Technical Appendix B: Existing System Parameters and Policies

Contents

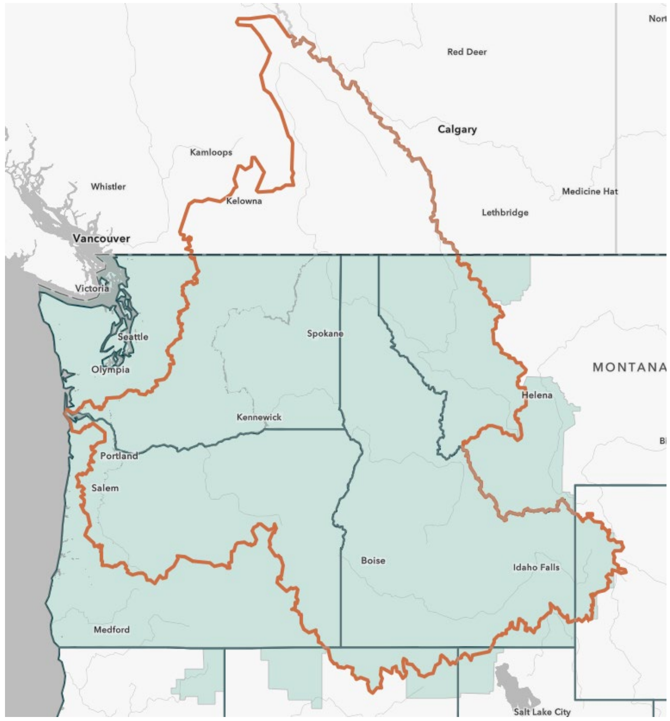
Existing System

The region finds itself in a state of flux, faced with higher load forecasts, steeper clean policy goals, an unpredictable federal policy landscape, a more variable generation mix, and uncertainty around how best to meet these challenges. One necessity of planning under such uncertainty is adequately representing what is known so that we can face the unknowns on firm footing. Identifying and accurately depicting the existing electric system helps us to define the parameters that our computer modeling will be solving. This section does that by documenting and characterizing operating resources as well as identifying and explaining relevant policies.

Defining the Pacific Northwest

The Northwest Power Act directs the Council to develop a power plan for the Pacific Northwest, referred subsequently as the “region.” The Act defines this geographic area as the Columbia River basin plus the areas outside the basin where the Bonneville Power Administration sells firm power. That includes Oregon, Washington, Idaho, and the portion of Montana west of the Continental Divide.

Figure B - 1: Map of the Region as Defined by the Power Act



Description of Existing Fleet by Generating Resource

To understand what the capabilities of the existing system are to meet regional demand, we must determine which resources fall within that defined area. It is not always a case of where the resource is built. Some resources are built outside the region but serve regional load, or vice versa. The Council works with individual utilities to parse those plants so we can understand our footprint as best as possible.

The Council tracks all generating projects in the region in its project database.[1] The database includes project and technology specifications, operating parameters, historical annual energy, and much more. The database also includes an interactive map of power generation projects in the region.

For the Ninth Power Plan, the Council defines resources as operating or under construction, as well as owner-announced planned retirements and conversions. This represents the existing system capabilities and provides a sense of certainty from which we can project future needs. New resources available for the capital expansion model to select are discussed in Technical Appendix G – New Generating Resources.

[1] This workbook is updated dynamically and is available on the Council's website: https://www.nwcouncil.org/energy/energy-topics/power-supply.

Historical Generation

The history of regional generation is characterized by clear phases of development. The most important and lasting of these was the growth of the hydrosystem, with the bulk of the development occurring from the 1930s through the 1970s. The hydrosystem continues to provide the foundation of the region's energy landscape. In the wake of this large-scale development and in response to continued load growth, in the 1970s and 80s the region looked to coal and nuclear resources to supplement the hydro system. The late 90's saw the growth of natural gas in the region quickly followed in the mid-2000s by significant wind development. The rising cost of coal, cheap natural gas and growing awareness of the electricity sector's impact on climate change and the environment laid the groundwork for this shift. Starting in the late 2010s, the region looked to solar as an addition to the region's renewable fleet in an effort to meet growing load and tightening clean regulations. The most recent phase has seen the region looking to battery storage to increase resource adequacy and better optimize variable power from renewable generation.

Figure B - 2: Regional Resources Currently Operating

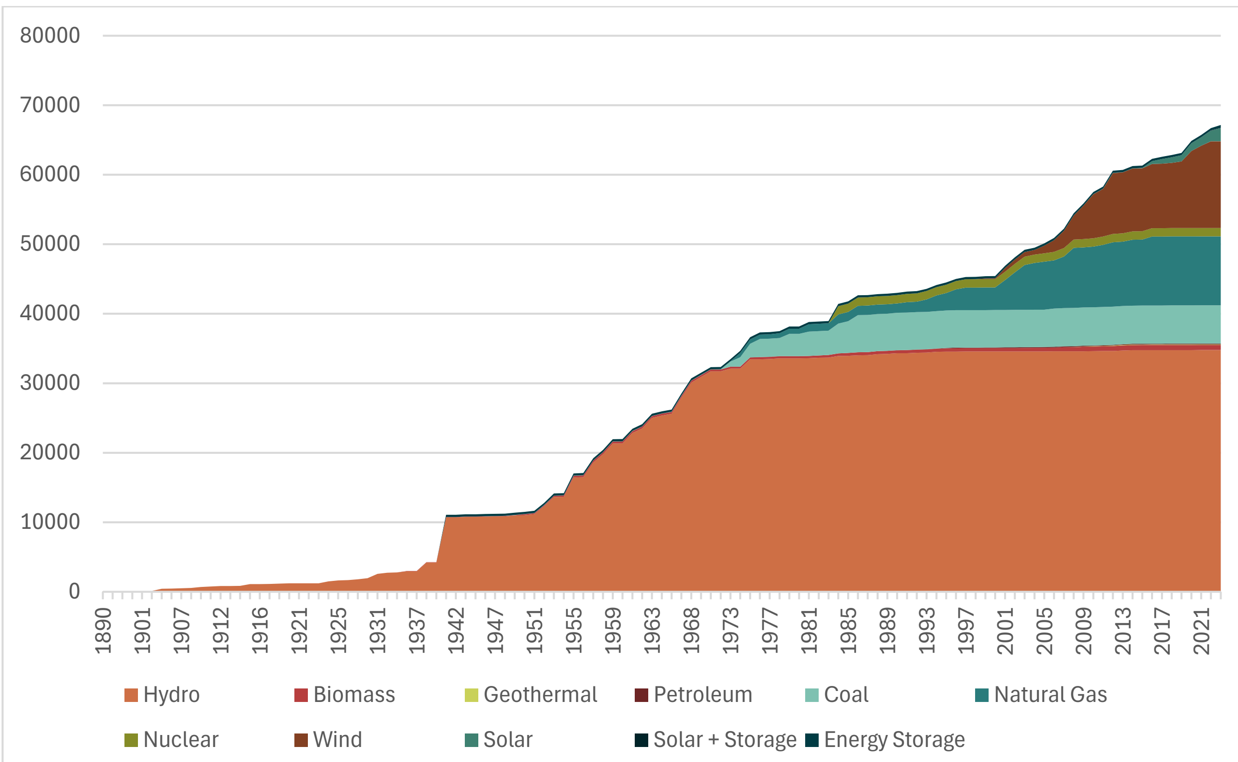
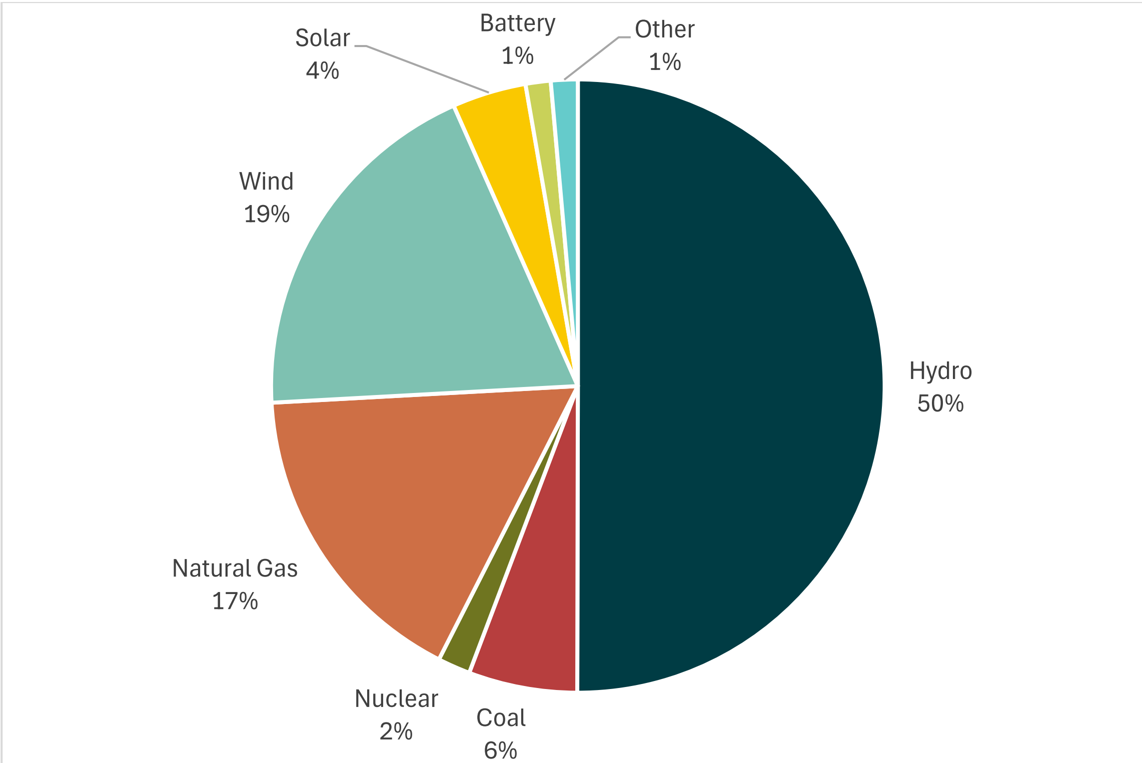


Figure B - 3: Current Installed Nameplate Capacity in the Region

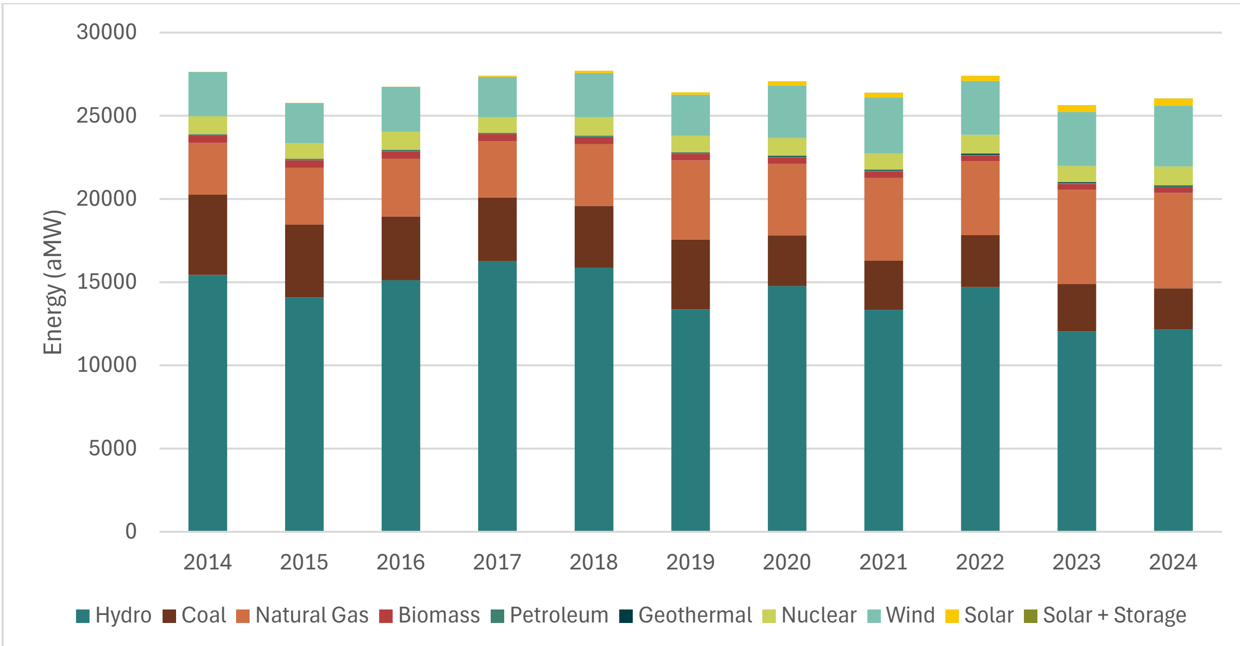


Historical Energy Production

The cumulative installed nameplate capacity of the region's existing system is not the same as the actual energy produced by that system. Hydro is the foundation of the region's energy supply and the rest of the system is utilized more or less to support the difference between load and hydro production. In high hydro years there is less need for supplemental generation from other sources, while lower hydro years rely more on the rest of the system, especially thermal production. As can be seen in Figure B - 4, 2017 and 2018 were higher hydro production years, and as a result there is less generation from other resources. On the opposite end of the spectrum, 2023 and 2024 were lower hydro years and the resulting compensation can be seen in higher generation from other regional resources. Beyond the hydro-driven variation, recent development trends can be seen in the year-to-year production with coal generation decreasing and renewables, especially solar, showing up more in recent years.

Additionally, most resources don't operate at their full capacity most of the time. Hydro, depending on the water year, is operating somewhere around 40% of the system's total capacity. Other renewables, by virtue of their variable fuel types, are similarly not providing the system with 100% capacity 100% of the time. A renewable plant's capacity factor is dependent on location, season, and time of day, but as an annual average over the past 10 years regional wind has had a capacity factor about 30% and solar has been at about 20%. Thermal generation fuel is generally available, so their utilization depends more on the economics of running those resources. Because thermal fuel is an additional cost, they are often the first to be curtailed to save on fuel cost. However, cost is not the only consideration, some thermal resources are less flexible than others. Nuclear plants, for example, are difficult to turn on and off, while a gas plant, depending on the technology type, can be ramped up and down relatively easily. The region's remaining nuclear plant operates at about 90% capacity, while natural gas is utilized more flexibly, with an average annual capacity factor of about 50%.

