for Renewable Energy Resources



2.1. Biomass

Biomass, in this context, refers to burning woody biomass in boilers. Most existing biomass in the Northwest works with steam hosts, also known as cogeneration or combined heat and power. Biomass is found mainly in the timber, pulp, and paper industries. That dynamic has limited the amount of biomass energy available to date. The typical biomass plant size is 10–50 MW. One significant advantage of biomass plants is they can operate as a baseload resource since they are not variable, unlike wind and solar. Biomass is considered separately from waste-to-energy technologies, including municipal solid waste, landfill, and wastewater treatment plant gas, which are discussed in Section 5.1: Renewable Resources Not Modeled.

We modeled biomass as a 15 MW, wood-fired facility with a heat rate of 14,599 BTU per kWh. These parameters reflect a cogeneration facility near a timber mill and are the same parameters presented in our 2021 with updates to cost data (e.g., capital costs, operations and maintenance, transmission). We show the operating assumptions for the 2021 IRP and this report in Table D.1.

Biomass technology is commercially available. Greenfield development of a new biomass facility — designing, permitting, and constructing a completely new, previously unplanned facility — requires approximately three years.

2.2. Wind

Wind energy is the dominant renewable technology used in the Pacific Northwest region to meet Washington State's Renewable Portfolio Standards (RPS) and Clean Energy Transformation Act (CETA) requirements. Wind technology is mature, is cost effective, is acceptable in various regulatory jurisdictions, and has a large utility-scale compared to other renewable energy technologies. However, wind also poses challenges. Wind power generation does not correlate with customer demand because the availability of wind is variable. Therefore, we must have other, more flexible resources ready to respond when wind is unavailable. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a power system that is already congested.

2.2.1. Land-based Wind Technology

Land-based wind turbine generator technology is mature. Although the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding higher towers, wider rotor diameters, greater nameplate capacity, and increased wind capture (efficiency). Commercially available turbines range in capacity from 2-4 MW, with an average of 2.55 MW per turbine. Hub heights and blade diameters average 90 meters and 121 meters, respectively[3]. The primary factor driving changes in wind technology is the need to site new development in less energetic wind sites because premium high-wind spots are already developed. This technology will likely continue to advance and become more accessible as the current generation of turbines pushes the physical limits of existing transportation infrastructure. The U.S. Department of Energy is researching potential solutions, including designing more slender, flexible blades and developing towers that crews can assemble on-site.[4]

The cost of installing a wind turbine includes the turbine, foundation, roads, and electrical infrastructure. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $28.36 to $55.37 per MWh (in 2021 U.S. dollars) for new wind resources entering service in 2024. This cost depends heavily on the capacity factor of wind at the location and federal tax credits, which, even with the extension under the Inflation Reduction Act (IRA), will likely decline or expire during the planning horizon.[5] Greenfield development of a new wind facility requires approximately two to three years and consists of the following activities at a minimum: one to two years for development, permitting, major equipment lead time, and one year for construction.

2.2.2. Offshore Wind Technology

Offshore winds blow at higher speeds and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can make significantly more electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and an average wind speed of 14 mph.

3 Lawrence Berkeley National Laboratory, Wind Energy Technology Update: 2020 Edition: https://emp.lbl.gov/sites/default/files/2020_wind_energy_technology_data_update.pdf

4 https://www.energy.gov/eere/articles/wind-turbines-bigger-better

5 U.S. Energy Information Administration (EIA), Annual Energy Outlook 2022, March 2022: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

However, offshore wind installations have higher capital and operational costs than land-based installations per unit of generating capacity, mainly because of turbine upgrades required for operation at sea and increased expenses related to turbine foundations, the balance of system infrastructure, interconnection, and installation, and the difficulty of maintenance access. In addition, developing infrastructure incurs one-time costs to support offshore construction, such as vessels to erect foundations and install turbines and related port facilities.

Wind turbine generators used in offshore environments require durability modifications to prevent corrosion and to operate reliably in harsh marine environments. Their foundations must be designed to withstand storm waves, hurricane-force winds, and even ice floes. The engineering and design of offshore wind facilities depend on site-specific conditions, particularly water depth, the geology of the seabed, and expected wind and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with various styles for each category. The fixed foundation is a proven technology used throughout Europe. Monopiles, the most prevalent foundation type, are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters. However, roughly 90 percent of the offshore U.S. wind resource occurs in waters too deep for a fixed foundation, particularly on the West Coast. The wind industry is developing new technologies, such as floating wind turbines, but this technology is not commercially mature.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. A power cable connects each turbine to an electric service platform (ESP). High voltage cables, typically buried beneath the seabed, transmit the power collected from wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

In Europe, offshore wind is a proven technology in shallow coastal waters. As of 2020, Europe's total installed capacity was 25 GW, with turbines spanning 12 countries[6]. The United States currently has two operational offshore wind projects — the 30 MW Block Island Wind Farm off the coast of Rhode Island, which began operation in December 2016, and the two-turbine 12 MW Coastal Virginia Offshore Wind pilot project, completed in June 2020. As a result of this dearth of data, reliable capital cost estimates for large-scale U.S. installations are unavailable.

However, this will change during the planning horizon for the 2023 Electric Report, as the Biden administration has set a goal of achieving 30 GW of offshore wind by 2030 and has subsequently approved the first two commercial-scale projects in the nation, Vineyard Wind and South Fork Wind projects, which are currently under construction. Additionally, in June of 2022, the administration launched the Federal-State Offshore Wind Implementation Partnership, intended to accelerate the offshore wind progress[7]. According to The American Clean Power Association, project developers expect 12 offshore wind projects totaling 10,300 MW to be operational by 2026[8]. As the market develops, costs should decrease as we all gain experience. Based on the current design trajectory of wind turbine development, bigger units will be able to capture more wind and achieve more significant economies of scale in the years ahead.[9]

6 https://windeurope.org/intelligence-platform/product/offshore-wind-in-europe-key-trends-and-statistics-2020
7 https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/23/fact-sheet-biden-administration-launches-new-federal-state-offshore-wind-partnership-to-grow-american-made-clean-energy
8 https://cleanpower.org/facts/offshore-wind
9 https://www.energy.gov/eere/wind/offshore-wind-research-and-development

2.2.3. Modeling Assumptions

We modeled wind in the following locations for this report: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho, and Washington offshore. Table D.2 summarizes the wind resources we modeled in the 2023 Electric Report and those we modeled in the 2021 IRP for reference. We held operating assumptions consistent with the 2021 IRP values, except for capacity factors, ELCC calculations, and cost assumptions.

Generic Wind Locations

Eastern Washington wind is in Bonneville Power Administration's (BPA) balancing authority, so this wind requires only one transmission wheel – transfer from one transmission provider to another – through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require three transmission wheels to deliver the power to PSE's service territory. Similarly, the Wyoming and Idaho wind sites are well outside PSE's service territory and will require three transmission wheels to deliver power in 2024-2030. From 2031 through the end of the planning horizon in 2045, we assumed the Gateway West[10] transmission projects would be complete. Once constructed, we assume two wheels will deliver power from Wyoming and Idaho: from Aeolus, Wyoming, to Hemmingway, Idaho, then from Hemmingway, Idaho, to Longhorn, Washington.

We modeled offshore wind located 16 miles off Grays Harbor County, Washington coast. Offshore wind requires a marine cable to interconnect the turbines and bring the power back to land. Once on land, a transmission wheel through BPA to PSE would be necessary.

Generate Wind Shapes

A wind (or solar) shape is the net capacity factor of a wind turbine (or solar array) at a specific location over time. A wind shape provides data on how well a given wind resource will perform. Puget Sound Energy engaged the consulting company DNV to generate wind shapes for each generic wind resource. Using a consulting firm was a departure from the 2021 IRP when we used the NREL Wind Toolkit database[11] to derive wind shapes. This 2023 Electric Report presents wind shapes as a net capacity factor for every hour within one calendar year. Figure D.3 shows the wind shapes for the generic wind resources we analyzed for this report.

DNV used an internal wind mapping system to generate hourly shapes at a 5-kilometer resolution for each potential wind site. This modeling process involves conducting dynamical downscaling to generate high-resolution mesoscale wind maps. Inputs include soil and sea surface temperatures, moisture levels, and NASA's MERRA-2 reanalysis dataset, which contains data obtained from various sources, including rawinsondes, radar, land-based stations, aircraft, ships, scatterometer wind readings, and NASA's EOS satellites. Outputs from this modeling include an hourly time series of wind speed, temperature, pressure, and direction at hub heights.

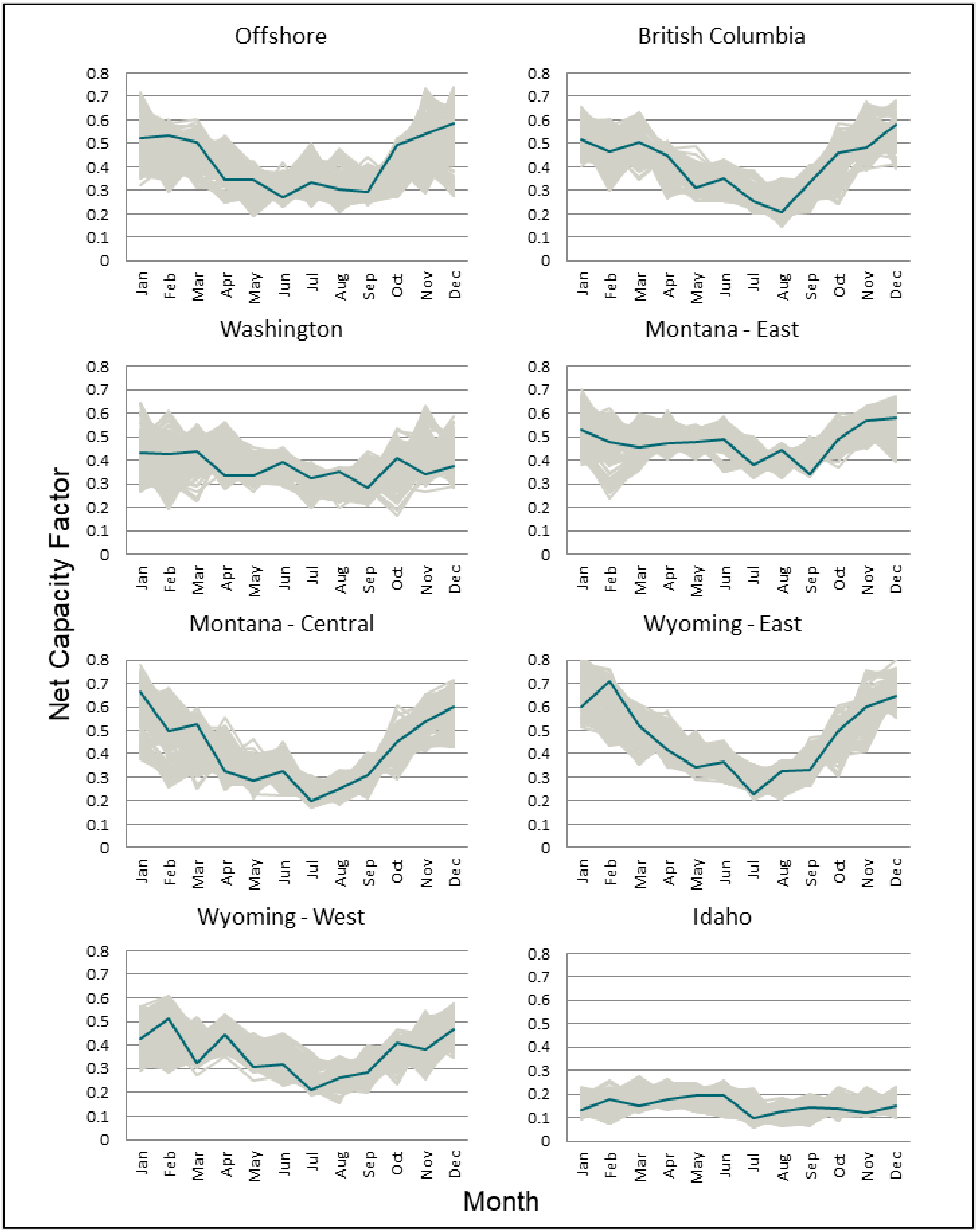
DNV subsequently used this output, in conjunction with turbine model and power data, as inputs to a stochastic model. The stochastic model generated 1,000 stochastic time series to represent the net capacity factor of a wind

10 http://www.gatewaywestproject.com
11 https://www.nrel.gov/grid/wind-toolkit.html

turbine for each site over the 22-year planning period. This methodology maintained daily, seasonal, and annual cycles from the original data. The stochastic model also maintained spatial coherency of weather, generation, and system load to preserve the relationships of projects across a region. DNV then randomly selected a sample of 250 annual hourly draws for each site, verified the data were representative of the total distribution, and provided the data to PSE for modeling purposes.

