THE 2021 NORTHWEST POWER PLAN

FOR A SECURE & AFFORDABLE ENERGY FUTURE

DRAFT PLAN

COUNCIL DOCUMENT 2021-5

September 2021

Northwest Power and Conservation Council

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Section 1: Introduction

Electricity generating resources in the Northwest – carbon-free hydropower and nuclear, gas, coal, wind, and solar – plus energy efficiency – have served the region's electricity needs well, providing capacity and energy supporting a reliable, adequate, efficient, and economical power system. In the years since the Council last revised the power plan, however, the power system has experienced changes that place more emphasis on renewables, such as wind and solar generation.

In this Draft 2021 Power Plan, the Council recognizes those states that have requirements and policies pursuing emission reductions that support cleaner electricity generation. Influenced by these policies, this plan includes significantly more renewable generation than all of our previous power plans. Looking forward five or six years, the mix of generating resources within the regional power system will likely see modest changes to this composition. The Power Act requires that the Council review the plan at least every five years. For this reason, the Council's work focuses most intently in this plan on the period between its release and the next one – the time we call the action plan period. However, this plan's forecast through 2041 indicates this region can expect a more substantial transformation in the fleet of regional resources used to generate electricity. Through this transformation into the future, hydropower and energy efficiency will continue to be a fundamental part of the region's power system.

The draft plan recognizes that there are social, political, and economic drivers leading to this region's turn toward cleaner sources of generation, primarily wind and solar. These intermittent or variable technologies are becoming less expensive to build and are seen as the primary path to reducing emissions associated with generating electricity. This emerging paradigm shift in how the region produces electricity is addressed in the draft plan's Resource Strategy. To forecast the potential impacts of this shift, the draft plan reflects the results of several energy models, public policy, technology, a blend of climate change assumptions, and economics in preparing for the action-plan period, and for the longer 20-year plan.

The Council's work leading to this plan has focused on developing a resource strategy to assure the region an efficient, adequate, economical, and reliable power supply that is available, sufficiently dispatchable, and deliverable within the region's transmission system from where electricity is produced to where it is needed. The Council's work also indicates that as more intermittent or variable generation from wind and solar power are added to the system, a corresponding increase in reserves is necessary. These reserves are accommodated by our existing hydropower, gas, nuclear, and remaining coal generation. In the end, the region's resources must be instantaneously balanced with the region's demand to reliably provide electricity across the entire Northwest power system.

The 2021 Plan contains 12 sections that provide more detail and specifics on the plan components. Section 6 details the new and existing resources anticipated to meet the future demand for electricity. Our work indicates that the region's large amount of hydropower, nuclear, and traditional thermal resources including those that burn natural gas and coal, remain an essential part of providing reliable electricity for the region. We also expect that the continued acquisition of energy efficiency now and in the future will play a critical role in meeting the region's future demand for electricity. In addition, the future system will be supported by the ongoing development of new renewable resources that are anticipated to provide needed energy, while reducing greenhouse gas emissions. We also recognize new demand response opportunities that can be expected to support and reduce system capacity needs. Finally, trading electricity with our neighboring regions in energy markets will continue to support current and future reliability.

This plan is intended to help transition the region into a new paradigm of cleaner energy that includes the use of our abundant hydropower, existing gas, nuclear, and remaining coal generation to provide reliability during the action plan, while also integrating the current and expected future renewables into the power system. As we look to the future, we anticipate that the transition to a new paradigm will be accompanied by risk and uncertainty. This region has dealt with and overcome risk and uncertainty in the past and can be expected to do so in the future. Implementing the strategy in this plan will require the flexibility and collaboration shown in the past era to accommodate the challenges of the new era while maintaining the reliability expected by Northwest electricity customers.

Section 2: Power Act Requirements and the Power Plan

In December 1980, in direct response to a set of linked problems the region faced concerning increasingly difficult resource issues and the decline of Columbia River salmon and steelhead runs, Congress enacted a comprehensive and innovative legislative solution—the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). The purposes for which the Northwest Power Act was enacted are captured in Section 2 of the Act and summarized here: 1.) to encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest; 2.) to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply; 3.) to provide for the participation and consultation of states, local governments, consumers, customers, users of the Columbia River system, federal and state fish and wildlife agencies, Indian tribes, and the public at large in the development of regional plans and programs, facilitating orderly planning of the region's power system, and providing environmental quality; and, 4.) to protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat. The Act was groundbreaking in its use of the Federal Columbia River Power system to achieve cost-effective conservation, its prioritization of conservation and renewable resources, its fish and wildlife protection and mitigation obligations as well as its required considerations of environmental quality, and, ultimately, its regional power planning process. Remarkably, the Act also implicitly recognized the inherent uncertainty in planning for a future electric power system, with power planning provisions and plan process providing a venue to accept and manage that uncertainty.

To carry out the Act's purposes, the Northwest Power Act authorized the states of Washington, Oregon, Idaho, and Montana to form an interstate compact agency—the Council—and directed the Council to: 1.) prepare and review a "regional conservation and electric power plan" not less than once every five years; 2.) prior to each plan, prepare and periodically amend a program to protect, mitigate, and enhance fish and wildlife affected by the Columbia River Basin hydropower system; and, 3.) develop both the power plan and the fish and wildlife program in a highly public process, with broad consultation and participation. Beyond charging the Council with these specific responsibilities, the Act also specifies, in Sections 4(d) through 4(g) of the Act, the process the Council is to follow in developing and amending the plan, what the Council must include in the power plan, what the Council must do prior to the review of the power plan (undergo a separate process to develop or amend the fish and wildlife program addressed in Section 4(h)), and, finally, in Sections 4(d)(2) and Section 6(a) through 6(c) how the Bonneville Power Administration is to use the power plan in implementing conservation measures and acquiring new generating resources. These provisions are discussed in more detail below.

Public Engagement and Process for Developing the Power Plan

While the Council is directed to prepare a regional conservation and electric power plan, a corresponding directive to the Council, and principal purpose of the Act, is to provide for broad public participation and consultation in the development of that power plan; Sections 4(d)(1) and 4(g) describe how the Council is to implement this mandate and engage the public throughout development and review of the power plan. Per section 4(g)(3), in the preparation, adoption, and implementation of the power plan, the Council and the Bonneville Power Administration administrator (Bonneville), must encourage the cooperation, participation, and assistance of appropriate federal agencies, state entities, political subdivisions, and Indian tribes. And, Sections 4(g)(1) and (2) add that the Council and Bonneville, in the formulation of regional power policies, must maintain comprehensive programs to inform the public of major regional power issues, obtain public views concerning major regional power issues, and secure advice and consultation from Bonneville's customers and others. Further, the Council and Bonneville must consult with Bonneville's customers, include the comments of such customers in the record of the Council's proceedings for the power plan and fish and wildlife program, and recognize and not abridge the authorities of state and local governments, electric utility systems and other non-federal entities responsible for the planning, conservation, supply, distribution, and operation of the electric generating facilities.

In practice, these provisions result in a multi-year, highly public process to develop the Council's regional conservation and electric power plan. For the 2021 Power Plan, the Council officially began the power planning process in February 2019 with a webinar that was open to the public and provided information regarding the history of the Act, the planning process, and opportunities for public participation, including through the Council's advisory committees, which are groups comprising technical and policy experts from around the region. Early and throughout the process, the Council utilized these advisory committees to gather information on priority issues for the region that informed the substantive issues for the power plan, to analyze issues and analytical work prepared in development of the power plan, and to discuss and review the findings for the power plan. All advisory committee meetings are open to the public, with notice provided through our website and email distribution lists, and presentations or materials also made publicly available. Additionally, the Council developed the power plan and discussed substantive issues from the power plan in the Council's Power Committee and regularly scheduled full Council meetings. All Power Committee and Council meetings are open to the public, with public notice provided through the Council's website and an opportunity for public comment during the Council meetings. In addition, the Council welcomed comment and informal participation and collaboration throughout the planning process through one-on-one meetings with staff and written communications. The comments provided through these opportunities were closely considered by the Council and informed the development of the power plan.

Once the draft power plan is issued, Section 4(d)(1) of the Act requires that the Council hold public hearings on the draft power plan in each of the Northwest states. In addition to the public hearings required under the Power Act, the Council also largely follows the notice and comment procedures of the federal Administrative Procedures Act. Therefore, the Council also provides wide public notice of the draft power plan and ample opportunity to submit written comments, as well as opportunities to provide comment at regularly scheduled monthly Council meetings and testimony at the public hearings. Further, the Council uses this public comment period to conduct consultations with Bonneville, Bonneville's customers, Indian tribes, state and federal agencies, and non-governmental entities to solicit their advice and comment as contemplated under Section 4(g).

Lastly, as a component of the final power plan, the Council explains and describes how comments were considered and responded to during the development of the power plan, including any changes from draft to final. While the process presents unique challenges, broad public participation, engagement, and consultation remain constant in the development of each plan.

Substantive Considerations and Elements in the Power Plan

Section 4(d)(1) provides the basic directive to the Council—to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan. However, Sections 4(e) and 4(f) provide the substantive priorities, considerations, and elements that the power plan must contain. Section 4(e)(1) specifies that the power plan is to give priority to resources which the Council determines to be cost-effective, with priority given first to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency, and fourth to all other resources.[1] Given this set of priorities, Section 4(e)(2) then focuses on what the Council is to deliver in its power plan, and that is a "scheme for implementing conservation measures and developing resources…to reduce or meet the Administrator's [Bonneville's] obligations." Further, Section 4(e)(2) requires that the Council must develop this resource scheme (or resource strategy) "with due consideration for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan." Therefore, taken together, these provisions require that the Council develop a cost-effective resource strategy to reduce or meet Bonneville's obligations, and, in doing so bring each of these considerations to bear.

Section 4(e)(3) lists the following specific elements the Council is to include in the power plan, but leaves it to the Council to describe the elements "in such detail as the Council determines to be appropriate":

(A) An energy conservation program, including model conservation standards
(B) Recommendations for research and development

[1] Cost-effective is defined in the Act in Section 3(4)(A), and a resource is cost-effective if it has an "estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof." Therefore, cost-effectiveness is a comparative exercise of resources.

(C) A methodology for determining quantifiable environmental costs and benefits under Section 3(4) of this Act [definition for cost-effective]
(D) A demand forecast of at least 20 years, to be developed in consultation with Bonneville, customers, states (including state agencies with ratemaking authority over electric utilities), and the public, in such a manner the Council deems appropriate, and a forecast of power resources estimated by the Council to be required to meet the administrator's obligations and the portion of such obligations the Council determines can be met by resources in each of the priority categories. The forecast of power system resources shall also include (i) regional reliability and reserve requirements, (ii) the effect, if any, of the requirements of the Council's fish and wildlife program on the availability of resources to Bonneville, and (iii) the approximate amounts of power the Council recommends should be acquired by Bonneville; this may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired
(E) An analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost
(F) The fish and wildlife program promulgated prior to the power plan by the Council under Section(h) of the Act.
(G) Any surcharge recommendation relevant to implementation of the model conservation standards and a methodology for calculating the surcharge.

Lastly, Section 4(f) provides and details the model conservation standards to be adopted into the plan and the associated surcharge authority, both addressed as elements of the plan in Section 4(e)(3). While the Act is prescriptive as to the elements, it also provides the Council with a substantial amount of discretion to use its expertise to develop and craft these elements for each plan.

For this power plan, the Council decided to structure the plan in such a way that each plan section corresponds with an element identified under the Act. For example, Section 5 details the energy conservation program and Section 9 details the cost-effective methods of providing reserves, while Section 6, Resource Development Plan, comprehensively describes the resource strategy for the 2021 Power Plan. However, specific components from the energy conservation program are also included in the resource strategy discussion of Section 6, as well as analysis and findings from the cost-effective methods of providing reserves detailed in Section 9, which is illustrative of the way in which each of these elements work together to inform the Council's power plan.

Relationship of the Power Plan to the Region and Bonneville

As noted above, per Section 4(d)(1), the Council is to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan, and, per Section 4(e)(2), the Council's power plan is to set forth a "scheme for implementing conservation measures and developing resources…to reduce or meet the Administrator's obligations." Therefore, under the Act, the Council's power plan must consider the entire region while planning for Bonneville's resource obligations, and this is so because when adopting the Northwest Power Act it was envisioned that Bonneville, the federal power marketing agency selling the electrical power produced by the Federal Columbia River Power System, would be the major engine for adding new resources as needed for the region and the purposes of the Act would be achieved through the use of the federal system. Thus, Sections 6(a)(2)(A) and (B) of the Act authorize and obligate Bonneville to acquire sufficient resources to (A) meet the agency's contractual power sales obligations and (B) to assist the agency in meeting the requirements of Section 4(h) of the Act, which is the Council's fish and wildlife program. Moreover, Section 4(d)(2) and Sections 6(a), 6(b), and 6(c) tie Bonneville's implementation of conservation and acquisition of new resources directly to the Council's power plan by requiring that Bonneville's resource acquisitions and conservation implementation be consistent with the Council's power plan, with certain narrow exceptions. Accordingly, the Act requires the Council include in the power plan a number of elements concerning Bonneville's resource acquisitions, specifically: a resource strategy to reduce or meet Bonneville's obligations (Section 4(e)(2)); an energy conservation program to be implemented under the Act (Section 4(e)(3)(A)); and a forecast of power resources estimated by the Council to be required to meet Bonneville's obligations and the portion of such obligations the Council determines can be met by resources in each priority category, with the forecast required to include the approximate amounts of power the Council recommends should be acquired by Bonneville on a long-term basis and may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired (Section 4(e)(3)(D)). For the 2021 Power Plan, to more explicitly recognize this relationship between the Council's power plan and Bonneville, the Council included specific plan sections for Bonneville (*See* Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity and Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation).

Despite the fact that the only legal link provided in the Northwest Power Act to the Council's power plan is to Bonneville and Bonneville's resource acquisition decisions and conservation implementation, because Bonneville is the primary provider and marketer of electric power in the region, the Council's power plan necessarily affects those entities that purchase power from Bonneville. In addition, the State of Washington's Energy Independence Act tied Washington utilities' conservation potential directly to the Council's methodology for conservation. Further, the Council's power plan remains influential and an important resource for other entities making resource decisions as well as legislators, regulators, and state energy offices around the region. As evidenced throughout this plan, the power plan remains a proper venue for embracing the uncertainty of the future system, which includes examining the potential implications of policy decisions on the regional system, and how to plan and manage in the face of that uncertainty.

Fish and Wildlife Program

One final important piece of the Council's power plan is the Council's fish and wildlife program developed pursuant to Section 4(h) of the Act. Specifically, Section 4(h) requires that the Council, "prior to the development or review of the plan, or any major revision thereto," call for recommendations from the state and federal fish and wildlife agencies and tribes and adopt or amend a program to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric facilities on the Columbia River and its tributaries. The fish and wildlife program process is heavily circumscribed, with the recommendations requested at the start of the process becoming the base from which the Council builds the program.

Per Section 4(e), the Council's fish and wildlife program is an element included in the Council's power plan, and the Council has an obligation to develop the power plan's resource strategy with due consideration for the protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish. Additionally, pursuant to Section 6 of the Act, Bonneville has an obligation to acquire sufficient resources consistent with the Council's plan to not only reduce or meet the administrator's obligations but to also meet the fish and wildlife protection and mitigation requirements reflected in the Council's fish and wildlife program. Thus, the Council's fish and wildlife program necessarily comes before the Council's power plan so that the Council may determine the non-power constraints on the hydrosystem necessary to protect, mitigate and enhance fish and wildlife, and then use the power planning process to assure an adequate, efficient, economical, and reliable power supply for the region taking into consideration these non-power constraints and any resulting impacts on generation. Sections 11 and 12 further discuss the integration and consideration of the fish and wildlife program.

Supporting Materials

Throughout this power plan, there are references to supporting materials. These supporting materials provide a substantial amount of information, data, and analysis, and provide the basis for and support the conclusions, recommendations, and explanations provided in this power plan. For example, Section 5 describes the conservation program, which is a required element of the power plan; however, sitting beneath Section 5 in the supporting materials is data and analysis to inform the conservation program, including the Council's methodology for estimating the energy efficiency resource potential for the region, estimated energy efficiency potential by sector, as well as the energy efficiency supply curve bins and workbooks. For another example, Section 6 provides the resource strategy, and sitting beneath that section are supporting materials providing detailed information and analysis on the existing system, potential system needs, and resource costs. These are just a few examples of the data and information found in the supporting materials and that underly and support the power plan's recommendations and explanations addressing each of the required elements outlined in the Power Act. The supporting materials are available for review at:

https://www.nwcouncil.org/2021powerplan_sitemap

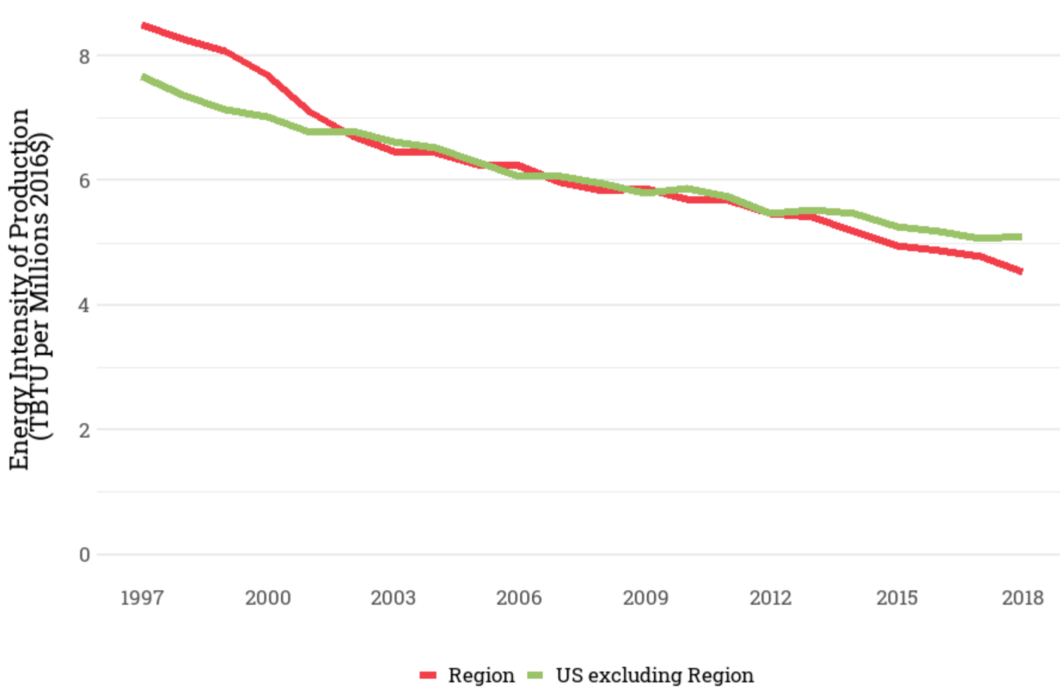
Section 3: Demand Forecast

The Evolving Role of Electricity in the Northwest

Electricity is so ubiquitous it's often overlooked. Our economy would hardly function without electricity. But increasingly, society is looking to electricity as a solution to reducing greenhouse gas emissions. Whether in electrification of light-duty vehicles or reducing fossil-fuel use in industrial applications, the use of electricity is broadening rapidly. At the same time, technologies like LED lighting have greatly increased the efficiency of long-standing uses for electricity.

The Northwest historically had industries with higher energy consumption than the rest of the United States, but that shifted over the last couple of decades. Now the regional consumption of energy is lower than the rest of the United States per dollar of production.

Energy Intensity of Regional Production is Falling Faster than the Rest of the US



Increasing the efficiency of our energy use and expanding the electricity available at a reasonable cost helps both grow the regional economy and accomplish the region's goals for reducing greenhouse gas emissions. An important requirement of the power plan is the development of a demand forecast. The Council develops a demand forecast for both electricity and natural gas use in homes and buildings, and examines both risks and opportunities in its forecast.

Potential New Sources of Load

Transportation – the movement of people and goods – is a large energy consumer. According to the U.S. Energy Information Administration (EIA), as much as 28 percent of all the energy consumed annually is for transportation, and most of that energy is delivered from petroleum-based fuels like gasoline and diesel. As a result, total greenhouse gas emissions from the transportation sector have reached parity with the emissions associated with electricity generation. Light duty plug-in electric vehicles provide better efficiency and lower fuel and maintenance costs than their gasoline counterparts and are gaining favor with the consumer. Electric passenger vehicles are also gaining favor with state clean policy-makers as the vehicles have zero tailpipe emissions and are poised to disrupt the automobile and petroleum-product business models over the next decade.

For the 2021 Power Plan, we have developed a forecast of transportation and the related fuel usage. In the near term, the electrification of light duty cars, trucks and vans results in cleaner and more efficient use of energy. Over the longer term (more than 10 years), heavy-duty vehicles, like long-haul trucks, offer further opportunity to electrify. Heavy vehicles are more challenging for plug-in battery technologies. The development of hydrogen fuel-cell powered trucks may become key for continued electrification of transportation, and the associated production of hydrogen required to fuel these vehicles could result in significant growth in the demand for electricity in the region.

The Council recommends policy makers and utilities that are pursuing regional emissions reductions utilize strategies that increase the adoption and use of zero- or low-emission vehicles. Battery electric vehicles are especially suited to meet passenger car and light truck requirements. Consumers in some areas within the region may be more concerned with range anxiety related to reduced battery electric vehicle performance in severe cold weather. Plug-in hybrid vehicles with gasoline engine range extenders, or hydrogen fuel cell vehicles may provide a better option. The hybrid and fuel cell vehicle technologies may also provide a solution for some heavy-duty vehicles like delivery trucks and large freight trucks. As these strategies are pursued, we recommend working with the Council, other regional bodies and power planners to ensure an adequate electric system through the vehicle stock transition.

Direct Use of Natural Gas Forecast

To form a more comprehensive understanding of expected regional emissions, we forecast the need for energy end-uses like transportation or space heating. An end-use is the need or purpose that is served by energy, such as electricity delivered over the electric distribution system, gasoline bought from a fueling station, or natural gas delivered by a pipe to a home or a business. We then estimate the proportion of the different end-uses that are served by different types of fuel. A residence can be heated either by a heat-pump that uses electricity or a furnace that burns natural gas.

End-use consumption of natural gas tends to be seasonal, with peaks in the winter months and lulls in the summer. Homes with gas hookups are the largest consumer of natural gas. Many residences use a gas furnace for heating during the winter, and roughly 75 percent of the residential usage occurs in the months of November through March. Overall, the forecast is showing slight growth in the end-use of natural gas through the planning horizon; roughly 0.5 percent per year on average.

Forecast of End-Use Natural Gas Consumption

Units in TBTU	2020	2025	2030	2035	2040	2045
Total Natural Gas	478	476	460	508	510	533
Fossil Natural Gas	478	473	451	487	479	492
Renewable Natural Gas	0	2	9	21	31	41

Renewable Natural Gas

Renewable Natural Gas (RNG) is biogas that has been conditioned and upgraded so that it can directly displace fossil natural gas. The RNG supply is limited in scope – recent studies suggest that regionally produced RNG could replace less than 10 percent of the natural gas end-use demand. For this power plan, the Council modeled a "blended" RNG/fossil gas supply as part of the forecast for end uses. This "blend" reflects the impact of regional RNG supply entering the existing natural gas pipeline system and displacing conventionally sourced fossil natural gas that is currently imported from Canada and the U.S. Rocky Mountain region.

The end combustion of RNG emits CO_2 just like fossil natural gas, and it is not always a net zero carbon product as its carbon intensity varies by feedstock. RNG, however, generally provides a lower carbon footprint than fossil natural gas. RNG that is produced from organic waste streams that would of otherwise release methane directly may be especially beneficial because the warming potential of methane is over 80 times that of carbon dioxide over a 20-year timeframe. RNG that displaces natural gas use can also reduce upstream methane emissions associated with the extraction and transportation of fossil gas. Reliable, locally sourced RNG could also help reduce gas price volatility.

The Council recommends incorporation of renewable natural gas into utility and other regional long-term planning including identifying the least-cost and lowest net emission profile projects to produce renewable natural gas that may be blended into the gas system. The Council also recommends regional utilities support renewable natural gas, when appropriate, as a method to reduce end-use natural gas emissions, supply low-carbon fuel for transportation, and provide diversity and price stability with a regionally sourced fuel product.

The Impact of Climate Change on the Use of Electricity

When looking at the impact of climate change on the use of electricity, the Council considers both the direct and the indirect effects. The direct effects look at existing buildings and businesses and their current equipment that uses electricity, and estimates the impact of changing temperatures and precipitation on the amount of electricity needed. For example, as temperatures increase, the air conditioning equipment currently installed at homes and businesses uses more electricity.

To estimate the direct impact of climate change on the use of electricity, the Council uses temperature projections downscaled for our region from three different General Circulation Models[2]. These models were selected to represent a broad range of possible conditions associated with an increased concentration of greenhouse gasses in the atmosphere[3].

The indirect impacts of climate change look at decisions or events where we anticipate different outcomes because of climate change. For example, more people moving to the region from hotter climates increases the population. The increase in population in turn increases the need for energy.

To estimate the indirect effects of climate change, the Council examined a broad range of sources and consulted with regional experts on climatic and demographic data. These data needed both sufficiently detailed projections and near-term impacts that fit within the 20-year forecast period we include in this plan. They also needed to be related to the demand for electricity.

Direct impacts of climate change

The models we use to estimate the need for electricity estimate the number of days the region is likely to need to use cooling or heating for buildings. These are represented as Cooling Degree Days and Heating Degree Days[4]. Fewer heating degree days means that there is less of a heating need in the winter, lowering the use of energy. Whereas, more Cooling Degree Days means that there is more energy needed in the summer.

[2] The three models selected were CanESM2, CCSM4, and CNRM, further details on these models and the selection process can be accessed using the link for the supporting material at the end of this section

[3] For more information on the River Management Joint Operating Committee (RMJOC) efforts on downscaling General Circulation Models see: https://www.bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx

[4] Cooling Degree Days (CDD) are calculated by adding up the degrees above 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined. Heating Degree Days are calculated similarly by adding up the degrees below 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined.