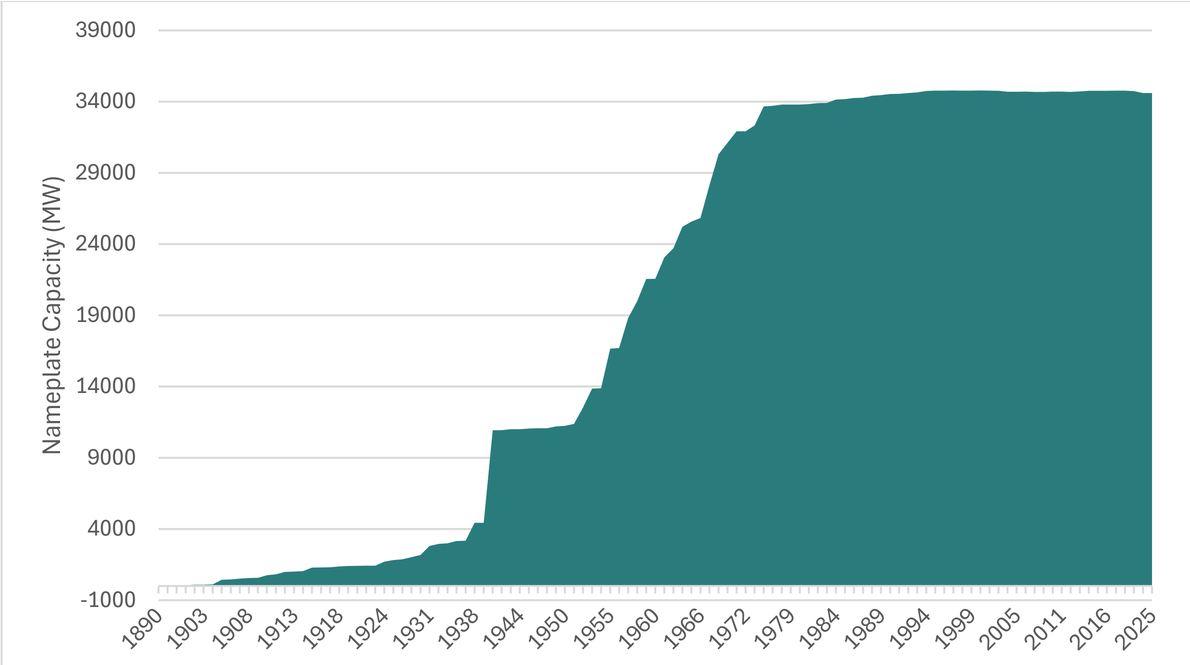
Figure B - 4: Historical Annual Energy Production



Hydropower

The Columbia River and its associated tributaries comprise one of the major economic and environmental resources in the Pacific Northwest. Originating in the Rocky Mountains in Canada, the mainstem Columbia River extends a total of 1,243 miles to the Pacific Ocean. Beginning in the 1930s, development of the Columbia Basin hydrosystem included over 250 hydropower dams and about 200 non-powered dams (built for other purposes such as irrigation and flood control). Today, the Columbia River Basin hydropower system delivers carbon-free, renewable energy that, on average, supplies about half of the electricity generation in the region. Figure B - 5 shows the growth of hydroelectric power in the region since 1890. This figure does not show the hydropower retirements in the system due to scale, but the region has seen about 400MWs of hydro retirement.

Figure B - 5: Regional Hydroelectric Nameplate Capacity Installed Over Time



Beginning in 1980, the operational flexibility and generating capability of the Columbia River Basin hydropower system has been reduced, due in part to efforts to better protect fish and wildlife.[2] Over the past forty years, the pattern of reservoir storage and release has shifted some winter river flow into the spring and summer periods for juvenile salmon migration. Minimum reservoir elevations have additionally been modified to provide better habitat and food supplies for resident fish. Other operational constraints on the system come from flood control, irrigation, recreation, and transportation to name a few.

Coal

Following the development of the Columbia River hydropower system, coal and nuclear power were viewed as the most economical new sources of electricity. Between 1968 and 1986, Northwest utilities brought into service 14 coal-fired units at six sites: Boardman (Oregon), Centralia (Washington), Colstrip (Montana), J.E. Corette (Montana), Jim Bridger (Wyoming), and North Valmy

[2] Under the Northwest Power Act, the Council is required to develop a Fish and Wildlife Program to protect, mitigate, and enhance the fish and wildlife affected by the development and operation of any hydroelectric project in the region. The Program is also expected to establish objectives for the development and operation of such projects in the region in a manned designed to protect, mitigate, and enhance fish and wildlife [§4(h)(2)(A), 94 Stat. 2708]. The Northwest Power Act also calls on the Council to “set forth a general scheme for implementing conservation measures and developing resources … to reduce or meet the Administrators obligations” [§4(e)(2), 94 Stat. 2708]. These obligations include Bonneville’s obligations to implement the Council’s Fish and Wildlife Program. Therefore, the Act intended that there would be some deration of the system for the benefit of fish and wildlife, and it is the task of the power plan to make up any resulting power needs.

(Nevada). At its height, the region's coal capacity (including several smaller coal units) totaled around 7,300 megawatts.

In recent years, the adoption of more clean policies as well as the dropping prices of alternative resources like natural gas and renewables has reduced the role of coal in the region. In the 2021 Power Plan, the Council analyzed the many owner-announced coal retirements without planned replacements. Many coal plant owners have since scrapped their retirement plans and will instead convert the plants to natural gas. Coal-to-gas conversions use the existing boiler with new natural gas burners and can be a quick way to maintain similar capacity while reducing emissions and fuel costs. However, converted coal plants maintain a similar heat rate and are therefore less efficient at turning natural gas into energy than other new natural gas plant technologies. Many utilities consider these conversions to provide an interim solution as they seek to develop and integrate other new generation onto the system. Table B - 1 shows the in-region coal plants included in the Ninth Plan and the assumed plans for conversion. Table B - 2 shows total operating coal capacity in the region as compared to retired and converted capacity.

Table B - 1: In-Region Coal

Coal Unit	Nameplate Capacity (MW)	Fuel	Announced Retirement Date	Notes
Centralia 2	730	Coal	n/a	Conversion expected late 2028
Jim Bridger 1	608	Gas Conversion	n/a	Converted in 2024
Jim Bridger 2	617	Gas Conversion	n/a	Converted in 2024
North Valmy 1	277	Gas Conversion	n/a	Conversion expected in 2026
North Valmy 2	289	Gas Conversion	n/a	Conversion expected in 2026
Colstrip 3	778	Coal	n/a	
Colstrip 4	778	Coal	n/a	
Jim Bridger 3	608	Coal w/ CCS	n/a	Adding CCS in 2030
Jim Bridger 4	608	Coal w/ CCS	n/a	Adding CCS in 2030

Table B - 2: In-Region Coal Capacity

	Nameplate Capacity (MW)
Retired Coal	3,060.8
Operating Coal	3,026.7
Converted Coal (incl. planned)	1,792

Nuclear

The region's first nuclear generating project – the Hanford Generating Project in Hanford, Washington, the site of plutonium production for atomic weapons used in World War II – was authorized by Congress in 1958 and came online in 1966. Around this time, regional utilities initiated the construction of five new nuclear power plants - part of the ill-fated and very expensive Hydro-Thermal Power Program, a plan to use thermal resources like coal and nuclear for baseload generation, and to use the flexibility of the hydropower system to meet daily and seasonal peaks in demand. Only two of the proposed nuclear projects were eventually constructed and operated in the region. Trojan, in Oregon, was finished in 1976 and the Columbia Generating Station (CGS) in Washington, began operations in 1984.[3]

Hanford operated until 1987, when it was placed on standby and eventually shut down in 1994. Trojan was permanently shut down in 1993, when it was deemed no longer cost competitive, and was demolished in 2006. Trojan's retirement and eventual demolishing was also a reaction to years of organized anti-nuclear pushback against the plant. These sentiments were codified into law in 1980 by Oregon's Ballot Measure 7, which banned the construction of new nuclear reactors without a permanent, federal repository for high-level nuclear waste and the approval of Oregon voters.[4]

Today, CGS is the only remaining nuclear plant operating in the region. Owned and operated by Energy Northwest, CGS is licensed to run through 2043, after the Nuclear Regulatory Commission granted a 20-year renewal to CGS's original 40-year operating license. CGS has a gross capacity of about 1,200 megawatts and provides on average between 950–1,100 average megawatts of energy to the region annually, depending on the refueling schedule (every other year, CGS schedules a refueling outage coinciding with the spring runoff to tackle refueling and maintenance projects on site). In May 2025, Bonneville approved an extended power uprate to CGS, which would increase generating capacity by around 160 megawatts by 2031.

The recent need for new resources, especially the perceived need for new baseload resources, has created interest in nuclear. Plants in other parts of the U.S. are being repowered, and there is ongoing

[3] A more detailed history can be found here: https://www.nwcouncil.org/reports/columbia-river-history/hydrothermal
[4] ORS 469.590 to 469.599 Siting of Nuclear-Fueled Thermal Power Plants: https://www.oregonlegislature.gov/bills_laws/ors/ors469.html.

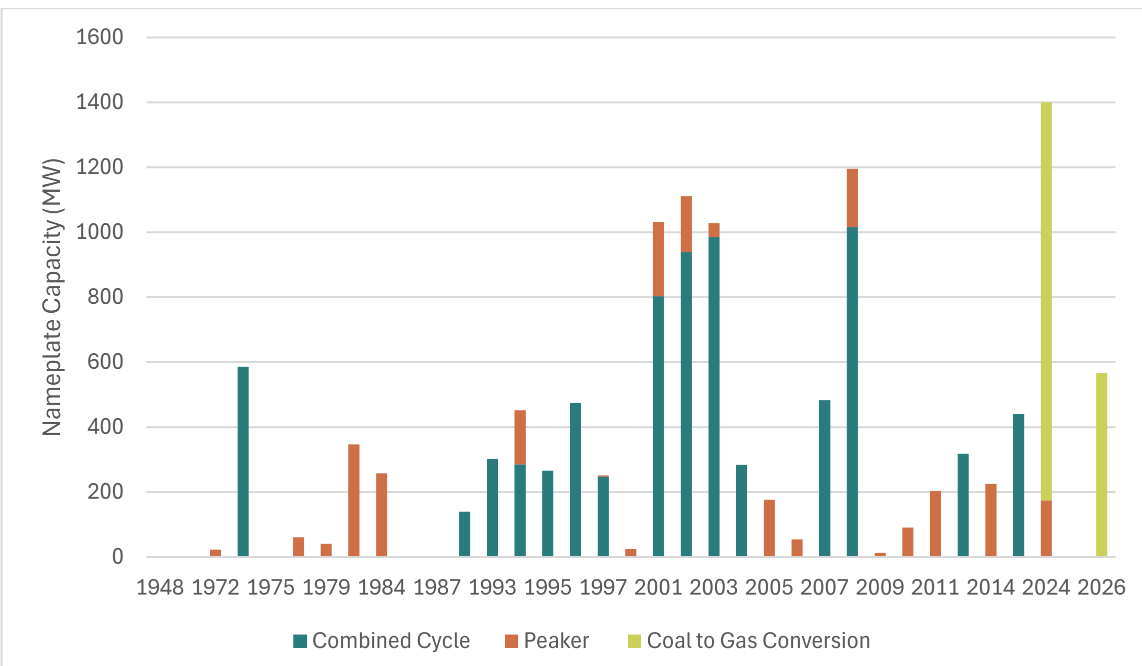
interest in new applications of nuclear technology. These emerging technologies are discussed further in Technical Appendix G – New Generating Resources.

Natural Gas

The first natural gas-fired baseload power plant developed in the region was Portland General Electric's 600 MW Beaver combined cycle power plant in 1974. A few gas peaking plants, primarily frame simple cycle combustion turbines, were constructed in the early 1980s, but it wasn't until the early 1990s that natural gas power plant development really gained steam. General Electric released its F-class frame unit, a machine with increased reliability and efficiency, and combined with low gas prices, the region saw a shift in development from coal to gas plants. A second wave of gas plant development by independent power producers came in response to the West Coast electricity crisis[5] in the early 2000s.

In recent years, the development of gas peaking plants (simple cycle and reciprocating engine)[6] in the Pacific Northwest and elsewhere can be attributed in part to the need for additional flexibility and efficiency in the power system to supplement and integrate variable energy resources such as wind and solar.

Figure B - 6: Types of Gas Plant Built in the Region Over Time



[5] More on that history here: https://www.nwcouncil.org/reports/columbia-river-history/energycrisis.

[6] These plant types are described in more detail in Technical Appendix G – New Generating Resources.

Biomass

Biomass includes a variety of fuels, including pulp and paper, woody residues (forest, logging, and mill residues), landfill gas, municipal solid waste, animal waste, and wastewater treatment plant digester gas. There are about 750 megawatts of installed biomass nameplate capacity in the Pacific Northwest. The majority of the region's biomass capacity burns fuel from spent pulping liquor and woody residues. In recent years, there have been several small (on average three megawatts or less) animal waste and landfill gas plants developed on existing dairy farms and landfill operations. With the economic recession in the late 2000s, several of the region's paper and textile plants have shut down, greatly reducing the supply of pulping liquor for pulp and paper biomass plants.

Industrial Cogeneration

Cogeneration, or combined heat and power plants produce both electricity and thermal or mechanical energy for industrial processes, space conditioning, or hot water. The Power Act[7] gives first priority to conservation, second priority to renewable resources, and third to generating resources using waste heat. Industrial cogen falls under this third priority category. In the Pacific Northwest, there are different types of industrial cogeneration, namely biomass and natural gas plants. Industrial cogeneration in the forest products industry has long been a component of Pacific Northwest electric power generation. These plants include chemical recovery boilers in the pulp and paper industry, and power boilers fired by wood residues, fuel oil, and gas in both the pulp and paper and lumber and wood products sectors. Gas-fired combustion turbines have also been installed as industrial cogeneration units, oftentimes with the waste heat (steam) being used for secondary heating purposes.