These updated wind shapes from DNV are generally consistent across sites with the wind shapes provided in the 2021 IRP, except for the existing Skookumchuck wind resource and the generic Idaho wind resource. Upon examining these resources further, we determined that the NREL wind toolkit database lacked wind speed data near the sites, so it did not adequately represent the Skookumchuck and Idaho wind sites. Therefore, we determined the DNV shapes provided a more accurate representation of wind conditions at these sites and adopted those shapes for this 2023 Electric Report.

Figure D.3: Seasonal Wind Shapes for Generic Wind Resources



2.3. Solar

Renewable portfolio standards (RPSs), falling prices, and tax incentives drive most utility-scale solar development in the United States, with solar installations accounting for 50 percent of total capacity additions across the U.S. in Q1

2022.[12] With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic growth has been relatively slow in the Northwest. However, since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably, and solar remains an appealing renewable technology for us to procure to meet RPS and CETA requirements. Like wind technology, solar resources pose challenges that include daily and hourly variability in power generation, the misalignment with generation and customer demand, and the need for the long-haul transmission to bring solar power generated in sunnier locations into PSE's system.

2.3.1. Solar Technologies

Photovoltaic (PV) technology, semiconductors that generate direct electric currents, uses solar radiation to generate electricity directly. The current typically runs through an inverter to create alternating current, which ties into the grid. Most PV solar cells are silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film PVs, have gained substantial market share. Significant ongoing research efforts continue for all PV technologies and have helped increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays ranging from a few watts for sensor or communication applications to hundreds of megawatts for utility-scale power generation. Photovoltaic systems can be installed on a stationary frame at a tilt to capture the sun (fixed-tilt) best or on a frame than can track the sun from sunrise to sunset.

Concentrating and bifacial PVs are high-efficiency technologies. Concentrating photovoltaics use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems. Bifacial photovoltaic modules collect light on both sides of the panel, instead of just on the side facing the sun (as in typical PV installations). Bifacial modules can achieve greater efficiencies per unit of land, reducing the land use requirements. Efficiency gains made by bifacial module are highly dependent on the amount of light reflected by the ground surface, or albedo.

Distributed solar uses similar technologies to utility-scale PV systems but at a smaller scale. The defining characteristic of distributed solar systems is that the power is generated at, or near, the point where the power will be used. This scenario means that distributed solar systems do not have the same costly transmission requirements as utility-scale systems. Distributed solar may include rooftop or ground-mounted systems, such as parking lot canopies.

The Solar Electric Industries Association (SEIA) reports that as of Q1 2022, the U.S. has installed over 121 GW of total solar capacity, with an average annual growth rate of 33 percent over the last ten years. Solar has ranked first or second in new electric capacity additions every year for the last nine years. Through early 2022, 46 percent of all new electric capacity added to the grid came from solar.[13] According to SEIA's U.S. Solar Market Insight report for Q4 2021, modeled U.S. national average costs for utility fixed-tilt and tracking projects averaged $0.82 and $0.95 per

[12] Solar Electric Industries Association (SEIA), Solar Industry Research Data: https://www.seia.org/solar-industry-research-data. Accessed 6/24/2022.

[13] Solar Electric Industries Association (SEIA), Solar Industry Research Data: https://www.seia.org/solar-industry-research-data. Accessed 6/24/2022.

$Watt_{dc}$, respectively; costs for residential systems had reached approximately \$3.06 per $Watt_{dc}$; and costs for commercial systems had reached \$1.45 per $Watt_{dc}$.[14]

2.3.2. Modeling Assumptions

We modeled two solar PV applications for this report: a utility-scale, single-axis tracking PV technology, and a residential-scale fixed-tilt, rooftop, or ground-mounted PV technology. We modeled six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho, and residential-scale rooftop or ground-mounted PV solar in western Washington. Table D.3 summarizes the solar resources modeled in the 2023 Electric Report and those modeled in the 2021 IRP for reference. We held operating assumptions consistent with the 2021 IRP values, except for capacity factors, ELCC calculations, and cost assumptions.

Generic Solar Locations

Washington solar resources are located either within PSE's service territory or in BPA's balancing authority, which would require one transmission wheel to PSE. However, Wyoming and Idaho solar resources are outside BPA's balancing authority and will need three transmission wheels to deliver the power to PSE's service territory from 2024–2030. From 2031 through the end of the planning horizon in 2045, we assumed the Gateway West[15] transmission project would be complete. Once constructed, we assumed two wheels to deliver power from Wyoming and Idaho: from Aeolus, Wyoming, to Hemmingway, Idaho, then from Hemmingway, Idaho, to Longhorn, Washington.

Solar Shape Generation

We used specific solar generation profiles or shapes provided by DNV. Using a consulting firm was a departure from the 2021 IRP when we used the shapes derived using irradiance data queries from the NREL's National Solar Radiation Database (NSRDB)[16] and then modeled using NREL's System Advisor Model (SAM) to create realistic generation profiles for each location. For this report, DNV generated 1,000 stochastic series to represent each site over a 22-year window for a total of 22,000 simulated years.

This method relied on inputs that included 22-year hourly solar power time series based on historical irradiance data and load and temperature inputs provided by PSE. Irradiance data was sourced from NASA's Geostationary Operational Environmental Satellites and processed by DNV to account for regional loss factors for each site. Loss factors include temperature, shading, soiling, availability, electric, inverter, and transformer losses.

All resources were modeled with a DC (direct current) to AC (alternating current) ratio of 1.3, and azimuth angles were assumed to be south facing. Utility-scale resources were modeled as ground mounted with single-axis tracking panels, whereas residential-scale resources were modeled as fixed-tilt for rooftop and ground-mounted units.

This methodology maintained daily, seasonal, and annual cycles from the original data and spatial coherency of weather, generation, and system load to preserve how projects are related across a region. A sample of 250 annual

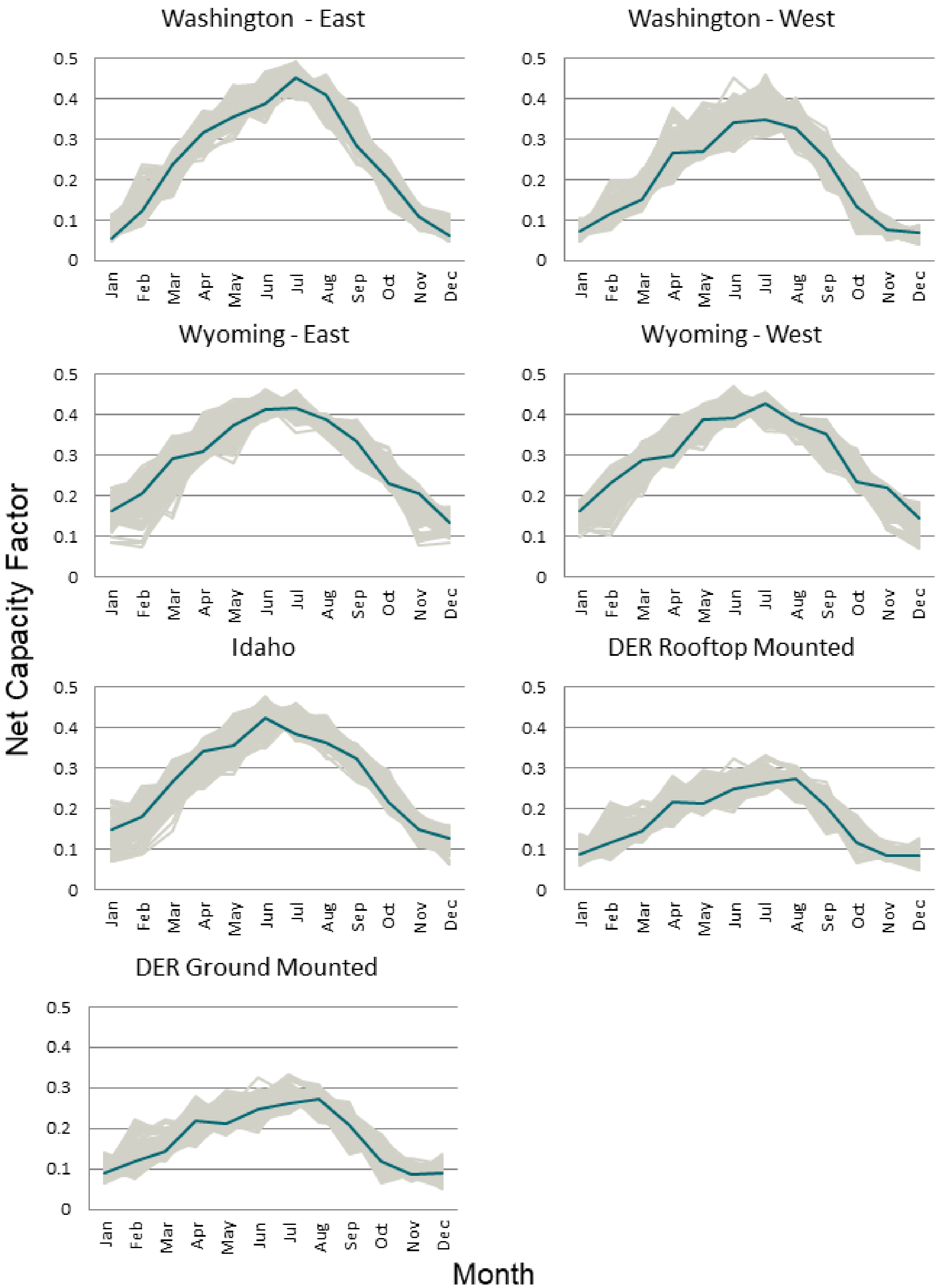
[14] SEIA, Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2021-q4.
[15] http://www.gatewaywestproject.com
[16] https://nsrdb.nrel.gov

hourly draws was then randomly selected for each site and, after being statistically verified to be representative of the total distribution of 22,000 annual draws for a site, provided to us for modeling.