Projection of Average Heating and Cooling Degree Days for each Global Climate Model

	Heating Degree Days			Cooling Degree Days		
	2020-2029	2030-2039	Decrease	2020-2029	2030-2039	Increase
			CanESM2			
Oregon	4409	4116	6.7%	451	486	7.8%
Washington	4669	4350	6.8%	364	403	10.9%
Idaho	5726	5398	5.7%	785	815	3.8%
Montana	6965	6527	6.3%	410	423	3.2%
			CCSM4			
Oregon	4542	4417	2.7%	385	401	3.9%
Washington	4847	4717	2.7%	299	327	9.1%
Idaho	5892	5534	6.1%	641	746	16.3%
Montana	7242	6966	3.8%	330	393	19.1%
			CNRM			
Oregon	4686	4222	9.9%	371	450	21.4%
Washington	4962	4482	9.7%	309	358	15.9%
Idaho	6073	5499	9.5%	673	713	5.9%
Montana	7378	6721	8.9%	353	362	2.6%

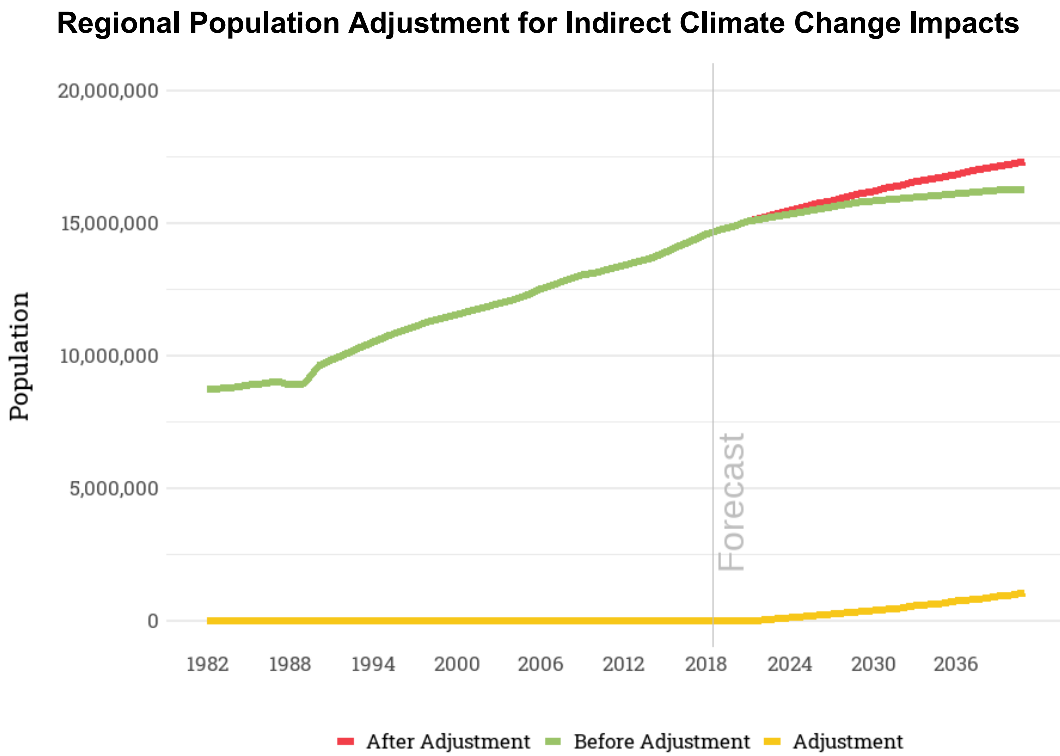
Another direct impact of climate change we anticipate is a change in regional precipitation. Our models look at the electricity used to pump water for agricultural irrigation. The use of electricity for agriculture and irrigation averaged about 690 average megawatts per year between 1986 and 2018. With more precipitation, less water needs to be pumped to fields for irrigation which, in turn, uses less energy. With less precipitation, the opposite holds, and more energy is used. However, an increase in irrigated land based on increasing regional population is included in our forecast as an indirect effect of climate change.

Indirect Impacts of Climate Change

There are many indirect impacts of climate change that could impact the demand for electricity. Events like flooding and wildfires with destructive effects on buildings and infrastructure that uses electricity are difficult to forecast and quantify. In those cases, we are unable to incorporate the potential impacts into our demand forecast but acknowledge these are potential impacts to electricity use in our region that deserve continued study.

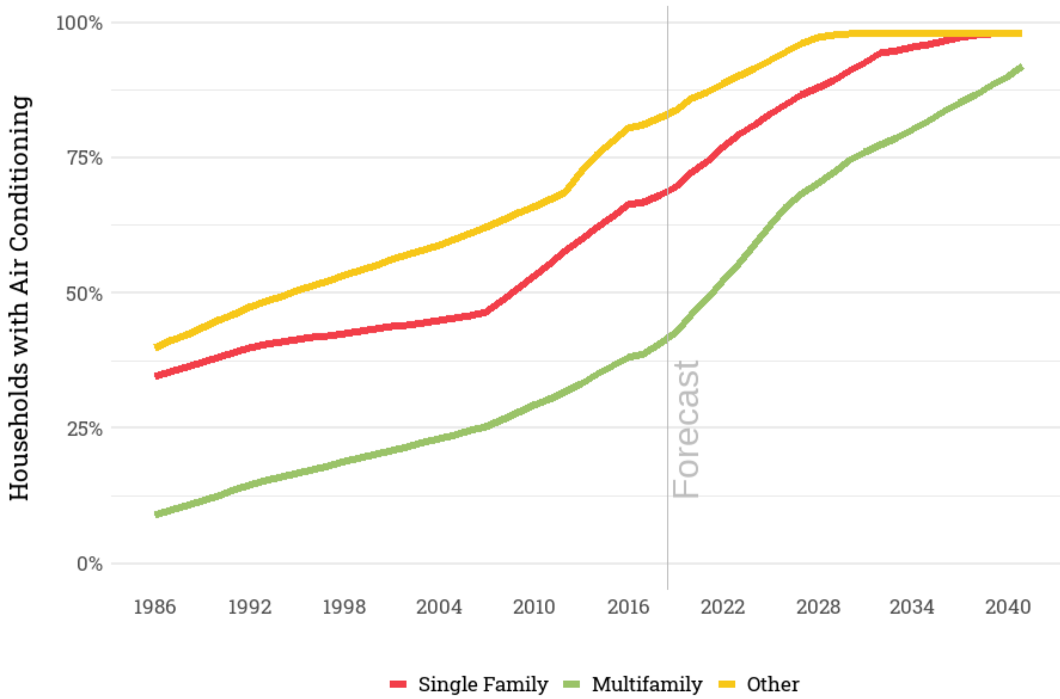
Some effects of climate change are easier to estimate. Where it has been possible to do so in a robust manner, we have included those impacts in our forecast. One adjustment we made is an increase to forecast population. Studies looking at the impact of climate change on migration[5] show a net increase in regional population. Using these studies, we have adjusted population projections in our forecasts.

[5] For detailed information on the studies and the population adjustment, see the supplemental material link at the end of this section.



We also adjusted the saturation of air conditioning in new construction for the region. We have seen a growing penetration of air conditioning installed in residential construction. With climate change, we see that penetration continuing to climb and have adjusted our forecasts to grow to a 98 percent penetration by 2050.

Increase in Air Conditioning Saturation Rate



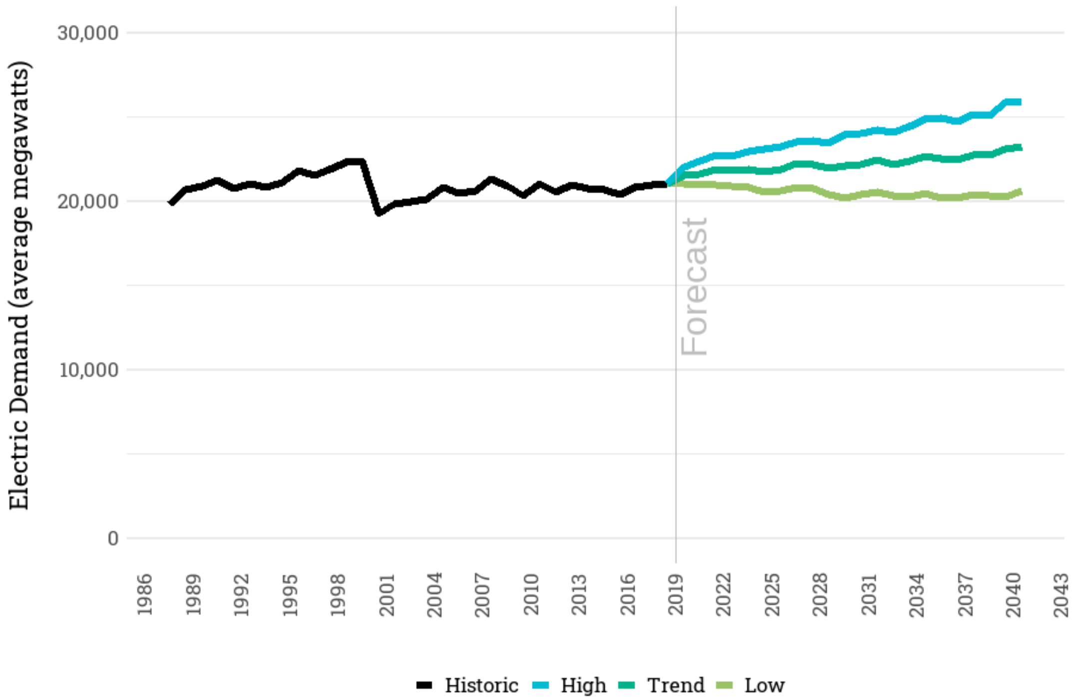
Forecast of Regional Demand for Electricity

Over the next 20 years, the Council forecasts the demand for electricity will be driven by many factors including economic growth, climate change, regional demographics, and expanding applications of electricity to reduce the use of fossil fuels. With all these considerations, we realize that no single forecast could appropriately capture the risks and opportunities to consumers and suppliers of electricity. To better assess the impact on the region, we forecast a possible range for electricity demand.

These forecasts are more uncertain further into the future. To some extent that is considered when we use a range in our analysis. However, our ability to predict what will drive demand for electricity has limits. Thus, the Council updates our forecasts as we get new information. Our forecasts in this power plan are updated and do not match the forecasts included in the last power plan. It should be expected that forecasts beyond the first 5 or 6 years could be missing key drivers that lie outside what would be considered a reasonable forecast at this time. Those drivers will be much clearer in the power plan that follows this one. The Council also forecasts based on current state and federal legislation and does not attempt to predict future legislative change. While recent experience demonstrates it is unlikely that there would be no legislation impacting the use of energy over the next 6 years, exploring this type of uncertainty is left to our scenario analysis. Our scenario analysis includes an examination of added demand for electricity driven by policies or activities aimed at reducing greenhouse gas emissions. Details of our scenario analysis are included in the *Section 6 Resource Development Plan*.

For economic growth, we forecast a range of conditions with a pessimistic estimate of around -8% and an optimistic estimate of +7%. Higher economic output drives higher use of electricity, and so demand for electricity is highest in the optimistic estimate. During Action plan period, range of uncertainty is lower, + 4% and -5%.

Range of Regional Demand for Electricity based on Economic Conditions

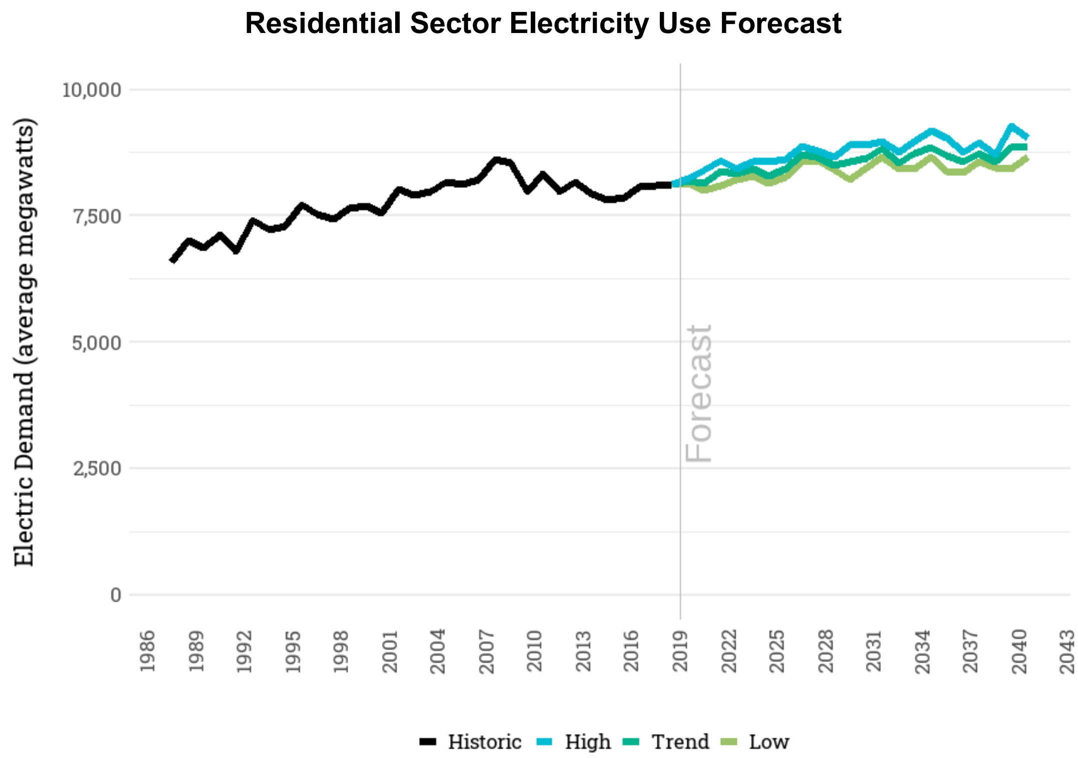


The Council uses this forecast to estimate what additional resources and reserves are adequate to supply the region's need for electricity.

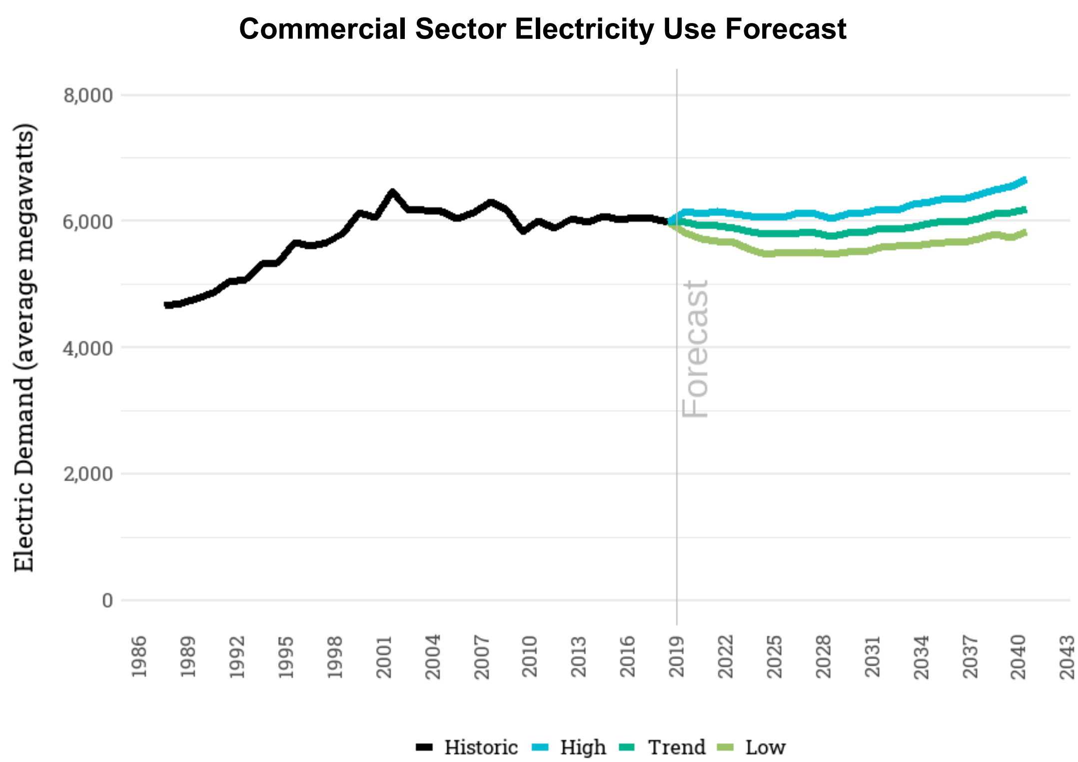
Demand by Sector

The Council's forecast is an end-use forecast. That is, it starts with the different uses for electricity, e.g. lighting or drying clothes, and builds up to sector-level forecasts. We anticipate a range of future loads. We estimate different economic and demographic drivers and then incorporate simulated temperatures from general circulation models. Including these temperatures means the forecasts are not smooth like forecasts that do not include weather variation. For example, anticipated energy needs for the residential sector are particularly sensitive to temperature variation. The loads range from 8,014 average megawatts to 9,726 average megawatts. An average megawatt[6] represents one megawatt of load for a full year. But the minimum and maximum happen in different years. While this means that each year may not reflect a specific likelihood of a load above or below our forecast, the use of these loads as a way of testing different resource strategies helps highlight the natural variation in electricity use that will happen with different temperatures.

[6] For context on what you can power with a megawatt see https://www.nwcouncil.org/news/megawatt-powerful-question



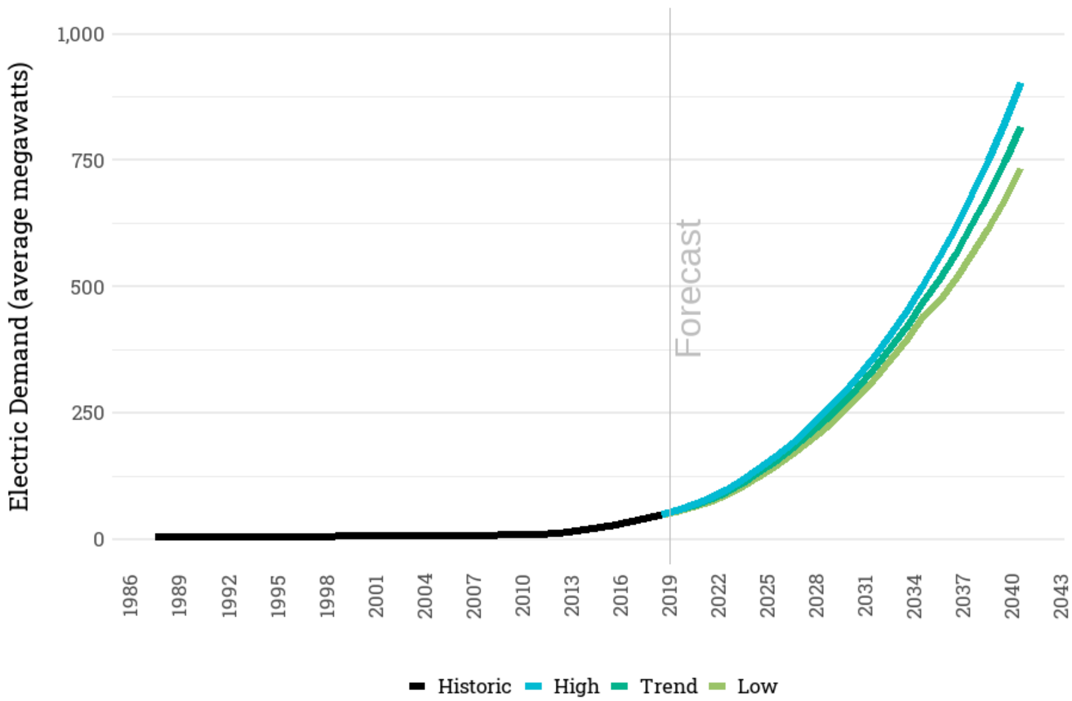
By contrast, the commercial sector load forecast shows less variation based on weather. The range of the commercial load is forecast to vary from around 6,000 average megawatts in the near-term to a high of around 7,359 average megawatts.



Industrial loads in our forecast range from a low of under 4,000 average megawatts to a high of just shy of 8,000 average megawatts. Irrigation loads are anticipated to grow to a range of 937 average megawatts to 1,734 average megawatts. Municipal loads like street lighting are anticipated to stay flat or decline at or under 300 average megawatts.

Our forecast also includes a quickly growing regional electric load in the transportation sector, and for data centers. In the case of transportation, we anticipate substantial growth relative to the amount of electricity used today. Whereas with data centers, we've seen substantial regional growth already that we are projecting will continue.

Transportation Sector Electricity Use Forecast



Taking the whole picture together creates a regional forecast for the use of electricity that shows a range of energy needs anywhere from 20,580 average megawatts to 25,895 average megawatts in 2041. The table below shows the range of loads in 2041 by the different sectors compared to the expected load in 2021. These forecasts have interactive effects so they do not add to the same range of loads as the total regional load, but they should give a sense of which sectors have more uncertainty and how they are anticipated to change throughout the forecast.

Forecast Range of Electricity Use in Average Megawatts by Sector

Sector Forecast	Expected Electricity Use in 2021	Forecast Electricity Use in 2041		
		Low	Medium	High
Residential	8148	8674	8860	9049
Commercial	5938	5833	6202	6673
Industrial	6186	4147	5892	7541
Transportation	67	733	816	904
Street Lighting and Water Services	271	252	280	303
Irrigation	1016	941	1164	1465
Data Centers	657	952	1179	1369

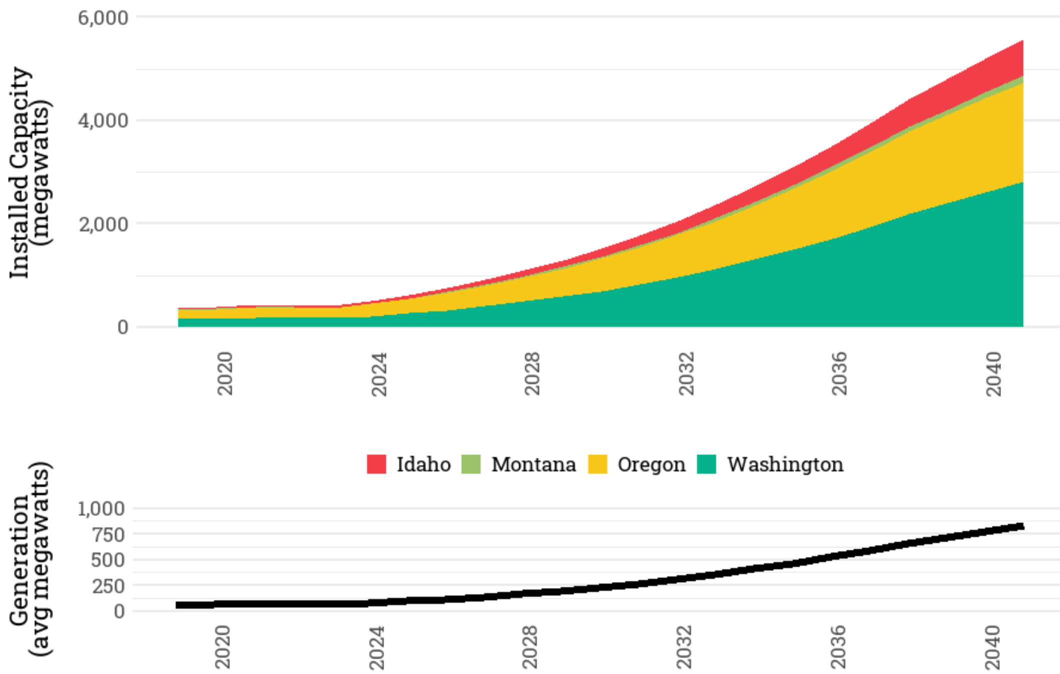
The Impact of Rooftop Solar on the Demand for Electricity

The Council's forecast includes an outlook for behind-the-meter solar installations in the region, which are generally rooftop-mounted systems in the residential, commercial, and industrial sectors. Solar panels are relatively simple to install and operate on homes and businesses. The cost to install and operate home solar has significantly declined and it is expected to continue to decline in our forecast.

Behind-the-meter solar installations in the Northwest have tripled in the five years from 2014 through 2018. By the end of 2018, nearly 90 percent of the 326 megawatts of overall capacity in the region was installed in Oregon and Washington.

The forecast for solar from our model is fairly aggressive. Because of cost declines, we anticipate the growth of installations could be rapid. The graph below shows our forecast of behind-the-meter solar installations by state for our region.

Forecast of Behind-the-Meter Solar Installed Capacity and Generation by State



Section 4: Forecast of Regional Reserve and Reliability Requirements

The fundamental objective of power system operations is to continuously match the supply of energy from electricity generators to customers' electrical demand at all times. This involves proper long-term planning to ensure that the power supply has sufficient generating capability, and that the transmission system can deliver that power within an acceptable range of frequency[7] and voltage[8]. The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas[9] and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." In general, ancillary services provide frequency and voltage control, load-following capability[10], short-term protection for system component outages and flexibility to cover daily, hourly and moment-to-moment variations in the electrical demand and generation.

Because our region is connected to the rest of the West, the policies and decisions outside the region have an impact on our adequacy. In addition to the regions demand for electricity and the combined capability of the regions electric generators to meet that demand, the Council's models

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[7] Frequency is controlled by maintaining a stable net interchange between neighboring balancing authority areas. The basic test of success for this is called the Area Control Error (ACE). ACE is a measurement, calculated every four seconds, based on the imbalance between load (demand for electricity) and generation within a balancing area, taking into account previously planned imports and exports and the frequency of the interconnection. The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic premise is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC), which monitors the frequency of the system and correspondingly adjusts participating generators' output (within seconds) to bring the frequency back in line.

[8] Voltage can be controlled in several ways with different types of system components installed at generating stations and the transmission system.

[9] Control areas (also referred to as Balancing Authorities) are entities, often utilities, that ensure the power system demand and supply are balanced on a section of the electric grid. When supply and demand become too far out of balance, equipment on the transmission and distribution system will disconnect creating local or widespread electric power outages.

[10] In the utility industry, the electrical demand is often called load. Load-following refers to a service provided by electric generators that increases or decreases the output of electricity to match the use of electricity.

show that regional adequacy will also be impacted if our neighbors continue to build large amounts of renewable generation, especially solar generation, leading to an increasing frequency of surplus generation in Western electricity markets. This creates an unexpected result of the near-term model simulations showing a regional system that is less adequate[11] than the same regional system with projected future electricity demand and markets, which depends on the continued operation of the region's existing hydropower, thermal, and renewable resources. With the anticipated pace of development of renewable resources and the currently announced generating resource retirements outside the region, our analysis shows shifting market dynamics impacted by surplus renewable generation as soon as 2025. This changes the dispatch and fuel use of the existing regional electric generators, which is a critical part of assessing regional adequacy. The region should be mindful of this adequacy challenge and attempt to make resources more accessible to help navigate these near-term challenges.

While the fundament objective will not change, the electricity grid seems poised to go through a paradigm change with an increasing penetration of new variable renewable generation displacing an increasing amount of the electricity that would have otherwise been generated by the existing fossil-fuel-based thermal generating fleet. The region and the rest of the West in the future will likely need to rethink how system capacity needs are measured and what different resources accomplish in providing for those needs.

Power Act Definition of Reserves

The Northwest Power Act defines reserves as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator… (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." Electric power that averts operating shortages (operating reserves) falls into four general categories and are either spinning (available for immediate dispatch) or non-spinning (must be at full output within 10 minutes).