As demand for paper and newsprint has declined over the past decade, several local wood product manufacturers have suspended operations. Without the biofuel waste produced from the factories, the biomass plants have been forced to close as well. Many industrial cogeneration plants do not sell power offsite and/or generate power only when fuel costs are favorable. Therefore a precise inventory of operating industrial cogeneration plants is difficult to obtain. For these purposes, the known plants have been included in the generating capacity of the primary resource, for example biomass and natural gas.

Geothermal

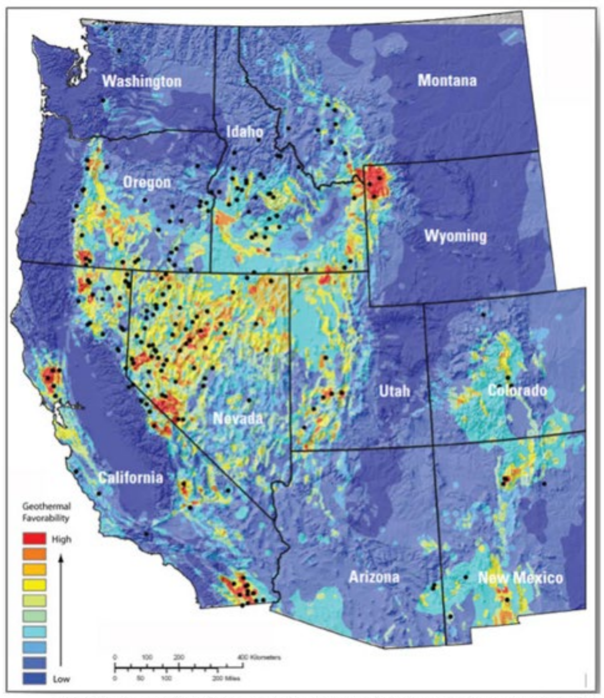
Geothermal is a renewable, clean energy resource with zero or low carbon emissions – depending on the technology used (flash steam technology emits minimal excess steam; dry steam and binary emit zero emissions). The Pacific Northwest is home to a significant, naturally occurring geothermal resource (heat + water + permeability) – especially in Southern Oregon and Idaho – and yet, development has been limited so far.[8] Between 2007 and 2015, four geothermal projects were

[7] Northwest Power Act, §4(e)(1), 94 Stat. 2705.
[8] USGS Assessment of Geothermal Resources: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.

developed in the region, totaling about 50 megawatts installed nameplate capacity. Each project utilizes binary, closed-loop technology – the hot water and steam from the production well is used to boil a working fluid that is contained in a separate, closed-loop process, which is then vaporized to steam to rotate the turbine.

Since then, there have been several efforts to explore and develop more geothermal resources in the region, but none have yet come to bear. There is significant risk involved with any geothermal development, it requires high upfront capital investment which often doesn't result in discovery of a viable resource. Recent developments in drilling technology that make discovery more certain have renewed excitement for the technology. These advancements are further explored in Technical Appendix G – New Generating Resources.

Figure B - 7: Map of Geothermal Favorability in the West[9]



Map of the favorability of occurrence for geothermal resources in the western United States
Warmer colors equate with higher favorability. Identified geothermal systems are represented by black dots.
Source: Williams et al. 2008

Wind

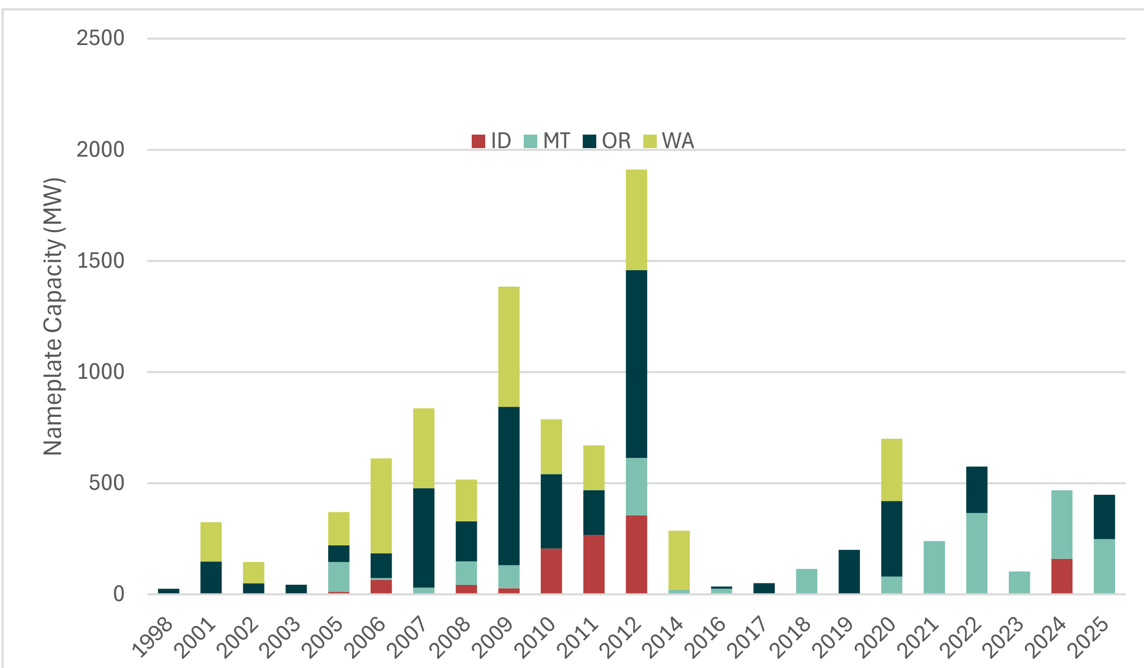
Utility-scale wind first started appearing in the region in the late 1990s and early 2000s. With the adoption of state renewable portfolio standards (RPS) in the mid-2000s, wind development ramped up significantly, peaking in 2012 - a record year for wind development in the region.

[9] USGS assessment of geothermal resources: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.

Driven by renewable policies, wind was adopted early as a renewable resource in the region. Many of the best resource areas are already developed, but new technologies are opening up more locales. Compared to solar, wind has higher annual capacity factors, but more variable generation as it is less predictable than the rise and set of the sun.

Technological advancements in hub heights and rotor diameters have allowed new wind turbines to access greater wind speeds at higher elevations and to “sweep” more wind through the blades, unlocking and reaching more wind resources than ever before. These innovations have helped broaden the application and location of wind projects. Wind speeds are classified by the International Electrotechnical Commission (IEC) on a scale from 1 to 4, with class 1 being a high-speed wind resource and class 4 being a very low speed wind. (These classifications are based on site wind speed, extreme gusts, and turbulence.) When wind development kicked off in the 2000’s, many of the locations were class 1 or 2 sites, to take advantage of the best wind resources available (the low hanging fruit). Now, new developments are occurring in lower classified wind speed areas with turbines designed to maximize the wind resource available – even at low or very low wind speed classifications. In addition, advancements in the electronic components of the turbine – such as the gearbox – allow for greater control, efficiency, and reliability, and a decrease in fixed operating and maintenance costs.

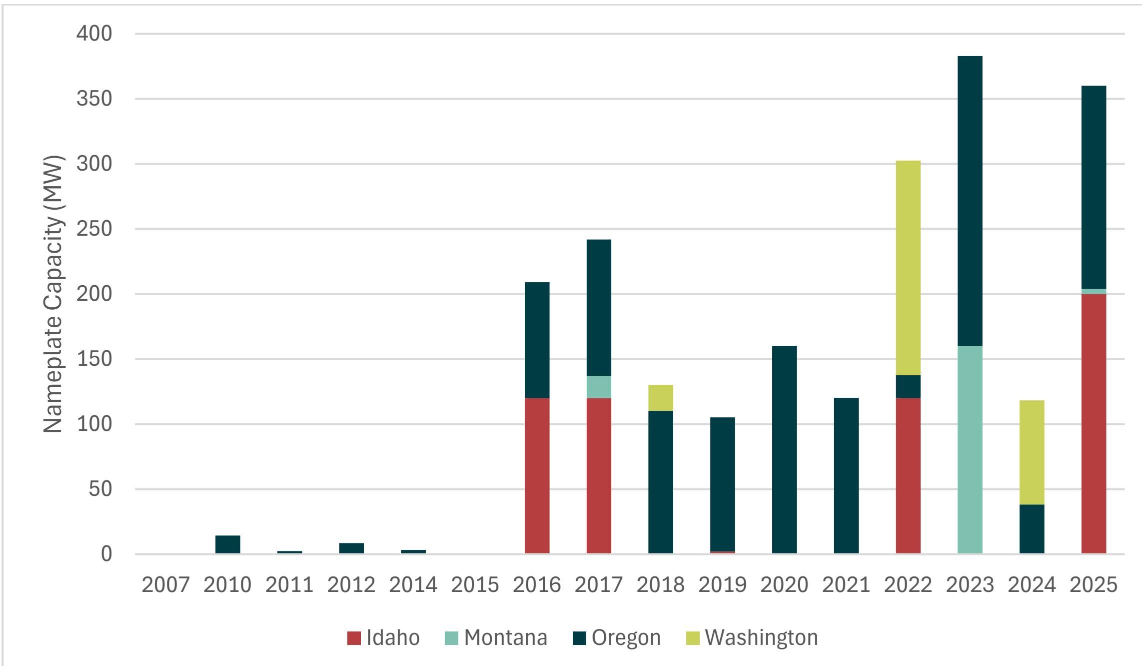
Figure B - 8: Regional Annual Wind Development



Solar

Solar photovoltaics are a newer technology relative to those already described, but installation of solar in the region has been accelerating in recent years. Early solar development in the country primarily occurred in places with a better solar resource like California and the desert Southwest. A flood of cheap solar energy onto the market from those sunnier locations meant that the lower capacity solar of the Pacific Northwest wasn't needed, discouraging early solar development in the region. However, this has changed in recent years. Load has continued to grow, clean policies have gotten more stringent, and the cost of solar has decreased significantly, with solar becoming the lowest-cost new generating resource option in the region on a levelized cost of energy basis. Accordingly, the region is seeing increased solar development.

Figure B - 9: Regional Installed Solar & Co-Located Solar + Battery Capacity



Storage

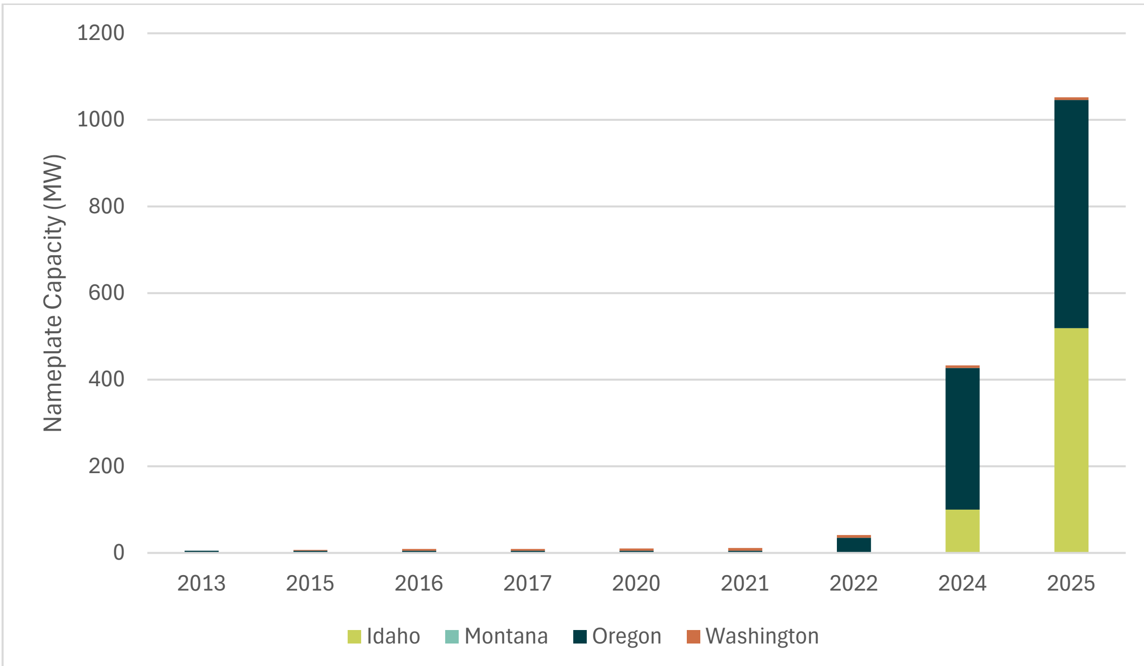
Storage resources are the latest phase of regional electric system development, with the installed capacity in the region increasing steeply since the Council's 2021 Power Plan. In 2024 and 2025, there region built 1000 MW of battery storage. Storage resources capture and store energy generated at one time to be discharged and used at another. They provide a wealth of benefits that align with modern grid needs. They can deliver variable energy integration, load shifting, transmission and distribution deferral, ancillary services, energy arbitrage, and emergency backup.

Lithium-Ion Batteries

The most common storage resource built in the region are lithium-ion batteries. The hydro system has insulated the region from the need for much storage up this point. However, as more renewables have come online, batteries allow for better balancing of their variable generation, shifting that production to better match load. Larger loads, more variable resources, and increasing clean policy requirements seem poised to continue to drive more battery development. Figure B - 10: Regional Battery InstallationsFigure B - 10 shows the installed battery storage capacity in the region. It illustrates the recency of the technology in the region, with only 55 MWs built in Oregon and 6.2 MW in Washington from 2013 to 2022, and then a steep increase in particularly Oregon and Idaho of over 1500 MW in 2024 and 2025.

This need is also driving interest in alternative storage technologies beyond the most common 4-hour lithium-ion batteries (discussed further in Technical Appendix G – New Generating Resources).

Figure B - 10: Regional Battery Installations[10]



Pumped Storage

Pumped Storage is a resource that is constrained by geography, requiring suitable topography and geologic conditions for constructing upper and lower reservoirs at different elevations. Despite the Pacific Northwest's prolific hydro resource, the region has not seen much pumped storage development. A proposed project between Banks Lake and Lake Roosevelt near the Grand Coulee Dam has seen recent development progress, but is still in very early stages.[11] Most pumped storage in the country was built in the 1970's, and there hasn't been much development since, despite many projects in the development and permitting pipeline.