All capacity factors are provided as AC, where the capacity of the inverter is taken as the nameplate of the solar facility. This differs from the DC capacity, which measures the capacity based on the capacity of the solar modules installed. The AC capacity is typically higher, because most solar facilities undersize the inverter as defined by the DC to AC ratio; in the case of PSE generic resources, the DC to AC ratio is 1.3.

We found these updated solar shapes were generally consistent across sites with the solar shapes we used in the 2021 IRP. Finally, a single, most-representative draw is selected from the 250 draws based on nearness to the annual average production of all 250 provided solar profiles. Figure D.4 summarizes the seasonal solar shapes used in the 2023 Electric Report. The grey lines represent the 250 stochastic draws, and the blue line represents the draw selected.

Figure D.4: Seasonal Solar Shapes for Generic Solar Resources



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2.4. Energy Storage

Energy storage encompasses a wide range of technologies capable of shifting energy usage from one period to another. These technologies could deliver essential benefits to electric utilities and their customers since the electric system currently operates on just-in-time delivery. PSE must perfectly balance generation and load to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, balance supply and demand, provide backup power when primary sources are interrupted, and help integrate intermittent renewable generation. Energy storage technologies are rapidly improving and can benefit all parts of the system – generation, transmission, distribution, and customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

2.4.1. Battery Storage Technologies

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable, and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for an extensive storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its performance characteristics, commercial availability, and costs. We chose to model lithium-ion as the generic battery resource in this report because the technology is commercially available, successful projects are operating, and cost estimates and data are available on a spectrum of system configurations and sizes. We received the most energy storage bids for 4-hour lithium-ion battery arrays[17] in response to our 2021 All Source RFPs.[18]

Lithium-ion batteries have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell memory, and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability, and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (e.g., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

At the end of 2019, the U.S. had 1,022 MW of large-scale battery energy storage resources in operation. Lithium-ion batteries continued to dominate the energy storage market, representing more than 90 percent of operating large-scale battery storage capacity. In 2019, U.S. utilities also reported 402 MW of existing small-scale storage capacity. [19] Forty-

[17] In an actual RFP solicitation, we would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees, and counterparty credit.

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[19] U.S. Energy Information Administration, Battery Storage in the United States: An Update on Market Trends, August 2021: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

one percent of this capacity was installed in the commercial sector, 41 percent in the residential sector, 14 percent in the industrial sector, and the remaining 4 percent connected directly to the distribution grid.

2.4.2. Pumped Hydroelectric Energy Storage Technology

Pumped hydroelectric energy storage (PHES, pumped hydro storage, pumped storage, pumped hydro, or PHS) facilities provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over several hours requires a large energy storage capacity, and a device like PHES is well suited for this application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are traditionally large, at 300 MW or more. Due to environmental impacts, permitting these projects can take many years. Pumped storage can be designed to provide 6–20 hours of storage with 80 percent roundtrip efficiency.

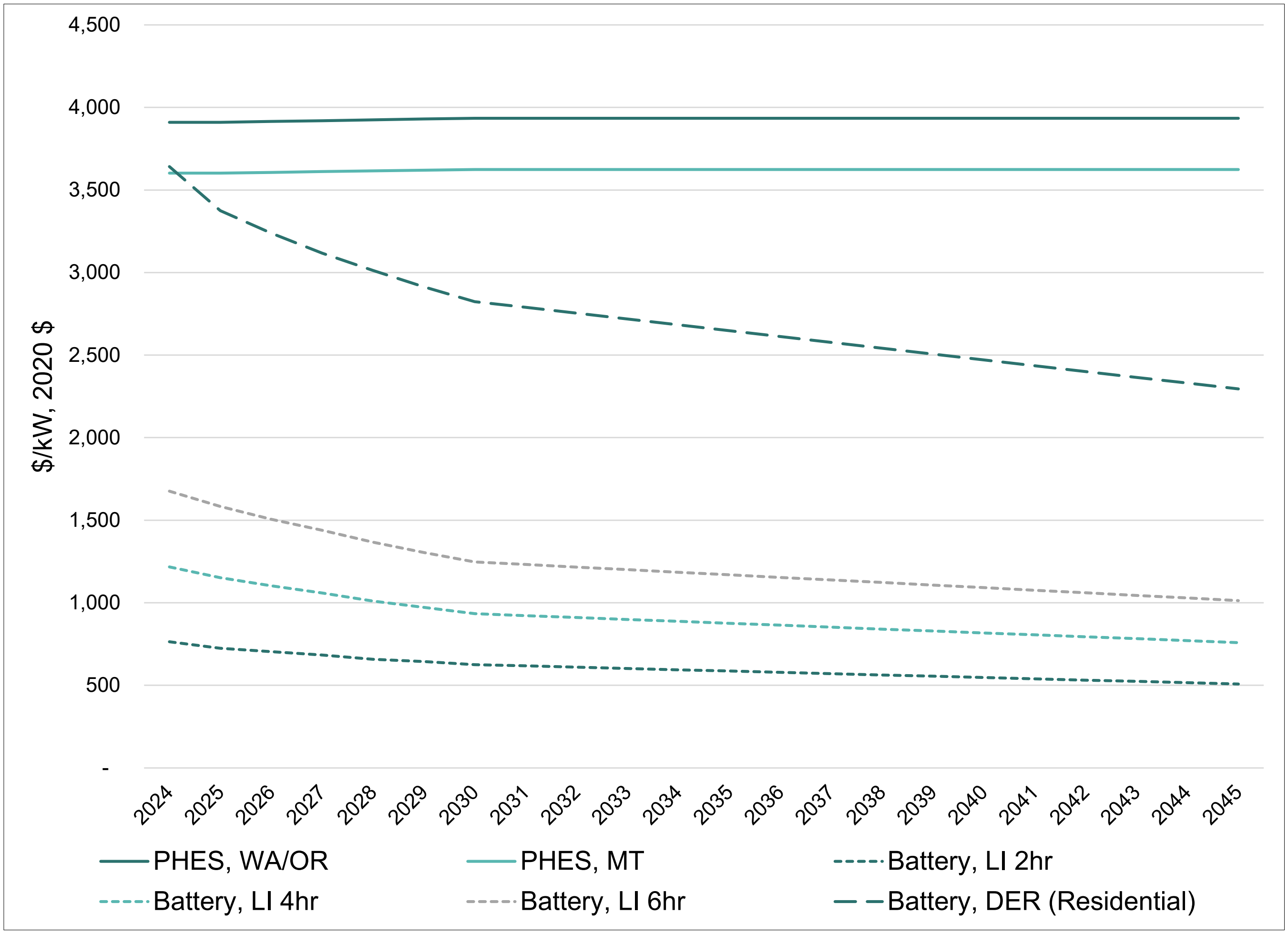
According to the U.S. Department of Energy's most recent *Hydropower Market Report*, there are 43 plants with a capacity of 21.9 GW, which represent 93 percent of utility-scale electrical energy storage in the U.S. Most of this capacity was installed between 1960 and 1990, and almost 94 percent of these storage facilities are larger than 500 MW. No new pumped storage projects have come online in the United States since 2012.[20] At the end of 2019, there were 67 pumped storage projects with a potential capacity of 52.48 GW in the development pipeline. The median project size in the development pipeline is 480 MW, but projects span a wide range of sizes from large projects greater than 3,000 MW to small closed-loop systems of less than 100 MW.[21]

2.4.3. Modeling Assumptions

We modeled six energy storage resources in this report: 100 MW lithium-ion batteries in 2-, 4-, and 6-hour sizes; a smaller 3-hour lithium-ion battery as a distributed energy resource; and two PHES systems, one located in Montana and the other in either Washington or Oregon. Table D.4 summarizes the generic cost assumptions used in the energy storage resource analysis and assumptions used in the 2021 IRP for comparison. Figure D.5 shows the capital cost curves for each energy storage technology through the planning horizon. All costs are in 2020 dollars.

[20] U.S. Energy Information Agency, Annual Electric Generator Report: https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf.
[21] Ibid.

Figure D.5: Capital Cost Curves for Generic Energy Storage Resources



2.5. Hybrid Technologies

Hybrid resources combine two or more resources at one location to take advantage of synergies created through the co-location of the resources. Hybrid resources may combine two generating resources, such as solar and wind, or one generating and one storage resource, such as solar and a battery energy storage system. Benefits of hybrid resources include reduced land use needs, shared interconnection and transmission costs, improved frequency regulation, backup power potential, and operational balancing potential, among others. From 2017 to 2020, the number of installed hybrid systems in the U.S. doubled from less than 30 to 80 facilities.[22] Furthermore, 73 percent of the battery storage power planned to come online between 2021 and 2024 will be co-located with solar or wind power plants.[33]

2.5.1. Modeling Assumptions

We are evaluating three hybrid systems, each of which pairs a generating resource with a storage resource. These hybrid resources include Washington wind plus 4-hour battery storage and Washington utility solar plus 4-hour battery storage. Additionally, we are evaluating a hybrid configuration of wind and solar generation plus a 4-hour battery storage resource, located in eastern Washington. We configured the hybrid resources in the model so the storage resource can charge using either energy from the generating resource to which it is connected from the market.

Table D.5 presents the operating assumptions for the hybrid systems modeled in this 2023 Electric Report and those modeled in the 2021 IRP for comparison.

3. Thermal Resource Technologies and Assumptions

Combustion turbines (CT) play an essential role in the portfolio, given their versatility and reliability. The following characteristics make combustion turbines a critical tool.

- Proximity: Combustion turbines located within or adjacent to PSE's service area avoid costly transmission investments required for long-distance resources like wind.
- Timeliness: Combustion turbines are dispatchable; we can turn them on to meet loads, unlike intermittent resources that generate power sporadically, such as wind, solar, and run-of-the-river hydropower.
- Versatility: Combustion turbine generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.

This section describes the thermal resources modeled in this report.

[22] https://www.eia.gov/todayinenergy/detail.php?id=43775.

3.1. Baseload Combustion Turbine Technologies

Baseload combustion turbine plants (combined-cycle combustion turbines or CCCTs) produce energy at a constant rate over long periods at a lower cost than other production facilities available to the system. Baseload combustion turbine plants are typically used to meet some or all of a region's continuous energy demand.

These baseload plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. The baseload heat rate for the CCCTs modeled for the 2023 Electric Report is 6,624 BTU per kWh. Many plants also feature duct firing. Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. Combined-cycle combustion turbines have been a popular source of baseload electric power and process steam generation since the 1960s because of their high thermal efficiency and reliability, relatively low initial cost, and relatively low air emissions. This technology is commercially available. Greenfield development requires approximately three years.

3.2. Peaker Technologies

Peakers are quick-starting single-cycle combustion turbines that can ramp up and down rapidly to meet spikes in need. They also provide the flexibility needed for load following, wind integration, and spinning reserves. We modeled two types of peakers; each brings strengths to the overall portfolio.

3.2.1. Frame Peakers

Frame CT peakers are also known as industrial or heavy-duty CTs and are sometimes referred to as simple cycle combustion turbines (SCCT); these are generally larger in capacity and feature frames, bearings, and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil, or a combination of fuels (dual fuel). The turndown capability of the units is 30 percent. This report's assumed heat rate for frame peakers is 9,904 BTU per kWh. Frame peakers also have slower ramp rates than other peakers at 40 MW per minute for 237 MW facilities. Some can achieve a full load in 21 minutes. Frame CT peakers are commercially available. Greenfield development requires approximately two years.