- Regulation reserves – provide minute-to-minute increases or decreases in generation to match electrical demand
- Load following reserves – bridge the gap between regulation reserves and hourly energy markets
- Balancing reserves – cover within-hour variations in electrical demand, and variations in wind and solar generation
- Contingency reserves – provide short-term (up to 60 minutes) protection against system component outages (transmission and generation)

The Council's adequacy model assigns operating reserves (regulation, load following, and balancing) and contingency reserves to appropriate resources.

[11] As measured by Loss of Load Probability

What Does it Mean for a Power System to be Adequate?

While the terms “adequacy” and “reliability” are related, they have specific and distinct meanings for power system planning. A power system is defined to be reliable if it is both adequate and secure, where adequacy generally refers to having sufficient generating capability and security generally refers to having a robust transmission system.

- An adequate power system can supply the aggregate electrical demand of all customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements, and
- A secure power system can withstand sudden disturbances, such as electrical short circuits or unanticipated loss of system elements.

The Council uses assumptions established by the transmission planning organizations to estimate the ability to deliver electricity around the Western electric grid. However, substantial retirements or additions of generation on the system may go beyond the scope of these limits. The Council in our work assumes that the transmission planning organizations and utilities will work together to ensure appropriate investment is made into the transmission system to at a minimum maintain the current ability to deliver electricity around the West. While we do not study expansion of the transmission system in this plan, we recommend the region work with the transmission planning organizations to explore the costs and benefits of doing so.

Council’s Resource Adequacy Standard

One of the key objectives of the Council’s power plan is to develop a resource acquisition strategy that will ensure the region of an adequate, efficient, economical, and reliable power system, while taking uncertain future conditions into consideration.

The Council’s overarching goal for its adequacy standard is to *“establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework.”*

The standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

Power supply adequacy is assessed five years into the future, assuming rate-based generating resources[12] and a specified level of reliance on imported and within-region market supply. Resources include existing plants and planned resources that are sited and licensed that are

[12] That is, electric generators that are built or purchased by regional utilities that have the cost recovered from the utility customers

expected to be operational during the year being assessed. Future electricity demands are based on the Council's load forecasting models[13], which are adjusted to include expected energy efficiency savings.

The metric used to measure resource adequacy is the annual loss-of-load probability (LOLP). The LOLP is assessed by simulating the operation of a future year's power system many times with different combinations of river flows, temperatures[14], wind and solar generation, and generator forced outages. Whenever demand for electricity is not served, it is considered a shortfall event. The LOLP is calculated as the number of simulations in which at least one shortfall event occurred divided by the total number of simulations. The Council deems the power supply to be adequate if the LOLP is five percent or less. That is, the power supply is adequate if the likelihood of having one or more shortfalls in an operating year is five percent or less.

Adequacy of the Existing Power Supply

The 2021 adequacy assessment differs from past assessments in three significant ways. First, the Council is using climate change projections of temperature and precipitation to forecast future electrical demand and river flows. These data are a better predictor of future conditions than assuming a repeat of observed historical conditions (which were used for past assessments). Second, the low cost of renewable resources along with clean-air laws and policies and renewable portfolio standards across the Western states are the impetus behind the expected acquisition of significant levels of renewable resources. The effect of these resources is to create a large mid-day market supply of very inexpensive energy, which will change the dynamics of the regional power supply operation. Third, because of the significant levels of renewable resources, it was necessary for the Council to redevelop its adequacy model to more accurately represent hourly operations. It was especially important to implement more hourly-specific hydroelectric system constraints.

The existing regional power supply has about 12,000 megawatts of winter rate-based thermal generating capacity (not including about 2,600 megawatts of thermal resources in the region but not rate-based). By 2023, the Northwest will have nearly 11,000 megawatts of installed wind nameplate capacity but only about 7,300 megawatts is dedicated to serving the regional electric demand. Also, by 2023 the region will have about 1,100 megawatts of installed solar nameplate capacity. The Pacific Northwest hydroelectric system's nameplate capacity totals nearly 35,000 megawatts. And finally, the region has been extremely successful in implementing cost-effective energy efficiency saving measures. Since the early 1980s, the region has avoided the need to build at least 7,000 average megawatts of additional electricity generation.

While the total nameplate capacity of the region's power supply is significantly higher than the expected 2023 winter peak electrical demand of about 32,600 megawatts, the deliverable (effective) capacity of the system is much lower. For example, the effective capacities of the wind and solar

[13] See Section 3: Demand Forecast.

[14] Temperatures impact the amount of electricity used; for example, during extremely hot days the regional needs more electricity for air conditioning

fleets are about 22 percent and 46 percent of the nameplate, respectively. And, while the hydroelectric system nameplate capacity is nearly 35,000 megawatts, it only generates about 12,000 average megawatts during a very dry year and about 16,000 average megawatts over an average year. And, because of limited storage and operating constraints, it provides about 25,000 megawatts of two-hour sustained-peaking capacity during winter and about 22,000 megawatts of two-hour sustained-peaking capacity during summer.

One way to gauge the sufficiency of the power supply is to compare its energy and effective capacity generating capabilities with the annual average electrical demand and with the peak electrical demand, respectively. Based on expected electrical demands and assuming critical water conditions (lowest stream flow year) the power supply's total annual average generating capability exceeds the expected 2023 annual electrical demand by about 2,570 average megawatts. Under the same conditions, the power supply's effective capacity exceeds the 2023 winter peak electrical demand by about 5,700 megawatts and exceeds the summer peak electrical demand by about 2,800 megawatts. However, using these simple comparisons does not accurately reflect the adequacy of the power supply because future conditions can vary significantly, and situations can occur when low wind and solar output combine with extreme temperature and low river flow conditions. This is why the Council uses probabilistic methods (as described above) to assess resource adequacy.

Our adequacy model indicates the power supply does not meet the Council's adequacy criteria in 2023 but does meet it by 2025[15]. In 2023, market prices are frequently low, causing many thermal units to not commit to service and therefore not be available should unexpected conditions arise that lead to a shortfall event. A thermal plant will commit if forecasted prices indicate that it can operate at a profit. When forecasted prices are low, the plant is not committed, and fuel is not allocated for its operation. When we reran the 2023 case forcing all thermal plants to commit regardless of market price, the model indicated the power supply exceeded the Council's standard for adequacy. Thus, utilization of the existing thermal fleet could be a cost-effective way to maintain adequacy. For example, requiring thermal resources to carry additional balancing reserves forces them to commit, which makes them available during potential shortfall events.

In 2025, we estimate the power supply meets the Council's adequacy standard. Our 2025 estimate includes 400 average megawatts of energy efficiency savings incremental to our frozen-efficiency demand forecast. However, it also includes the retirement of the Jim Bridger 1 coal plant (530 megawatt nameplate). While this results in less total regional resource in 2025, forecast electrical demand and prices have sufficiently increased at times that prompt more thermal units to commit. Thus, we see fewer shortfalls driven by operational challenges.

[15] Since GENESYS does not model out-of-region resources and loads stochastically, maximum limits for imports of 2,500 megawatts per hour and 1,250 megawatts per hour were set for the winter and summer periods, respectively. The model assesses market prices dynamically and imports when prices are sufficiently low to displace higher-cost regional resources or to maintain adequacy.

To maintain adequacy, the region will need about 1,600 megawatts of effective capacity (or some combination of added capacity and additional balancing reserves) before 2023. The Council's adequacy assessment does not go beyond 2025, but the power plan's planning horizon is 20 years. Therefore, all future expected resource retirements are accounted for in the Council's resource expansion model. In addition, the Council has also examined multiple sensitivity scenarios to determine the effects of early retirement, different West-wide resource buildouts, greater load growth due to electrification programs, and others[16].

Method for Assessing Regional Power System Needs to Maintain Adequacy

The Council uses its evaluation of the adequacy of the existing system to establish a method for assessing potential regional power system needs to maintain resource adequacy under a broad range of different scenarios and conditions. In projecting how the region could meet these system needs; we evaluate both the magnitude of those needs and the varying capability of different generating technologies or demand-side resources to meet them.

Gaps Between Existing System Capabilities and Anticipated Future Requirements

Using the Council's adequacy standard (as described above), the needs to maintain adequacy are defined as any gaps between existing system capabilities and anticipated future requirements that fall outside that standard. The existing system capabilities are evaluated on an hourly basis accounting for operational and fueling limitations, in addition to generating or demand-reduction capability for all the resources in the existing regional power system. The anticipated future requirements incorporate both regional demand and reserve requirements. The gaps between existing system capabilities and anticipated future requirements are evaluated for each quarter, which broadly can be defined as the fall, winter, spring, and summer seasons using a broad range of estimated hydro conditions, electrical demands, and renewable generation output.

The methodology to identify the size of shortfall events that need to be addressed to maintain adequacy is as follows:

1. The shortfall events in our simulations are sorted from highest magnitude to lowest magnitude on an annual basis including the simulations where we have no shortfall events or the magnitude of the shortfall event is zero.
2. The top 5 percent of the simulated shortfall events (those of the highest magnitude) are assumed to be acceptable under the Council's standard. We do not consider these further.
3. We take the highest magnitude shortfall events remaining for each season as the gap between the existing system capabilities and anticipated future requirements necessary to

[16] See Planning for an Uncertain Future in Section 6: Resource Development Plan.

maintain the Council's adequacy standard. If there are shortfalls greater than zero in more than 5 percent of the simulations, then these seasonal gaps will be non-zero.

The size and composition of the gaps varies between scenarios. We discuss the gaps resulting from this method for different scenarios in *Section 6: Resource Development Plan*.

Future Resource Capability to Fill Gaps

When exploring the capability of future resources or reserve additions to fill the gap described above, the Council evaluated the attributes of each resource and how those interacted with the existing system to change the total regional capability to meet anticipated future requirements. The existing system, including the regions hydropower generation, can adapt in different ways that fill these gaps. When adding resources that increase the need for reserves, like wind and solar generation, it may reduce the existing system's peak capability. The ability of the regional hydropower system to support the regional electric grid in different ways is a valuable attribute. However, the demands on the system must be balanced, making sure not to double count the contribution of these resources. Further the regional hydro system has many purposes beyond generating electricity that take priority and must also be accounted for in any future projections of what the power system can rely on from these resources. The Council models reserves required from both the existing system and any new resources to capture this important dynamic. The examination of future resource characteristics included operational and fueling limitations on an hourly basis in addition to generating or demand-reduction capability within the context of the existing regional power system.

To determining how a resource or combination of resources[17] fill the gaps in the existing system capabilities, we:

1. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and no new resource additions, then record the maximum gap between existing system capability and system obligations.
2. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and with a combination of new resource additions. Then record the maximum gap between existing system capability and system obligations.
3. Take the difference in the gaps from the simulations step 1 and 2 and divide that difference by the total nameplate resource additions from the combination of new resources in step 2.
4. Use that percentage as a multiplier when assessing the capability of a combination of new resources to meet any identified gaps.

[17] For all combinations not explicitly tested, a multilinear interpolation allows the capability of any new combination of new resources considered in the resource strategy analysis to be identified and considered when attempting to address gaps associated with peak conditions.

Section 5: Energy Conservation Program

Background on Energy Efficiency in the Northwest

Energy conservation is defined in the Power Act as “any reduction in electric power consumption as a result of increases in the efficiency of energy use, production or distribution.”[18]

In recent years, the Northwest region’s utilities have spent about $480 million dollars per year on energy efficiency. This includes investments in incentive programs, market transformation initiatives, evaluation, and research such as in market research, building stock assessments, and emerging technologies. Estimates indicate that in our region over 100,000 people are employed working with energy efficiency at utilities, the Northwest Energy Efficiency Alliance (NEEA), the Energy Trust of Oregon, state agencies, and at the many trade allies and contractors that work to implement programs and deliver efficiency services.[19]

This investment has resulted in more than 7,000 average megawatts of savings since 1978. About 60 percent of those savings are from direct utility program incentives.[20] The remainder is from NEEA market transformation initiatives, improvements in codes and standards, and other market adoption. These savings amount to a regional resource second only in magnitude to hydropower and are equivalent to the annual energy consumption of around 5.1 million homes. By reducing electricity generation from fossil-fuel power plants, the savings have avoided more than 22.2 million metric tons of carbon dioxide emissions. The cumulative efficiency savings since 1980 have reduced consumer electricity bills by about $4 billion per year. Efficiency has also shown to provide reductions in other non-energy consumables, such as water, and provide additional benefits to consumers in the form of health, comfort, and productivity.

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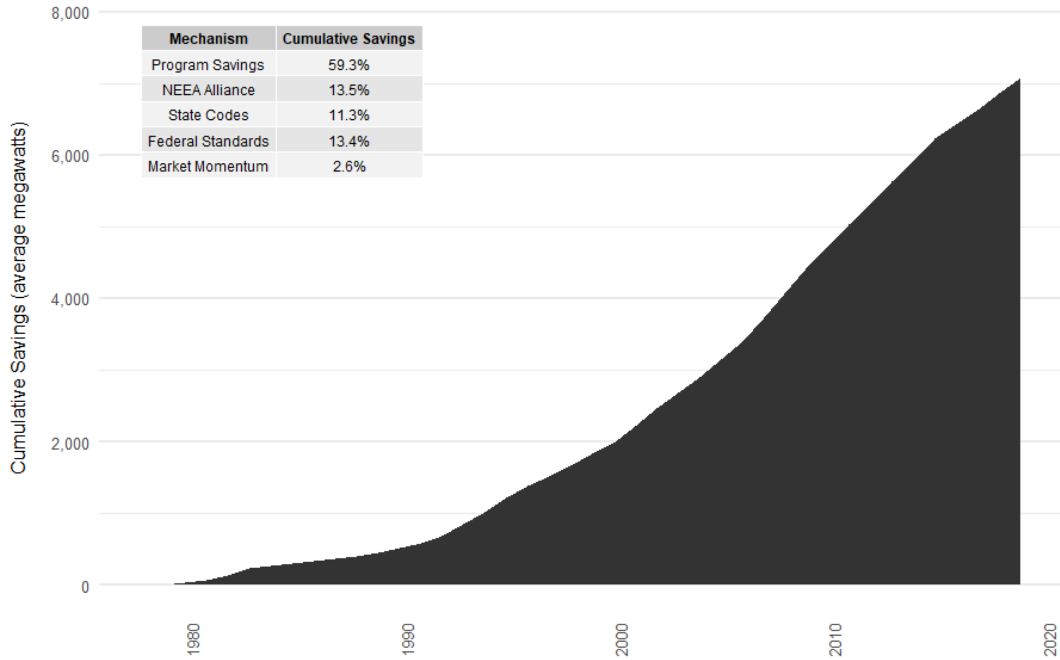
[18] Northwest Power Act Section 3(3), 94 Stat 2698
[19] U.S. Energy and Employment 2020 report https://www.usenergyjobs.org/
[20] More information on conservation achievements can be found on the Regional Technical Forum website https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2019

Cumulative Regional Energy Efficiency Savings by Mechanism



In recent years, with all the accomplishments and increasing efficiency levels, the future amount of low-cost efficiency available has diminished. One key example is LED light bulbs that have transformed the industry; a 9 watt LED bulb provides at least as much illumination as the traditional 60 watt incandescent. These are significant savings, and future lighting improvements cannot be as profound. However, savings remain[21] in lighting and other end uses, and continued investment is needed to ensure low-cost efficiency remains available.

Regional Recommendations on Energy Efficiency

Amount of energy efficiency the region should acquire

The Council recommends that the region acquire between 750 and 1,000 average megawatts of energy efficiency by the end of 2027 and at least 2,400 average megawatts by the end of 2041. The lower end of this recommended range represents cost-effective energy efficiency acquired at a moderate pace, whereas the higher end of the range represents cost-effective efficiency that is acquired more rapidly.

We expect that most of the short-term savings will be via direct-funded utility programs, but this recommendation also includes efficiency accomplished through market transformation initiatives through NEEA, building codes, appliance standards, and natural market adoption. Regional support

[21] See *New Opportunities for Energy Efficiency* in *Section 6: Resource Development Plan* for further details.

of all mechanisms is needed for long term achievement and continued availability of energy efficiency.

The Council's regional recommendation includes efficiency acquired at all regional utilities including the Bonneville customer utilities. Our specific recommendations to the Bonneville Administrator regarding energy efficiency are included in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

In order to achieve this overall goal, all utilities within the region will need to deliver energy efficiency to their end-use customers. For utilities within urban centers, efficiency may be more readily accomplished given greater availability of contractors and suppliers of efficient products and easier access to a large and diverse number of customers. In contrast, utilities with a rural customer base (primarily residential and agricultural) have significant challenges and fewer resources for implementing cost-effective efficiency programs. These challenges are recognized, and Bonneville and/or other regional organizations such as NEEA should support these rural utilities in reaching efficiency goals.

Continued investment in NEEA and efficiency-related research and development[22] is critical to achieve the long-term goals. To help ensure a robust efficiency infrastructure, work is needed all along the product adoption curve: continuing research into emerging technologies to introduce new efficiency opportunities, working with retailers and manufacturers to increase the availability of efficient products, and encouraging acceptance by consumers. NEEA and the utilities will need to be diligent in ensuring progress in all these facets of the market. As such, to help ensure that the necessary levels of cost-effective conservation are acquired, we recommend the region's utilities:

1. Maintain ratepayer-funded efficiency programs (utility direct programs and market transformation initiatives) at a funding level sufficient to achieve the 2027 goals;
2. Continue to fund research and development on emerging technologies in an amount commensurate with 2020 levels or greater;
3. Continue to fund regional market research, stock assessments, and related analysis in an amount commensurate with 2020 levels or greater;
4. Support initiatives to enhance building codes and appliance standards, at both the state and federal government-level.

In addition to the amount accomplished under the target, we recommend the region continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. These measures are critical to provide livable homes for all people.[23] Much of this work is currently being accomplished through low-income weatherization programs, co-sponsored by utilities and state and federal agencies. However, there may be homeowners or renters who do not qualify under those programs but live in substandard

[22] See Section 10: Recommendations for Research and Development for more discussion on this topic.
[23] Some of these measures will not be cost effective relative to the plan but should still be included in the programs.

housing, and utilities should strive to weatherize those structures as well. In some cases, the structures' needs may be beyond weatherization services, and home replacement programs should be considered.[24] Utilities should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes.

Utilities should also begin utilizing energy use intensity (EUI) data for commercial buildings to identify buildings that have consumption levels significantly higher than other comparable buildings. This approach can provide a market-sector-neutral way of identifying those customers in the greatest need of efficiency measures and otherwise previously missed by programs. For example, utility program managers have indicated (and supporting data suggest) that small commercial customers typically have higher EUIs than their larger counterparts. All customers with these higher than average EUIs should be targeted for implementation of cost-effective conservation.

Objectives of Conservation Programs

All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system, as established in the 2021 Power Plan. To achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to ensure levels of efficiency that are cost-effective for the region and economically feasible for the consumer.
2. Conservation acquisition programs should target conservation opportunities that are not anticipated to be developed by consumers.
3. Conservation acquisition programs should be designed so that their benefits are distributed equitably.
4. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.
5. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities or to take advantage of market trends. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in commercial buildings, measures can be installed at the time of renovation or remodel.
6. Conservation acquisition programs should be designed to capture all cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken to develop it or hold it for future use.
7. Conservation acquisition programs should be designed to maintain or enhance environmental quality. Acquisition of conservation measures that result in environmental degradation should be avoided, mitigated, or minimized.

[24] For example, some utilities have programs replacing an old manufactured home with a new efficient model.

8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

Not all energy efficiency provides equivalent value to the regional electric system. Some distinguishing attributes, such as cost and savings shape, have been captured in the portfolio analysis. However, energy efficiency's ability to improve building resilience[25] and grid flexibility[26] is not well modeled. These attributes are important to maintaining a robust electric system infrastructure, and energy efficiency that provides these values should be prioritized, and we will endeavor to improve our estimates over the action plan period. The Council's Regional Technical Forum (RTF) should explore the mutual benefits of energy efficiency and demand response in providing grid flexibility.

Consequences of not achieving the regional recommendations

The minimum of 750 average megawatts of energy efficiency by the end of 2027 is what we have determined to be more cost-effective than pursuing other resources when considering risk and uncertainty of meeting adequacy needs, decarbonization, renewable resources availability and reliability, and future market pricing. Not achieving this efficiency may result in higher costs to the system and impede development of a more equitable energy system. This efficiency will maintain jobs, lower greenhouse gas emissions, reduce energy burdens for households and businesses, and avoid adequacy shortfalls. In developing this target, the Council also considered specific values for measures to improve a home's resilience to power outages and enable future interconnectedness with the electric grid. Thus, the cost-effective efficiency will help enable a robust electric power system. In addition, investment in measures to improve livability of poorly insulated houses will help toward achieving equity of residential energy burden.

Model Conservation Standards

The Northwest Power Act directs the Council to adopt and include in its power plan a conservation program that includes model conservation standards (MCS). The MCS are applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

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[25] Building resilience refers to the building's ability to withstand a power outage or extreme weather event. For example, a well-insulated home will maintain its conditioned temperature for longer during an outage or extreme temperatures.

[26] Grid flexibility refers to a building's ability to respond to the needs of the grid. Energy efficiency that enables this flexibility could have additional value. For example, an efficient lighting system that has embedded controls could be tapped by a utility to balance the grid.

In addition to the requirements set forth in the Act, the Council believes the model conservation standards in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of seven model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, and the standard for conservation programs not covered explicitly by the other model conservation standards.[27] Since the Council adopted its first model conservation standards, all four states within the Northwest have adopted strong energy codes that incorporate the standards.

The MCS for the 2021 Power Plan have two main components. The first is that the Council adopts two specific components to the standards to ensure equity in efficiency adoption through codes and standards. The second component provides the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel.

The focus of the codes and standards component of the MCS is on two areas intended to improve equity around efficiency acquisition through codes and standards. These areas include supporting common appliance standards in the Northwest and discouraging backsliding or reducing codes or standards.

In addition, as municipalities around the region are considering reducing their carbon footprint, electrification of end-use equipment has gained interest. The second component of the MCS is the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel. The Act definition of conservation clearly excludes fuel switching as energy efficiency. However, if fuel switching were to be promoted, this MCS directs action to ensure the switching is performed with all cost-effective electric energy efficiency incorporated.

Common Appliance Standards

The minimum efficiency requirements of many appliances and equipment are regulated at the federal level.[28] These standards are a low-cost, equitable means of achieving cost-effective efficiency. For products without a federal standard, states may adopt their own minimum efficiency requirement. In the past few years, several states have adopted their own standards, including

[27] The 2021 Power Plan model conservation standards and surcharge methodology supersede the Council's previous recommendations.
[28] https://www.energy.gov/eere/buildings/appliance-and-equipment-standards-program

Washington[29] and Oregon[30]. Often, these standards are consistent with those in California allowing for a uniform market in the western-most United States. This commonality is preferred by manufacturers to minimize regulatory confusion and multiple product lines. To further efficiency and limit market disruption, Northwest states should consider adopting common standards and work to synchronize updates. Coordinating with additional states, such as through initiatives by the Appliance Standards Awareness Project,[31] would strengthen the likelihood of compliance and manufacturer buy-in.

No Backsliding on Codes or Standards

Once a code or standard has been adopted, no state or federal agency should change the standard such that a subset of buildings or appliances are subject to a less stringent standard. Codes and standards are a low-cost, equitable means of achieving cost-effective conservation. When markets are segmented into product classes and thus subject to differing requirements, this dilutes the efficacy of the code or standard and decreases efficiency. This in turn has impacts on the ability for the region to equitably provide low-cost energy efficiency to all Northwest consumers.

Conversion to Electric Space Conditioning and Water Heating

Per the Power Plan analysis, jurisdictions pursing economy-wide decarbonization goals should pursue multiple approaches to reduce carbon, including significant energy efficiency investment. Those jurisdictions (state or local governments) or utilities with such decarbonization goals should take actions through codes, service standards, user fees or alternative programs, or a combination thereof, to achieve electric power savings from buildings. These savings should be comparable to those that would be achieved if each building converting to electric space conditioning or water heating were upgraded to include related conservation measures at least as efficient as the lowest-efficiency measure included in the 2021 Plan or adopted by the RTF (whichever is more recent). While some of the measures may not be cost-effective under the Council's current methodology, the Council believes they would be for jurisdictions with deep decarbonization initiatives. Similarly, for those jurisdictions, any existing inefficient electrical space or water heating equipment should also be upgraded to a minimally efficient level at time of replacement.[32]

Surcharge Recommendation and Methodology

The Power Act authorizes the Council to recommend a surcharge and the Bonneville Administrator may thereafter impose such a surcharge on customers that have not implemented conservation measures that achieve energy savings comparable to those which would be obtained under the Model Conservation Standards in the plan. Section 4(f)(2) of the Northwest Power Act directs the

[29] https://www.commerce.wa.gov/growing-the-economy/energy/appliances/
[30] https://www.oregon.gov/energy/energy-oregon/Pages/Appliance-Standards.aspx
[31] https://appliance-standards.org/
[32] There may be cases where the savings are minimal relative to the expense (e.g. installing ductless heat pumps in small multifamily units) and may not be a priority efficiency investment. Jurisdictions will need to consider policy goals in determining what a reasonable cost-effectiveness limit should be.

Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the Administrator’s applicable rates for a customer’s load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The Council does not recommend a surcharge to the Administrator under Section 4(f)(2) of the Act at this time. The Council intends to continue to track regional progress toward the plan’s MCS and will review its decision on the surcharge recommendation, should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the Administrator be granted the authority to place a surcharge on that customer’s rates to recover those costs.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region’s electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville’s utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the Administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council’s plan set forth a methodology for surcharge calculation for Bonneville’s administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is set out below.

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer’s load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be

purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

Section 6: Resource Development Plan

How the Electric Sector has Changed

The Council's 2021 Power Plan is significantly different than its Seventh Power Plan, adopted just five years ago. This is due to changes in the economics of renewable resources and the adoption of regional clean energy policies. The rapid cost reduction for solar and wind power technologies, when coupled with federal and state inducements, has provided an incentive for building large amounts of utility-scale solar and on-shore wind power across the region and put increased competitive pressure on thermal generators that operate at higher costs.[33] Along with this changing economic landscape, this plan also recognizes clean-energy policies and goals implemented at state, city, and utility levels in many jurisdictions across the western electricity interconnection and their impact on the future development of significant renewable and non-carbon emitting resources. The combination of increased competitive pressure and clean energy policies has resulted in the early retirement of less efficient thermal generators, and also increased thermal generator planned retirements during the initial five-year "action period" of this plan. This indicates that the capacity of coal-fired power plants in the region will be reduced by more than 60 percent over the next decade.[34] Furthermore, uncertainty remains over the role of existing natural gas-fired power plants beyond this decade, and also the future development of new gas-fired generators within the region.