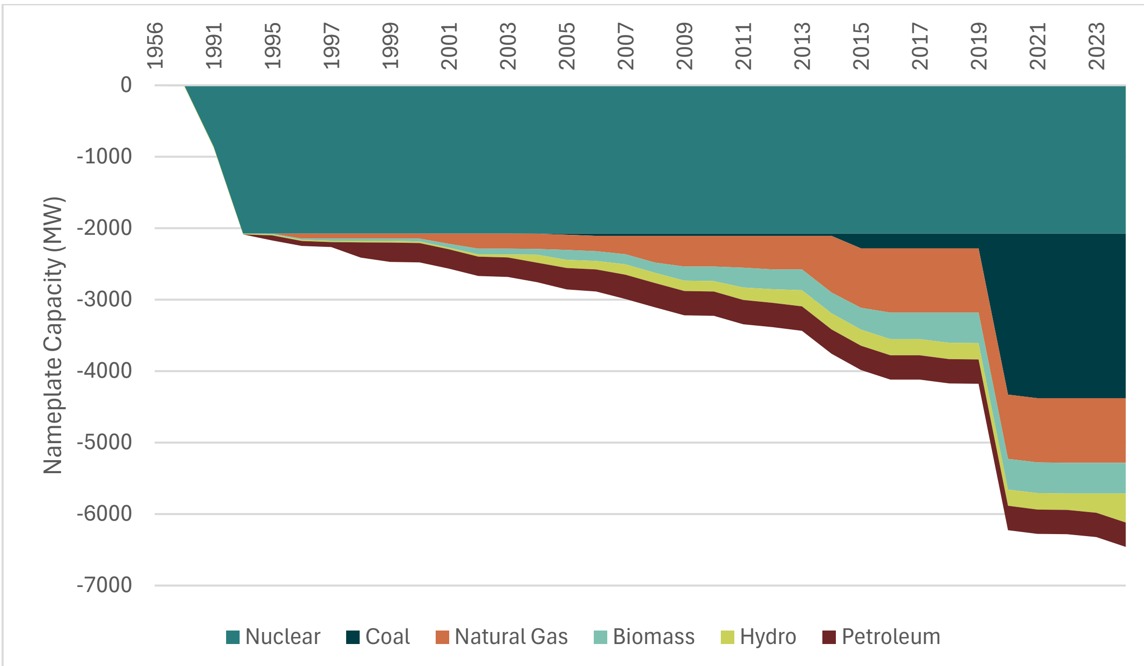
Generation Retirements

The evolving electric power system of the region also includes resource retirements. These are captured in the existing system to ensure the Council power plan accounts for any new generation

[10] This includes batteries built on the same site as solar PV. About 132 MW of the over 1000 MW of batteries installed in the region are collocated.
[11] https://www.usbr.gov/pn/programs/lopp/bankslake.

needed to offset retirements and to accurately represent the capabilities of the region's resources. The wide teal area in Figure B - 11 shows the retirement of Hanford and Trojan nuclear plants in 1991 and 1993 respectively. After that it shows some natural gas retirements in the 2000's to early 2010's and most recently coal retirements starting in 2020.

Figure B - 11: Recent Regional Resource Retirements



Demand Side Resource

Demand side resources are an important part of our existing system. Today, the three primary demand side resources that impact the power system are conservation, demand response, and rooftop solar.

Conservation

The Northwest Power Act directed the Council and the region to consider and prioritize conservation as a resource. Since the 1980s the region has been running conservation programs and accumulating savings from these programs. The Council's 2024 Regional Conservation Progress[12] survey reported that the region has acquired over 8,000 aMW since 1980, or enough electricity as the average production of three Grand Coulee dams. Because of these acquisitions, the region has avoided having to build generating resources to provide that electricity. The Ninth Plan, like all prior plans, includes a

[12] The Regional Conservation Progress Report: https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2024.

detailed assessment of new conservation potential for the Northwest (See Technical Appendix H – Conservation Methodology and Potential).

Demand Response

Because the Northwest power system has historically been energy constrained (not capacity constrained), demand response (DR) is a relatively untapped resource in the region. DR programs have been around the region for a while, primarily in the agriculture sector, but have not been widespread. However, in recent years, the need for new capacity has become increasingly evident by individual utilities, who have begun developing and offering DR programs. DR has also been more prominent in the Council's Seventh and 2021 Power Plans which have shown the region has a need for cost-effectively implementing DR. As of the end of 2023, the region reported 687 MW of DR actively being implemented. The Ninth Plan includes a robust supply and analysis of DR products (See Technical Appendix I – Demand Response Methodology and Potential).

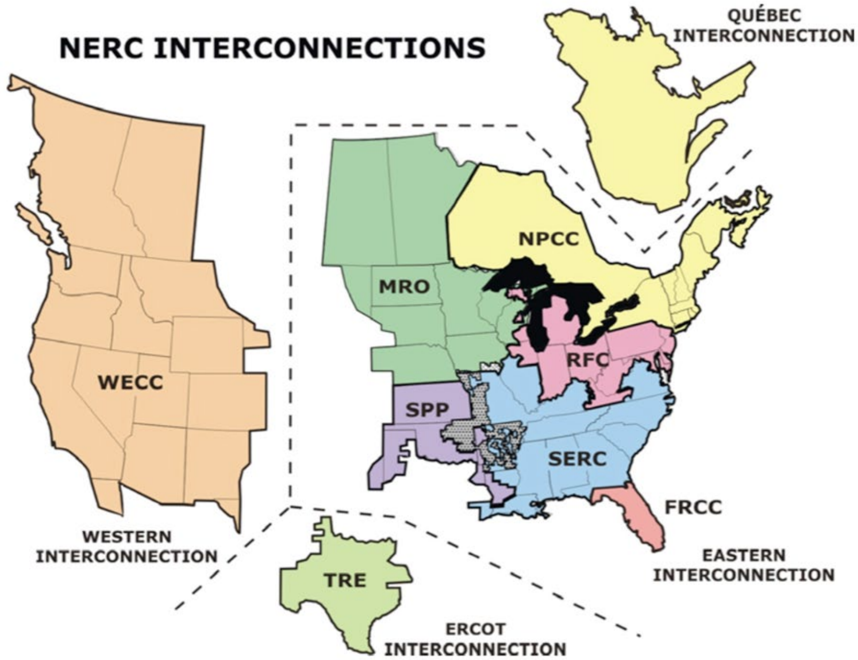
Rooftop Solar

Rooftop solar installations in the Northwest have been steadily climbing. In prior power plans, rooftop solar has been included as a demand reduction in the load forecast, but has not been developed as a new resource to compete with other supply and demand side resources. This is because the costs were relatively high, and the impacts were low. Both of those have now changed: costs have come down substantially and installations have increased. In 2011, there were 4 MW of rooftop solar capacity installed and that number has grown to over 1300 MW (forecasted) in 2025. The Ninth Plan includes a potential assessment of new rooftop solar in both the residential and commercial sectors (See Technical Appendix J – Rooftop Solar Methodology and Potential).

Transmission

The Pacific Northwest transmission grid is a part of the Western Interconnection, one of three major National Energy Regulatory Commission (NERC) grid interconnections in the continental United States, encompassing all or parts of the states and provinces west of the Rocky Mountains to the Pacific Ocean, and Northern Baja California. The other two interconnections are the Eastern Interconnect which covers states and provinces east of the Rocky Mountains to the Atlantic Ocean and the Electric Reliability Council of Texas (ERCOT) Interconnection which covers most of Texas. The transmission system is composed of major alternating current (AC) and direct current (DC) high voltage lines, distribution lines, substations, transformers, source generators, and delivery points or load centers.

Figure B - 12: Map of National Energy Regulatory Commission Interconnections[13]



Northwest utilites are connected to the greater West through interties into California, BC, and the Rocky Mountain area. According to the Western Electricity Coordinating Council (WECC) ,[14] the Western Interconnection comprises roughly 136,000 miles of transmission lines.[15] The system was strategically developed to connect the major load centers with remote resources, and in particular in the Pacific Northwest, to connect the hydropower dams to high-voltage transmission lines in order to support the transfer capability of seasonal energy.

[13] https://www.nerc.com/who-we-are/key-players.

[14] The WECC acronym is used to describe both the Western Interconnect and the Western Electricity Coordinating Council which have overlapping definitions but are technically different. The Western Interconnect is a grid region that covers states from the Pacific Ocean to the Rocky Mountains. The Western Electricity Coordinating Council a non-profit corporation that exists to ensure a reliable Bulk Electric System in the geographic area known as the Western Interconnection.

[15] https://wecc-spdp-weccgeo.hub.arcgis.com/pages/transmission-availability.

Figure B - 13: Western Interconnection[16]

While the Pacific Northwest does not have a single regional transmission operator (RTO) or independent system operator (ISO), there are balancing authorities (BA) that ensure the dispatch of generation to the electricity grid meets energy demand (load) at any given time. Balancing authorities work independently to balance the needs within their designated footprint, but there are coordinated agreements among BAs to collaborate on reserve sharing, transmission maintenance, and expansion activities. A recent iteration of such a collaborative body is the Western Transmission Expansion Coalition (WestTEC), which is serving as the source for much of the Ninth Plan's future transmission assumptions, discussed in more detail in the uncertainty section at the end of this appendix.

In general terms, the Pacific Northwest power system operates within a bilateral (decentralized) transmission market in which the developer or owner of a generating resource must typically secure or hold the rights to a long-term firm transmission contract in order to proceed with constructing and selling the output of the resource. A bilateral contract can create price stability for both the buyer and the seller. A long-term firm contract is essentially a reservation for transmission capacity between specific points, for all hours of the day. While there are some conditional firm capacity contracts, they are limited and only available on a short-term basis. A conditional firm contract allows a resource to

[16] Ibid

access the grid, but the operator reserves the right to curtail the reservation under specified conditions in favor of long-term firm contracts.

Long-term firm contracts are maintained regardless of whether or not the capacity is physically used (i.e. whether or not there is generation at a given hour). However, FERC Order 889 requires that all unused transmission capacity must be marketed on the Open Access Same-Time Information System (OASIS) for short-term duration use. This can have limited value to developers who may need a firm transmission deliverability guarantee to secure financing and begin construction.

The Bonneville Power Administration owns the majority of the transmission system in the Pacific Northwest, although there are some utility and energy service supplier owners as well. There is currently limited available transmission capacity (ATC) within the Pacific Northwest grid, as much of the capacity is tied up in long-term firm contracts. To secure transmission, resources in the region must proceed through an interconnection request as well as a parallel transmission service request with a specific point of receipt (POR) and point of delivery (POD). As major projects retire, additional capacity may open up on certain paths and transmission rights could be resold or developed by the owners.

When Bonneville receives transmission service requests to bring generation online from a certain point on the system, they enter a Transmission Service Request and Expansion Process (TSEP) queue and are analyzed as “clusters” where projects in similar areas are grouped together. One issue Bonneville and any transmission provider in a bilateral market faces is that through the OATT process, they cannot make a judgement call on which project requesting transmission service will move forward out of the group. Rather, they either process the requests serially under the assumption that requests earlier in the queue will actually come online (this is not always the case) or when analyzing a cluster study they assume that all of the requests come online together. This can be problematic for a number of reasons. As an illustrative (and oversimplified) example, thousands of megawatts of capacity (across many projects) enter the queue in response to one request for proposals (RFP) for 100 megawatts capacity where there is currently 99 megawatts of available transfer capacity (ATC). These projects are studied in aggregation (thousands of megawatts vs. 100 megawatts of need identified in the RFP) as if they are all going to be built, rather than one winning bid. This can result in a study showing the need for significant system upgrades to meet the thousands of megawatts in the queue, rather than the 1 megawatt needed (in addition to the 99 megawatts ATC) to meet the RFP. Thus, the result is that the transmission offer is not made to any of the projects in the queue.

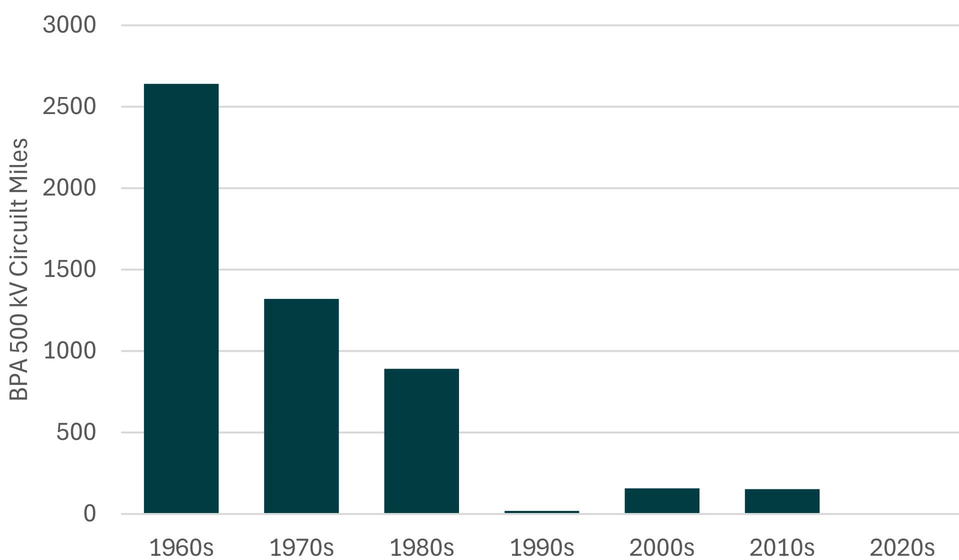
Project developers can also experience significant delays to project construction due to long transmission request queues. If developers were able to build (and secure funding) under the assumption that they could purchase the unused short-term physical capacity tied up in long-term firm contracts through OASIS, more projects could be developed and the transmission grid could be better used. This is currently not a reality for many project developers who require firm transmission guarantees to proceed. Transmission system expansion and upgrades are long-term projects that can be very expensive and intensive to complete.