3.2.2. Reciprocating Peakers

Reciprocating internal combustion engines (recip peakers or RICE) use a reciprocating engine technology evaluated based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher oxygen ratio to fuel, allowing the reciprocating engine to generate power more efficiently. Ramp rates are 16 MW per minute for an 18 MW facility. The heat rate is 8,445 BTU per kWh. However, reciprocating engines are constrained by their size.

The largest commercially available reciprocating engine for electric power generation produces 18 MW, less than the typical frame peaker. Larger-sized generation projects would require more reciprocating units than an equivalent-sized project implementing a frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and minimizes the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers. This technology is commercially available. Greenfield development requires approximately three years.

3.3. Modeling Assumptions

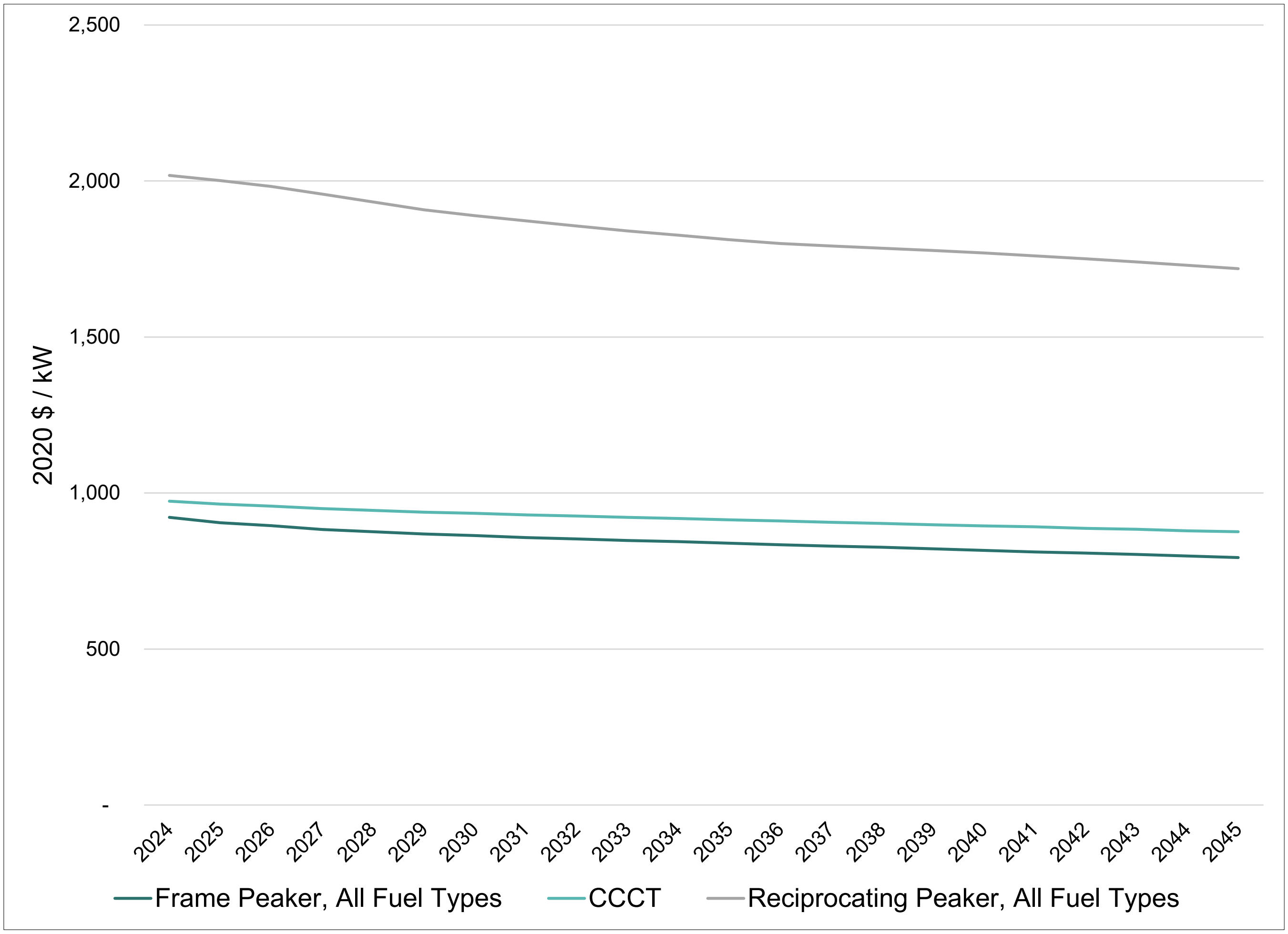
PSE modeled two general types of thermal resources in this 2023 Electric Report: baseload combustion turbine plants (CCCTs), and peaking capacity plants. As PSE moves towards CETA goals, we explored fuel alternatives to natural gas to operate thermal resources and provide non-emitting dispatchable power. Alternative fuels modeled in this 2023 Electric Report include hydrogen and biodiesel.

We modeled a single natural gas-powered CCCT in this report. We modeled three frame-peaking capacity plants: one fueled with natural gas, one with a hydrogen blend, and another with biodiesel. Finally, we modeled two types of reciprocating peaking capacity plants, one fueled with natural gas and the other with a hydrogen blend.

For natural gas-powered CCCT units, we assumed the natural gas supply would be firm year-round at projected incremental gas pipeline firm rates. We assumed natural gas-powered frame peaking units have oil backup, and natural gas supply is available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. We assumed that 20 percent of gas storage is available to baseload CCCT plants and peaking plants and modeled it to accommodate mid-day start-ups or shutdowns. Regardless of fuel type, all thermal units are assumed to be connected to the PSE transmission system and therefore do not incur any direct transmission cost.

The following subsections describe these technologies, including cost assumptions and commercial availability. Figure D.6 presents the capital cost curves for each thermal technology through the planning horizon. Because the fuel type does not affect the overall capital cost of the units, Figure D.6 includes the three different thermal technologies modeled. Table D.6 summarizes the cost and operating assumptions used in the analysis for thermal resources. We also presented assumptions from the 2021 IRP for comparison. All costs are in 2020 dollars.

Figure D.6: Capital Cost Curves for Generic Thermal Resources



3.3.1. Natural Gas Transportation Modeled Costs

Fixed and variable natural gas transportation costs for the combustion turbine plants assumed that natural gas is purchased at the Sumas Hub. Natural gas transportation costs for resources without oil backup assumed the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 20 percent of the plant's complete fuel requirements. This scenario applies to the baseload CCCT and reciprocating engine without oil.

The analysis assumed that we would meet the gas transportation needs for these resources with 100 percent firm gas transportation on a Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on the Westcoast Pipeline expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential gain between Sumas and Station 2 mitigates the gas transportation costs. We assume oil backup with no firm gas transportation for the natural gas frame peaker resources. Table D.7 shows the natural gas transport assumptions for resources without oil backup, and Table D.8 shows natural gas transport assumptions for frame peakers with oil backup.

3.3.2. Green Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and could become an essential energy carrier in the power sector.[23] Hydrogen is abundant in several feedstocks, including water, biomass, fossil fuels, and waste products, but it requires a significant amount of energy to produce elemental hydrogen from these feedstocks. It is common practice to classify hydrogen with color to describe the feedstock and energy source used to produce the hydrogen. Green hydrogen is the most attractive variety of hydrogen in the context of a clean energy transformation. Green hydrogen is typically made from water electrolysis using low- or non-emitting energy sources to power the process.

Green hydrogen has the potential to act as a useful energy carrier to store and deliver low- or no-carbon energy where and when it is needed. When wind and solar generation is plentiful, we can turn on electrolyzers to produce and store hydrogen. When demand is high and renewable generation is unavailable, the stored hydrogen may be combusted in a turbine or electrochemically reacted in a fuel cell to produce electricity. A key advantage green hydrogen has over other storage technologies (e.g., battery energy storage systems or pumped hydroelectric storage) is that hydrogen is stable over long periods, meaning we can store energy monthly instead of hour-to-hour as in other storage systems. This long storage period allows hydrogen to store excess energy in spring and autumn for use in the peak summer and winter seasons.

Despite its potential usefulness, the green hydrogen industry must overcome several obstacles before it can play a significant role in the power sector. Large-scale electrolyzers are an emerging technology with relatively few installations scattered across the globe. Research and development into scaling up production and reducing the costs of electrolyzers are necessary to produce the quantities of hydrogen needed to support the power sector. Powering large installations of electrolyzes will also require a large amount of low- or no-carbon electricity. It is necessary to develop adequate quantities of wind, solar, or other non-emitting generation and the transmission to move the power to the electrolyzers.

After production, hydrogen must be stored and transported. Pipelines are the obvious choice for storage and transportation, but utilities will need dedicated pipelines for high-purity hydrogen storage and transport. Finally, to access the energy stored in hydrogen, existing combustion turbines will require modifications to accommodate the new fuel, or new technologies, such as fuel cells, will need to be researched and developed. These infrastructure-related hurdles add cost and require detailed long-term planning to incorporate green hydrogen into the power system successfully.

The enactment of the 2022 Inflation Reduction Act provides incentives that dramatically reduce the cost barriers to establishing the infrastructure required to make green hydrogen an economically viable energy carrier for the power system. Production Tax Credits (PTCs) from the Inflation Reduction Act could reduce hydrogen prices by up to $3 per kilogram[24], putting green hydrogen price forecasts on par with natural gas prices by the mid-2030s.

[23] https://www.nrel.gov/docs/fy21osti/77610.pdf
[24] https://www.congress.gov/bill/117th-congress/house-bill/5376/text

This development and additional momentum behind green hydrogen from the Department of Energy's Regional Clean Hydrogen Hubs[25] spurred us to include green hydrogen as a fuel source in the 2023 Electric Report. We will likely obtain green hydrogen as part of an offtake agreement from an independent fuel supplier; therefore, hydrogen is modeled simply as a fuel source in the AURORA model.

We assumed several resources are eligible to combust green hydrogen, including a generic frame peaker, a generic reciprocating peaker, and PSE's existing thermal generation fleet. Supply is essential in modeling green hydrogen as a fuel source because it will take time to establish the required infrastructure. Based on our understanding and engagement in the nascent green hydrogen industry, it seems likely the first year significant quantities of hydrogen will become available is 2030. From 2030 forward, we forecast a growing green hydrogen supply in the Pacific Northwest large enough to supply PSE's existing thermal generation fleet. Table D.9 illustrates a trajectory of hydrogen supply using a blend rate with natural gas.