Perhaps even more uncertain is the extent to which clean energy policies will affect other sectors of the economy and the demand for electricity. There is an increasing number of jurisdictions within the interconnection that have established policy goals and timelines to reduce greenhouse gas emissions economy-wide, leading to potentially high levels of new demand. For example, in the transportation sector, the focus is on converting fossil fuel-fired vehicles to electricity or hydrogen. The widespread use of electric- and hydrogen-fueled vehicles would have a substantial impact on future electricity load growth. To this point, our early modeling work indicates significant electric system demand devoted to hydrogen fuel production for transportation – demand perhaps double the average output of the existing hydroelectric system. Combined, these actions signal a major paradigm shift for the electricity sector in the region (and elsewhere), presenting challenges to maintaining and enhancing an adequate, efficient, economical, and reliable power supply.

[33] To this point, the accelerated addition of renewable generators operating without fuel costs to the power supply has led to lower electricity prices, sometimes crossing below zero during intra-day trading.

[34] Uncertainty regarding the future of existing coal plants in the region was apparent during preparation for the Seventh Power Plan becoming a central issue for utility resource planning. Accordingly, the planned retirements of Centralia units 1 and 2, Boardman, and North Valmy units 1 and 2 between 2020 and 2026 were incorporated into the power plan.

In the Seventh Power Plan, energy efficiency – the priority resource in the Northwest Power Act – was the clear, least-cost resource, with cost-effective energy efficiency acquisitions meeting the majority of load growth through 2035. The region was undergoing a shift from a focus on energy needs to a focus on capacity - in particular peaking capacity - and ensuring an adequate system in poor water years or extreme weather conditions when the hydropower system has limited flexibility to meet peak needs. Deployment of demand response was also recommended to meet and reduce system capacity needs. Following energy efficiency and demand response, new natural gas-fired generation was the most cost-effective resource. The plants, and greater utilization of existing gas-fired plants, were part of the least-cost strategy to meet remaining resource needs and to reduce carbon dioxide emissions from the electricity system. Finally, renewable resources were acquired near the end of the 20-year planning period to meet state renewable portfolio standards (RPS). Utilities were largely in compliance with near-term RPS targets due to earlier wind resource development, which saw the region build about 8 gigawatts in five years in the late 2000s and early 2010s.

For the 2021 Power Plan, the outlook is much different. There is less low-cost energy efficiency potential available due to the same price competition from solar and wind resources that now impacts thermal units, although the total cumulative potential at the end of the planning period remains the same. Ongoing construction of inexpensive renewable resources is influencing the wholesale electricity market, with low prices particularly in the middle of the day when solar PV is producing at its peak. In light of the construction of renewable resources anticipated in this plan, these low prices are likely to become increasingly negative through time, making it very difficult for resources with variable operating costs (like thermal plants) to commit and compete, leading to concerns about the adequacy and reliability of the system. The region's hydropower system – the biggest generating resource and "battery" in place – will also be facing long-term alterations in flow from climate change effects on weather and precipitation, as well as ongoing requirements to spill water to enhance fish passage. Water that is spilled cannot be used to generate power. These challenges are magnified when the hydropower system is increasingly used for flexibility and integration of new renewable resources.

In summary, the electric grid is shifting to renewable resources at an aggressive pace. This shift, along with the speed at which the system must react to demand for power, creates potential risks to system operations that we address in this plan. These changes also point to significant levels of low- or no-cost power available to the region during most daylight hours throughout the year. It is through the efficient management of these resources that the region will assure a reliable and economical power supply.

Recommended Resource Strategy

The Northwest Power Act requires the Council to prepare a regional conservation and electric power plan that assures the region an "adequate, efficient, economical, and reliable power supply." Since the first power plan in 1983, the Council considers a range of uncertainties and potential futures to determine its preferred resource strategy. The strategy balances analytical findings, policy expectations, and operational limitations within the grid. The resource strategy covers the entire plan horizon of 20-years (2022-2041) with a focus on a near-term, six-year action plan period (for this plan, the action plan period is 2022-2027).

The resource strategy provides guidance to the entire Pacific Northwest region – encompassing both public and private utility territories - on how best to meet the electric power system needs. It is similar to integrated resource plans (IRPs) conducted by many utilities in the Northwest and around the country. Both consider supply- and demand-side resources as comparable means to meeting future needs and account for state policies that influence resource options. However, the Council's plan differs from IRPs in some important respects. By being a regional strategy, specific balancing authority or utility nuances are not necessarily captured. For example, the plan's strategy does not have specific requirements for additions to the transmission or distribution systems.[35] In addition, as a regional plan, there is less specificity on resource acquisition recommendations than what may be provided in an IRP.

Regional Resource Recommendations

The 2021 Plan resource strategy includes recommendations on energy efficiency, generation, and demand response. Together, these will help support an adequate, efficient, economical, and reliable power supply while limiting greenhouse gas emissions. The recommendations for the Bonneville Power Administration, in part highlighted here, are specified in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

The Council recommends Bonneville and the regional utilities plan to acquire between 750 and 1,000 average megawatts of cost-effective energy efficiency by the end of 2027 and a minimum of 2,400 average megawatts by 2041. This level of efficiency is cost-effective for meeting energy needs and is a low-risk approach to meeting adequacy needs (further described in *Section 9: Cost Effective Methodology for Providing Reserves*) by providing a hedge against reliance upon the availability of other resources at the time needed and supporting opportunities to unlock additional hydropower system flexibility. The addition of efficiency-based resources will also defer need for transmission and distribution system upgrades, reduce emissions, and support jurisdiction-specific decarbonization goals. In addition to the energy efficiency acquisition recommendation, *Section 5: Energy Conservation Program,* outlines other recommendations related to ensuring this efficiency is prudently acquired. Section 5 also provides the Model Conservation Standards and Surcharge Recommendation and Methodology, two required components of the plan.

Our recommendation is based on energy efficiency supply curves developed using estimated costs and savings data available through early 2020 for many different potential energy efficiency measures. We understand and expect the costs to acquire energy efficiency measures will vary

[35] *Section 10: Recommendations for Research and Development* includes a recommendation for the region to conduct a study on the ability of the transmission system to incorporate the proposed renewable power additions.

between utilities and from one year to the next. This will likely alter the mix of efficiency measures available through utility programs in the region during the action-plan period. How much any particular utility invests in conservation and which measures the utility invests in are decisions for the utility to make based on a number of factors particular to the utility, including whether it makes economic sense to the utility in its particular circumstances given what that utility will gain for what it will cost. Given this reality there will always be some uncertainty of whether the amount of conservation that is cost-effective regionally will actually be acquired. Because of these factors we believe it prudent to monitor progress in the acquisition of energy efficiency resources over the action plan period, including the cost to deliver such resources to customers. Further, we encourage greater collaboration between utilities to advance the overall effectiveness of energy efficiency resources.

For generation resources, the Council recommends the region acquire at least 3,500 megawatts of renewable resources by 2027, as a cost-effective option for meeting energy needs and reducing emissions. The Council also recommends that policymakers and utilities pursuing aggressive emissions reductions evaluate adding more renewables as a means of displacing emissions both within their portfolio and in the broader market. While these recommendations are part of the least-cost resource strategy, it is also important to note that we project there will be times that market conditions will result in substantial generation curtailment of both these new renewable resources and the existing renewable resources in the region. That is, there will be times when there is more electricity being produced than demand for electricity, and the region as well as the broader West will need to reduce the amount of generation on the system in part by not using the total capability of renewables.

When considering renewable resources, the Council recommends Bonneville and regional utilities also evaluate the suitability and efficacy of a broad range of resources including cost-effective resources not explicitly modeled as options in the power plan, such as distributed generation; hybrid configurations of resource technologies; alternative-fuel combustion turbines; natural gas conversion to renewable natural gas or hydrogen; biomass-fired generation; small hydropower; repowering existing generators; and other technologies that provide similar system benefits. The plan evaluates broad regional trends but should not be seen to preclude more local and site-specific opportunities. In addition, the Council acknowledges that all energy infrastructure development and construction – including new solar and wind plants – has an impact on the environment. The Council recommends that the region be mindful of individual and cumulative impacts when siting new resources so that new renewable resource development is carried out in a manner that also protects the wildlife, fish, and cultural resources of the Pacific Northwest.

These resource additions will depend on sufficient transmission capability on the system to deliver electricity from the source of generation to the locations where electricity is needed. The Council understands that utilities with existing transmission rights should be compensated for the investments needed to construct large transmission projects. In our resource strategy, we do not identify what rights are available for adding renewable resources, but we understand regional utilities building these projects will need to use a variety of approaches to fit this expansion of renewable resource generation into the existing transmission system, respecting the rights of the transmission system owners and operators.

The Council recommends utilities examine two demand response products: residential Time-of-Use (TOU) rates[36] and Demand Voltage Regulation (DVR) as a means to offset the electric system needs during peaking and ramping periods and to reduce emissions. A given utility's time of need may differ from the region's, but these products are likely still part of a cost-effective strategy. Our assessment shows about 520 megawatts of DVR and 200 megawatts of TOU available by 2027. There may be other similar products that are also frequently deployable, low cost, and with minimal customer impact that could provide similar benefits and those should also be considered in utility planning. In addition to benefits on the power system side, demand response could be used to relieve transmission constraints and defer transmission and distribution system upgrades. The Council will track regional demand response implementation to assess progress, recognizing that the lack of a regionwide economic signal for capacity makes adopting demand response challenging. Based on the scenario analysis, the Council recommends Bonneville and regional utilities consider the value of adequacy, capacity, and emissions reduction when evaluating demand response in integrated resource plans and other analyses. As organizations and utilities develop demand response capability, they should do so by leveraging existing energy efficiency infrastructure and considering them together as part of an "integrated demand-side management" (IDSM) approach to optimize delivery of both resources holistically and equitably. We recognize, however, that our demand-response target recommendation is, in part, dependent upon investments made by utilities to install advanced meters (AMI) across their service territories. While many utilities have installed advanced meters and the back-office architecture necessary to implement TOU rate designs, those that have not may need financial support to accomplish it. Therefore, we encourage Bonneville, regulators, and utility leadership to support investment in AMI architecture as a tool to encourage the most efficient use of grid resources.

In addition to these resources, the Council recommends Bonneville and the regional utilities, along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools, such as capacity and reserves products, that contribute to system accessibility and efficiency. We would expect to see significant cost savings from greater regional collaboration to drive more efficiency into the system operations. A more aggressive examination would expand such a cost and benefit analysis to include the development of an organized or independently operated electricity market across the region. While any market design should protect the region's investments in its existing generation

[36] The Council included both price (or tariff)-based and control-based products in the demand response supply curves. As a tariff-based product, TOU is not dispatchable and does not have a "cash incentive" for customers to participate and thus utilities have less ability to deploy for emergency needs. However, for a consistent, short-duration period of need, TOU can be beneficial. TOU was included in our demand response supply for analytical purposes, utilities may choose different analytical approaches in determining the value for their system.

and transmission system, there may be reliability and cost benefits from the central dispatch of resources across a broad footprint. We also recommend the region concurrently work toward more collaborative understanding of the impacts of changes in market liquidity outside the region and the implications especially for peaking and ramping periods and pursue additional collaborative approaches to mitigate identified risks.

Historically, the Council has prepared a mid-term assessment of the plan a few years after its release and before work begins on the next plan. The primary purpose of the mid-term assessment is to check on the region's progress in implementing the plan.

The 2021 Northwest Power Plan includes many recommendations to the regional and to Bonneville. We recognize that the regional power system is in an extraordinary time of change with many uncertainties associated with future system operations. The Council monitors the region closely and prepares annual adequacy assessments, forecasts, and other reports.

In the mid-term assessment for the 2021 Plan, we will update and examine findings related to the plan and examine any changes since the plan was finalized. While some circumstances will undoubtedly change after publication of the plan, we will examine if anything calls into question the fundamental strategy described in the plan.

The Process of Developing the Recommended Resource Strategy

To make a recommendation to the region on how to most effectively meet the future needs for electricity, the Council has to assess capabilities of the existing system and estimate the cost of adding new resources to keep up with system demands. The Council also needs to understand the costs of building and operating the system and how those costs change with different strategies for how to meet future energy needs. But both the system needs and the future cost of the system are uncertain. So, we project more than just an expected future need and associated costs; rather, we look at a wide range of potential system costs and needs.

This is done with a combination of computer-based mathematical models and analysis. The Council uses the Energy2020 model[37] to estimate the future need for energy. The output demand for electricity, which is part of the total energy need, is then carried into the AURORA model[38] that is used to estimate electricity prices and the GENESYS model[39] used to evaluate if the regional electric system can adequately meet the demand for electricity. We also use the output demand for

[37] https://www.energy2020.com/
[38] https://energyexemplar.com/solutions/aurora/
[39] https://www.nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/genesys-%E2%80%93-generation-evaluation-system-model

electricity to formulate supply curves for energy efficiency and demand response. And we use the output of all these models and analyses in our capacity expansion model, the Regional Portfolio Model[40].

These models, used in conjunction with our staff expertise and consultation with regional experts, inform the Council's recommended resource strategy. All these models are made to explore a range of possible future conditions and outcomes. We cannot pinpoint the future the region will experience, but we can hope that by exploring how resource strategies perform under a wide range of potential future uncertainty, our recommendations will be adaptable and reduce the risks our region faces going forward.

Forecasts Used in Developing the Recommended Resource Strategy

To estimate the impacts of the recommended resource strategy, the Council forecasts elements that impact the cost, operation, environmental impact, and reliability of the regional electric system. Some elements that impact the cost of supplying electricity include the price for importing electricity from outside the region and the cost of fuel for power plants that operate inside the region. There are dozens of power plants operating in the region that consume fossil fuels like natural gas and coal; and in particular, natural gas-fired generation has been growing. These fossil-fuel-based power plants become especially important to the region during low-water years when hydropower generation is limited. The price of fuel for these generating resources, or power plants, is a key determinant of the cost of the electricity they generate. This makes the fuel price forecast an important input for the power plan.

While these forecasts are directly tied to the cost of providing electricity, we also need to estimate how much electricity will be needed. The Council uses its 20-year demand forecast, which covers a range of future potential electricity needs, when developing the resource strategy.

The electric system is part of the broader regional use of energy, and increasingly there are technologies that can switch between using fossil fuels and electricity. One example of this is electric vehicles that use electricity to charge a battery rather than the traditional internal combustion engine vehicle that uses gasoline or diesel. Understanding the future need for electricity requires that the Council adopt a broader view of energy use in the region. This allows the Council to forecast how much of the demand for energy will be served by electricity and also get a holistic view of greenhouse gas emissions related to different energy choices in the region.

Electricity Price Forecast

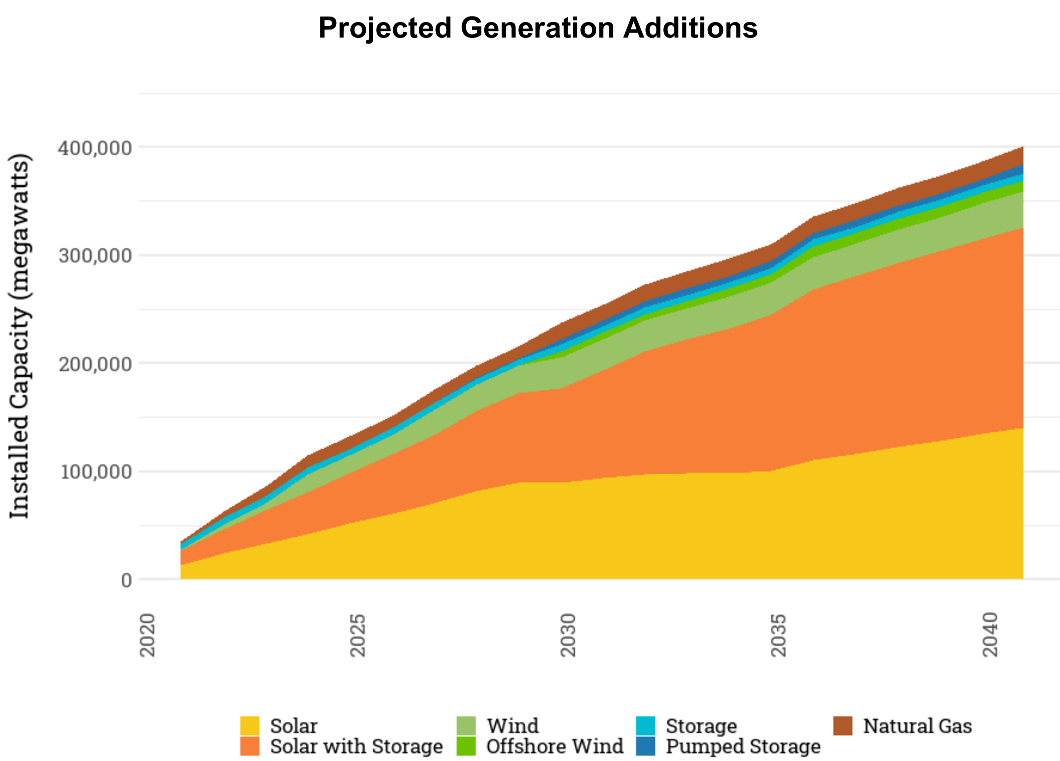
To forecast the future electricity price, the Council must look at the broader Western electricity grid. How many and what types of power plants utilities and other power producers around the West operate, build, or retire impacts the price of electricity in our region. The ability or lack of ability to

[40] https://www.nwcouncil.org/regional-portfolio-model

move electricity from where it's generated to where it's needed also impacts the price we pay for electricity.

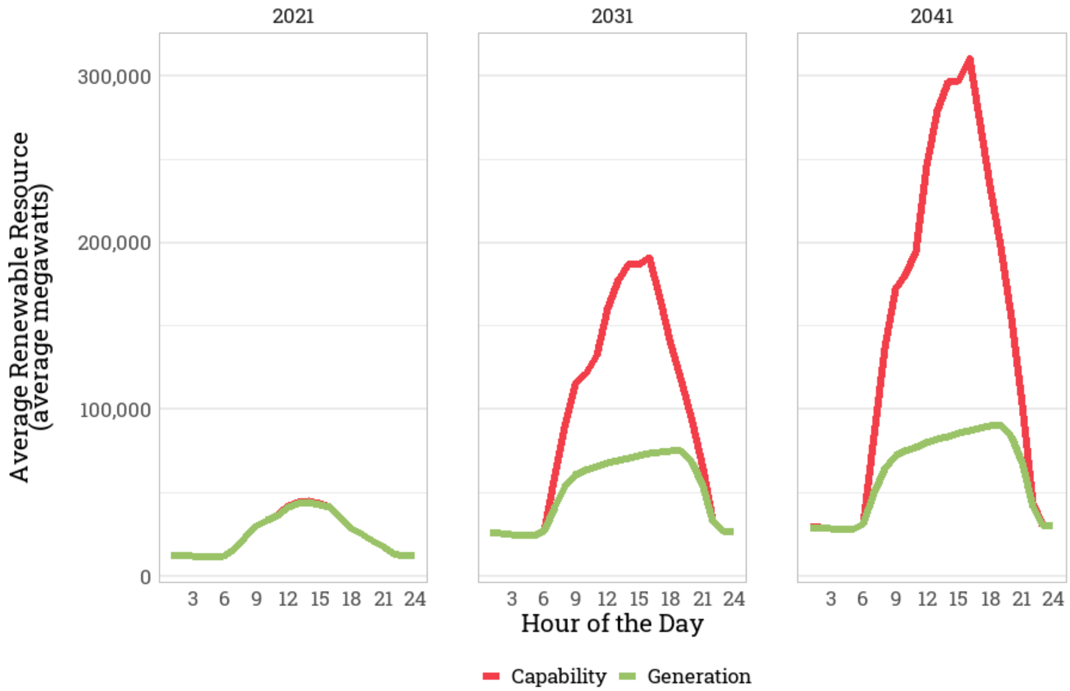
There are many factors that impact what power plants are built in the Western electric grid – the cost of different generating technologies, state and federal legislation intended to limit greenhouse gas emissions, the services and support needed to maintain the balance of supply and demand for electricity, and the regulatory barriers to building new fossil-fuel-based power plants, are examples of the influences that affect where a facility is located and its technology. Further, no power plant is built without available transmission deliver its output to the utility network or location paying for the output. The Council looks at a variety of scenarios that have different compositions and magnitudes of the plants built to produce electricity. These are developed in consultation with regional experts to understand the factors that will influence electric utility decisions. Considering the Council's' duty to assure an adequate and economically efficient supply of electricity for the region while respecting the renewable and clean energy targets of many western states, the Council forecasts an extremely large addition of renewables. For example, the Council's baseline electricity price forecast adds around 400 gigawatts of nameplate capacity[41] to the Western electric grid by 2041. The size of this addition meets the estimated reliability requirements for utilities outside the region and the states' requirements for renewable and clean power. It also limits the amount of new natural gas power plants to be built within region. To be clear, this forecast doesn't represent a forecast of power plants the Council expects will be built in the future. Rather, it shows what we estimate it would take to meet all the various requirements put on Western electric utilities.

[41] The nameplate capacity of a power plant is the maximum amount of electricity it can generate when it's fully functional and under optimal conditions or using the maximum amount of fuel. Another way of representing nameplate capacity is the manufacturer's rated output of the generator. Nameplate capacity should not be seen as representing the capacity contribution to system peak needs for any of the generating technologies examined in this plan. For example, a wind plant with a 100-megawatt nameplate capacity will generate 100 megawatts when every turbine in the wind plant is at maximum output. However, during many hours when there is not enough wind. the wind plant will produce less electricity. Depending on location, a wind plant may average between 30 and 40 megawatts of generation over a whole year. In this case, the wind plant has between a 30- and 40-percent capacity factor. Further, neither nameplate capacity nor capacity factor should be confused with the capacity contribution to system peak needs, which is discussed in Section 4: Forecast of Regional Reserve and Reliability Requirements.



However, such a large addition of new renewable power plants leads to a substantial oversupply of electricity during certain hours of the day and seasons in the year. The amount of electricity that could have been produced but instead is expected to be curtailed increases substantially through time with an addition of this magnitude. The chart below shows how the average amount of curtailed renewable generation increases substantially in 2031 and 2041 compared to 2021.

Renewable Resources in the Western Electric Grid
Average Generation versus Capability by Hour of the Day



Regardless of how many power plants are built, the Council expects electricity prices to vary from year-to-year based on natural variability in demand for electricity and the available supply of electricity. In our region, electricity generated by hydropower is a substantial portion of the electricity we use. But the amount of electricity that can be produced depends on the weather. The weather can also drive demand for electricity, with extreme cold in winter or extreme-heat in summer increasing the need for heating or air conditioning and thus requiring more electricity than normal.

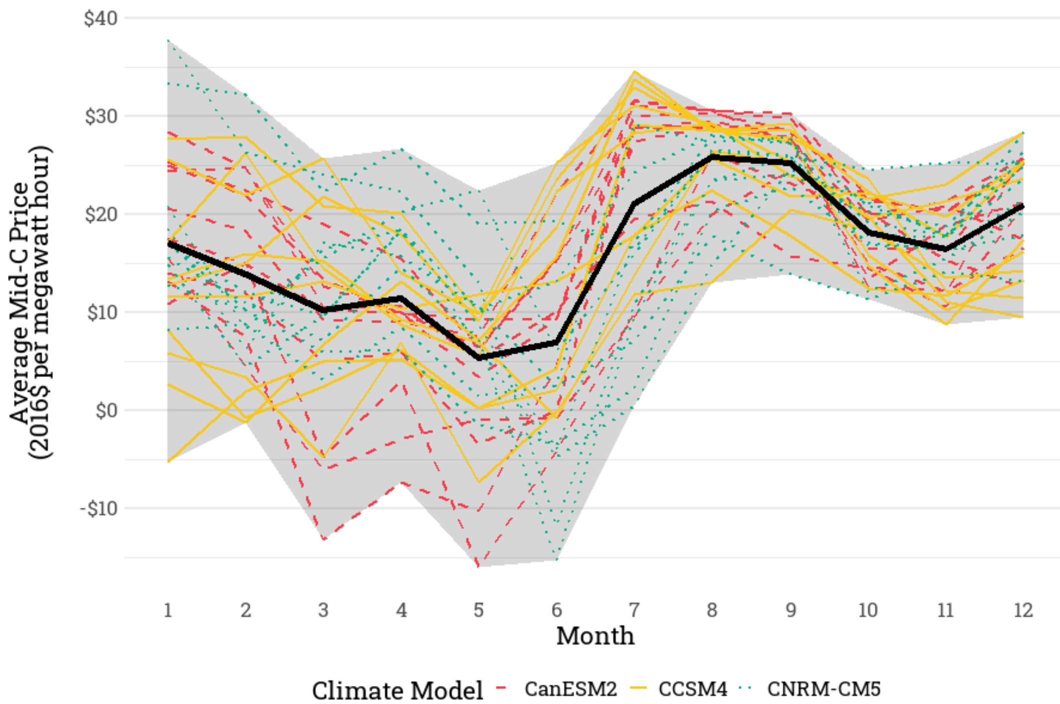
The Council projects that impacts of climate change on temperatures and precipitation will change both hydropower generation and demand for electricity. In general, these changes will increase winter hydropower generation while reducing the frequency of extreme winter weather. This puts downward pressure on winter electricity prices. In summer, we expect less hydropower generation and an increased frequency of extreme summer weather. This also aligns regional needs in the summer with the predominant electricity use in the Western electric grid. The Western electric grid uses more electricity in the summer than in the winter. All these factors taken together will put upward pressure on summer electricity prices.

The Council modeled projected hydropower generation from the River Management Joint Operating Committee (RMJOC) studies downscaling General Climate Models[42] to look at the boundary

[42] https://www.bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx

conditions of potential regional climate change impacts. The Council selected data for 30 different potential water conditions for each year of the forecast horizon. These data also include a decadal shift showing different anticipated conditions for the 2020s, 2030s, and 2040s. The changes from one decade to the next reflect the continued impact of climate change[43]. Hydropower conditions with more water available for generating electricity cause lower electricity prices, whereas conditions with less water and thus less hydropower generation cause higher electricity prices.