These contractual constraints and complications of the transmission system are often a barrier for building and connecting new resources to the grid, however, the Council’s models only take physical transmission limits into consideration. If there is space on a line, regardless of contractual availability, the models will allow resources to be built to fill that space. This simplifies modeling and the Council considers this ideal use of the transmission system, unencumbered by contractual obligations, to be appropriate at the regional-level that the power plan operates.

Transmission in the Ninth Plan

Much of the region's existing transmission system was built in the 1960s through the 1980s, as illustrated in Figure B - 14 below. This stagnation in new transmission development has become increasingly pressing in recent years, as increasing loads and more dispersed generation asks more of the aging system.

Figure B - 14: PNW Transmission Build Out by Decade[17]



The Ninth Plan intends to explore how the pace of transmission development might impact new resource selection through scenario analysis.[18] However, this need for new transmission is already prompting action in the region, with a number of new projects planned and underway. In the Plan, any transmission that already exists or is under construction by the start of the action period[19] is included in the representation of existing transmission. Projects under construction and therefore considered in the existing system are described in Table B - 3 below.

[17] https://www.nwcouncil.org/fs/18429/2023_08_3.pdf.
[18] Technical Appendix N – Scenario Modeling and Results.
[19] 2027-2032.

Table B - 3: New & Under Construction Transmission Projects Included in Existing Transmission

Planned Transmission	Capacity	Path	Online Date
Ten West Link	3200 MW	SCE to APS	2024
SunZia	3000 MW	PNM to APS	2026
Transwest Express	3000 MW	WAPA Wyoming to PACE UT	2027
	1500 MW	PACE UT to Nev South	2027
SWIP North	1700 MW	IP to North Nevada	2027
B2H	1000 MW	IP to BPA_OR	2026

WECC Existing System and Retirements

The WECC encompasses the states of Washington, Oregon, Idaho, Western Montana, California, Nevada, Wyoming, Utah, Colorado, Arizona, New Mexico, a small portion of Texas, the Canadian provinces of British Columbia and Alberta, and a small portion of Baja Mexico.

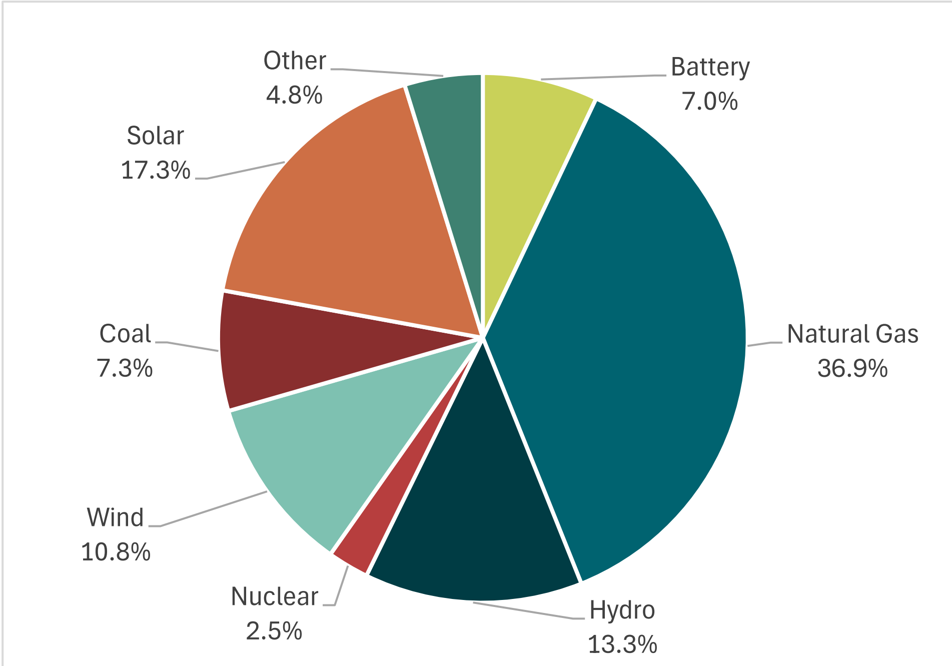
The Council's modeling of the WECC informs market availability. All three primary Council models, Aurora, OptGen/SDDP, and GENESYS, include a load and resource representation of the WECC.[20] As a result, the Council tracks load and resource developments across the WECC.

Description of Existing Fleet by Generating Resource

Comparing the scale of the regional resource mix, shown in Figure B - 3, and that of the WECC, see Figure B - 15, the region has installed about 62,000 MW of nameplate capacity, while the WECC, excluding the region, has about 242,000 MW of installed resource.

[20] More information on these models can be found in Technical Appendix K – Modeling Framework.

Figure B - 15: Installed Nameplate Capacity in the WECC



The mix of the region is particularly distinct within the broader WECC, with over half of our energy coming from hydro while the WECC has a more varied mix. Those discrepancies can largely be explained by geographical access and sizes of load served, but it is notable that as the Pacific Northwest's load grows and clean policies drive resource builds across the west, those mixes may start to look more similar.

Proposed Retirements and Conversions

Similarly to the region, states in the wider WECC are retiring their coal fleets for similar reasons, including rising fuel cost, aging efficiency, and rising policy enforced concerns about carbon emissions. These planned changes to the existing system are captured in the model so that the final power plan is responsive to and plans for these large changes in existing generation. Concerns about ballooning load growth has prompted many previously announced coal retirements to instead convert the plant to burning natural gas rather than shuttering entirely.

Table B - 4: WECC-Wide Coal Retirements and Conversion by Plant

State	Plant Name	Nameplate Capacity (MW)	Planned Retirement
AZ	Apache Station	*204*	Conversion by 2027
AZ	Cholla	425.9	2025
AZ	Coronado	821.8	2032
AZ	Springerville	1765.8	2027/2032
CA	Argus Cogen Plant	62.5	

State	Plant Name	Nameplate Capacity (MW)	Planned Retirement
CO	Comanche (CO)	1252.8	2022/2025/2030
CO	Craig (CO)	1427.6	2025/2028
CO	Hayden	465.4	2027/2028
CO	Pawnee	*552.3*	Conversion by 2026
CO	Rawhide	293.6	2029
CO	Ray D Nixon	207	2029
MT	Colstrip	1647.4	
MT	Colstrip Energy LP	46.1	
MT	Hardin Generator Project	115.7	
MT	W. Sugar Cooperative - Billings	1.5	
NM	Four Corners	1636.2	2031
NV	North Valmy	*567*	Conversion by 2026
NV	TS Power Plant	242	
UT	Bonanza	499.5	
UT	Hunter	1472.2	2042
UT	Huntington	1015.5	2036
UT	Intermountain Power Project	*1640*	Converted in 2025
UT	Sunnyside Cogen Associates	58.1	
WA	Transalta Centralia Generation	729.9	Conversion expected late 2028
WY	Dave Johnston	*816.7*	Conversion by 2029
WY	Dry Fork Station	483.7	
WY	General Chemical	30	
WY	Genesis Alkali	41	
WY	Jim Bridger 3&4	1216	
WY	Jim Bridger 1&2	1225	Converted in 2024
WY	Laramie River Station	1863	
WY	Naughton	*380.8*	Conversion in 2026
WY	Neil Simpson II	90	
WY	Wygen 1-3	90, 95, 116	
WY	Wyodak	362.1	2039

Table B - 5: WECC-Wide Coal Retirements

	Nameplate Capacity (MW)
Retired Coal	10,660
Operating Coal	21,300
Coal Leaving System	
Coal-to-Gas Conversion (incl. planned)	*4,160*
Planned Retirement by 2030	*5,685*
Planned Retirement post-2030	*6,812*
Total Coal Leaving System	**16,658**

Greenhouse Gas Emissions from Generation

Regional and state policies are shaped by the goal of reducing emissions and countering climate change by deploying clean energy resources. In describing the existing system it is important to understand historical emissions, changes in the generation stack and dispatch, and trends (both past and present).

The electricity sector is one of the primary sources of greenhouse gas emissions globally. An analysis from the Energy Information Agency (EIA) has shown that amongst energy-related sectors at the national level, the electricity sector has been the greatest emitter of carbon dioxide (CO_2) until 2016 when the transportation sector surpassed it.[21]

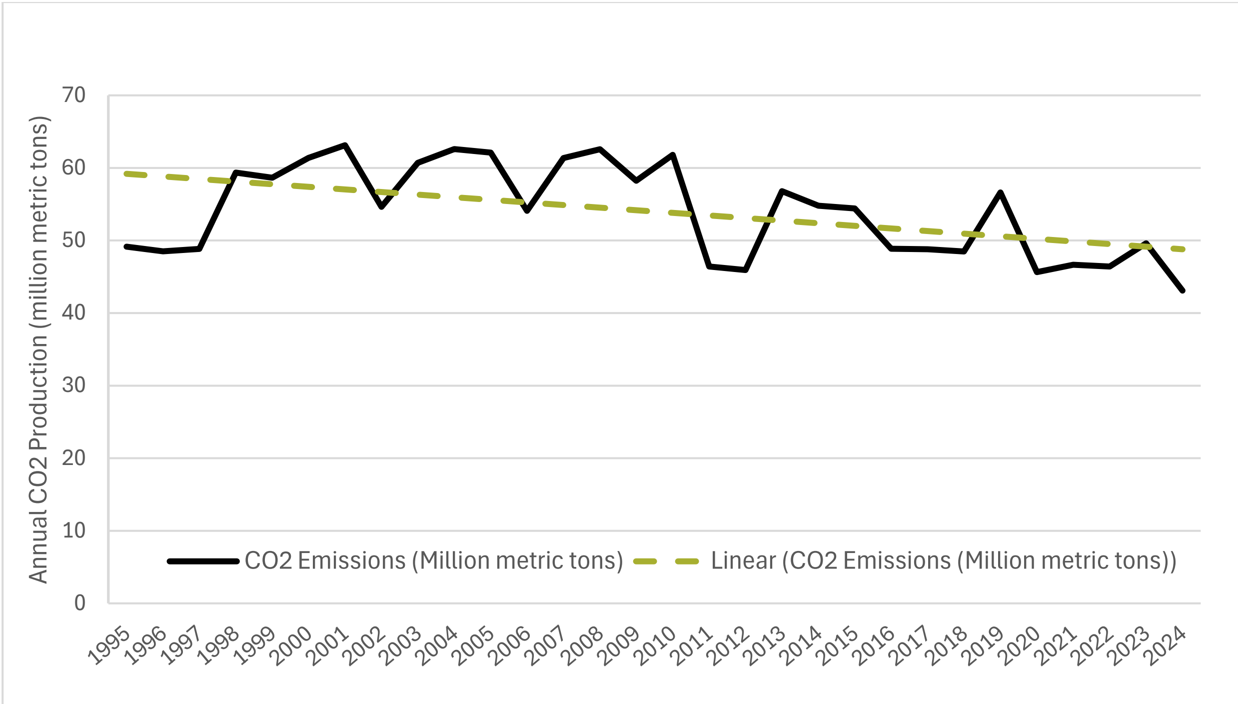
This section will describe historical regional emissions as well as how ongoing and future emissions are captured in the modeling. For a more comprehensive look at the environmental effects of the power system and how those are considered in the power plan, see Technical Appendix C: Methodology for Quantifiable Environmental Costs and Benefits.

Historical Carbon Dioxide Emissions

In the Pacific Northwest, the amount of annual carbon emitted from the generation of electricity is directly related to hydro conditions. Because the region's power supply is dominated by hydropower, other resources – primarily fossil fuels – are dispatched around the hydro supply and the region's carbon emissions often bounce around from year to year accordingly as seen in Figure B - 16. The recent move away from coal has prompted a downward trend on the region's CO_2 emissions as that hydro backup is getting cleaner.

[21] https://www.eia.gov/environment/emissions/carbon/pdf/2024_emissions_report_final.pdf.

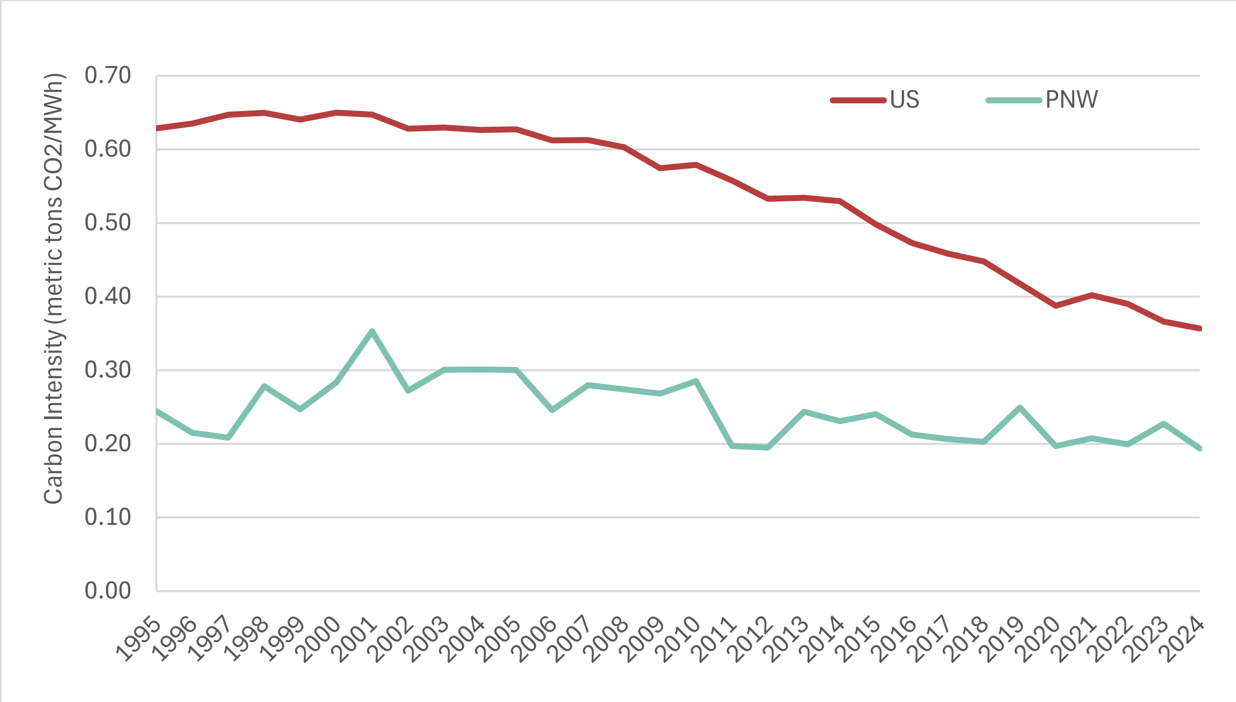
Figure B - 16: Annual CO_2 Emissions from Electricity Generation in the Region



United States Generation and CO_2 Emissions

The region's robust hydro resource has kept its electricity emissions relatively low in comparison to the rest of the nation, as well as its concerted investment in energy efficiency. However, United States carbon emissions from the electricity sector have been declining steadily since the mid-2000's. Due to hydropower's smaller role in the nation's resource portfolio, there is not the same variability from year to year as seen in the Pacific Northwest. Rather, declining emissions can be directly attributed to the change in fossil fuel dispatch and greater reliance on the less carbon intensive natural gas resources over coal. Carbon intensity is the amount of carbon emitted per unit of energy generated and serves as an illustrative lens by which to compare the United States' emissions to the Region's. In table we can see that the Pacific Northwest's energy mix has been relatively clean but varies depending on the Hydro system supplying more or less of the region's energy in a given year. The United States on the other hand has been steadily decreasing in CO_2 intensity as higher emitters are replaced and their energy mix becomes more renewable.