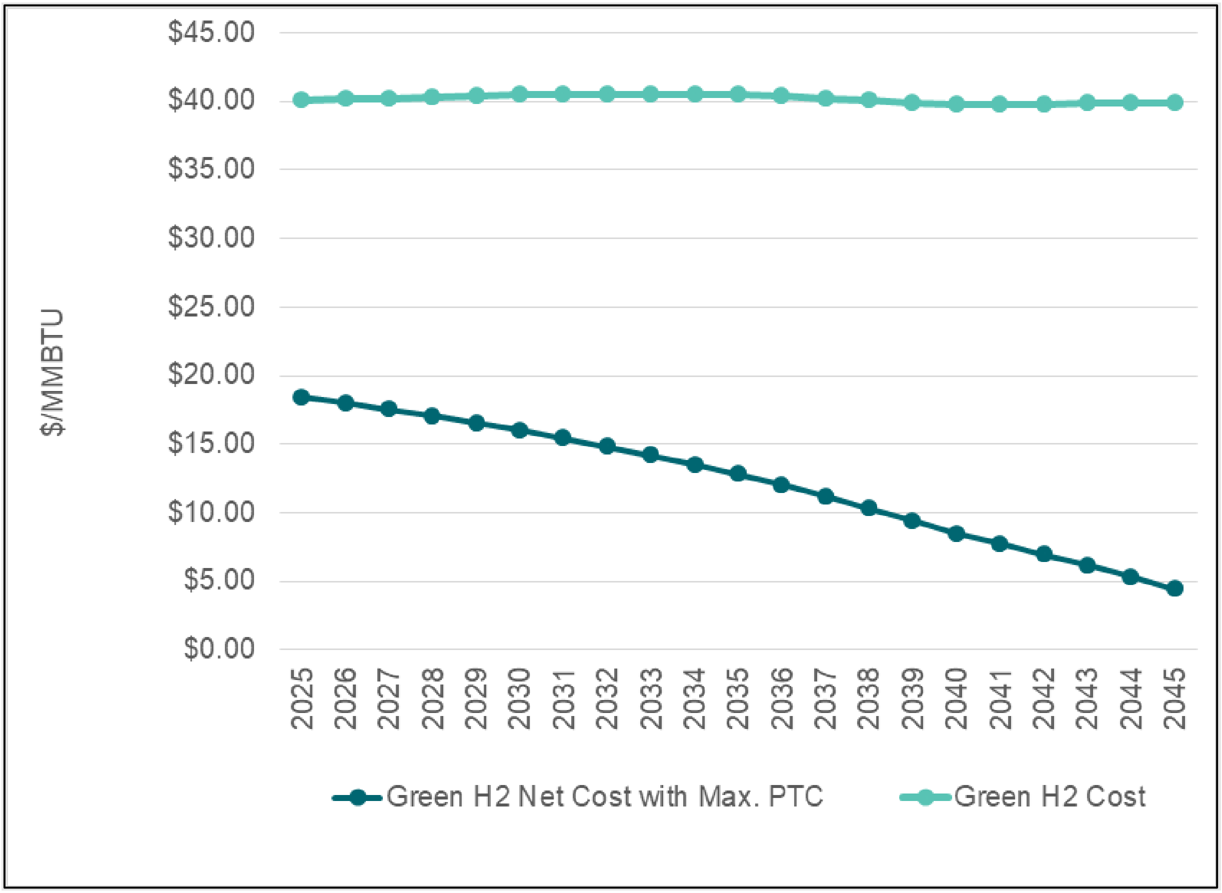
Developing a hydrogen pipeline to the regions of PSE's generation fleet will also constrain green hydrogen fuel supply. To reflect this constraint in the model, we limited access to green hydrogen for PSE's existing thermal fleet to a schedule based on our estimate of probable hydrogen production regions and subsequent expansion of pipelines from those regions. Table D.10 reflects the timeline we forecast a hydrogen pipeline may be available at new and existing thermal resources.

Price is the final consideration required to model green hydrogen. We developed a hydrogen price forecast based on assumptions from the E3 Pacific Northwest report[26] and industry consultations. We also applied the maximum PTC benefit to the green hydrogen price, reflecting the incentives expected for green hydrogen development in the Pacific Northwest. Figure D.7 illustrates the price forecast for green hydrogen in the AURORA model.

[25] https://www.energy.gov/oced/regional-clean-hydrogen-hubs

[26] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Figure D.7: Green Hydrogen Price Forecast



3.3.3. Biodiesel

Washington State defines biodiesel as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old-growth or first-growth forests. Biodiesel is chemically like petroleum diesel but is derived from waste cooking oil or dedicated crops. According to the U.S. Energy Information Administration, two facilities in Washington State make biodiesel, which together can manufacture upward of 100 million gallons of biodiesel a year.

Biodiesel may become a viable fuel supply for combustion turbines to provide peak capacity in the future. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At total capacity, a 237 MW frame peaker would require approximately 25,000 gallons of biodiesel per hour. At this fuel feed rate, a facility would require about 1.2 million gallons of biodiesel storage to fire for a 48-hour peak event continuously. The existing Washington State biodiesel production capacity of 107 million gallons per year in 2022[27] could plausibly supply several combustion turbines intended to supply reliable power during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low-hydroelectric conditions.

We explored biodiesel used in simple-cycle combustion turbines in this 2023 Electric Report. We included a generic frame peaker with biodiesel as the primary fuel in the AURORA long-term capacity expansion analysis. We

[27] https://www.eia.gov/biofuels/biodiesel/capacity/

configured this biodiesel peaker to purchase a fixed seven-day biodiesel supply during critical peak hours each year. This limited fuel supply equals an approximate 2 percent capacity factor for the biodiesel peaker. We estimated biodiesel prices at $33.13/MMBTU based on the Department of Energy Alternative Fuel Price Report, January 2022.[28]

4. New Resource Technologies and Assumptions

Puget Sound Energy considered modeling several emerging technologies, particularly energy storage technologies. However, due to accurate and reliable data availability, advanced nuclear small modular reactors (SMRs) are the only new technology considered in this 2023 Electric Report. Advanced nuclear SMR resource technology, cost, and operating assumptions are provided below. Other emerging technologies are discussed further in the following section, Resource Technologies Not Modeled.

4.1. Advanced Nuclear Small Modular Reactors

Nuclear power is considered a source of non-emitting electric generation under section 2 (28) of CETA [RCW 19.405.020.[29] This configuration has the distinct advantage over traditional nuclear resources of being far more flexible in terms of scaling energy output and therefore has the potential for use as a dispatchable resource rather than being utilized strictly as baseload capacity. In practice, this resource could be either entirely dispatchable or have a portion dedicated to baseload and a part held in reserve to cover peak events. In addition to the flexibility benefits, this resource is a non-variable resource making it highly reliable and non-emitting. This combination of dispatchability, reliability, and emission-free production could make this a very attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

An advanced nuclear SMR plant consists of a cluster of nuclear reactors that share land and infrastructure while retaining the ability to activate and deactivate independently. Each module consists of a single reactor, similar in size and technology to the units employed on nuclear submarines, with an output ranging from 40 to 80 MWs. An entire SMR plant may consist of four to twelve modules. Advances in nuclear engineering in fuel containment and cooling systems, including the ability to dry cool a system even in total water loss, make SMR systems much safer than traditional large-scale nuclear plants.

An SMR plant is far more cost-effective than a traditional nuclear plant because they require a fraction of the land footprint, and the modules are small and can be prefabricated off-site and shipped to the desired location. Although SMR plants are a relatively new application of nuclear technology in utility-scale electric generation, this application appears to be entering commercial availability, with several companies bringing this application to market. Those companies include X-energy, which currently has a contract to install an SMR facility at the Hanford Nuclear site for Energy Northwest, and NuScale, also constructing an SMR facility in Idaho Falls in partnership with the Idaho National Laboratory.

[28] https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_january_2022.pdf
[29] RCW 19.405.020

There is not a significant amount of literature on SMR waste disposal. However, one influential study whose authors include a former chairperson of the U.S. Nuclear Regulatory Commission[30] suggests that although SMRs use less fuel than traditional nuclear plants, they could generate significantly more waste due to increased irradiation of specific reactor components. Although the current practice for existing nuclear facilities is to store waste on-site in casks built to contain the waste material, the cited paper recommends that a portion of waste material would ideally be treated before disposal in a geologic repository with engineered barriers for shielding material from the environment. It suggests this could significantly raise disposal-related costs.

Greenfield development of a new SMR facility requires approximately four years.

4.1.1. Modeling Assumptions

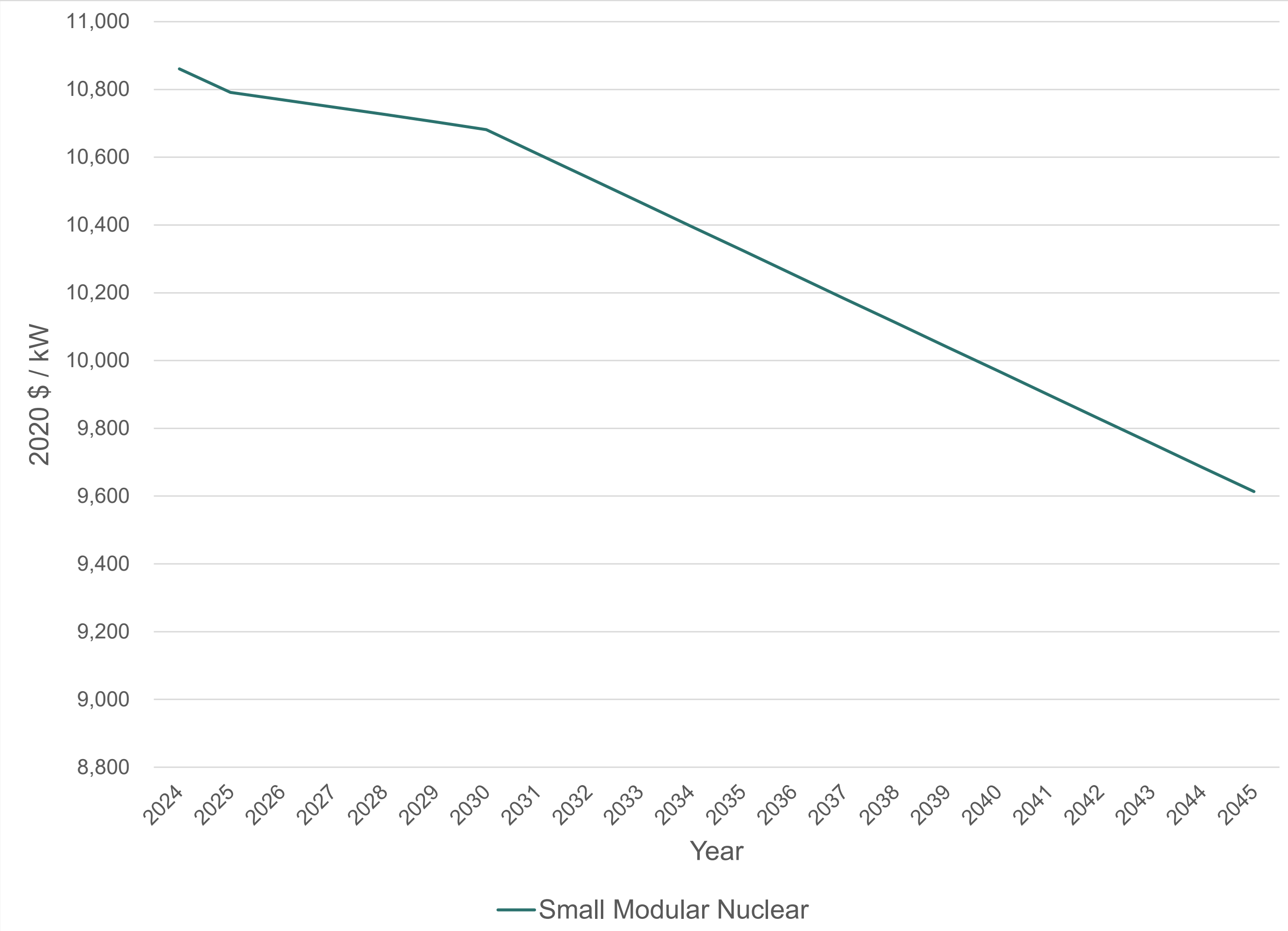
For the first time, we modeled an SMR plant in this report. We modeled an SMR configuration consisting of 12 modules with an output of 50 MWs each, totaling 600 MWs of capacity and a heat rate of 10046 BTU per kWh. This configuration is consistent with information provided by the EIA's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies.[31]

Figure D.8 presents the capital cost curves for SMR plants through the planning horizon. Table D.11 summarizes the cost and operating assumptions used in the analysis for SMR resources. All costs are in 2020 dollars. Because this technology is not commercially available at the time of this analysis, we constrained the model to allow the first year of SMR resource builds in 2030.