2026 Forecast Electricity Prices by Climate Model Hydro Conditions



Using the estimated range of electricity demand, the range of expected hydropower generation, and the range of expected wind and solar generation, the Council estimates electricity prices 20 years into the future. These prices help test the resource strategy under a wide range of potential electricity prices. In summary, the Council finds that:

- Timing and magnitude of wind and solar generation and how the generation aligns with electricity demand is a major driver of prices throughout the West
- Different amounts of water going through the hydropower system continue to be a major driver of seasonal price variation within the region

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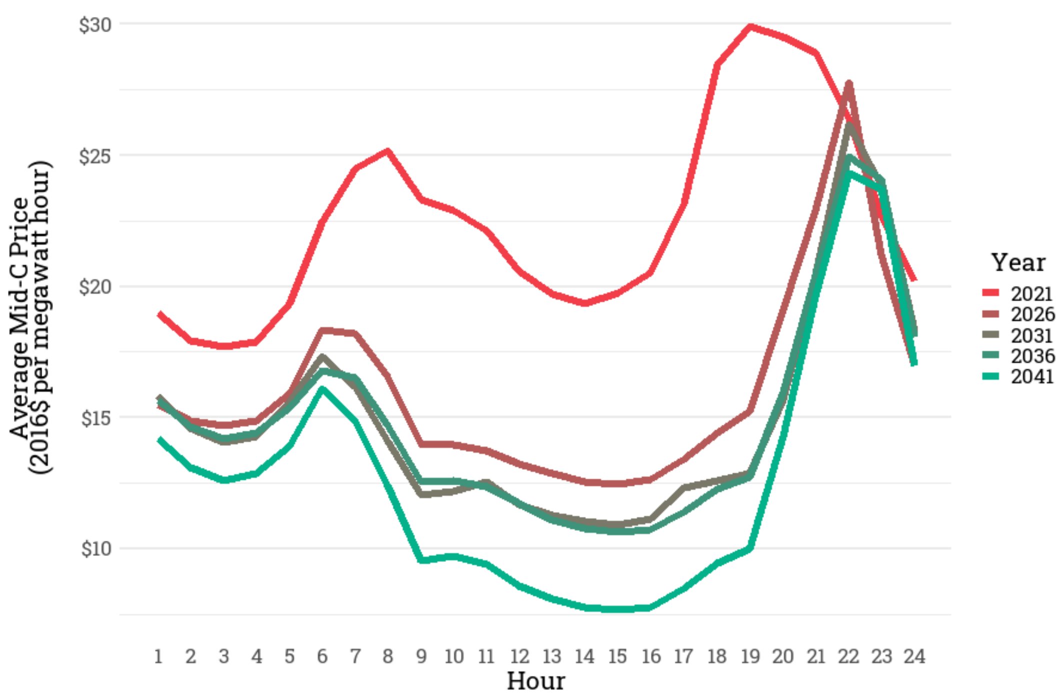
[43] Specifically, the Council uses the Representative Concentration Pathway (RCP) 8.5 which reflects an end-of-century radiative forcing of 8.5 watts per square meter.

- At some level of building additional renewable generation, extremely low or even negative prices occur, and these are aligned with times when we see substantial curtailment of renewable generation
- Prices for natural gas and coal continue to impact the electricity price during hours when fossil-fuel-based power plants are needed to preserve the balancing of the supply and demand for electricity

Altogether, this shows a downward trend for prices when looking at averages. Certain hours, especially during the evening, continue to show potential for higher prices, but prices during the middle of the day are driven down by an increasingly large amount of solar generation throughout the West.

Mid-Columbia Average Hourly Prices



Natural Gas Price Forecast

Generally, the price of fuel is a function of supply and demand. Factors that impact regional supply include how much gas can be extracted and processed, the capability to deliver natural gas to the region over pipelines, and how much gas is stored and ready to be delivered. The natural gas consumed in the Northwest originates from extraction fields in British Columbia, Alberta, and the U.S. Rockies. From there, high-pressure interstate pipelines move the natural gas into the region, where it is distributed to power plants, gas storage facilities, and homes, businesses, and industrial plants. Demand for gas typically peaks in the heating season, and if there are disruptions to supply, such as pipeline ruptures or equipment “freeze-offs”, prices on the spot market can quickly escalate.

When this power plan was being developed, natural gas supply in North America was setting all-time high records through extraction techniques like hydraulic-fracturing and horizontal drilling. As might be expected, this resulted in low prices. In 2020, the average daily spot price for natural gas at the Sumas Hub on the Washington-Canadian border was $2.15 per MMBtu. Ten years ago, the price per MMBtu in current dollars was $4.60, and in 2005 it was $9.50. With the expectation of a sustained abundant supply and robust infrastructure, the Council forecasts continued low natural gas prices. However, as the region experienced in October 2018 with a pipeline rupture[44] in British Columbia, as well as the 2021 troubles in Texas[45], natural gas prices can skyrocket on a daily or even monthly basis.

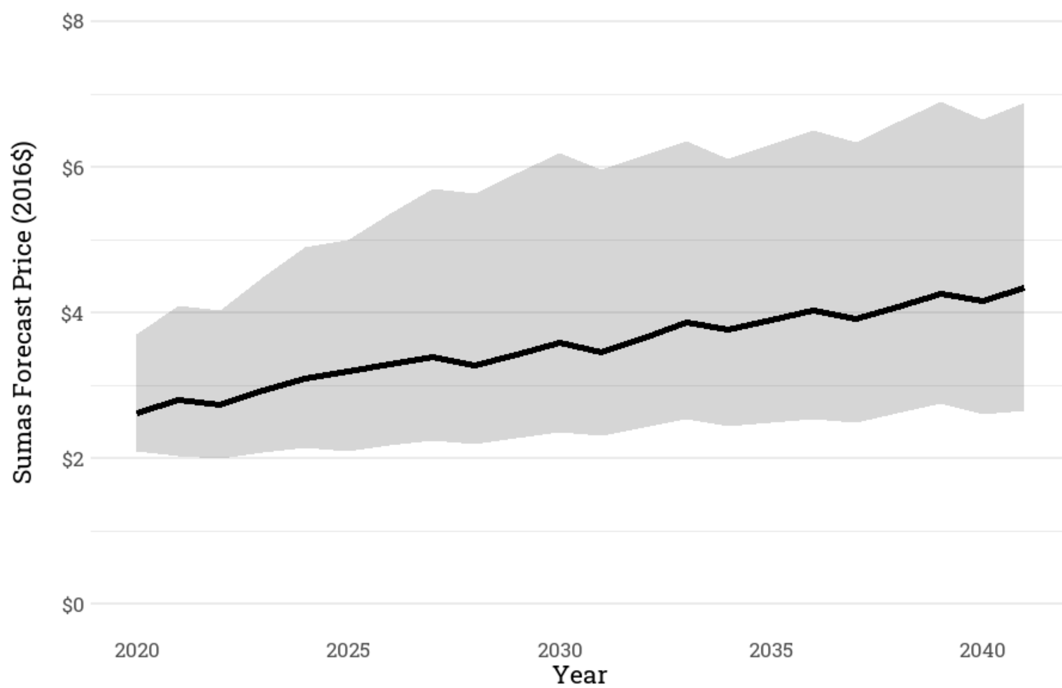
For the plan, the Council developed a range of prices across a suite of gas delivery points, including major gas hubs, power plant delivery points, and the city gate[46]. The figure below is the forecast of annual prices at the Sumas gas hub.

[44] https://www.nwcouncil.org/news/gas-prices-spike-response-late-winter-cold-spell-and-pipeline-constraints

[45] https://www.naturalgasintel.com/texas-investigating-natural-gas-pricing-during-february-winter-storm/

[46] City gate is the point where a natural gas LDC (local distribution company) takes the gas off the pipeline system to distribute to customers. City gate prices are a common price point to look at for retail market prices.

Natural Gas Price Forecast for the Sumas Hub



Coal Price Forecast

The price forecast for coal – which represents the delivered fuel price to each state from the Powder River Basin in Wyoming – is relatively flat and stable. Wyoming is the largest coal-producing state in the United States and a single mine – the North Antelope Rochelle/Peabody Mine – supplies 13 percent of the coal in the country.

Forecast of Delivered Coal Price in 2016 $/MMBtu

State	2020	2025	2030	2035	2040	2045
Montana	$1.37	$1.46	$1.51	$1.52	$1.55	$1.56
Oregon	$2.19	$2.33	$2.41	$2.43	$2.45	$2.46
Washington	$1.91	$1.90	$1.89	$1.91	$1.93	$1.94

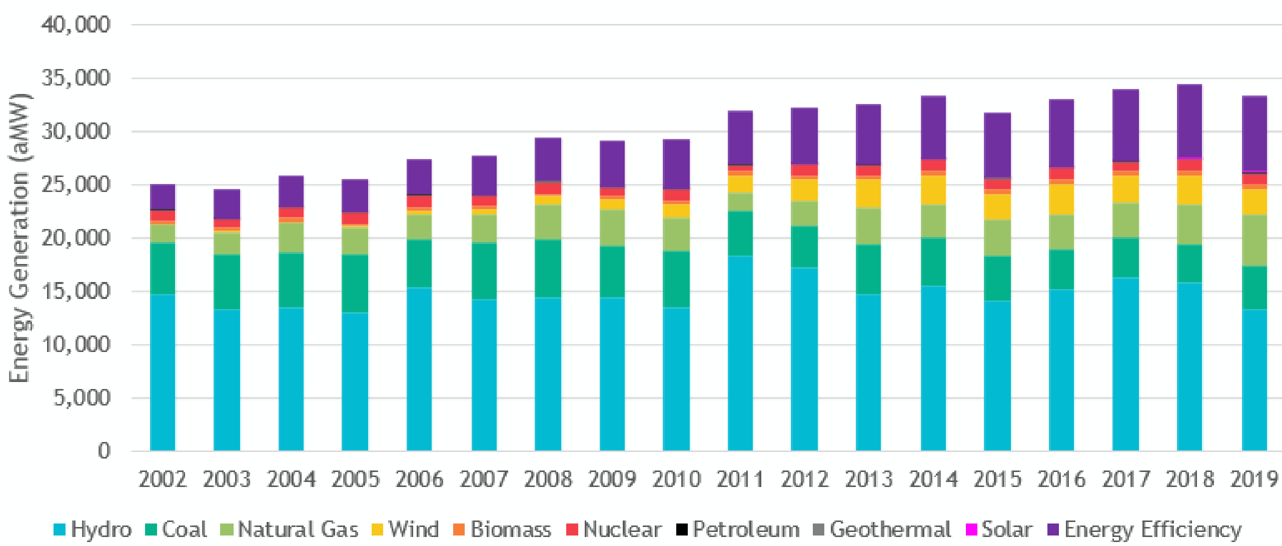
Assessing the Capabilities of the Existing Regional Electric System

The Pacific Northwest power system is undergoing a major shift that will alter the current energy supply landscape over the next several decades. New state and local policies are affecting existing resource dispatch and future resource development. Coal-fired generators are being phased out due to economics and initiatives to reduce greenhouse gas emissions. The future of natural gas development and contributions to the system are uncertain. Inexpensive wind and solar development continues to dominate new construction. Energy storage is becoming more common in the West, both as a stand-alone resource technology and partner to renewables, with the cost for the technology declining substantially in the last few years.

Resources

There are about 63,000 megawatts[47] of generating resource capacity either installed in the Pacific Northwest or located just outside the region and under contract. In addition, some of these megawatts installed in the region are also serving load outside of the region, such as wind projects under long-term power purchase agreements to California and surplus supply exported outside the region through the electricity markets. On average, the region's resource portfolio generates about 26,000[48] average megawatts annually. When energy efficiency is included, that number increases to about 32,500 average megawatts.

Pacific Northwest Annual Energy Production, including Energy Efficiency



Hydropower generation remains the cornerstone of the Pacific Northwest power system, dominating the regional energy supply. However, hydropower generation varies significantly from year to year, depending on weather conditions and snowpack levels. The regional dispatch of fossil fuel resources is directly related to how much electricity is produced with hydropower. In years with lots of water flowing through the hydropower system (for example, 2011), coal and natural gas resources generate less electricity, whereas in years with less water (for example, 2019) they generate more.

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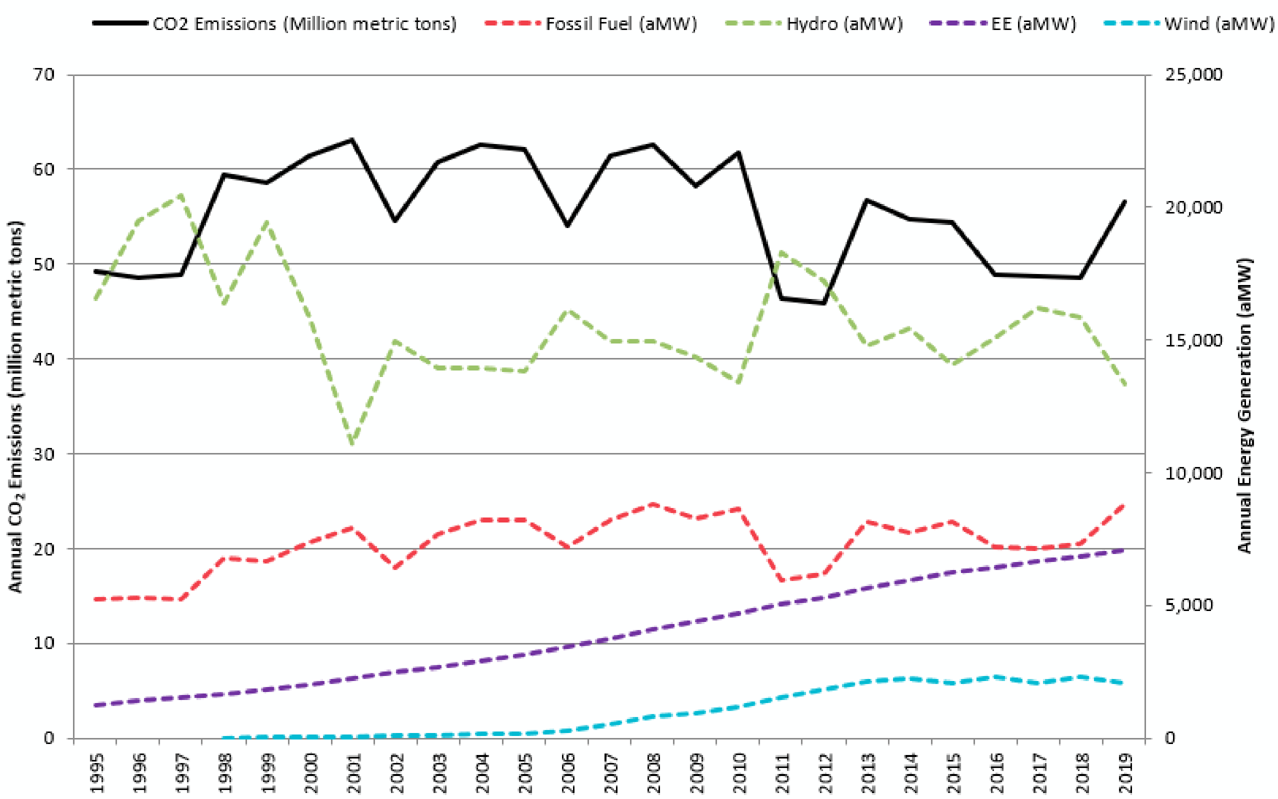
[47] See https://www.nwcouncil.org/news/megawatt-powerful-question.
[48] From 2012 to 2018 the total generation in the western electric grid was about 99,131 average megawatts so the region is about a quarter of the total load.

The Pacific Northwest has one nuclear plant – Columbia Generating Station – that produces consistent and predictable generation, following a biennial springtime refueling schedule. Onshore wind has made an increasing annual contribution to the region's energy supply, as wind development picked up in the mid-2000's in response to state renewable portfolio standards and federal tax incentives. Solar photovoltaics (PV) began to appear in the region in 2010, and while the current solar PV fleet is relatively small compared to other resources, it is expected to increase because the cost of solar has declined so significantly. Rounding out the region's energy generating portfolio are biomass resources, geothermal, and standby petroleum plants.

In addition to generating resources, demand side management resources play a significant role in the region. Energy efficiency is the region's second largest resource. Since 1978, the region has achieved more than 7,000 average megawatts of efficiency savings – around three times the average output of the Grand Coulee Dam, the region's largest generating plant.

Direct Carbon Emissions (left y-axis) from the Generation of Electricity Compared to Amount of Generation by Fuel (right y-axis)



Over the past 25 years, annual carbon emissions from the generation of electricity have averaged 55.5 million metric tons of carbon dioxide (not including upstream emissions). The relationship between hydropower generation and fossil fuel dispatch leads to the region's carbon dioxide emissions varying from year to year. This can make it difficult to decipher overall trends, although there are indications that demonstrate emissions have been decreasing overall – and that is because of fossil fuel generation dispatch. While fossil fuel generation largely dispatches based on hydropower conditions, overall, fossil fuel generation has been steadily increasing. However, the dynamic between coal and natural gas dispatch is changing. On average, coal generation has been slowly declining in the past few years due to coal plant economics and low natural gas prices. Conversely, natural gas dispatch has been increasing thanks to low fuel prices and increased natural gas availability. In 2018, natural gas generation surpassed coal generation on an annual basis for the first time. As coal units in the region are scheduled to retire, and as energy efficiency, wind, and solar continue to increase, emissions will begin to noticeably decline on a consistent basis.

Upstream Methane Emissions

Natural gas has been undercutting coal economically for some time, and the combustion of gas emits less carbon dioxide (CO_2) than coal. However, the primary component of natural gas is methane (CH_4); a greenhouse gas that when released directly into the atmosphere has a warming potential over 80 times[49] that of CO_2 over 20 years.

There are two primary greenhouse gases related to the combustion of natural gas – CO_2, and CH_4. Direct emissions refer primarily to the CO_2 emissions released at the point of use. Upstream emissions occur as methane is released or accidently leaked to the atmosphere as fossil natural gas is extracted and transported to the point of use.

The global atmospheric concentration level of methane has been steadily growing since NOAA[50] began taking measurements in 1983. Some of the largest annual increases have occurred in recent years, indicating the problem is getting worse. It’s not clear what all the causes are, but oil and natural gas activities contribute to the overall global methane emissions. By estimating upstream methane emissions related to fossil fuel use in the region, the Council gets a more accurate picture of greenhouse gas emissions related to regional energy use. With an increased focus on the upstream methane release issue, the Council expects there will be fewer releases in the future.

Policies

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana[51] in the mid-2000s, combined with federal and state tax incentives and renewed opportunities for PURPA-qualifying facilities, contributed to a significant increase in renewable resource development over the last two decades. Now, as tax incentives phase out and upcoming RPS targets are on track for compliance, a new policy movement is developing – decarbonization of the electricity system. States, utilities, and communities have instituted aggressive clean-energy targets and economywide greenhouse gas reduction goals that will influence the future construction of generating plants in the region, western electric grid, and national electric system. In the Northwest, Washington and Oregon have statewide clean-energy regulations, requiring a 100-percent clean, non-emitting electricity

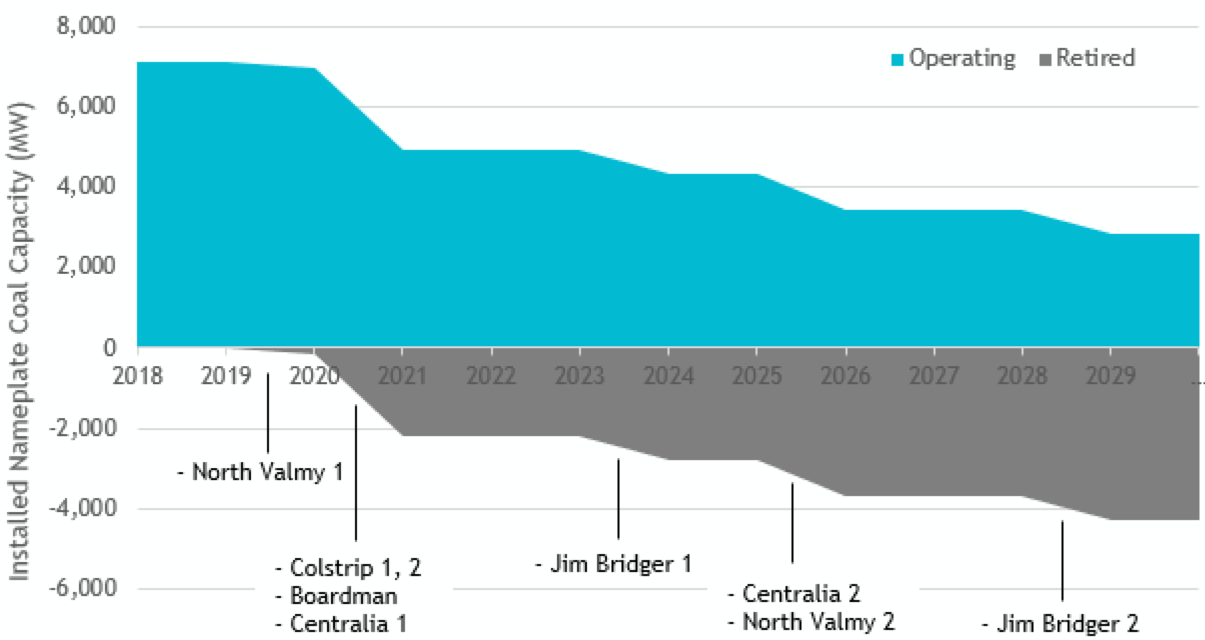
[49] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials
[50] https://gml.noaa.gov/aggi/aggi.html
[51] Montana repealed its RPS in May 2021

supply by 2045 and 2040, respectively. Idaho and Montana also have state greenhouse gas reduction goals, and utility- and community-level clean electricity goals that, in addition to a state RPS, lead to considerable aggregate state clean-energy goals.

Retirements

With the increasing emphasis on decarbonization, specific policies that prohibit coal-fired generation in the future have been enacted in several states in the West – including Oregon and Washington. In addition, the economics that previously favored inexpensive coal-fired generation have dramatically swung to favor natural gas generation due to consistently low natural gas prices and low-cost renewable resources that have low or no variable operating costs. This has led to the early closure of coal-fired generators in the region and across the West.

Pacific Northwest Coal Fleet: Unit Retirements



In 2018, the region's coal fleet totaled around 7,000 megawatts of capacity. In just a few short years, with the retirement of Colstrip units 1 and 2, Boardman, Centralia unit 1, and Idaho Power's exit from North Valmy unit 1, the coal fleet is now just under 5,000 megawatts. By the end of 2028, that number will decrease even more to around 2,400 megawatts through the planned retirements of Jim Bridger units 1 and 2, Centralia 2, and North Valmy unit 2. While some coal units remain in 2029, with multiple owners and competing interests for each remaining unit, the future of these resources is uncertain.

Assessing the Potential for New Resources

In assessing the potential for new electricity resources, the Council considers not only the cost of maintaining and fueling the existing electric system, but also the cost of adding new resources to meet changing and expanding needs for electricity in the region. The Council estimates the cost and potential for resources that the region can use to meet these needs. This helps in getting a complete picture of the cost of supplying the region's future electricity needs. In developing a resource strategy, the Council analyzes the difference in cost and performance of potential additional resources to make recommendations for the most effective way to adequately meet regional demands for electricity.

New Opportunities for Energy Efficiency

Energy efficiency is a reduction in the use of electric energy as a result of the increase in the efficiency of energy use, production, or distribution, and historically has been the "least cost" resource acquired by energy providers. As such, energy efficiency acquisition reduces system costs and is specifically referenced in the Act as the priority resource to be selected by this plan before renewables, natural gas plants, and other generators are considered. Energy efficiency has helped the region avoid the need for and the costs associated with building and maintaining numerous power plants, as well as the price risk associated with fuel purchases needed for thermal plant operations. In addition, energy efficiency supports system reliability and hydro system flexibility, and has been used to avoid or delay distribution system investment to serve peak load. For these reasons, assessing the potential for energy efficiency to meet future system needs is an essential part of this plan. The Council assesses all efficiency completed through utility programs, energy codes, appliance standards, and natural market impacts prior to the start of the plan. These are included as part of the demand forecast and not included in the forward-looking energy efficiency potential estimates.[52]

The starting point for assessing the potential for energy efficiency as a resource is to define each unit of savings, or "measure". A few examples of these measures[53] include efficient light bulbs, insulation, better windows, heat pump water heaters, and more efficient fans. The energy savings per unit (e.g., electricity consumption of a heat pump water heater relative to a standard electric resistance unit), combined with the number of units (e.g., number of homes with electric water heating) provides the amount of savings potential for a given measure. Adding up all the possible measures for homes, businesses, and industries results in a forecast of efficiency potential.

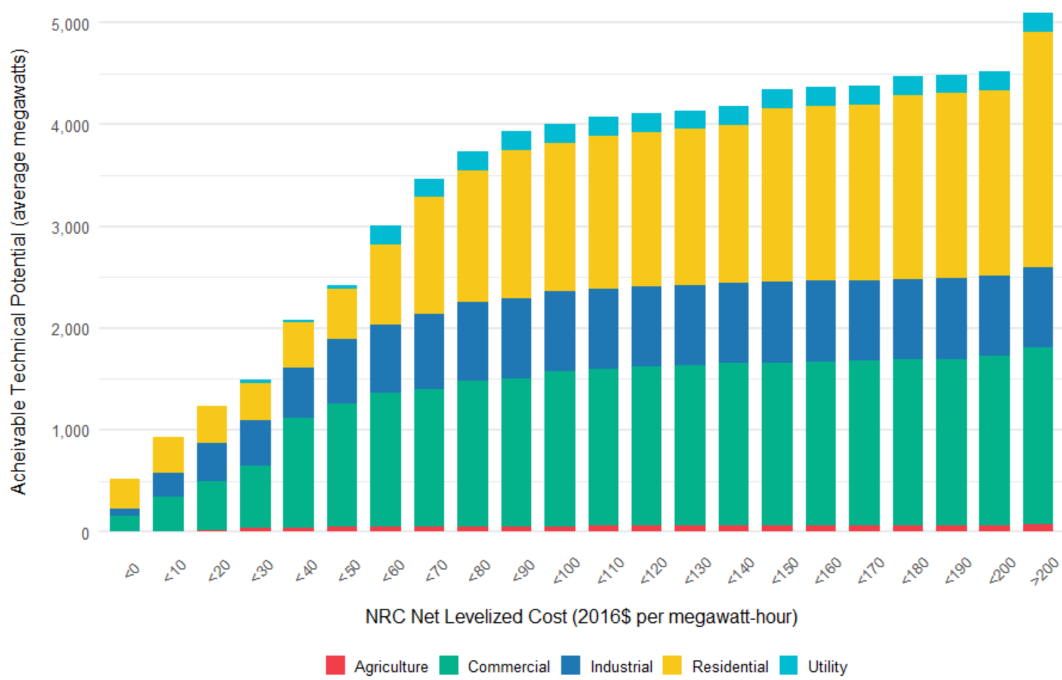
In addition to the electricity savings, a measure is defined by the incremental cost to install or implement the efficiency and a variety of other costs (e.g., maintenance cost) or benefits (e.g.,

[52] Energy building codes and appliance efficiency standards established prior to the end of 2019 are accounted for in the Council's baseline forecast.
[53] To define the individual measure costs and savings, several sources are used. Primary among them is the Regional Technical Forum (RTF). For measures not considered by the RTF, the Council relies on secondary studies from both regional (e.g., NEEA) and national sources (e.g., DOE). The total number of units (e.g., number of homes) in the region is largely based on the sector-specific stock assessments conducted by NEEA.

additional water savings). The Council takes all the costs and benefits and adjusts the total cost[54] of these measures to come up with a cost that can be compared to other types of resources.