Figure B - 17: CO_2 Intensity of the Region's Electricity Mix versus the United States'



Emissions Rates

Different emissions rates associated with the dispatch of emitting resources. Each fuel type has a particular emission rate which is then applied to a particular plant based on its fuel use and heat rate. These emissions by fuel type are detailed in Table B - 6 below. The Council utilizes the CO_2e emissions rate, to account for the global warming potential of CO_2 (carbon dioxide), CH_4 (methane), and N_2O (nitrous oxide).

For modeling in the Ninth Plan, the Council's models are agnostic to these emissions, in that they will not retire a plant or temper its dispatch to reduce emissions to meet any of the clean targets. However, the economics of a high emitting resource, as clean policies become more stringent and carbon prices in applicable jurisdictions rise, will affect the further dispatch of that resource. In that way, these emissions rates affect the ongoing costs of the existing system and those resulting costs have bearing how the system is used.

Table B - 6: CO2e Emissions by Fuel Type[22]

Fuel Type	Time Horizon	Total CO2e (lbs CO2e/MMBtu)
Natural Gas	GWP[23] 100 yrs	117
	GWP 20 yrs	117
Coal	GWP 100 yrs	213
	GWP 20 yrs	216

Existing Policies

Treatment of Policies in Ninth Power Plan

The energy policy landscape lays the groundwork upon which the Council understand the future of resource development in the region and country. What those policies are and how they are represented in the Council's planning is an important early step in the power plan development process.

In developing its regional power plan, the Council must consider and incorporate environmental effects associated with the power system into its analysis and development of a resource strategy. As identified in the Northwest Power Act, the Council is to encourage, in a manner consistent with applicable environmental laws and through the unique opportunity provided by the Federal Columbia River Power System, conservation and efficiency in the use of electric power and the development of renewable resources to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply.[24] With a finer point, the Act requires that the Council set forth a scheme for implementing conservation measures and developing resources with due consideration by the Council for, among other things, environmental quality, compatibility with the existing regional power system, and protection, mitigation, and enhancement of fish and wildlife.[25] It additionally requires the Council include as an element of the power plan a methodology for determining quantifiable environmental costs and benefits of new resources,[26] and the Council's planning assumes all

[22] Emissions by fuel type source: https://www.epa.gov/system/files/documents/2025-01/ghg-emission-factors-hub-2025.pdf. Global warming potential source: https://www.edf.org/sites/default/files/content/emission_equivalency_tool_documentation_methodology_23062022.pdf.

[23] Global warming potential (GWP) measures the radiative efficiency, or ability to absorb energy, of the greenhouse gas over its lifetime. It is used to normalize GHGs to CO_2e so that they can be compared by potency, or how much energy the gas absorbs over x number of years.

[24] Northwest Power Act, §2(2), 94 Stat. 2697.

[25] Northwest Power Act, §4(e)(2), 94 Stat. 2706.

[26] Northwest Power Act, §4(e)(3)(C), 94 Stat. 2706.

generating and conservation resources will meet existing federal, state, tribal, and local environmental regulations. More detail about what is included in that methodology and how it is developed can be found in Technical Appendix C - Methodology for Quantifiable Environmental Costs and Benefits.

Policy Levels

The Council represents multiple regulatory levels of policy and the ways they interact and potentially impact future loads, resource costs, and other power planning dynamics. The policies described below are sorted into federal, regional, and WECC-wide and then additionally delineated into state, local, and utility policies.

The below-described policies are further grouped within a simple framework intended to broadly designate how the policy is captured in modeling, whether in terms of a load impact, resource options, impact, or resource cost impact. Policies that impact resource options are those that affect what resources are available to the model and how/if they might be selected. For example, renewable portfolio standards would fall into this category because it impacts how much renewable resource the model required to select. Policies with resource cost impacts describe policies that influence the cost of a resource either through cost of compliance with an environmental regulation or via an incentive. Finaly, policies categorized as load impacting refer to those that affect the electric load by, for example, promoting electrification or incentivizing energy efficiency.

Federal

A primary cost quantified in the environmental methodology are those from assumed compliance with existing regulations, which are incorporated into the total system cost of a new resource. To inform that analysis, Table B - 7 provides a high-level overview of the primary federal statutes that arise when considering the environmental impacts of resources and the regulation thereof.

This section also provides high-level status overview of several recent federal regulations, which, at the moment present a regulatory backdrop in flux given the number of environmental regulations proposed and issued during the last presidential Administration, the legal challenges to those regulations, and the early executive orders and agenda of the new administration regarding the environment and climate change – all of which spanned the development of this power plan.

Notably Table B - 7: Federal Policy SummaryTable B - 7 describes the Inflation Reduction Act (IRA) and the Bipartisan Infrastructure Law (BIL), both of which have been pared back by the current Administration’s One Big Beautiful Bill Act (OBBBA). Capturing existing policies is an early step in the Plan process, and during the initial analysis both bills were still fully in-effect and a significant legislative change since the previous plan. At the time of this writing, that is no longer the case. For the most part, the OBBBA rolled back federal money available for clean energy grants and energy efficiency programs and incentives. Most of those changes, while impactful to the energy landscape as a whole, are not modeled explicitly and therefore will not affect our analysis directly. More details about energy efficiency funding can be found in Technical Appendix H – Conservation Methodology and Potential. The most impactful changes were to the clean energy tax credits, narrowing the resources they apply to, notably excluding wind and solar resources. The OBBBA also repealed the IRA's changes to the Clean Air Act § 111(b) and (d) which set source performance standards for carbon emissions from new and existing sources, reverting them back to the previous standard of best available technology.

Policy can be a locus of high uncertainty in planning. The four-year cadence of potential administration turnover means that policy can be volatile and highly reactive to political winds. The risk of this uncertainty is explored in scenario analysis, the details of which are discussed in Technical Appendix N – Scenario Modeling and Results.

Table B - 7: Federal Policy Summary

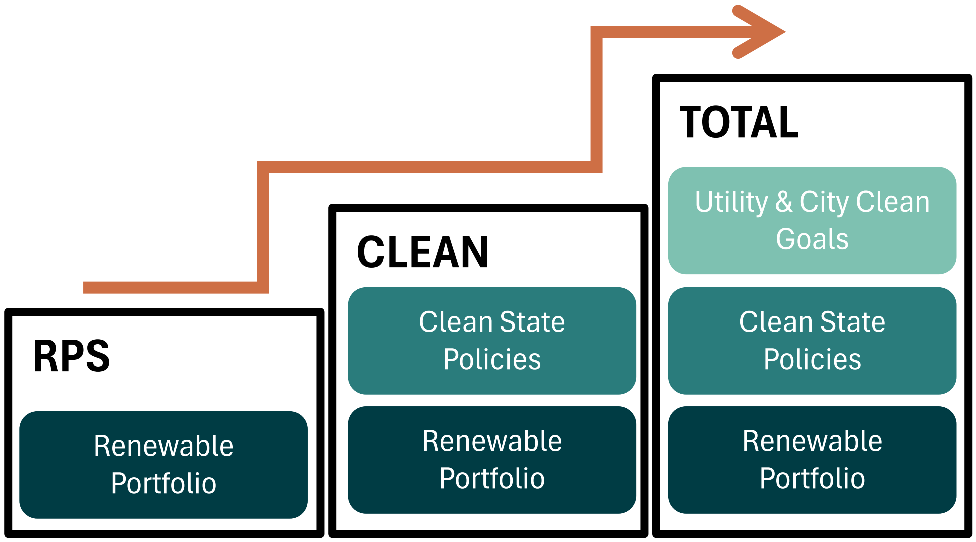
Name	Role in Modeling	Summary
One Big Beautiful Bill Act (OBBBA)	Resource Cost (minor Load & Resource Choice Impacts)	In relation to the Council's work, this Bill operates as primarily a dampener on the impacts of the IRA. Its main impacts are: • Removing tax credits for wind and solar technologies, energy efficiency programs, and electric vehicles. • Rolling back the new carbon emission performance standards for new and existing sources in the Clean Air Act.
Inflation Reduction Act (IRA)	Resource Cost Load	A broad policy that is most impactful to Council's work in the implementation of a technology neutral 30% investment tax credit and/or a 2.75 cent production tax credit The technology these credits apply to was altered by the passage of the OBBBA These tax credits remain in the modeling as the basis for the evolving federal policy landscape sensitivity
Bipartisan Infrastructure Law (BIL)	NA	Another wide-ranging policy, that mostly focuses on grants, pilot programs, & demonstration projects. A few notable pieces though they won't be explicitly modeled: Power marketing administration (BPA) transmission borrowing authority expanded, incentives for maintaining and enhancing hydroelectricity
Clean Air Act	Resource Cost Resource Options	The primary purpose of the Clean Air Act is to protect and enhance air quality to promote the public health and welfare of the nation's population. Most relevant, and new since the last plan are: • New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d): • New baseload stationary combustion turbines must have 90% CCS by 2032. Existing coal fired plants planning on operating after 2039 must be equipped with 90% CCS by 2032

Name	Role in Modeling	Summary
Endangered Species Act	Resource Costs (cost of compliance)	Established a framework to conserve and protect endangered and threatened species and their critical habitats
National Environmental Policy Act		Procedural statute that requires federal agencies to consider the environmental impacts of their proposed actions and provide for public involvement in the federal decision-making process
Clean Water Act		Principal federal statute regulating water pollution and protecting the nation's "navigable waters."
Public Utilities Regulatory Policies Act	Resource Options (mostly NA)	PURPA established a class of non-utility generating facilities that, if meeting certain requirements, are permitted to sell the output of their power plants to utilities at the price the utilities would have to pay to develop their own resources. Qualifying facilities are primarily small power production facilities and cogeneration facilities
Codes & Standards	Load	Regulations that establish minimum requirements for energy performance in buildings, appliances, and other products, aiming to reduce energy consumption, essentially defining a level of energy efficiency that must be achieved

In-Region

In past plans, only federal and state level mandates were represented as parameters in the model, but the 2021 Power Plan made the methodological change to incorporate clean policies more broadly. The new methodology included all clean policies and goals at the state, utility, and community level framed as a portion of sales obligated to meet a percentage clean target. By aggregating the different jurisdictions' clean policies based on the percentage of sales they represent, on either the regional or WECC level, the Council was able to roll those up into a total regional or WECC clean policy goal. This roll up is necessary for modeling, in that it is more efficient that inputting each policy individually. It also represents all applicable clean policies and their impacts on the energy policy landscape of the region in a way that previous methodologies that excluded the utility, city and municipality level policy goals, did not. This process, and how it is incorporated into the modeling, is described in more specific detail by state below.

Figure B - 18: Aggregating Clean Energy Policies and Goals



Washington

Washington's Clean Energy Transformation Act (CETA) is the only policy in the region to set a statewide goal of 100% clean energy by 2045. Washington takes a ramped approach, eliminating coal-fired generation serving Washington customers by 2025, making all electric utilities greenhouse gas neutral by 2030, and requiring 100% of electric utility power to come from renewable or zero-carbon resources by 2045. CETA applies to 100% of Washington state sales. These goals are paired with the Climate Commitment Act (CCA) which was established in 2021. It sets an economy-wide cap on greenhouse gas emissions and established a cap-and-invest program with emissions allowances that decrease over time in alignment with meeting the state's emissions reduction commitments. This creates a price for carbon that is accounted for in the Council's modeling.

Oregon

Oregon's clean energy targets apply primarily to its largest utilities and are borne of a few different policies. The most recent, and most impactful, is HB2021, the Clean Energy Targets Bill, which requires Porland General Electric (PGE), PacifiCorp (PAC), and Electricity Service Providers to reduce greenhouse gas emissions from the electricity they sell to retail consumers in Oregon by 80% below baseline emissions levels by 2030, 90% below baseline by 2035 and 100% by 2040. The state also has a longstanding renewable portfolio standard, which for investor-owned utilities is quickly subsumed by HB2021, but remains for consumer owned utilities to whom HB2021 does not apply. PGE, PAC, and smaller utilities have had personal clean utility goals, that have similarly been surpassed by larger state goals. PGE and PAC make up about 60% of state sales, while qualified Electricity Service Suppliers account for about 5%, meaning that Oregon's most stringent clean goals, those set by HB2021, apply to about 65% of total state sales.

Idaho

Idaho has no statewide clean energy goals, but that does not mean there are no clean goals to plan for in Idaho. The state's two largest utilities have clean energy goals as well as the state's largest city:

- Boise 100% citywide clean by 2035: ~20% state sales
- Idaho Power 100% clean energy by 2045: ~60% state sales
- Avista 100% clean electricity goal by 2045 and carbon neutral by 2028: ~15% state sales

Accounting for overlap between the City of Boise and the two utilities, the percentage of state sales under a clean policy goal is about 75% by 2045.