30 https://www.pnas.org/doi/10.1073/pnas.2111833119

31 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Figure D.8: Capital Cost Curve for Advanced Nuclear Small Modular Reactors



5. Resource Technologies Not Modeled

This section discusses the resource technologies PSE considered but did not model in this 2023 Electric Report. Some technologies, such as coal, are becoming obsolete in a clean energy landscape; others PSE determined to be either geographically or technologically infeasible for PSE's system at this time.

5.1. Renewable Resources Not Modeled

Several renewable resource technologies were not modeled in this 2023 Electric Report because 1) the technologies are in the early development stages and cost and operational data is lacking; 2) the technology is not feasible within geographic proximity to PSE; and/or 3) the technology has not been built to operate on a large, utility scale. Several of these technologies are summarized in this section.

5.1.1. Solar Thermal Plants

Solar thermal plants focus the direct irradiance of the sun to generate heat that produces steam, which in turn drives a conventional turbine generator. Two general types are used or in development today, trough-based and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun on a horizontal pipe carrying water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A transfer fluid collects and transfers the heat to make steam. Thermal solar plants have been operating successfully in California since the 1980s.[32]

5.1.2. Fuel Cells

Fuel cells combine fuel and oxygen to create electricity, heat, water, and other by-products through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, and larger ones can power equipment, buildings, or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures, and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. Fuel cell systems must be cost-competitive with and perform as well as traditional power technologies over the system's life[33] to be economical.

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the U.S. Department of Energy's report *State of the States: Fuel Cells in America 2017*,[34] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that California remains the leader with the greatest number of stationary fuel cells. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington State offers no incentives specific to stationary fuel cells. The EIA, estimates fuel cell capital costs to be approximately $7,224 per kW.[35]

5.1.3. Geothermal

Geothermal generation technologies use the natural heat under the earth's surface to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

32 SEIA, Solar Spotlight – California for Q3 2018, December 2018: https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_California_1.pdf.

33 U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.

34 U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2017," dated January 2018, https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf.

35 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

- Dry steam plants use hydrothermal steam from the earth to power turbines directly. Dry steam plants were the first type of geothermal power generation technology developed.[36]
- Flash steam plants operate similarly to dry steam plants but use low-pressure tanks to vaporize hydrothermal liquids into steam. This technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius) like dry steam plants.[37]
- Binary-cycle power plants can use lower-temperature hydrothermal fluids to transfer energy through a heat exchanger to a liquid with a lower boiling point. This system is an entirely closed loop; no steam emissions from the hydrothermal fluids are released. Most new geothermal installations will likely be binary-cycle systems due to the limited emissions and greater potential sites with lower temperatures.[38]
- Enhanced geothermal or hot dry rock (HDR) technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[39]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower-than-anticipated production from the geothermal resource. In 2021, geothermal power plants in seven states produced about 16 GWh, equal to 0.4 percent of total U.S. utility-scale electricity generation.[40] As of November 2019, 2.5 GW of geothermal generating capacity was online in the United States.[41] Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and Idaho's 15.8 MW Raft River plant.

The EIA estimates capital costs for geothermal resources are approximately $2,521/MW.[42] Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that can be built in the Northwest Power Pool region, where most of the proposed sites are located. Site-specific factors, including resource size, depth, and temperature, can significantly affect costs.

5.1.4. Waste-to-energy Technologies

Converting wastes to energy is a way to capture the inherent energy locked in wastes. Generally, these plants take one of the following forms.

- Waste combustion facilities: These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. Waste combustion is a well-established technology, with 75 plants operating in the United States, representing 2,534 MW in generating capacity. According to the U.S. EPA's website, only one new facility has opened since 1995. However, some existing facilities have expanded their capacity to convert more waste into electricity.[43]

36 http://energy.gov/eere/geothermal/electricity-generation
37 Ibid
38 Ibid
39 http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
40 U.S. Energy Information Administration, https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php.
41 U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=42036.
42 U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020.
43 U.S. Environmental Protection Agency website. http://energyrecoverycouncil.org/wp-content/uploads/2019/10/ERC-2018-directory.pdf.

- Waste thermal processing facilities include gasification, pyrolysis, and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, the facility generates syngas, which can be combusted for heat or to produce electricity. Several pilot facilities once operated in the United States, but only a few remain.
- Landfill gas and municipal wastewater treatment facilities: Most landfills in the United States collect methane from decomposing landfill waste. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both processes produce low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then fuel a boiler for heat recovery or a turbine or reciprocating engine to generate electricity. According to the U.S. EPA's website, as of June 2022, there are 541 operational landfill gas energy projects in the United States.[44]

Washington's RPS initially included landfill gas as a qualifying renewable energy resource but excluded municipal solid waste. The passage of Washington State Senate Bill (ESSB) 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

Several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities — the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant, and the Emerald City facility — use landfill gas for electric generation in Washington State; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and can produce a maximum capacity of 36.5 MW.[45] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and can produce up to 22 MW of electric capacity.[46] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.8 MW of electricity. The facility became commercially operational in December 2013.[47] Puget Sound Energy purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which we discuss in Appendix C. The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies gas to meet pipeline natural gas quality; the gas is sold to PSE rather than used to generate electricity.

Few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2018* estimates municipal solid waste-to-energy costs to be approximately $8,742 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience for more than 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion

[44] U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/lmop/basic-information-about-landfill-gas, June 2022.

[45] Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10 MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, January 2019.

[46] Spokane Waste to Energy website. Retrieved from https://my.spokanecity.org/solidwaste/waste-to-energy, January 2019.

[47] BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC and renamed Emerald LFGTE Facility). Retrieved from https://energyneeringsolutions.com/wp-content/uploads/2018/02/ESI_CaseStudy_Emerald.pdf, January 2019.

facilities, the output is typically more stable because we can more easily control the amount of input waste and heat content.

5.1.5. Wave and Tidal

We can use the natural movement of water to generate energy through the flow of tides or the rise and fall of waves.

Tidal generation technology uses tidal flow to spin rotors that turn a generator. Two significant plant layouts exist: barrages, which use artificial or natural dam structures to accelerate the flow through a small area, and in-stream turbines, placed in natural channels. France's Rance Tidal Power barrage system was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. The 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada, is the world's next-largest operating tidal generation facility. China, Russia, and South Korea have smaller tidal power installations.[48] Also worth noting is the planned 398 MW MeyGen Tidal Energy Project in Scotland, which, if completed, would be the largest tidal generation facility in the world. The project's first phase, a 6 MW demonstration array, began operating in April 2018.[49] The project is designed to be constructed in multiple phases, with phase 2B completed in September 2020.[50]

Wave generation technology uses the rise and fall of waves to drive hydraulic systems and fueling generators. Technologies tested include floating devices and bottom-mounted devices. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[51] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's website, the 20 kW Azura device, developed by EHL Group and Northwest Energy Innovations, is the nation's first grid-connected wave energy converter device.[52]

Since mid-2013, several significant wave and tidal projects and programs have slowed, stalled, or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting, and the early stage of the technology's development. The FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After operators obtain permits, they must conduct studies of the site's water resources and aquatic habitat before they install test equipment.

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48 U.S. Energy Information Administration website. Retrieved from https://www.eia.gov/energyexplained/index.php?page=hydropower_tidal, January 2019.
49 https://tethys.pnnl.gov/project-sites/meygen-tidal-energy-project-phase-i
50 Ibid
51 CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
52 The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

There are three tidal demonstration projects in various stages of development in the United States located on Roosevelt Island (New York), Western Passage (Maine), and Cobscook Bay (Maine). Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[53] Several years ago, Tacoma Power considered and abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years, and their production volumes are limited, so costs remain high, and the durability of the equipment over time is uncertain.

5.2. Energy Storage Not Modeled

Several energy storage technologies are still in development, or are still new enough that reliable cost and operational data are not yet available. Some of these technologies are described in this section.

5.2.1. Flow Batteries

Flow batteries are rechargeable batteries that are charged by two chemical components dissolved in liquids contained within the system. A membrane separates the two components, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can offer the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time.

In 2016, Avista Utilities installed the first large-scale[54] U.S. flow battery storage system in Washington; in 2017, utilities in Washington and California installed two additional flow battery facilities. Approximately 70 MW and 250 MWh of flow batteries have been deployed worldwide, almost all in medium- to large-scale projects.[55] Flow batteries have limited market penetration at this time.

5.2.2. Liquid Air Energy Storage

Liquid Air Energy Storage (LAES) technology involves supercooling air into a liquid state for storage in insulated tanks. As the air is reheated and expands back into a gaseous state, the pressure created moves a turbine. The LAES technology utilizes a relatively small footprint and has no other special siting requirements, giving the technology geographical flexibility and the potential to be deployed as a distributed resource. This technology can store energy for long periods with little degradation and provide long-duration discharge to the grid. Finally, additional insulated tanks are the main component required to scale up the size and capacity of a LAES system, making this technology modular, flexible, and inexpensive compared to other storage alternatives.

[53] The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project, October 2014.

[54] Large-scale refers to a facility that is typically grid connected and greater than 1 MW in capacity. Small-scale refers to systems typically connected to a distribution system that are less than 1 MW in power capacity.

[55] IDTechEx Research, Batteries for Stationary Energy Storage 2019-2029.

The LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage, and expansion of pressurized gasses. Although the components are based on proven technology currently used in industrial processes and available from large Original Equipment Manufacturers (OEMs), no commercial LAES systems are currently in operation in the U.S. However, in June 2018, Highview Power Storage, a small U.K. company partnering with GE to develop utility-scale LAES systems, launched the world's first grid-scale LAES plant at a landfill gas site near Manchester, England. The pilot plant can produce 5 MW/15MWh of storage capacity. Furthermore, the company is constructing a 50 MW LAES resource in Vermont and up to 2 GWh storage in Spain. According to Highview Power Storage, the technology can be scaled up to hundreds of megawatts to better align with the needs of cities and towns.[56]

5.2.3. Hydrogen Energy Storage

Hydrogen energy storage systems use surplus renewable electricity to power a process of electrolysis, passing a current through a chemical solution to separate and create hydrogen. This renewable hydrogen is then stored for later conversion back into electricity and for other applications such as fuel for transport. Hydrogen does not degrade over time and can be stored for long periods in large quantities, most notably in underground salt caverns. This pure hydrogen can be used for re-electrification in a fuel cell or combusted in a gas turbine.