The amount of energy efficiency available during the planning horizon is developed and formulated into a “supply curve,” which gives the amount in average megawatts of savings at different measure costs (in dollars per megawatt-hour). The energy efficiency supply curve below shows all energy efficiency available through 2041, differentiated by sector and by cost. The figure shows 1,345 average megawatts as the total amount of energy efficiency potential by 2027 and 5,103 average megawatts by 2041, accounting for technical and feasibility limitations. The supply curve is used to compare energy efficiency to other electricity resources, providing an amount of efficiency available at increasing costs, and can be used to meet future regional electric system needs.

Energy Efficiency Supply Curve, Differentiated by Sector for 2041



The timing of when the savings from energy efficiency occur is also an important part of our analysis. As the price of electricity varies by day and by season, the value of the energy efficiency will also vary, depending on the timing of savings. For the supply curves, energy savings are

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[54] The measure costs include total system cost (per the Northwest Power Act), and both costs and benefits combined into a net levelized cost. This levelized cost is the net present value (NPV) of the measure costs divided by the measure savings. In this manner, the costs for conservation are developed consistently with other generating resources.

greater during winter than summer. The shape of the savings for the complete set of energy efficiency is developed by combining all the individual measure shapes.

Demand Response Supply Curve

Demand response (DR) is "*a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties.*" The need for demand response arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might encourage them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

The Council evaluated demand response products that impact residential, industrial, commercial, and agricultural sectors, as well as the utility distribution system. Demand response products evaluated include utility-controllable and price-responsive options across the sectors. Utility-controllable products are those for which the utility can change the operation of end-use equipment to reduce peak. Price-responsive products are those for which the end-use customer can choose how to modify loads based on a price signal from the utility. In general, price-responsive products are less expensive because equipment needs are lower, but the utility has less control over the resulting impact.

In total, 23 demand response products were incorporated into demand response supply curves. The Council estimates about 3,721 megawatts of summer load reduction potential and 2,761 megawatts of winter load reduction potential[55]. This potential was focused on reducing load during times of system need, though it is recognized that demand response could also be used to increase loads during low or negative prices to balance with supply. The potential is based on an estimated impact per participant and the potential number of participants based on eligibility (e.g. customers need to have air conditioning to participate in an air conditioning control program), assumptions of

[55] The difference in load reduction is based on the underlying demand response measures. Some programs, like curtailment of residential air conditioning only impact the summer season, while other programs like space heating only impact the winter season. While the potential numbers referenced here give a sense of the impact of demand response relative to other resources the deployment of demand response by utilities could differ based on needs.

willingness to participate, and participation rates for any given demand response event (a customer may opt out of any given event).

Products range in cost from -$5 per kilowatt-year up to $250 per kilowatt-year (2016 dollars). These costs include setup, operation and maintenance, equipment, marketing, and incentives. The Council also incorporates benefits (or negative costs), such as deferring buildout of the transmission and distribution system by reducing electricity use during times of the highest electricity need.

New Generating Resources Potential

New generating resource technologies are assessed based on their cost, operating, and performance characteristics, and developable potential in the region. Resources that are commercially available and proven and have the potential to meet future needs in the region are further developed into reference plant estimates representative for the Pacific Northwest – with a designated plant size and configuration, performance attributes, costs, and other attributes such as construction schedule and economic life.

The Council developed reference plants for utility-scale solar photovoltaics (PV), solar PV + battery storage, stand-alone battery storage, onshore wind, natural gas combined cycle turbines, natural gas peakers, and pumped storage. In addition, one emerging technology reference plant was developed as a proxy for the many promising new technologies (for example, offshore wind, small modular nuclear, and enhanced geothermal systems) that could provide value to the region in the future.

The costs of renewable resources – and in particular solar PV – have decreased significantly[56]. Despite recent price fluctuations due to tariffs on imported materials and cells, the cost of solar PV is expected to further decrease in the future. While the cost of natural gas combined cycle plants has largely remained the same, the cost of a natural gas frame unit – operated in simple cycle mode as a gas peaker – has decreased due to lower equipment costs and greater competition among vendors to secure fewer project development contracts. The costs of conventional geothermal and pumped storage hydropower resources are extremely site-specific, and thus it can be difficult to see any major trends.

[56] According to the Lawrence Berkeley National Lab, over the past decade, the installed cost of solar has declined about 70 percent and the installed cost of wind has declined about 40 percent. (https://emp.lbl.gov/webinar/utility-scale-wind-and-solar-us)

New Generating Resource Reference Plants: Capital Cost (2016$/kW) Trends

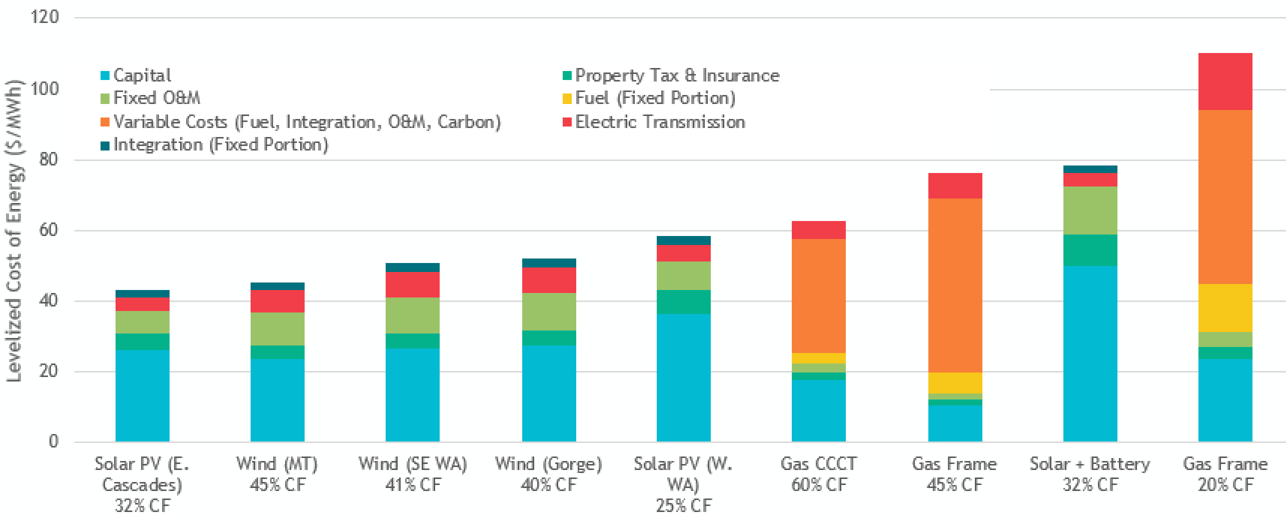
Resource	Seventh Plan (2016$/kW)	2021 Plan (2016$/kW)	Trend
Onshore Wind	$2,382	$1,450	Significant decrease
Solar PV	$2,566; $1,792 (low cost)[57]	$1,350 (E. Cascades); $1,465 (W. WA)	Significant decrease
Solar PV + Battery Storage (4 hr)	--	$2,568	--
Battery Storage (4hr)	--	$1,400	--
Pumped Storage	--	$2,300	--
Geothermal	$4,575	$5,400	No significant change
Natural Gas - Combined Cycle Combustion Turbine	$1,220	$1,150	No significant change
Natural Gas – Peaker (Frame)[58]	$859	$550	Decrease
Proxy Emerging Tech – Small Modular Reactor	--	$5,400	--

One way to compare the cost of a resource against another is to look at the levelized cost of energy, which is a metric used to estimate the cost of energy across a resource's expected economic life. It is calculated as the cost per unit of energy a resource is expected to generate (under an assumed level of dispatch, or capacity factor) and which also includes variable costs such as fuel. Although

[57] When the Council was evaluating solar PV in 2015 for the Seventh Power Plan, costs were dropping so quickly that a lower-cost solar PV resource option was added to the model analyses.
[58] This price decrease also reflects a change in the reference plant technology class

the initial cost for solar and wind may be higher than gas resources, with minimal operating costs (no fuel purchases), the overall cost of producing energy can be significantly less.

New Generating Resource Reference Plants: Levelized Cost of Energy ($/MWh)[59]



While the Council doesn't explicitly model all new resource options, there are other commercially available resources with smaller-scale, location-specific potential in the Pacific Northwest (for example, biomass, small hydropower, distributed generation) that if cost-effective should be considered viable resource options for future power planning.

Planning for an Uncertain Future

The electric sector is in a time of transition. A wave of coal unit retirements will happen over the next decade. Climate change is altering hydropower generation, and policies designed to limit greenhouse gas emissions constrain how the electric sector expands the supply of electricity. Utilities and regulators are looking to replace coal with completely different generating technologies like wind and solar generation. The cost of building solar and solar with on-site batteries has fallen substantially. But relying more on new technologies requires changing how the electric grid operates. The expansion of the Western Energy Imbalance Market makes the operation of the Western electricity grid more automated and intertwined. But it's just a start on the scope of change needed to transform the way electricity is generated.

The future of Northwest utilities will be different than the past.

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[59] In this graph, CF denotes capacity factor. For each generator, the capacity factor indicated the average amount of energy over a year relative to the installed capacity that was used in the levelized cost calculations for comparison.

Exploring Key Power Supply Questions through Scenario Analysis

Understanding the potential future risk that will impact the electric sector of the economy takes a broad range of analyses. Some analyses involve creating a range for potential risks. For example, the Council forecasts a range of natural gas prices. The Council uses analytical approaches to consider the implications of natural gas prices that deviate from our expectation.

Other risk analyses involve setting up scenarios, or a set of high-level questions, that help assess future alternatives. The Council builds these scenarios by asking what conditions and processes would change and then reflecting them in our analytics.

Ultimately, scenario analyses help inform decision-making when developing the recommended resource strategy for the region and for Bonneville.

How the Scenarios were Selected

The Council looked at high-level themes in the electric sector and the Northwest Power Act in constructing the scenario analyses. To incorporate Power Act requirements, the Council first focused on analyses that examined the adequacy of generating resources to meet the regional needs. Given the expansion of the Energy Imbalance Market in the West since the last power plan, the Council saw changing and expanding markets for electricity as an important theme for this plan. The Council also used analyses to distinguish between the impacts of a resource strategy on Bonneville's portfolio of resources and the demand for electricity Bonneville is obligated to serve with those resources. Finally, the Council expected that understanding the implications for greenhouse gas emissions for the region was an important part of looking at future strategies on how the region can meet the demand for electricity.

After identifying these high-level themes, the Council examined seven scenarios to guide the analyses. The scenarios connected to one or more of the high-level themes and created distinct narratives that the Council determined would help construct an overarching resource strategy.

How the Scenarios were constructed

To construct the scenarios, the Council developed models and analyses that would be part of this plan. The Council then identified, given the narrative for each scenario, where the models and analyses had parameters that would differ. Each scenario involved exploring a range of different values and combinations for these parameters.

Scenarios Explored

The Council explored a range of scenarios designed to answer key questions about the future of the electricity grid. These scenarios echo previous Council plans and also break new ground. The scenarios are:

Change in Reliance on Extra-Regional Markets for Resource Adequacy – an analysis of the impacts of relying on markets outside the region for resource adequacy.

Organized and Limited Markets for Energy and Capacity – an analysis of potential impacts from changing the structure and reliability of markets outside the region.

Early Retirement of Coal Generation – an analysis of the implication of accelerating planned retirement dates for coal generation throughout the western electricity grid.

Robustness of Energy Efficiency – an analysis of how the resource strategy would change with different estimates and assumptions regarding the supply of energy efficiency.

Analyze the Bonneville Portfolio – an analysis of the Bonneville Administrator's obligation to provide electricity and the available federal resources dedicated to meeting that obligation.

Greenhouse Gas Regulation and Cost Impacts – an analysis of the impacts of limitations, financial or otherwise, on greenhouse gas emissions from the electricity sector.

Pathways to Decarbonization – an analysis of the impact on the electricity sector of efforts to substantially reduce economywide greenhouse gas emissions.

Findings from Our Scenario Analyses

The Council has different methods for accounting for uncertainty. While some uncertainty or risk is modeled using ranges of values, for example the range of future electricity prices, some uncertainty does not lend itself to using a range of values. For those types of uncertainty, the Council uses scenario analysis. While scenario analysis is a useful method to describe uncertainty, it often looks at very unlikely outcomes to help in understanding the direction that policies or goals lead. The following descriptions of our scenario analyses focus on what we learned from these exercises. They should not be taken as a forecast of what is likely or as the sole basis for how we formulate a resource strategy.

Change in Reliance on Extra-Regional Markets for Resource Adequacy

The Northwest spent billions building transmission to connect to the rest of the West. This enables surplus electricity sales that offset the regional cost of electricity and allows purchases when the regional need exceeds the capacity of regional generators. Relying on electricity purchases from outside the region defers the need to build new generators, which reduces the cost of using electricity. However, maintaining reliable electricity requires both transmission to the Northwest and available generators outside the region.

Our baseline setup limits the amount of imports from the external market. After accounting for imports from power plants that are located outside the region but have contracts or obligations to deliver electricity to the region, the analysis limits regional imports to no more than 2,500 megawatts in the winter and 1,250 megawatts in the summer. Those limits are well below the ability of the region to import electricity on our transmission system. Because the Council has less information on the supply and demand for electricity outside the region, the Council uses these limits to represent uncertainty about the availability of electricity during times when the region is short of generation and fuel.

For this scenario the Council relaxed these limits to allow the region to import up to the capability of the transmission system. While this reduced the adequacy-needs input into our resource analysis, the results from our models had minimal changes to the resource additions examined. While there were some minor changes to the pace at which renewable generators are built within the region, the overall results did not indicate removing these limitations would change the resource strategy.

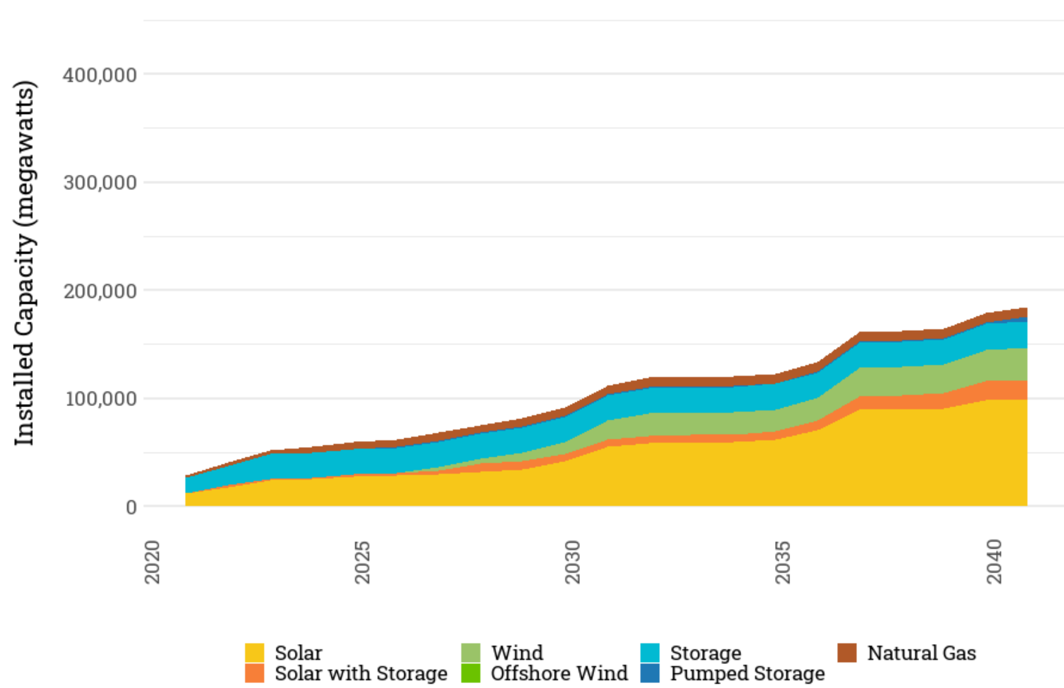
Organized and Limited Markets for Energy and Capacity

The Council's analysis for this power plan has shown that the costs and risks faced by the region are connected to the policies and decisions beyond our borders. The choices of utilities in the rest of the West on what resources to build and retire directly impacts cost and reliability of power in the region.

To help explore the impacts of electricity markets outside the region the Council developed several different external generating resource addition projections and looked at the impacts of those different additions on the resource strategy.

In one projection, the Council substantially limited the supply of electricity outside the region. This projection met the current Renewable Portfolio Standard or RPS requirements and the clean-energy requirements that limit the types of generation used in some Western states through about 2035 but fell slightly short of meeting these policies after then. By intent, the Western grid outside the Northwest did not have sufficient generation to meet the demand for electricity under stressful conditions. However, the Council did still see a substantial addition of especially solar power to both meet policy goals and at least partially replace retiring generation.

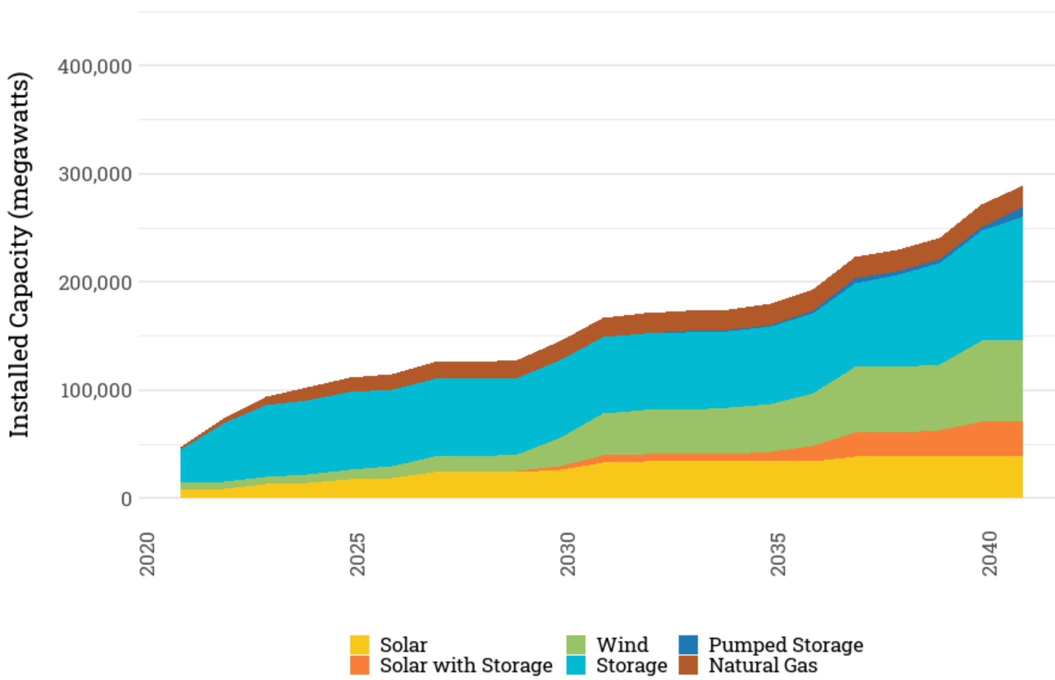
Projected Generation Additions with Limited External Market Supply



In another projection, the Council also explored resource additions in the event that utilities created a combined approach to planning for new resources and created a unified transmission rate[60]. This was a proxy for how centrally dispatched markets with a consistently applied adequacy standard could impact decisions about resource additions.

Currently the Western electric grid has many different markets with a variety of manners for determining when generating resources are dispatched. There are standards that grid operators must meet set by FERC and NERC, but the operators in an inadequate system may be forced to selectively shut down electricity to parts of the grid to meet these requirements. Consistently applied adequacy standards would make the chances of curtailing electric service both lower and consistent from one region to the next.

Projected Generation Additions with a Unified Market



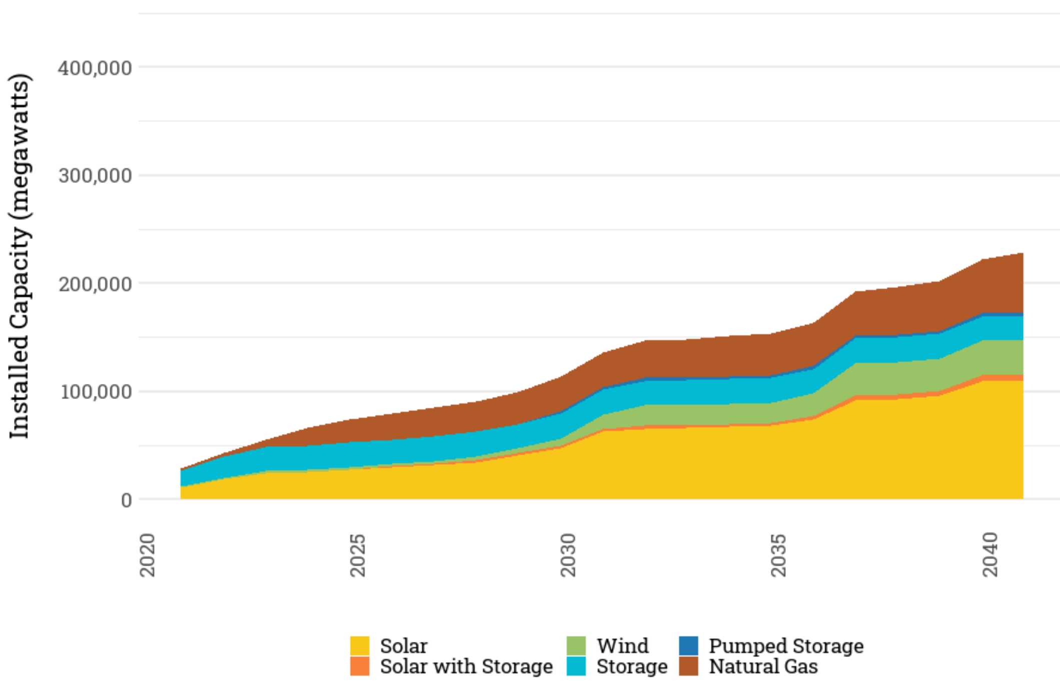
In both projections, the Council included limits on the amount of new natural-gas-fired generation that could be built within the Western electricity grid. These limitations were based on both Council

[60] The important distinction is that access to the transmission system is available at the same rate everywhere, so dispatch is not driven by different transmission charges in different regions of the electric grid. This does not mean a unified transmission rate is necessarily cheaper, nor does it mean that transmission owners would all get the same return. This scenario should not be considered an indication that transmission right owners would either benefit or be disadvantaged from unifying a transmission rate. Discussing how unifying a transmission rate would work is beyond the scope of this scenario analysis.

expertise and consultation with regional experts on their expectation about resource selection around the West.

However, these limitations substantially increased the addition of solar and wind generation outside the region. To assist in understanding the impact of limiting new natural-gas-fired generation, the Council removed these limits and projected what adding natural gas generation would look like. In this case, the Council saw over 26 gigawatts of natural gas generation added by 2027, and over 55 gigawatts added by 2041. There was also a corresponding reduction in the addition of renewable resources, though there still was over 33 gigawatts of solar generation built by 2027, and over 115 gigawatts built by 2041.

Projected Generation Additions without Limiting Natural Gas Builds



The Council also wanted to isolate the impact of renewable generation included in the regional resource addition to help show the impacts of additions within the region compared to additions outside the region. To implement this, the Council removed renewable generation from the resource selections in our analysis and examined the impact to the resource addition.

While the regional electricity prices associated with these additions varied, the addition of renewable resources only had minimal changes throughout all of these projections except the one where renewable generation in the region was specifically excluded.

Average Renewable Resource Builds by Market Scenario

This indicates that renewable resource additions at this level are likely required to meet regional policy targets in addition to being part of the least-cost portfolio under various assumptions about external markets.

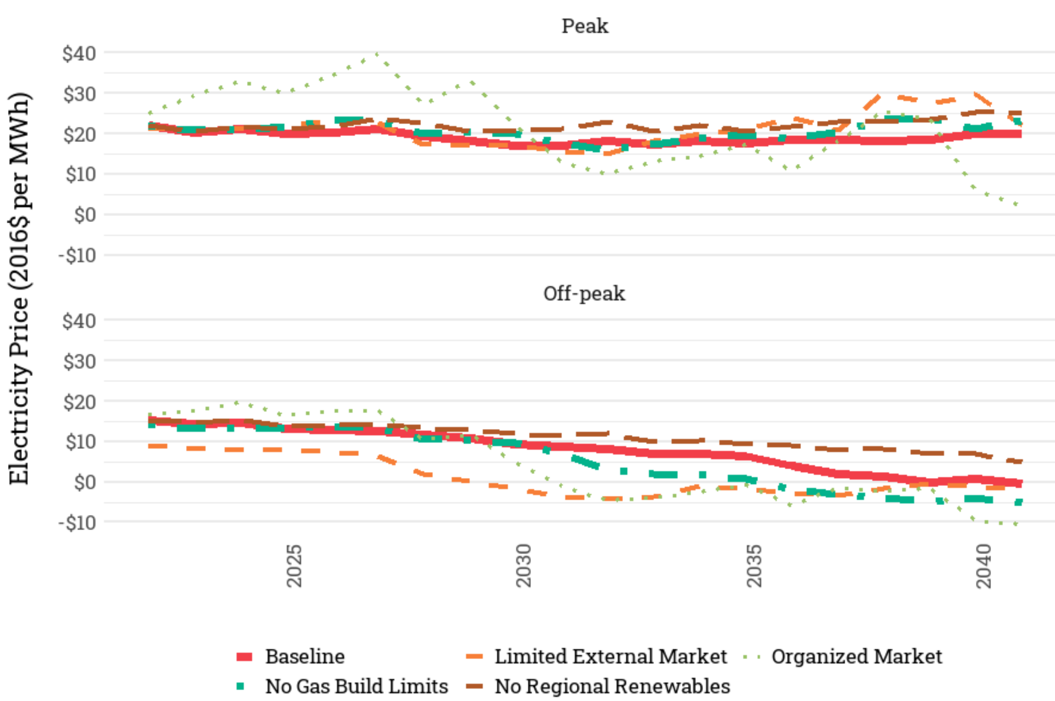
In the projection where the Council eliminated regional renewables, there was a requirement for new natural-gas-fired generation to meet adequacy requirements. In this scenario, there was a high probability of adding at least one new power plant.

However, the biggest impact was on the addition of energy efficiency. In the projection where no renewables were built in the region, almost 750 average megawatts of energy efficiency were developed. In the projection with limitations on the external market, less than 150 average megawatts were developed.

Energy Efficiency Acquired by Market Scenario

These results show that while the regional addition of renewable generation was not particularly sensitive to electricity market prices, the addition of energy efficiency was sensitive.