Montana

Montana also has no statewide clean goals – having repealed their RPS in 2021. But, similarly to Idaho, there are key energy sector actors that have set their own goals:

- Bozeman, Missoula, and Helena have 100% clean electricity goals by 2030: ~20% of state sales
- NorthWestern Energy has a Net Zero Vision of 100% clean electricity by 2050: ~38% of state sales excluding three clean cities

The portion of Montana sales committed to meeting clean goals is about 58% by 2050.

Cumulative/Aggregate Regional Clean Energy Goals

In aggregating the region-wide clean target, each state represents the below assigned portion of regional sales, and therefore their policies apply to that percentage of the total region. That cumulative clean policy target is then set as a parameter for the region in the model.

Table B - 8: In-Region State Sales

State	State Sales (MWh)	Portion of total Regional Sales[27]
Washington	88,072,642	49%
Oregon	56,091,824	31%
Montana	11,316,503	6%
Idaho	25,124,385	14%

[27] Based on a three-year average (2022-2024) of state sales as reported by Form EIA-861: https://www.eia.gov/electricity/data/eia861.

To translate Table B - 8, any clean goals set by Washington will apply to 49% of the total region's sales, Oregon's goals will apply to 31%, and Montana and Idaho will apply to 6% and 14% respectively.

Table B - 9: In-Region Clean Policies as Percentage of Regional Sales[28]

	2027	2030	2035	2040	2045
PNW RPS	13%	15%	16%	17%	17%
PNW RPS + Clean State Policy Targets	13%	66%	68%	72%	76%
WECC RPS + Clean State & Jurisdiction Targets	16%	70%	74%	83%	88 %

Table B - 9 shows in 2027, the beginning of the power plan analysis, 13% of regional sales are obligated to be clean by regional RPS policies. Both Oregon and Washington have state-wide clean policies that set higher clean targets by 2030, requiring 66% of the region's sales to be clean by that year. While Idaho and Montana have no clean policies at the state level, the clean city and utility targets set within the state are folded into the final row of the above table, with a cumulative regional clean target of 83% clean sales by 2045. The progression of figures, from the much lower RPS target in Figure B - 19 to the total target incorporating all clean policies at all jurisdictional levels in Figure B - 21, shows how the individual state goals compare to each other, and how they coalesce into a single regional goal.

[28] The final target set by both Oregon HB2021 and Washington CETA, obligates 100% of load be clean, which is a higher requirement than 100% clean sales due to line losses. That difference has been incorporated into these aggregate percentages.

Figure B - 19: In-Region Renewable Portfolio Standards

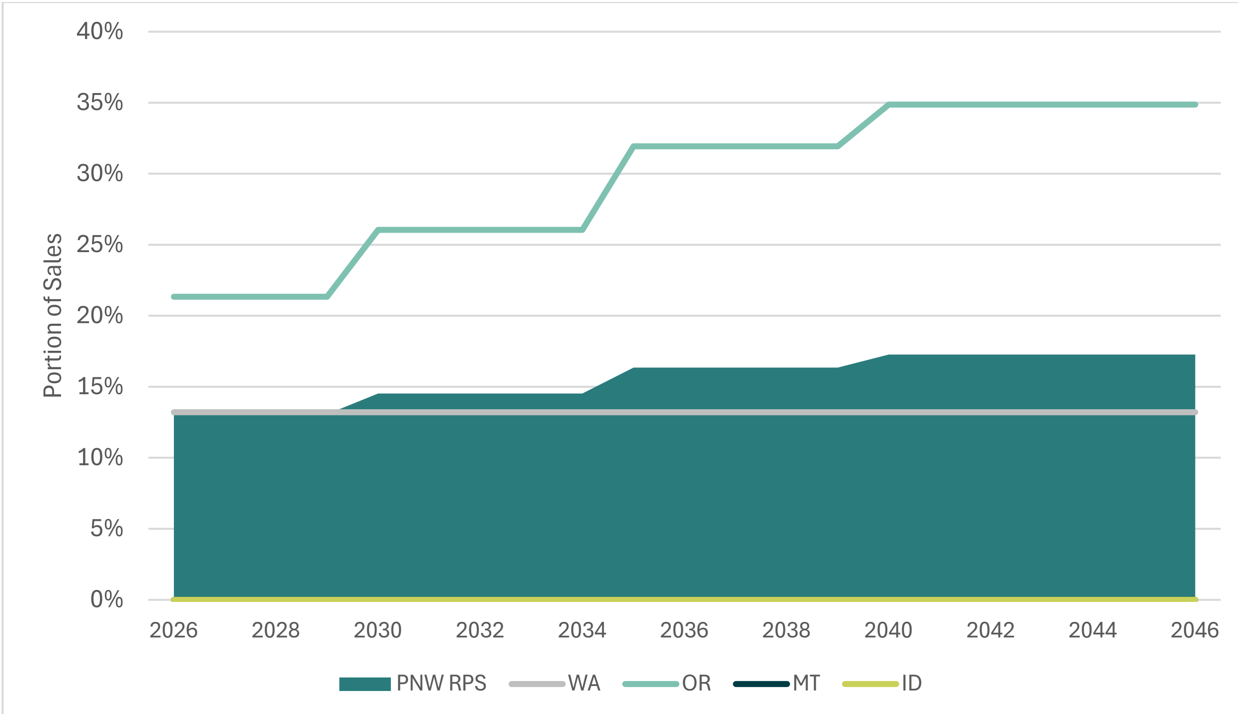
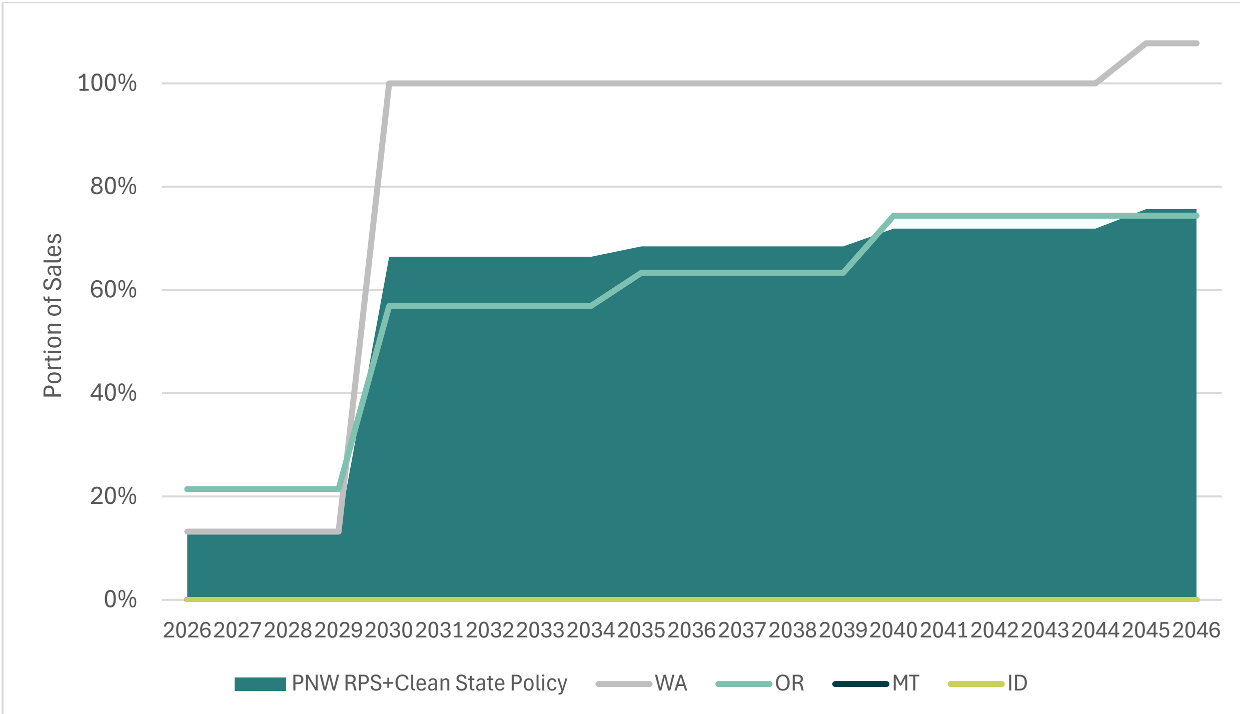
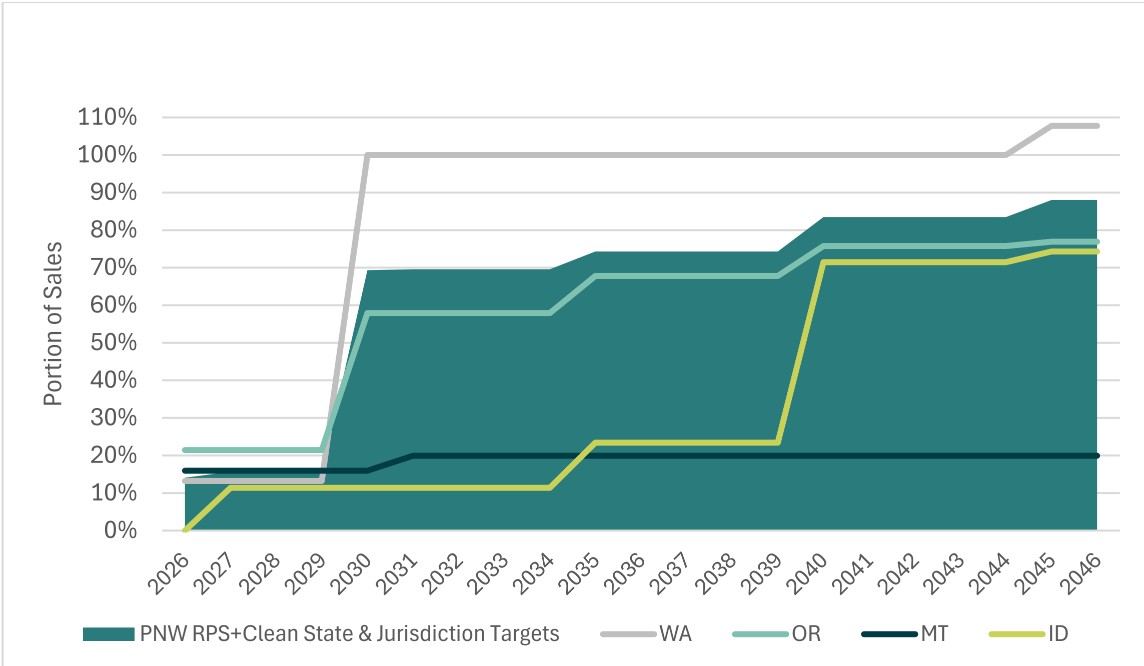


Figure B - 20: In-Region RPS & Clean State Policies[29]



[29] As described in the previous footnote WA and OR policies apply to 100% of load which is a larger than sales (pre-line losses). In application during modeling, these percentages will be applied to future load and will account for line loss, but when applied to sales, like in these charts, the portion of sales is higher than 100%.

Figure B - 21: In-Region RPS, Clean State Policies, & Jurisdictional Targets[30]



The data and calculations behind the figures above can be found here: https://nwcouncil.box.com/s/rml2931at2xtxfngtomj6w6xlidyo6bu.

Table B - 10 summarizes the in-region policies relevant to the Ninth Power Plan assumptions.

Table B - 10: Washington Energy Policy Summary

Name	Role in Modeling	Summary
Washington		
Clean Energy Transformation Act (CETA)	Resource Options	Requires utilities: • eliminate coal-fired resources from WA rates by 2025 • be carbon neutral by 2030 • be 100% clean by 2045 • use the social cost of carbon in their resource planning

30 "Jurisdictional" refers to local city and utility goal, these are not necessarily binding, but the intentions of these sub-state jurisdictions are still important to account for when planning.

Name	Role in Modeling	Summary
Climate Commitment Act (CCA)	Load (electrification) Resource Cost (added cost to emitting resources)	Cap & invest program, utilities subject to CETA are allocated allowances under CCA in alignment with their carbon reduction goals set by CETA
Advance Clean Cars II Rulemaking on Low and Zero Emission Vehicles	Load	Requires 100% of new light duty vehicles to be ZEV or PHEV by 2035 Adopted CA clean truck rules
Clean Fuel Standard	Load	Requires suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034
Clean Building Performance Standard	Load	Covered buildings must comply by meeting an energy performance metric (EUI target)
Codes & Standards	Load	Building code and appliance standards above and beyond the federal standards
Renewable Portfolio Standard	Resource Options	15% by 2020
Healthy Environment for All (HEAL) Act	NA (could consider in narrative)	Requires Ecology and the state departments of Agriculture, Commerce, Health, Natural Resources, Transportation, and the Puget Sound Partnership to identify and address environmental health disparities in overburdened communities and for vulnerable populations.
Oregon		
HB2021	Resource Options	Directs utilities to reduce emissions levels below 2010-2012 baseline levels by: • 80% by 2030 • 90% by 2035 • 100% by 2040 Also expanded the capacity standard for Small Scale Renewables from 8% to 10%
Climate Protection Program 2024	Load (electrification)	Sets an enforceable declining cap on GHG emissions from fossil fuels used throughout Oregon, including diesel, gasoline, and natural gas. Designed to reduce these emissions by 50% by 2035 and 90% by 2050

Name	Role in Modeling	Summary
		Regulated entities include natural gas utilities, fuel suppliers, energy intensive trade-exposed industry sources, and direct natural gas sources – this policy does not apply directly to the electric sector.
Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles **Advanced Clean Truck Rules**	Load	100% of new light duty vehicles to be ZEVs or PHEVs by 2035 Increasing sales targets for zero emission MHDV starting in 2025
SB1547 Community Solar	Resource Options	Requires the Oregon Public Utility Commission to establish a program for the procurement of electricity from community solar projects.
Energy Performance Standard for commercial buildings	Load	Based on 2024 ASHRAE Standard 100, with OR specific amendments, sets EUI targets for different building commercial types
Codes & Standards	Load	Building code and appliance standards above and beyond the federal standards
Renewable Portfolio Standard	Resource Options	Directs utilities' generation be: • 35% renewable by 2030 • 45% by 2035 • 50% by 2040 *With lower requirements for smaller utilities.
Montana		
Missoula- 100% Clean Electricity Initiative	Resource Options	100% clean electricity by 2030 for the Missoula urban area
Bozeman-2020 Climate Plan	Resource Options	100% net clean by 2030 Carbon neutral by 2050
Helena-100% Clean Electricity Goal (city council resol.20592)	Resource Options	100% clean electricity by 2030, interim goal of 80% by 2025

Name	Role in Modeling	Summary
NorthWestern Energy "Net Zero Vision"	Resource Options	Net zero emissions by 2050
Idaho		
Boise's Energy Future	Resource Options	100% citywide clean electricity by 2035
Idaho Power	Resource Options	100% clean energy by 2045
Avista	Resource Options	100% clean electricity by 2045 and carbon neutral by 2028

WECC

The Council produces a *regional* power plan. However, the region does not exist in a vacuum, and the resource type and the amount of energy available from the broader west impacts in-region behavior and decision making. The Council's modeling of the WECC informs market availability of energy in the region. As a result, it is important to capture the relevant polices that impact resource development and dispatch in the WECC, which will affect market fundamentals within the region.