In 2018, Enbridge Gas Distribution and Hydrogenics opened North America's first multi-megawatt power-to-gas facility using renewably sourced hydrogen, the 2.5 MW Markham Energy Storage Facility in Ontario, Canada. In the United States, SoCalGas has partnered with the National Fuel Cell Research Center to install an electrolyzer demonstration project, powered by the University of California at Irvine on-campus solar electric system. SoCalGas also partnered with NREL to install the nation's first biomethanation reactor system located at their Energy Systems Integration Facility (ESIF) in Golden, Colo. Full-scale hydrogen energy projects are also in development, most notably a 1,000 MW Advanced Clean Energy Storage (ACES) facility in Utah through a partnership of Mitsubishi Hitachi Power Systems and Magnum Development, which owns large salt caverns to store the hydrogen. Xcel Energy is partnering with the NREL to create a 110 kW wind-to-hydrogen project using the site's hydrogen fueling station for storage, to be converted back to electricity and fed to the grid during peak demand hours.[57]

5.2.4. Solid Gravity Storage

Solid gravity storage is an emerging alternative to PHES. Several companies are pioneering different forms of solid gravity storage technology, which can involve raising and lowering large bricks using a crane or elevator system or moving a rail car loaded with weight along an inclined rail track.

Only a handful of prototypes or demonstration projects are in operation now. The company Energy Vault has constructed a modular crane kinetic storage demonstration unit in Switzerland, storing 20-80 MWh of energy and delivering 4–8 MW of continuous power to the grid.[58] The European company, Gravitricity, has built an above-

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[56] Forbes website. Retrieved from https://www.forbes.com/sites/mikescott/2018/06/08/liquid-air-technology-offers-prospect-of-storing-energy-for-the-long-term/#3137f759622f, January, 2019.
[57] Sources: Fuel Cell & Hydrogen Energy Association, Energy Storage Association, Utility Dive.
[58] Energy Vault website: https://www.energyvault.com/gravity.

ground prototype of their underground kinetic storage technology, which is currently operating in Scotland.[59] The rail kinetic storage company, Advanced Rail Energy Storage, has been contracted to build a facility in Nevada which will supplement the CAISO grid but is still in the planning phase.[60] However, these technologies are still emerging, and publicly available and reliable data on operating parameters are costs are unavailable at this time.

5.3. Thermal Resources Not Modeled

Laws, practical obstacles, and cost constrain other potential thermal resource alternatives. Long-term coal-fired generation is not a resource alternative because RCW 80.80[61] precludes utilities in Washington from entering into new long-term agreements for coal. The Clean Energy Transformation Act (CETA) also requires utilities to eliminate coal-fired generation from their state portfolios by 2025. New traditional nuclear generation is neither practical nor feasible.

5.3.1. Coal

Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

New coal-fired generation is not a resource alternative for PSE because RCW 80.80[61] sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.[62] With current technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard. Carbon capture and sequestration technology are not yet effective or affordable enough to significantly reduce those levels. Furthermore, CETA passed on May 7, 2019, explicitly requires Washington state utilities to eliminate coal-fired electricity generation from their state portfolios by 2025.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

5.3.2. Traditional Nuclear

Capital and operating costs for large-scale nuclear power plants are significantly higher than most conventional and renewable technologies such that only a handful of the largest capitalized utilities can consider this option. In addition, nuclear power carries significant technology, credit, permitting, policy, and waste disposal risks over other baseload resources.

[59] Gravitricity website: https://gravitricity.com.
[60] S&P Global IQ Pro Platform. Available at: https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home.
[61] RCW 80.80
[62] To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

There is little reliable data on recent U.S. nuclear developments from which we can make reasonable and supportable cost estimates. The construction cost and schedule track record for nuclear plants built in the U.S. in the 1980s, 1990s, and 2000s have been poor at best. Actual costs have been far higher than projected, construction schedules have been subject to lengthy delays, and interest rate increases have resulted in high financing charges. The Fukushima disaster in 2011 also motivated changes to technical and regulatory requirements and contributed to project cost increases.

With many other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution, and the bankruptcy of a major nuclear supplier all lead to significant uncertainty. These factors make a full-scale nuclear plant an unwise and unnecessary risk for PSE.

5.3.3. Aeroderivative Peakers

Aeroderivative Combustion Turbines (Aero) combustion turbines are a mature technology. However, suppliers continually bring new aeroderivative features and designs to market. These turbines can be fueled by natural gas, oil, renewable natural gas, hydrogen, biodiesel, or a combination of fuels (dual fuel). A typical heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another critical difference between aero and frame units is size. Aero CTs are typically smaller, from 5 to 100 MW each. This small scale allows for modularity but also tends to reduce economies of scale.

The Aero peakers are higher cost than the Frame peakers and smaller and more modular than the frame peakers. We modeled the Aero peakers for several IRPs in a row but never selected them as a cost-effective resource given the higher cost than the frame peakers. Given that we are already modeling a large frame peaker and the smaller Recip Peaker to show how a smaller, more modular unit can benefit the portfolio, we felt there was enough diversity in the resource alternatives and removed the Aero peakers as an option.

This technology is commercially available. Greenfield development requires approximately three years.

6. Tables

Table D.1: Biomass Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Assumptions	2023 Electric Report Assumptions
Nameplate Capacity (MW)	15	15
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	--	--
Capacity Credit (ELCC), Summer (%)	--	--
Operating Reserves (%)	3	3
Capacity Factor (%)	85	85
Capital Cost ($/kW)	7,093	4,822
O&M Fixed ($/kW-yr)	207	151
O&M Variable ($/MWh)	6	6
Land Area (acres/MW)	6 – 8	6 - 8
Degradation (%/year)	--	--
Location	WA	WA
Fixed Transmission ($/kW-yr)	22.2	23
Variable Transmission ($/MWh)	0.00	0.26
Loss Factor to PSE (%)	1.9	1.9
Heat Rate – Baseload (HHV) (Btu/kWh)	14,599	14,599
NOx (lbs/MMBtu)	0.03	0.03
SO2 (lbs/MMBtu)	0.03	0.03
CO2 (lbs/MMBtu)	213	213
First Year Available	2024	2024[i]
Economic Life (Years)	30	30
Greenfield Dev. & Const. Lead-time (Years)	3.3	3.3

Notes:

i. Given the 2021 All Source RFP process, it is possible some of these resources will be in process of development before the beginning of this analysis, and will therefore be available as soon as 2024.

Table D.2: Wind Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values					2023 Electric Report Values					
	Offshore	WA	MT East / Central	ID	WY East / West	Offshore	BC	WA	MT East / Central	ID	WY East / West
Nameplate Capacity (MW)	100	100	200	400	400	100	100	100	100	100	100
Winter Peak Capacity (MW)	--	--	--	--	--	32	34	13	36	48	182
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	48	18	22 / 30	24	40 / 28	32	34	13	36	12	46
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	--	--	41	13	5	23	17	34
Operating Reserves (%)	3	3	3	3	3	3	3	3	3	3	3
Capacity Factor (%)	35	37	44 / 40	33	33	42	41	37	41 / 48	15	46 / 36
Capital Cost ($/kW)	5,609	1,806	1,806	1,806	1,806	4,728	1,730	1,464	2,472	1,772	1,772
O&M Fixed[ii] ($/kW-yr)	110	41	41	41	4	71	42	42	42	42	42
O&M Variable ($/MWh)	0	0	0	0	110 / 0	0	0	0	0	0	0
Land Area (acres/MW)	--	48.2	48.2	48.2	48.2	--	48.2	48.2	48.2	48.2	48.2
Degradation (%/year)	0	0	0	0	0	0	0	0	0	0	0
Fixed Transmission[iii] ($/kW-yr)	33	33	50	158	231 / 211	31	62	31	59	61	97
Variable Transmission ($/MWh)	10	10	10	10	10	0.26	0.26	0.26	0.26	0.26	0.26
Loss Factor to PSE (%)	1.9	1.9	4.6	4.6	4.6	1.9	1.9	1.9	4.6	6.9	6.9
First Year Available	2030	2024	2024	2026	2026	2030	2024[iv]	2024[iv]	2024[iv]	2026	2026

Parameter	2021 IRP Values					2023 Electric Report Values					
	Offshore	WA	MT East / Central	ID	WY East / West	Offshore	BC	WA	MT East / Central	ID	WY East / West
Economic Life (Years)	30	30	30	30	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time (Years)	3	2	3	2	2	3	2	2	2	2	2

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches, with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy.

ii. Fixed operations and maintenance for wind, solar, battery storage, and hybrid resources change over time. This table shows the 2023 value.

iii. The Wyoming wind and solar rates apply to 2024–2030 and assume the use of Idaho Power Company transmission infrastructure. Between 2031 and 2045, fixed transmission rates for wind and solar resources from Wyoming decreased to $67 and $64/kW-year, respectively, assuming the Gateway West transmission line is completed in 2030.

iv. Given the 2021 All Source RFP process, some of these resources may be in development before the beginning of this analysis and be available as soon as 2024.

Table D.3: Solar Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values				2023 Electric Report Values			
	WA (East / West)	ID	WY (East / West)	DER Rooftop / Ground-mounted WA West	WA (East / West)	ID	WY (East / West)	DER Rooftop & Ground-mounted WA West
Nameplate Capacity (MW)	100 / 50	400	400	300 / 50	100	100	100	5
Winter Peak Capacity (MW)	--	--	--	--	4	32	42	0
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	4 / 1	3	6	2 / 1	4	8	11	4
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	--	54	38	29	28
Operating Reserves (%)	3	3	3	3	3	3	3	--
Capacity Factor (%)	24 / 16	26	27 / 28	16	25 / 20	27	29 / 30	17
Capital Cost ($/kW)	1,675	1,675	1,675	4,389 / 3,568	1,230	1,537	1,537	2,287
O&M Fixed[ii] ($/kW-yr)	22	22	22	0	19	19	19	25
O&M Variable ($/MWh)	0	0	0	0	0	0	0	0
Land Area (acres/MW)	5 – 7	5 – 7	5 – 7	-- / 5 – 7	5 – 7	5 – 7	5 - 7	--
Degradation (%/year)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	--
Fixed Transmission[iii] ($/kW-yr)	30 / 8	155	228 / 208	0	28	58	94	5
Variable Transmission ($/MWh)	10	10	10	0	0.26	0.26	0.26	0.26
Loss Factor to PSE (%)	1.9 / --	4.6	4.6	--	1.9	6.9	6.9	--
First Year Available	2024	2026	2026	2024	2024[iv]	2026	2026	2024
Economic Life (Years)	30	30	30	30	30	30	30	30
Greenfield Lead-time (Years)	1	1	1	1	1	1	1	--

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy.

ii. Fixed operations and maintenance for wind, solar, battery storage, and hybrid resources change over time. The 2023 value is in this table.

iii. Rates for WY solar apply to 2024–2030 and assume the use of Idaho Power Company transmission infrastructure. Between 2031 and 2045, fixed transmission rates for solar from WY go down to $64/kW-year, assuming the Gateway West transmission line is completed in 2030.

iv. Given the 2021 All Source RFP process, it is possible that some of these resources will be in development before the beginning of this analysis and will be available as soon as 2024.