Regional Electricity Price by Market Scenario



Early Retirement of Coal Generation

Since the last power plan, utilities in the region and outside the region have announced the retirement of coal-fired power plants at dates that precede the end-of-useful-life dates that have been previously assumed in analyses by the Council and others. The Council understands that there is risk in retiring resources sooner than planned, especially coal-fired generation. This scenario explores this risk using the coal-fired generation fleet in the West. There are likely other types of generation that could have retirement dates accelerated based on economics or regulation. The Council did not analyze the likelihood of early retirement for all types of generation. Thus, this should be considered a directional analysis that was used to help the Council understand this observed risk.

To implement this, the Council assumed that all regional coal-fired power plants were retired by the end of 2026. For coal plants outside the region, the Council assumed that all plants were retired by 2030[61].

[61] These dates are not intended to represent likely dates that the coal-fired power plants would retire, rather they are intended to be a stress test of the power system and be informative on coal-fired generation's impact on greenhouse gas emissions.

Regional Coal Plant Unit Retirement Scenario Assumptions

Coal Plant Unit	Nameplate Capacity (MW)	Announced/ Existing Retirement Date (EOY)	Baseline Conditions Retirement Assumptions [62]	Early Coal Retirement Scenario Assumptions
Colstrip Unit 1	358	2019		
Colstrip Unit 2	358	2019	Retired	Retired
Boardman	601	2020	Retired	Retired
Centralia 1	730	2020	Retired	Retired
North Valmy 1	277	2019[63]/2021	Retired	Retired
Centralia 2	730	2025	2025	2025
North Valmy 2	289	2025	2025	2025
Jim Bridger 1	608	2023	2023	2022
Jim Bridger 2	617	2028[64]	2028	2026
Colstrip 3	778	--	2037	2025[65]
Colstrip 4	778	--	2037	2025
Jim Bridger 3	608	--	2037	2026
Jim Bridger 4	608	--	2037	2026

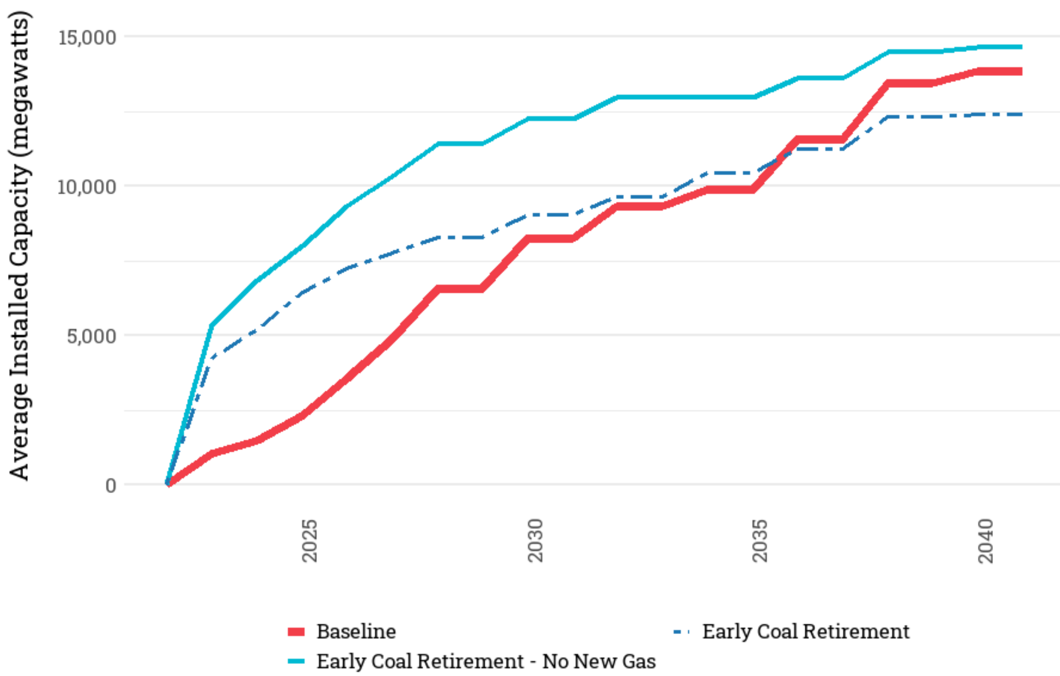
Our analysis shows with this scale of retirement, emissions in the West would decrease just under 40 percent after all the coal plants are fully retired. Emissions in the Northwest would decrease over 80 percent. The emissions reductions are greater in the region because the hydro generation in the region has resulted in a smaller natural-gas-fired generation fleet relative to the rest of the West.

Without limiting the types of new generation, the expected resource addition by 2030 includes around 1,400 megawatts of nameplate capacity of new natural-gas-fired generation. Considering the decisions that would lead to early coal retirement, it seems unlikely that new natural-gas-fired generation would be considered for replacing retired coal generation. By eliminating new natural-

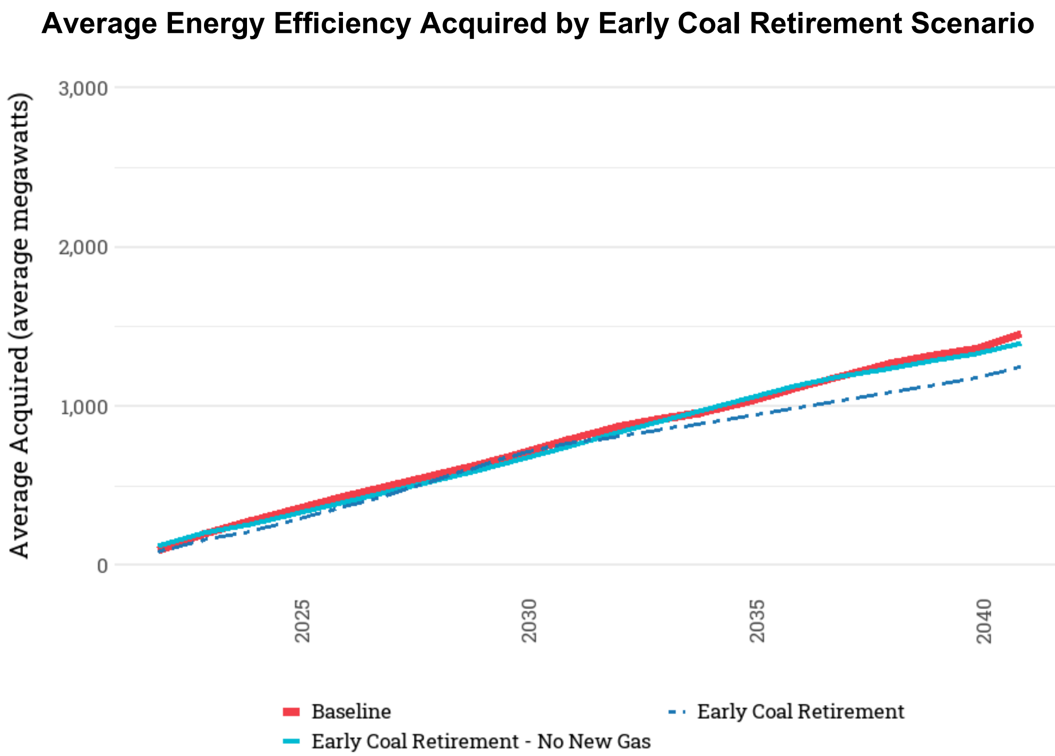
[62] For our baseline assumptions we use either the announced retirement dates or end-of-useful life dates used in utility IRPs.
[63] Idaho Power ended its participation in this unit in 2019.
[64] PacifiCorp and Idaho Power are still working out details of the accelerated retirement of Bridger 2, this date should be considered tentative.
[65] For a potential early retirement date for Colstrip Unit 3 and Unit 4, 2025 was selected based on the Washington state utility requirements in the Clean Energy Transformation Act.

gas-fired generation from consideration, the expected renewable-energy addition in the region substantially increases.

Average Renewable Build by Early Coal Retirement Scenario



While the Council sees a response in the renewables addition for this scenario, there is relatively little change in the addition of energy efficiency.



The Council also sees an expected increase of 7.2 percent in residential electricity bills in this scenario.

Robustness of Energy Efficiency

Energy efficiency has been the cornerstone resource of the Northwest since the first power plan. For this scenario, the Council explored assumptions about the supply of energy efficiency and the drivers that impact acquiring more or less of this resource.

Specifically, the Council looked at the impacts of differing regional adequacy needs, rate of acquisition, the amount available, the contribution to regional capacity needs, and the impact of varying our treatment of emissions impact on portfolio costs. The Council examined how it collects supply curves for portfolio analysis and then ran a sensitivity on how other resource decisions would change under high and low acquisition of energy efficiency.

When the Council increased or decreased the regional adequacy need, especially when testing an extremely high regional need to develop new generating resources, the energy efficiency resource acquired came close to doubling. The Council also tested increasing the capacity need on the system. Renewables were not particularly sensitive in this test, but the analysis added thermal resources.

Altering the rate of acquisition of energy efficiency and the amount available resulted in more and less energy efficiency acquired for faster and slower ramps respectively. The increase and decrease of energy efficiency were driven by the differing availability of efficiency in the early years of the study. However, in both cases the Council also observed an increase in the overall system cost. In the case where there was an increase in energy efficiency, there was not a significant difference in the unit cost of the energy efficiency being acquired, but the increased amount resulted in more money spent on the resource in total. In the case of decreasing energy efficiency acquisition the increased costs manifested in purchasing more expensive resources. While acquiring more energy efficiency absent other changes would increase the reliability of the system, the Council saw the faster acquisition of energy efficiency alter other resource decisions in a manner that resulted in no meaningful increase in the reliability of the system.

The contribution of energy efficiency to capacity needs is estimated using the best data that are available to the Council on the timing of the use of electricity. However, some of these data are outdated, and the region is currently conducting research that will allow for updated information to be used in the next power plan[66]. The Council tested how resource additions would respond if the capacity contribution of energy efficiency was increased. In part, this test assumed that the updated data may show better alignment between peak electricity needs and energy efficiency. The test showed changes in other types of resources built in response to the overall change in system need based on the contribution of energy efficiency to the peak system need. However, the Council did not see additional acquisition of energy efficiency in this test.

When the Council constrained energy efficiency to look at the impact of suboptimal acquisition, acquiring more energy efficiency led to a more expensive system by displacing less expensive resources and by acquiring more resource than was needed. With less energy efficiency acquired, the result was a less reliable system.

In our baseline for our analyses, the Council incorporated an emissions cost based on the Social Cost of Carbon from the Intergovernmental Panel on Climate Change into the portfolio cost. For this scenario the Council tested the impact of this on the acquisition of energy efficiency. When removing this impact on portfolio costs the Council saw minimal reduction in the near-term acquisition of energy efficiency but a larger reduction in the total energy efficiency acquired over the 20-year plan duration.

[66] https://neea.org/data/nw-end-use-load-research-project

Energy Efficiency Acquired in Robustness of Energy Efficiency Tests

Scenario / Test	Energy Efficiency Acquired (average megawatts)	
	2027	2041
Baseline Conditions	500	1462
Change Supply Curve Binning	470	993
Increased Acquisition Ramp and Potential	1362	2562
Decreased Acquisition Ramp and Potential	370	1235
No Emissions Related Portfolio Cost	175	780
Increased Adequacy Requirements	932	2656

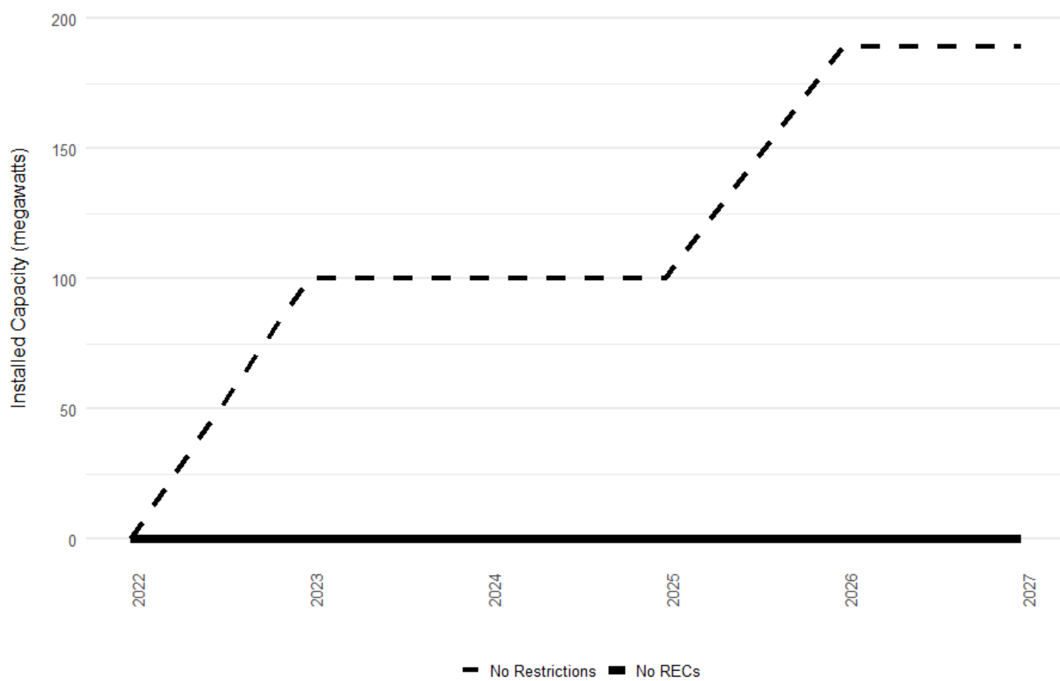
Analyze the Bonneville Portfolio

Bonneville is a central part of the Northwest electric system. A large portion of the transmission in the region is owned and operated by Bonneville. The Council considers a broad array of information from all the various analyses included in this plan when making recommendations to Bonneville. One key part of that perspective is understanding the obligations Bonneville has to provide electricity and the federal resources and contracts that are designated to be used to meet those obligations -- that is, the Bonneville portfolio.

The Council analysis see a small need for additional resources. The Council describes the existing federal resource capability and obligations in *Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity*. Under many of the forecasts for an increase in the Bonneville obligation, the Council sees that resources are sufficient to meet the need. However, there are infrequent circumstances where increase in the demand for electricity exceeds the seasonal firm energy in the Federal power system. Our analysis shows the least-cost way to meet these needs is a combination of energy efficiency, demand response, and renewable resources.

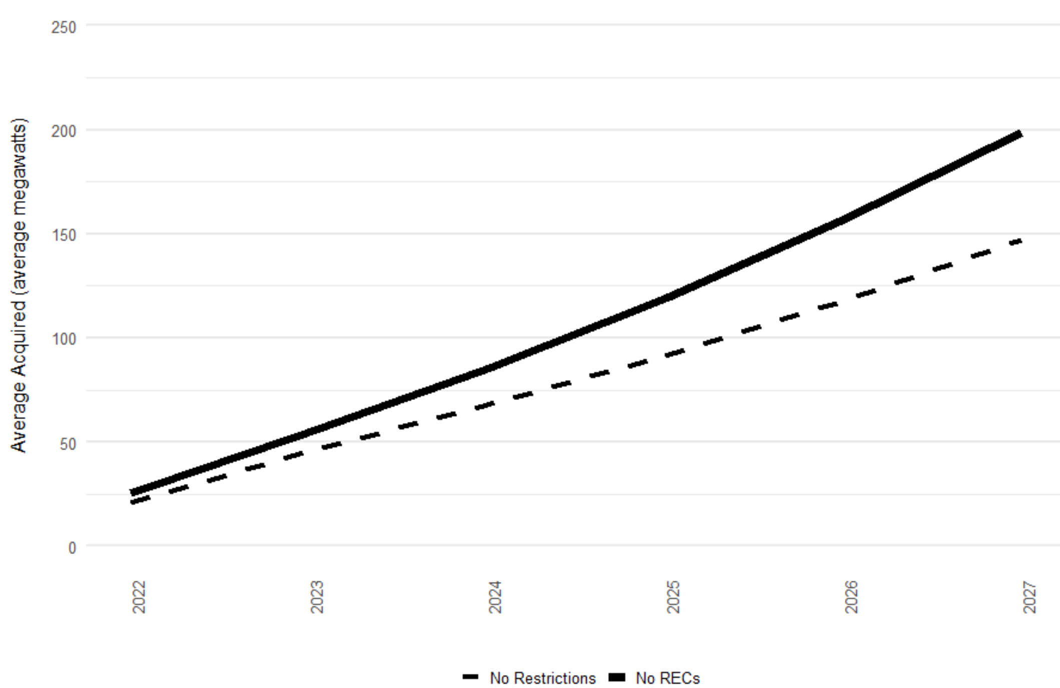
Part of this analysis was looking at the cost of resources. When examining the cost of renewable resources, the treatment of Renewable Energy Credits (RECs) altered the amount of renewable generation additions to the portfolio. When the RECs were assumed to offset the cost, more renewable resources were selected as part of the portfolio. However, currently Bonneville passes RECs through to its customer utilities, so they do not accrue value to the Bonneville portfolio. When excluding the value of the RECs, the addition of renewable generation is much more limited.

Renewables Build with and without Accounting for the value of RECs



The treatment of RECs also impacts the amount of energy efficiency acquired. Because renewable resources meet part of the energy need, there is a reduced need for energy efficiency.

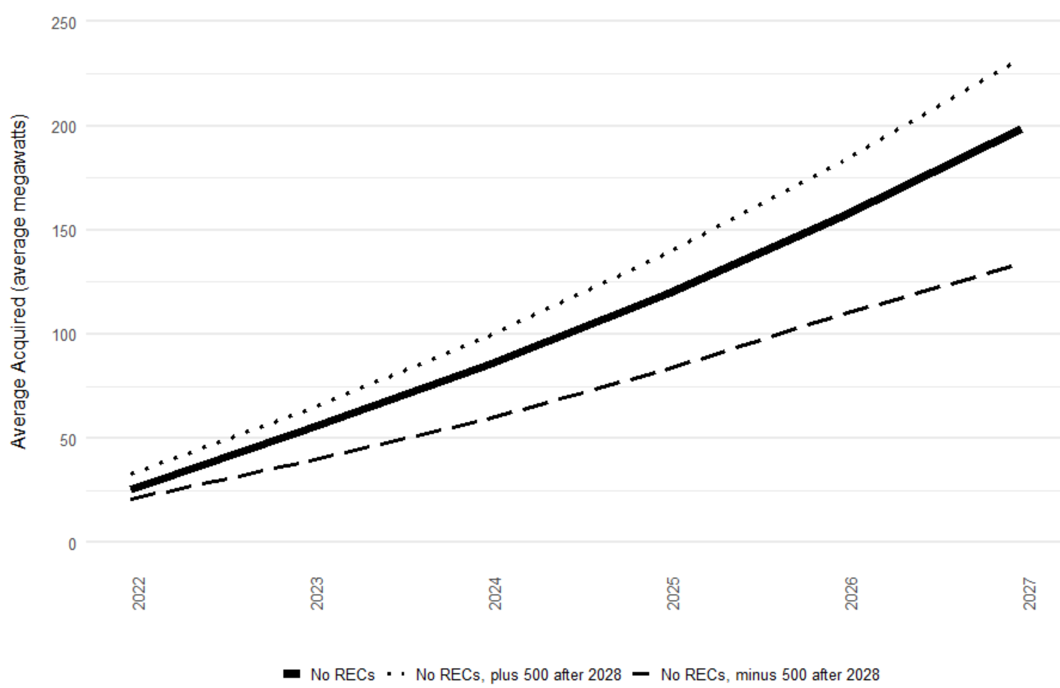
Energy Efficiency Acquired with and without Accounting for the value of RECs



The Council also tested the demand response measures seen to be low-cost and part of the resource additions in the regional analyses. The measures examined were Demand Voltage Regulation (DVR) and Time-of-Use rates (TOU). These measures reached 300 megawatts of capacity by 2027 in the portfolio.

The Council also examined the implications of a change in obligation after the Bonneville contracts expire in 2028.[67] The purpose was to see if there would be near-term changes in resource additions based on the obligation change in 2028. To test this, the Council added and removed 500 average megawatts from the Bonneville obligation in 2028. When adding obligation, the Council saw additional near-term resource additions as the least-cost solution. When removing it, the Council saw lower near-term resource additions. Adding to the obligation in 2028 increased the addition of energy efficiency by 2027 by 35 average megawatts. Decreasing the obligation removed around 65 average megawatts of energy efficiency.

Energy Efficiency Acquired with Obligation Changes After 2028



Similarly, for renewable resources – when excluding the value of RECs – our analysis shows an increase of almost 175 megawatts of nameplate capacity additions by 2027 when the obligation

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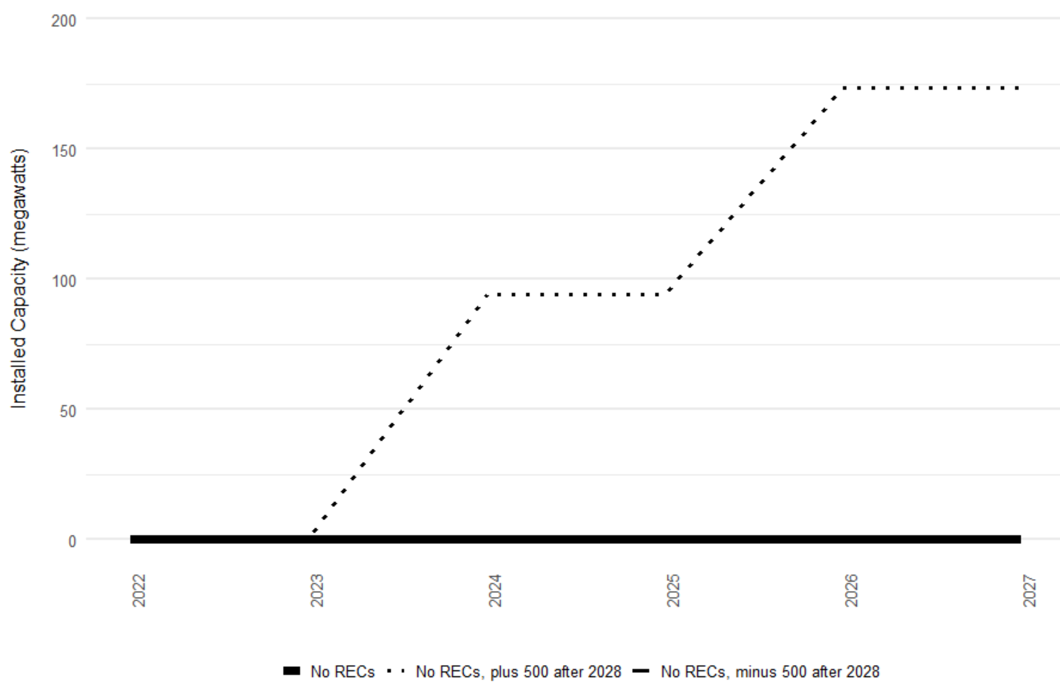
[67] The eventual size of Bonneville's obligation to serve after 2028 adds a level of uncertainty to our needs forecast that may not be fully realized until the end of this Plan's action period and may require further analysis by the Council to determine the full impact of Bonneville's future contractual obligations.

increases in 2028. Decreasing the obligation does not impact near-term resource additions and shows no additions of renewable resources after 2028.

Renewables Build with Obligation Changes After 2028



Greenhouse Gas Regulation Cost and Impacts

The Council has been analyzing greenhouse gas emissions and the impact of regulation to reduce emissions on the electricity sector throughout most of its history. Analysis of emissions first appeared in the 1991 Power Plan[68]. However, in recent years the scope and variety of regulation related to emissions have expanded, not just in the region but throughout the West.

This plan has aggregate renewable energy requirements and clean-energy requirements. The Council also included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation. However, the Council did not assume generating resources that emit greenhouse gases would dispatch with emission pricing included in their variable cost.

The Council developed this scenario to explore the implications of regulation throughout the West intended to limit or reduce greenhouse gas emissions.

The Council started by examining the implications for adding generating resources outside the region. Like the scenario work on organized and limited markets, this scenario looked at what

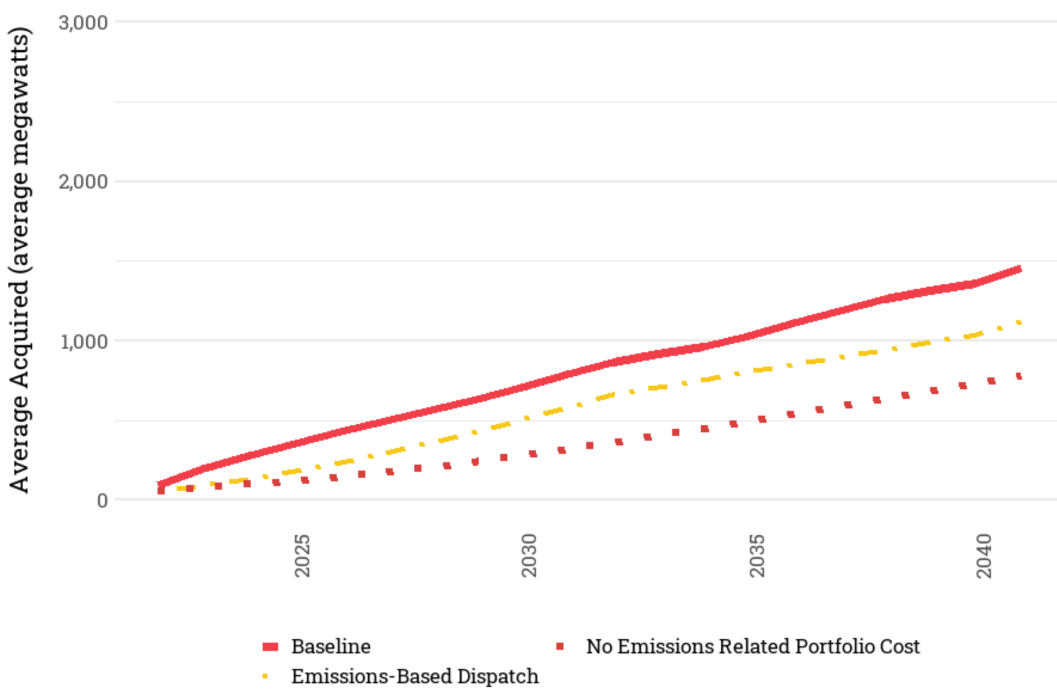
[68] https://www.nwcouncil.org/reports/1991-northwest-conservation-and-electric-power-plan

resources would be built if limitations on new natural gas generation were removed. The scenario showed the addition of almost 60 gigawatts of natural gas generation by 2040 when the scenario was not constrained by resource options.