Policies that are especially impactful in the region – because they both set steep clean goals and are from large jurisdictions therefore placing a large percentage of the WECC under a high clean energy goal – are the Californian and Canadian carbon prices. When paired with Washinton's carbon tax, set by the CCA, a large portion of the West's emitting resources fall under a high, and rising, price. This steeply disincentivizes the use of the existing thermal fleet or the building of new thermal resources – because it becomes increasingly difficult to find a place to sink that energy that doesn't have to pay that premium.

Table B - 11 and Table B - 12 below summarize the existing policies in the WECC that inform the Council's Ninth Power Plan analysis.

Table B - 11: US WECC-Wide Policy Summary

Name	Summary
California	
Assembly Bill 1279 (2022)	Reduce economy wide GHG emissions 85% below 1990 levels by 2045
Advanced Clean Cars II rule	By 2035 all new passenger vehicles sold in CA will be ZEVs
100% Clean Energy Act (SB 100) +Clean Energy, Jobs & Affordability Act	100% of CA electricity to come from clean sources by 2045 Interim targets:

Name	Summary
	• 90% of all retail sales of electricity to CA end-use customers clean by 2035 • 95% by 2040 • 100% by 2045 • 100% of electricity procured to serve all state agencies clean by 2030
Renewable Portfolio Standard	60% renewable by 2030
Utah	
Community Renewable Energy Act (HB411)	Opt-out program with a goal of being 100% net renewable by 2030 (19 cities in UT are currently participating and have adopted 100% renewable goals by or before ~2030)
Renewable Portfolio Standard	20% renewable by 2025
Wyoming	
Reliable and Dispatchable Low-Carbon Energy Standard Statute (HB 200)	Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2033 if technically and economically feasible (at least 20%)
Nevada	
Renewable Portfolio Standard	50% renewable by 2030
SB358	100% carbon free energy production by 2050
Arizona	
Renewable Portfolio Standard	15% renewable by 2025 (30% of that from distributed resources)
Arizona Public Service	100% carbon neutral by 2050 65% clean (45% renewable) by 2030
Tucson Electric Power Company	Net zero direct GHG emissions by 2050, 80% reduction in CO2 by 2035
Salt River Project	Goal is to reduce the amount of CO_2 emitted by generation (per MWh) by 82% from 2005 levels by 2035 (~284 lbs./MWh) and reach net zero carbon emissions by 2050.
Colorado	
Renewable Portfolio Standard	IOUs: 30% renewable by 2020 Munis: 10% by 2020 Coops: 20% by 2020
Roadmap to 100% Renewable Energy	Governor goal/commitment: 100% renewable energy by 2040

Name	Summary
HB-1261	Sets economy-wide targets for reducing greenhouse gas pollution, with goals of 26% reduction by 2025 below 2005 levels, 50% reduction by 2030 and 90% reduction by 2050
H21-264	GHG reduction targets for gas utilities: 4% reduction below 2015 GHG emission levels by 2025 and 22% by 2030.
XCEL Energy	Reduce CO2 emissions 80% lower by 2030 100% carbon-free electricity by 2050
Platte River Power Authority	100% noncarbon energy mix by 2030
Poudre Valley REA	80% carbon-free energy by 2030
Holy Cross Energy	100% clean energy by 2030
Denver Renewable Energy Action Plan	100% renewable electricity community wide by 2030
New Mexico	
Renewable Portfolio Standard (NM Energy Transition Act)	IOUs: 50% by 2030 100% carbon-free by 2045 Rural Co-ops: 10% by 2020, 40% by 2025, 50% by 2030, 100% carbon-free by 2050
Xcel Energy	100% carbon-free by 2050
Public Service of NM	100 emissions free by 2040

Table B - 12: International WECC-Wide Policy Summary

Name	Summary
Canada	
British Columbia: Clean electricity target	100% by 2030
Alberta: Clean electricity target	30% by 2030
National: Carbon Tax	Canada-wide

Cumulative/Aggregate WECC Clean Energy Goals

For the purposes of aggregating WECC policies into a WECC-wide clean target, each state represents the below assigned portion of WECC sales, and therefore their policies apply to that percentage of the total WECC. The aggregate clean policy target for the entire WECC then is set as a parameter in modeling. The logic of the tables and charts below follows that laid out on the regional scale above. For example, California makes up 28% of WECC-wide sales and so their policies apply to 28% of the total WECC. Additionally, in this look, the region is just a portion of the total WECC with Washington, Oregon, Montana and Idaho making up 14%, 9%, 2%, and 4% of the broader WECC respectively.

Table B - 13: WECC-Wide State Sales

	State	Portion of total WECC Sales
Region	Washington	14%
	Oregon	9%
	Montana	2%
	Idaho	4%
WECC	Arizona	14%
	California	28%
	Colorado	9%
	New Mexico	5%
	Nevada	6%
	Utah	5%
	Wyoming	3%

Table B - 14: Clean Policies as a Percentage of WECC Sales

	2027	2030	2035	2040	2045
WECC RPS	28%	32%	33%	34%	35%
WECC RPS + Clean State Policy Targets	28%	51%	60%	63%	67%
WECC RPS + Clean State & Jurisdiction Targets	29%	55%	66%	71%	74%

The data and calculations behind the figures above can be found here on the Council's Ninth Power Plan webpage.[31]

[31] https://nwcouncil.box.com/s/rml2931at2xtxfngtomj6w6xlidyo6bu.

Figure B - 22: WECC-Wide Renewable Portfolio Standards

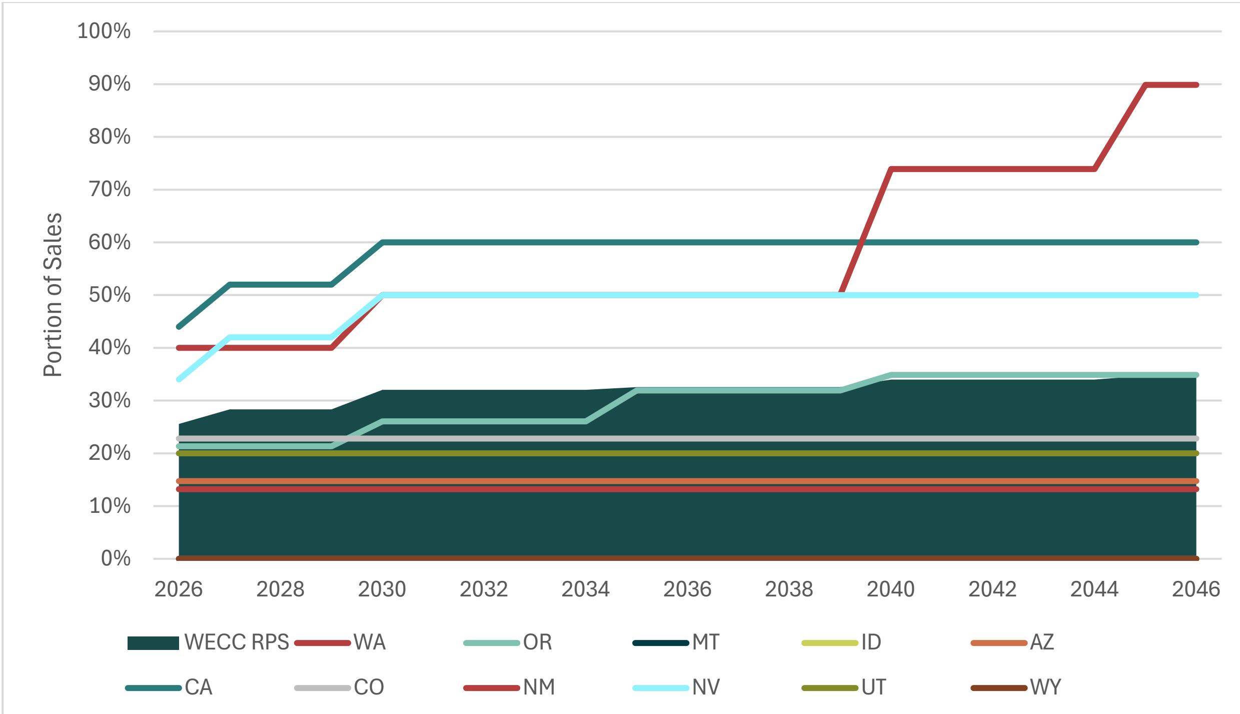


Figure B - 23: RPS & Clean State Policies

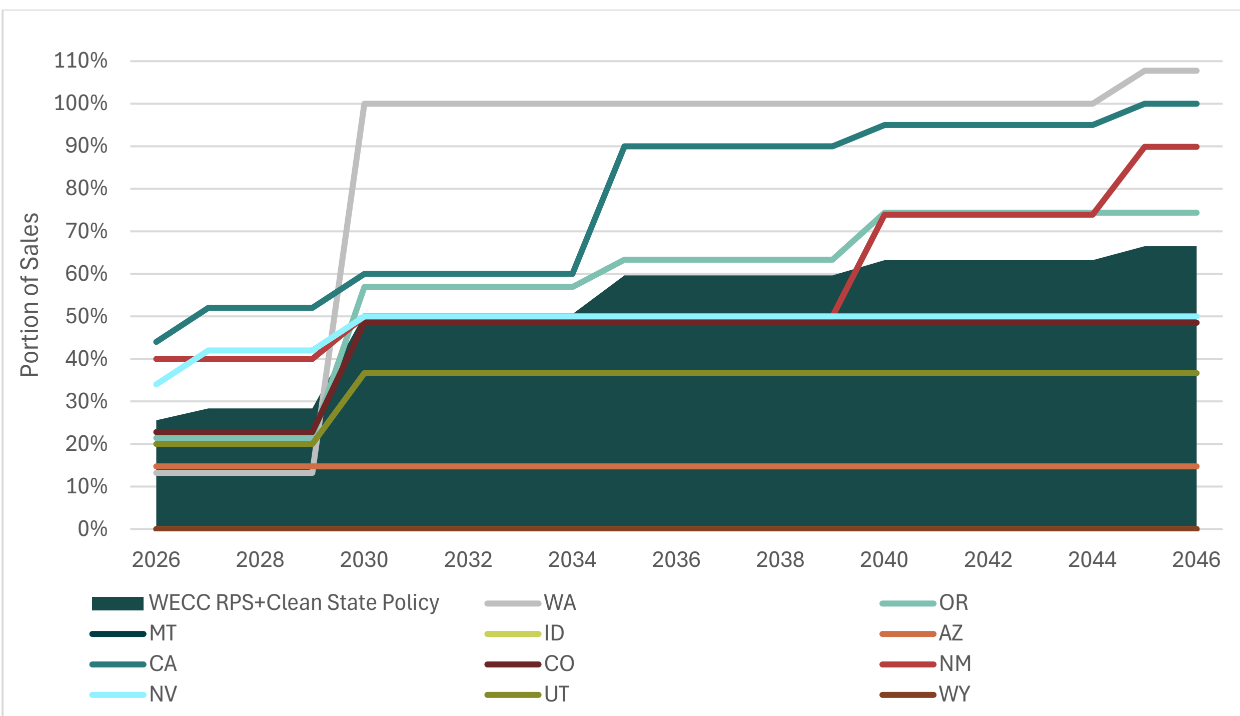


Figure B - 24: RPS, Clean State Policies & Jurisdictional Targets

Planning Under Uncertainty

The work of power planning always takes place under uncertainty. One source of uncertainty is around decisions impacting the existing system into the future. Another is around policies. In an effort understand the breadth of that uncertainty, the plan relies on scenario analysis, designed to test the impact and risk of changing resource availability, resource costs, and transmission availability. Different sensitivities in this analysis will allow for exploration of how changing background conditions might change the solutions produced by the model. More information provided in Technical Appendix N – Scenario Modeling and Results.

Policy in Scenario Testing

During the early scoping process for the Ninth Plan, there was a federal administration change that reversed major energy legislation passed by the previous presidency. These policies are described in Table B - 7 above. Most of the Plan will reflect the current administration's policies, as those are the ones currently enacted as law. However, one scenario that explores changing hydro operations, began analysis before the new law was enacted and therefore reflects previous policies.[32]

[32] This scenario is described in Technical Appendix N – Scenario Modeling and Results.

New Resource and Transmission Risk Scenario

This scenario aims to explore a range of uncertainty and risk related to the region's ability to build new resources and transmission. Each sensitivity within the larger scenario will provide an optimized regional build out given that suite of assumptions across the range of futures. From these different looks collectively, the Council can learn what resources in what amounts are robust across the range of uncertainty as well as what resources or suites of resources might be built to mitigate different risks.

One key sensitivity included in this scenario is the Evolving Federal Policy Landscape sensitivity. Over a 20-year planning horizon, there are always elements of policy uncertainty, and this sensitivity is designed to test how much policy decisions at the Federal level impact resource decisions in the region. This felt especially pertinent given the distinct policy shift between administrations experienced in the early days of this planning cycle.

To test this, the Council designed a sensitivity that brings back policies similar to the tax credits in the IRA and new source emissions requirements under the Clean Air Act. The sensitivity would assume new tax credits for renewables, clean air requirements for new combined cycle combustion turbines, and tax credits for certain energy efficiency measures. These assumptions will be based off of those from the IRA and would come into effect in 2030. The other sensitivities in this scenario will reflect the current policy landscape without clean tax credits or updated emissions requirements.