Table D.4: Generic Energy Storage Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Electric Report Values					
	PHES	BESS		PHES		BESS			
	Closed Loop (8-hour)	Li-Ion 2-hour	Li-Ion 4-hour	Closed Loop (8-hour) WA, OR	Closed Loop (8-hour) MT	Li-Ion 2-hour	Li-Ion 4-hour	Li-Ion 6-hour	DER Batteries (3-hour)
Nameplate Capacity (MW)	25	25	25	100	100	100	100	100	5
Winter Peak Capacity (MW)	--	--	--	99	99	85	96	98	--
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	37.2	12.4	24.8	99	99	85	96	98	--
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	99	99	90	97	98	--
Operating Reserves (%)	3	3	3	3	3	3	3	3	3
Capital Cost ($/kW)	2,656	1,172	2,074	3,910	3,602	805	1,310	1,819	3,923
O&M Fixed ($/kW-year)	16	23	32	18	18	20	33	45	98
O&M Variable ($/MWh)	0.00	0.00	0.00	0.51	0.51	0.00	0.00	0.00	0.00
Forced Outage Rate (%)	--	--	--	1	1	2	2	2	0.1
Degradation (%/year)	0	--	--	(ii)	(ii)	(iv)	(iv)	(iv)	2.2
Operating Range (%)	147-500[iii] MW	2	2	147-500[iii] MW	147-500[iii] MW	2	2	2	10
R/T Efficiency (%)	80	82	87	80	80	86	87	88	87
Discharge at Nominal Power (Hours)	8	2	4	8	8	2	4	6	3
Maximum Storage (MWh)	200	50	100	800	800	200	400	600	15
Fixed Transmission ($/kW-year)	22	0	0	23	50	0	0	0	0
Variable Transmission ($/MWh)	0.00	0.00	0.00	0.26	0.26	0.00	0.00	0.00	0.00
First Year Available	2028	2023	2023	2029	2029	2024[v]	2024[v]	2024[v]	2024
Economic Life2 (Years)	30	30	30	40	40	30	30	30	30
Greenfield Dev. & Const. Leadtime (years)	5–8	1	1	5–8	5–8	1	1	1	0.5

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy..

ii. PHES degradation is close to zero.

iii. The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).
iv. Fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life.
v. Given the 2021 All Source RFP process, it is possible that some of these resources will be in development before the beginning of this analysis and will be available as soon as 2024.

Table D.5: Hybrid Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Progress Report Values		
	MT Wind + PHES	Wind + Battery (WA)	Solar + Battery (WA)	Wind + Battery (WA)	Solar + Battery (WA)	Wind + Solar + Battery (WA)
Nameplate Capacity (MW)	300	125	125	150	150	250
Winter Peak Capacity (MW)	--	--	--	101	77	83
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	54	24	14	67	51	33
Capacity Credit (ELCC), Summer (%)	--	--	--	53	87	54
Operating Reserves (%)	3	3	3	3	3	3
Capacity Factor (%)	44	37	24	37	25	62
Capital Cost ($/kW)	4,016	2,680	2,563	(i)	(i)	(i)
O&M Fixed ($/kW-year)	57	64	46	(i)	(i)	(i)
O&M Variable ($/MWh)	0	0	0	0	0	0
Land Area (acres/MW)	48.2	48.2	5-7	48.2	48.2	48.2
Degradation (%/year)	0	0.5	0.5	(ii)	(iii)	(ii, iii)
Fixed Transmission ($/kW-year)	50	33	30	31	28	36
Variable Transmission ($/MWh)	10	10	10	0.26	0.26	0.26
Loss Factor to PSE (%)	4.6	1.9	1.9	1.9	1.9	1.9
First Year Available	2028	2024	2024	2024[iv]	2024[iv]	2024[iv]
Economic Life (Years)	30	30	30	30	30	30
Greenfield Dev. & Const. Lead time (years)	5 – 8	2	1	2	1	2
Operating Range (%)	147-500 MW	2	2	2	2	2
R/T Efficiency (%)	80	82	82	87	87	87
Discharge at Nominal Power (Hours)	8	2	2	4	4	4

Notes:

i. We input individual capital costs and fixed operations and maintenance values for each element of the hybrid resource into the AURORA model. The individual hybrid component capital costs are adjusted (discounted) from stand-alone counterparts to account for savings in installation, grid connection, and system balance.

ii. Battery fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life; degradation for wind is 0 percent.

iii. Battery fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life; degradation for solar is 0.5 percent.

iv. Given the 2021 All Source RFP process, some of these resources may be in development before the beginning of this analysis and therefore be available as soon as 2024.

Table D.6: Generic Combustion Turbine Resource Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Electric Report Values					
	Frame Peaker	CCCT	Recip Peaker	Frame Peaker[1]	CCCT[i]	Recip Peaker[i]	Frame Peaker Blend H_2	Recip Peaker Blend H_2	Frame Peaker Biodiesel
Nameplate Capacity (MW)	225	336	219	225	336	219	225	219	225
Winter Capacity Primary (23º F) (MW)	237	348	219	237	348	219	237	219	237
Incremental Capacity DF (23º F) (MW)	--	19	--	--	19	--	--	--	--
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	--	--	--	96	96	84	96	84	96
Capacity Credit (ELCC), Summer (%)	--	--	--	98	96	92	98	92	98
Capital Cost ($/kW)	948	1,255	1,671	944	987	2,045	944	2,045	944
O&M Fixed ($/kW-year)	8	13	6	16	23	15	16	15	10
Flexibility ($/kW-year)	--	--	--	-10	-5	-28	-10	-5	-10
O&M Variable ($/MWh)	7.86	3.32	7.05	1.02	6.16	1.16	1.02	1.16	1.02
Start-up Costs ($/Start)	7.86	3.32	7.05	11,729[ii]	0	0	11,729[ii]	0	11,729[ii]
Operating Reserves (%)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Forced Outage Rate (%)	2.4	3.9	3.3	2.4	3.9	3.3	2.4	3.3	2.4
Heat Rate — Baseload (HHV) (Btu/kWh)	9,904	6,624	8,445	9,904	6,624	8,445	9,904	8,445	9,904
Heat Rate — Turndown (HHV) (Btu/kWh)	15,794	7,988	11,288	15,794	7,988	11,288	15,794	11,288	15,794
Heat Rate — DF (Btu/kWh)	--	8,867	--	--	8,867	--	--	--	--
Min Capacity (%)	30	38	30	30	38	30	30	30	30
Start Time (hot) (minutes)	21	45	5	21	45	5	21	5	21
Start Time (warm) (minutes)	21	60	5	21	60	5	21	5	21

Parameter	2021 IRP Values			2023 Electric Report Values					
	Frame Peaker	CCCT	Recip Peaker	Frame Peaker[1]	CCCT[i]	Recip Peaker[i]	Frame Peaker Blend H_2	Recip Peaker Blend H_2	Frame Peaker Biodiesel
Start Time (cold) (minutes)	21	150	5	21	150	5	21	5	21
Start-up fuel (hot) (MMBtu)	366	839	69	366	839	69	366	69	366
Start-0up fuel (warm) (MMBtu)	366	1,119	69	366	1,119	69	366	69	366
Start Fuel Amount (warm) (MMBtu/MW/Start)	1.544	3.214	0.317	1.54	3.21	0.32	1.54	0.32	1.54
Start-up fuel (cold) (MMBtu)	366	2,797	69	366	2,797	69	366	69	366
Ramp Rate (MW/minutes)	40	40	16	40	40	16	40	16	40
Fixed Ga Transport ($/Dth/Day)	0.00	0.25	0.25	0.00	0.27	0.27	0.00	0.00	0.00
Fixed Gas Transport ($/kW-year)	0.00	14.67	18.70	0.00	15.41	19.65	0.00	20	0.00
Variable Gas Transport ($/MMBtu)	0.04	0.06	0.06	0.04	0.06	0.06	0.04	0.06	0.06
Fixed Transmission ($/kW-year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable Transmission ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2 - Natural Gas (lbs./MMBtu)	118	118	118	118	118	118	118 declining to 0	118 declining to 0	0
NOx - Natural Gas (lbs./MMBtu)	0.004	0.008	0.029	0.004	0.008	0.029	0.004	0.029	0.004
First Year Available	2025	2025	2025	2024[iii]	2024[iii]	2024[iii]	2024[iii]	2024[iii]	2024[iii]
Economic Life (years)	30	30	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time (years)	1.8	2.7	2.3	1.8	2.7	2.3	1.8	2.3	1.8

Notes:

i. Technology assumptions: the frame peaker is a 1x0 F-Class Dual Fuel; the CCCT is a 1x1 F-Class; and the reciprocal peaker is a 12x0 18 MW class reciprocating internal combustion engine.

ii. The startup cost adder of $52.13/start/MW, from the 2020 CAISO default values, is applied to the frame peaker.

iii. Given the 2021 All Source RFP process, some frame peakers may be in development before the beginning of this analysis and therefore be available as soon as 2024.

Table D.7: Natural Gas Transportation Costs for Western Washington CCCT and Reciprocating Engine Peakers without Oil Backup — 100% Sumas on NWP + 100% Station 2 on West Coast

Pipeline/Resource	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion[i]	0.6900	0.0083	0.0013	1.41	3.85
Westcoast Expansion[ii]	0.7476	0.0551	--	--	--
Basis Gain[iii]	(0.8139)	--	--	2.71	3.85
Gas Storage[iv]	0.0767	--	--	2.00	3.85
Total	**0.7004**	**0.0634**	**0.0013**	**6.12**	**3.85**

Notes:

i. Estimated NWP Sumas to PSE Expansion.

ii. Estimated West coast Expansion Fixed Demand.

iii. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses, and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0551 per Dth per day, and fuel losses are 2.71 percent per Dth. A state utility tax of 3.852 percent applies to the natural gas price.

iv. We based storage requirements on current storage withdrawal capacity to peak plant demand for the natural gas for power portfolio (approximately 20 percent).

Table D.8: N Natural Gas Transportation Costs for Western Washington Frame Peakers with Oil Backup — No Firm Gas Pipeline

Pipeline / Resource	Fixed Demand ($/Dth/day)	Weighted Average Variable Demand ($/Dth)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Demand	0.0000	0.0300	0.0083	0.0013	1.41	3.82
Total	**0.0000**	**0.0300**	**0.0083**	**0.0013**	**1.41**	**3.82**

Table D.9: Green Hydrogen Blend Rate

Year	Green Hydrogen Blend Rate (%, H_2 energy / total energy)
2025	0
2030	30
2035	50

Year	Green Hydrogen Blend Rate (%, H_2 energy / total energy)
2040	70
2045	100

Table D.10: Resource Access to a Green Hydrogen Fuel Supply

Resource	Access Year
New generic resources	2030
Frederickson 1, 2, CC	2030
Whitehorn 1, 2	2030
Ferndale	2030
Encogen	2035
Fredonia 1,2,3,4	2035
Mint Farm	2035
Sumas	2040
Goldendale	2045

Table D.11: Advanced Nuclear Small Modular Reactor Resource Assumptions, 2020 $

Parameter	Assumptions
Nameplate Capacity (MW)	50
Capacity Credit, (Effective Load Carrying Capacity) (%)	100%
Operating Reserves (%)	3%
Capital Cost ($/KW)	$10,930
O&M Fixed ($/KW-yr)	$114
O&M Variable ($/MWh)	$3

Parameter	Assumptions
Forced Outage Rate (%)	10%
Heat Rate – Baseload (HHV) (Btu/KWh)	10,046
Heat Rate – Turndown (HHV) (Btu/KWh)	12,500
Min Capacity (%)	30%
Start Time (minutes)	60
Ramp Rate (MW/min)	30
Location	PSE
Fixed Transmission ($/KW-yr)	$0
Variable Transmission ($/MWh)	$0
First Year Available	2028
Economic Life (Years)	30
Greenfield Dev. & Const. Lead Time (years)	4