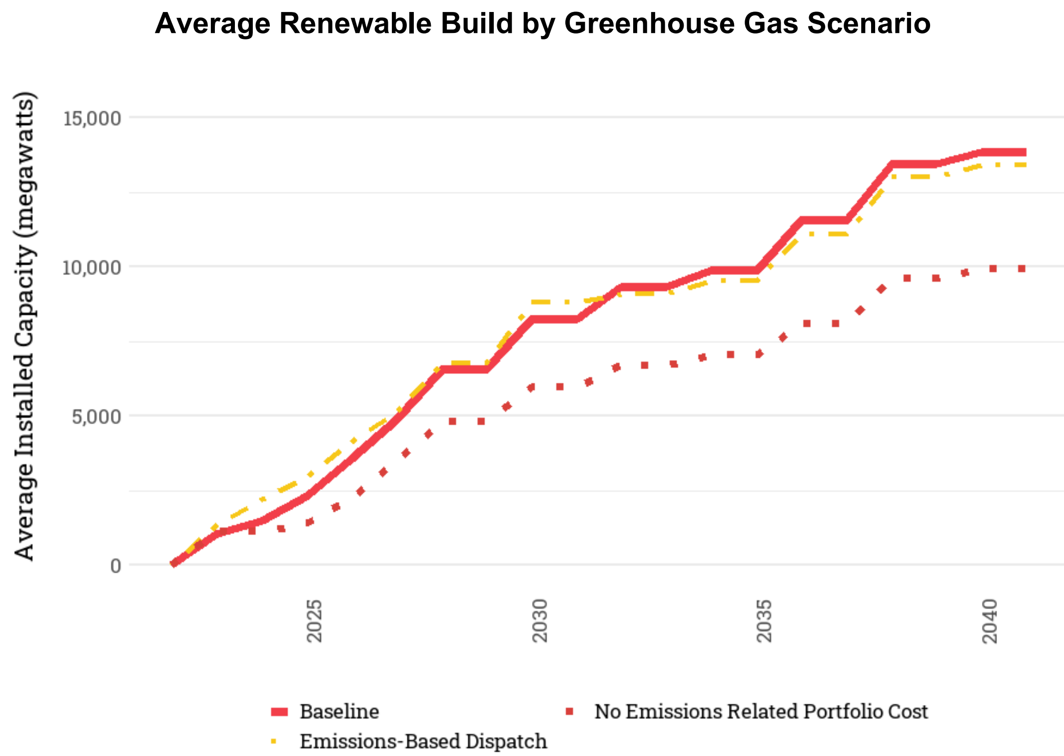
The Council also looked at the implications of explicit emissions pricing included in the dispatch of all resources in the West. In this case, renewable resource additions increased by just over 13 percent in 2040.

The Council's analysis shows that emissions regulation has a substantial impact on the resource strategy. While the Council does not set emissions-related policies either in the region or outside the region, the Council consider the impacts of these policies when making recommendations for a resource strategy. The analysis showed that both including the price of emissions in resource dispatch and removing emissions-related portfolio costs reduced the energy efficiency acquired.

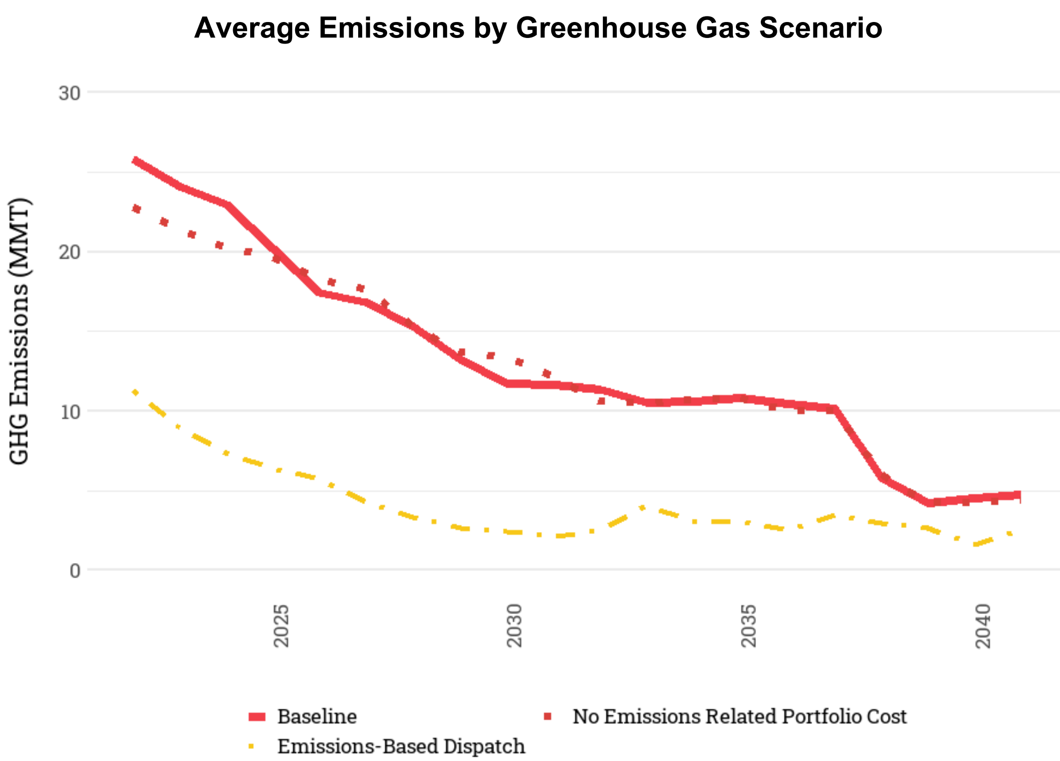
Average Energy Efficiency Acquired by Greenhouse Gas Scenario



While implementing an emissions-based dispatch slightly increased the number of renewable resources built, removing emissions-related portfolio costs decreased the amount of renewable resources built to around 3,500 megawatts of nameplate capacity by 2027.



There was little impact on regional emissions when removing the emissions-related portfolio costs, but changing how regional resources dispatch to include an emissions-based price substantially reduced the amount of emissions in the region.

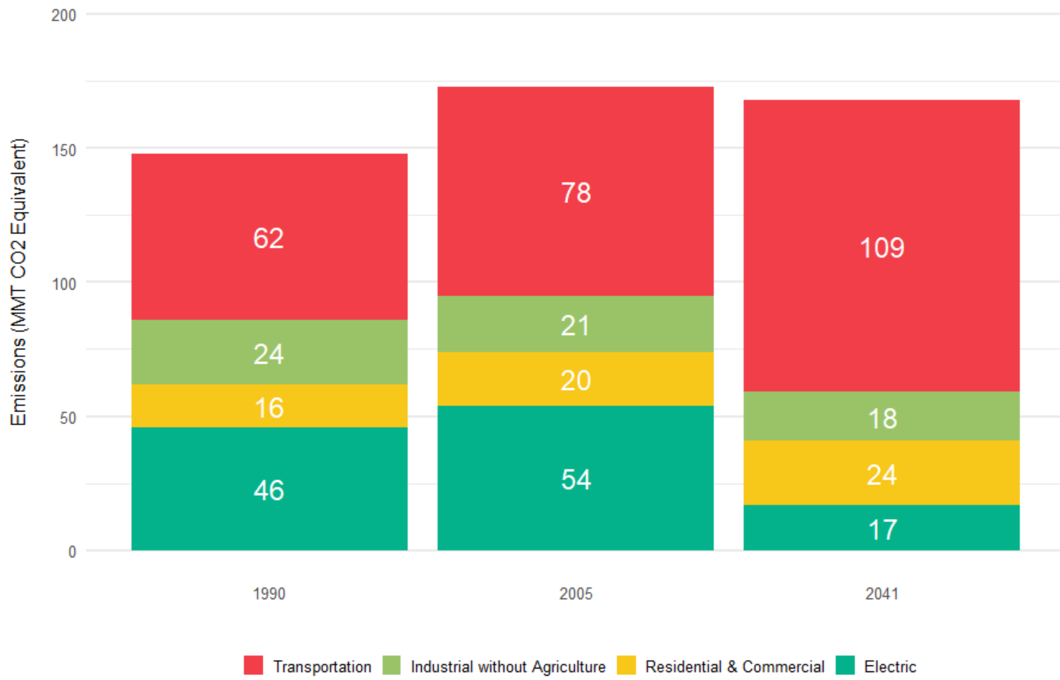


Pathways to Decarbonization

The states of Oregon and Washington have set goals and limits on future greenhouse gas emissions. Oregon's goal is to reduce emissions 80 percent below 1990 levels by 2050. Washington's goal is to reduce emissions 95 percent below 1990 levels and be at net-zero emissions by 2050.

These goals include the electricity sector in a broad range of emissions. To analyze the impacts on the electric system in this scenario, the Council forecasted the region's demand for natural gas as well as transportation fuels. Including the impact of emissions from the use of these fuels, the resulting estimates show that regional emissions will rise compared to 1990 levels in our baseline conditions.

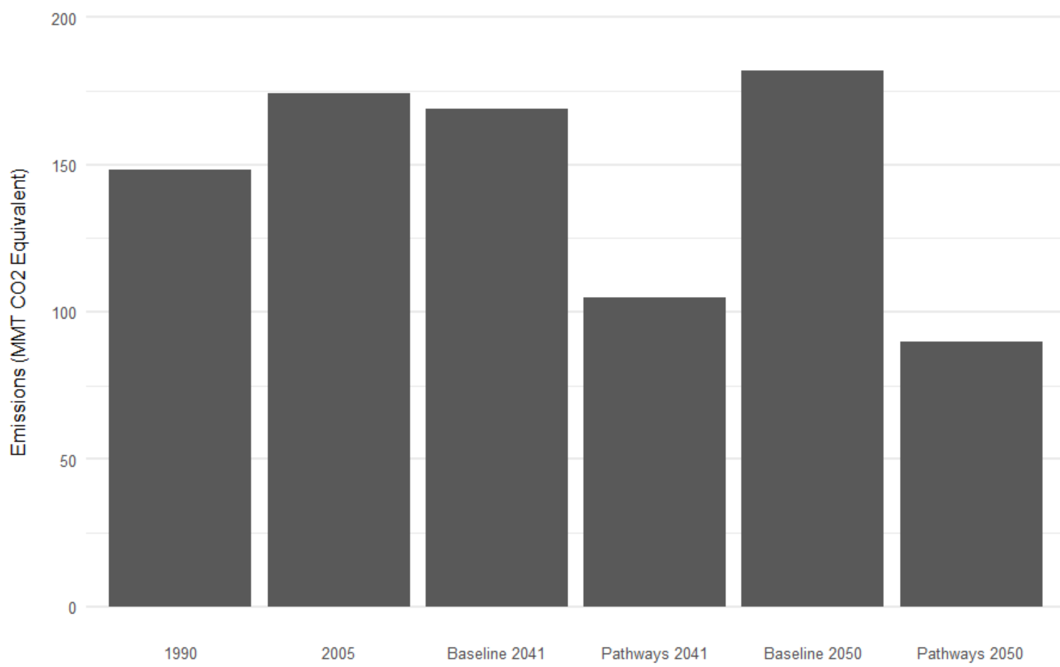
Expected Sector Emissions Based on Baseline Conditions



By 2041 under baseline conditions for the analysis, most regional emissions will be associated with the use of fuel for transportation. One potential approach to reducing emissions in the transportation sector would be the electrification of transport and potentially the production of hydrogen through electrolysis as a non-greenhouse-gas-emitting fuel for use in vehicles or other applications. The analysis shows it would be possible to reduce emissions by almost 27 percent by 2040, but it would require more than 12 gigawatts of additional electricity to meet the demand that new transportation technologies would place on the electricity grid.

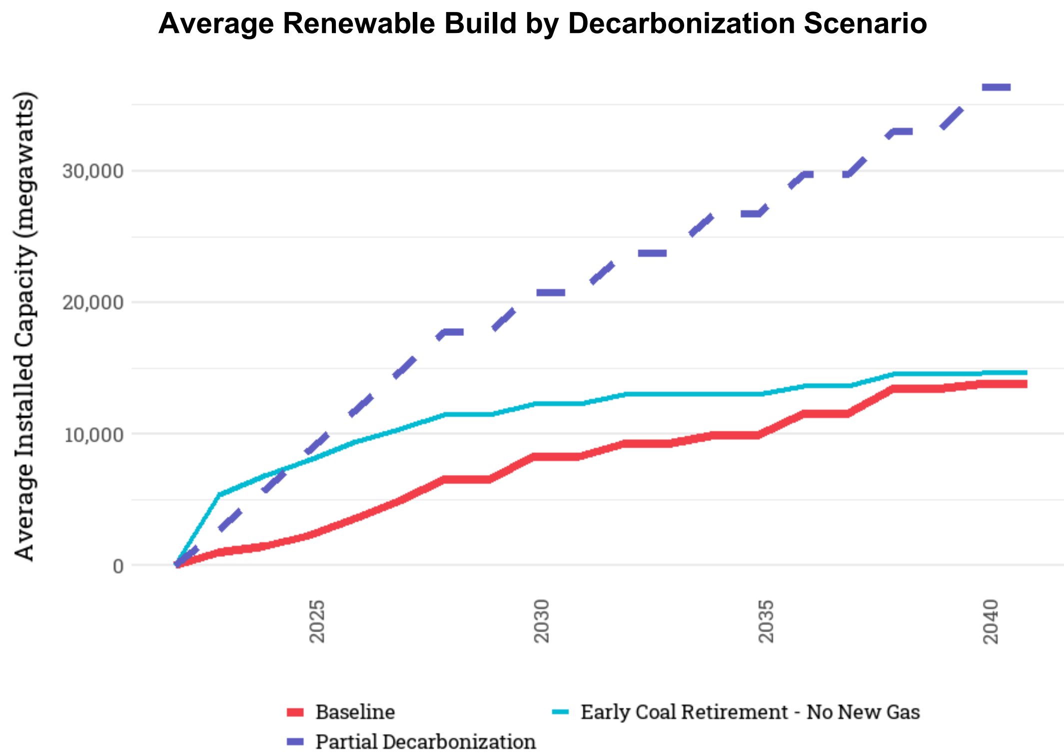
However, even adding the reduction from aggressive electrification of transportation with a collection of equally aggressive policies to reduce other emissions in the broader regional energy sector, the analysis does not show a path to getting to the targeted reductions within the energy sectors using the current technologies. The policies the Council tested include replacing vehicles and appliances and equipment in homes, businesses, and manufacturing at an accelerated but possibly obtainable pace.

Regional Emissions from Energy Used in Residential, Commercial, Industrial, Agriculture, and Electric Utilities

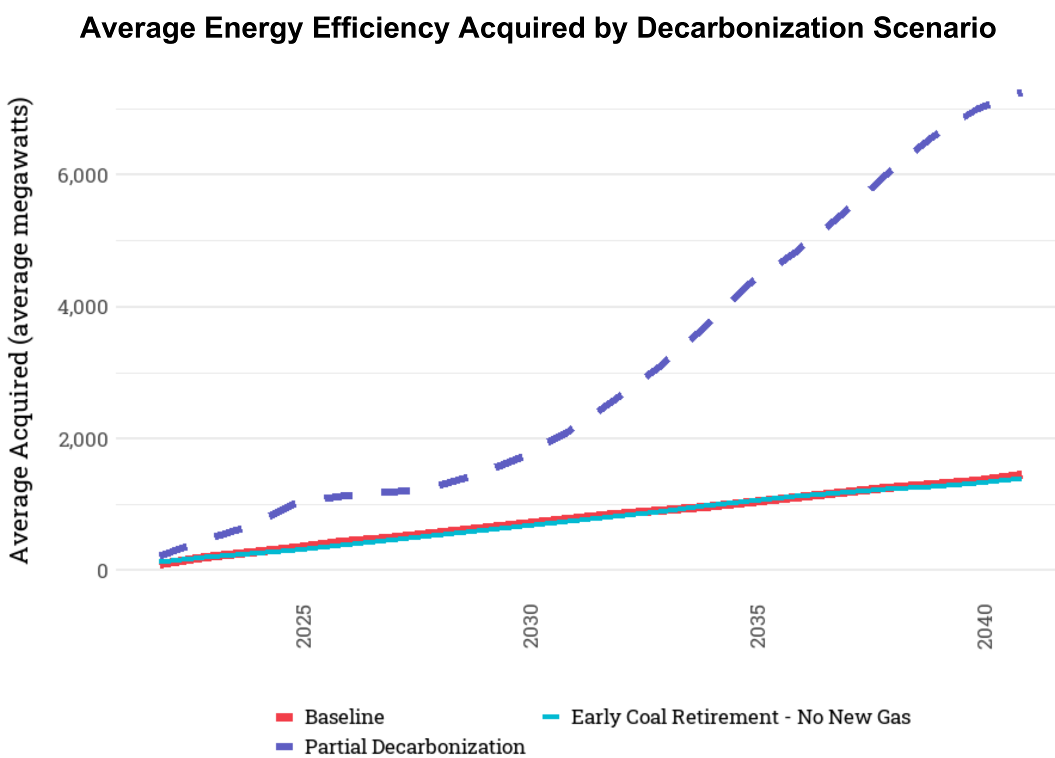


Looking at the scope of change in this analysis, the Council decided the incremental demand to the electric system was beyond the resource expansion that could be supported by the structure of our analysis. To test the impact on the resource strategy, the Council removed a substantial proportion of the demand associated with the production of hydrogen by electrolysis. While this reduced the likelihood of reaching the Oregon and Washington targets for reducing greenhouse gas emissions, it provided a directional analysis of the possible impacts to resource additions. It also still represents aggressive emissions reductions relative to baseline conditions in the analysis. By 2040, this more moderate but still aggressive emission reduction increased the demand for electricity by just over 52 percent.

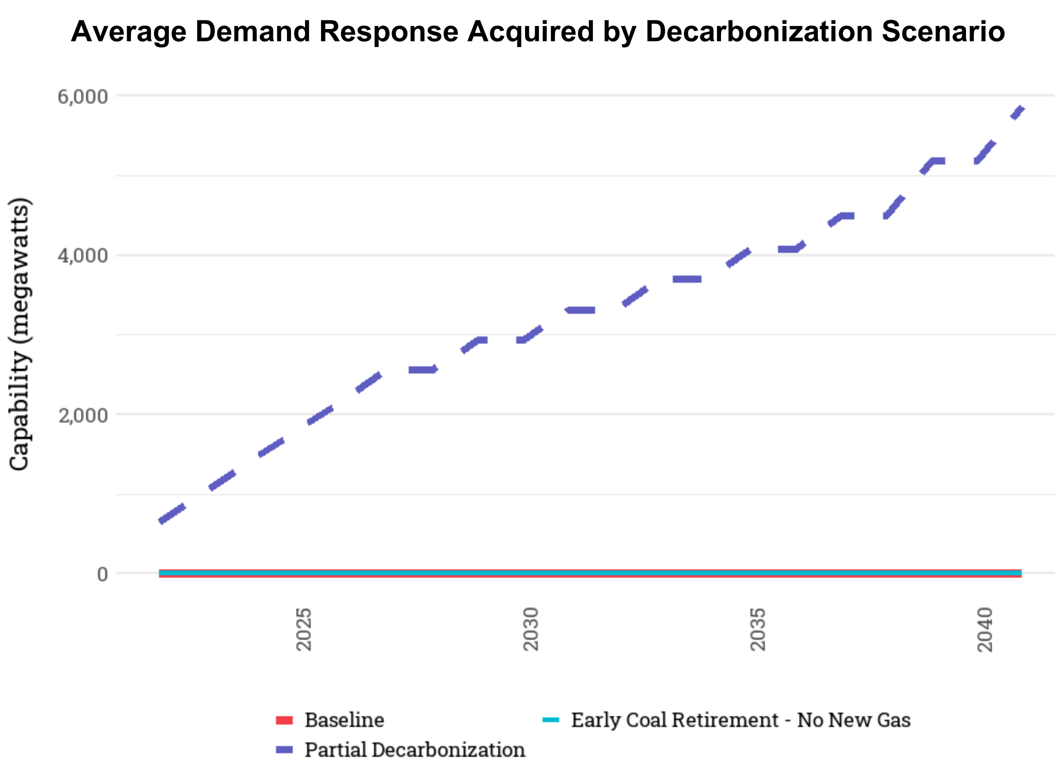
In response to this increased demand, the analysis showed a substantial increase in the addition of renewable resources relative to other scenarios the Council explored.



The Council also altered the supply of energy efficiency and demand response to incorporate the additional anticipated demand for electricity. This analysis showed substantial increases in energy efficiency.



The analysis also showed a substantial uptake of demand response to support system adequacy.



The resource addition also included an expected 800 megawatts of battery storage capacity. Part of the renewable resource addition included an expected 2,100 megawatts of solar generation nameplate capacity with on-site batteries. In addition, there were some conditions where the increased demand resulted in a conventional geothermal power plant being part of the least-cost resource addition for this scenario.

Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity

What the Northwest Power Act Requires of the Council Regarding Bonneville's Resource Acquisition

The Northwest Power Act directs the Council to "set forth a general scheme for implementing conservation measures and developing resources [...] to reduce or meet the Administrator's obligations." The Council also is required to prepare a demand forecast of at least 20 years and "a forecast of power resources estimated by the Council to be required to meet the Administrator's obligations." Further, the Council is required to include, to the extent practicable, an estimate of the types of resources from which such power should be acquired.

To accomplish these requirements, the Council forecasts both demand for electricity from the Bonneville Power Administration and the electricity currently produced by the Federal Columbia River Power System, which is marketed by Bonneville. Further, the Council is required to make a recommendation to the Bonneville administrator on the amount of power needed to meet or reduce the agency's obligation and what types of resources that power should be acquired from. Our recommendation is included in *Section 8 Recommendation for the Amount of Power and Resources Bonneville Should Acquire to Meet or Reduce the Administrator's Obligation*.

Forecast of Demand for Electricity from the Bonneville Power Administration

The Council estimates[69] that the proportion of the regional demand for electricity that Bonneville is obligated to supply[70] with the federal power resources starts at just under 37 percent in the first year of the 20-year power plan forecast period and falls to just above 32 percent by the end. Through 2028, this estimate is based on the current Bonneville Regional Dialogue contracts[71]. After 2028 the Council assumes the contracts will be substantially similar, but in our scenario analysis we test the implications of both adding to and subtracting from Bonneville's obligation. That is, in our analysis we anticipate that Bonneville and its customers will sign new contracts, but we also acknowledge there is uncertainty about any contracts that may follow the current Regional Dialogue.

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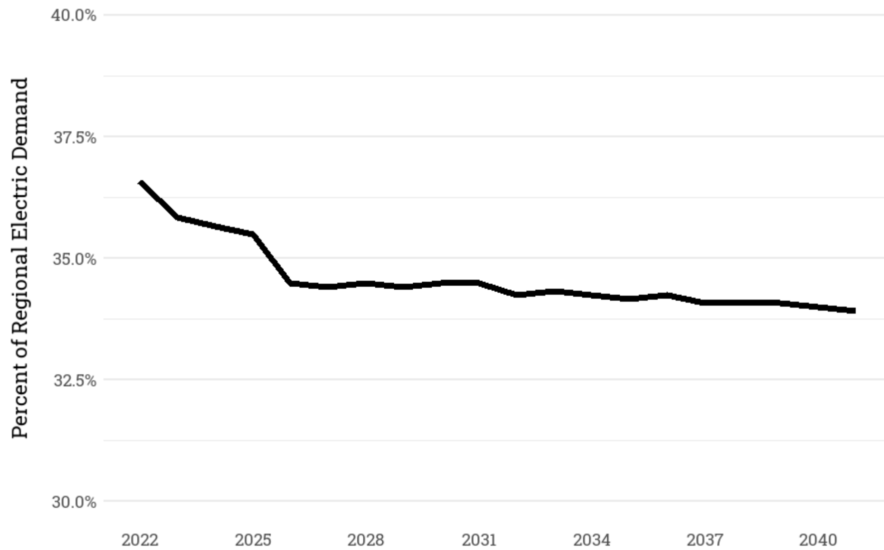
[69] The Council greatly appreciates Bonneville supplying data and supporting our analysis, which enabled the estimates included in this section. However, these estimates do not correspond to any publicly released forecast from Bonneville, nor are they intended to represent the forecasts Bonneville uses for its various functions and purposes.

[70] While Bonneville has broad obligations under the Northwest Power Act, we use "obligation" to refer to the amount of electricity that will be requested from Bonneville by entities that have a statutory right to have Bonneville supply electricity to them.

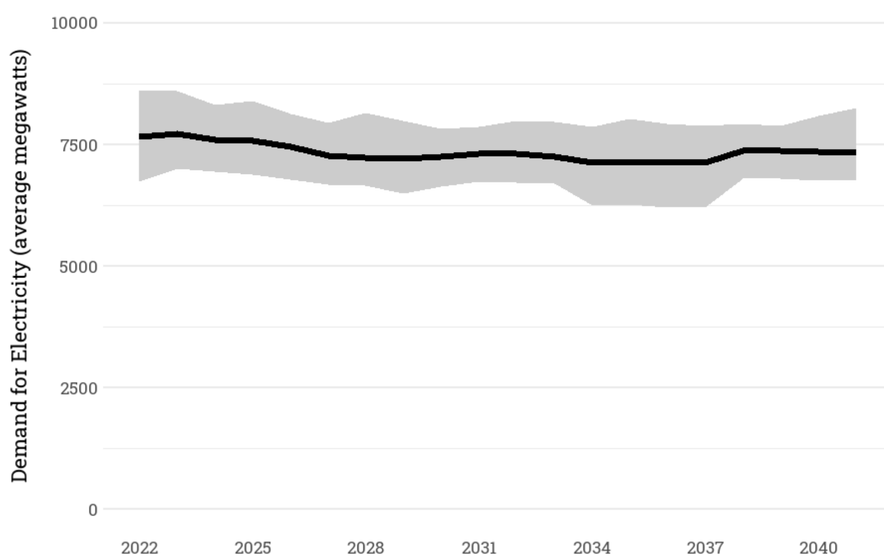
[71] https://www.bpa.gov/p/Power-Contracts/Regional-Dialogue/Pages/Regional-Dialogue.aspx

Estimated Bonneville Obligation as a Percentage of Annual Regional Electric Demand



This graphic shows that Bonneville's obligation decreases as a proportion of the total regional demand for electricity through 2026. After 2026, Bonneville's obligation increases slightly.

Forecast Electric Demand Bonneville is Obligated to Supply



The Council's forecast includes estimates of climate-change impacts. However, Bonneville is less impacted by temperature than is the region. To incorporate the impacts of temperature, we partitioned Bonneville's obligation into three categories: contract obligations, subscription obligations, and temperature-sensitive obligations.

Contract obligations are fixed amounts of electricity that Bonneville is obligated to deliver. These amounts do not increase or decrease based on temperatures in the region.

Subscription obligations are driven by the amount of power the federal resources generate. Temperature does not impact the total amount of power Bonneville is obligated to deliver in this category, but it may impact the timing of when that power is delivered.

Temperature-sensitive obligations are deliveries that respond to weather extremes and generally are less than half of Bonneville's obligation, but that changes between different quarters of the year and also between forecast years.

Percentage of Bonneville's Obligation Categorized as Temperature-Sensitive

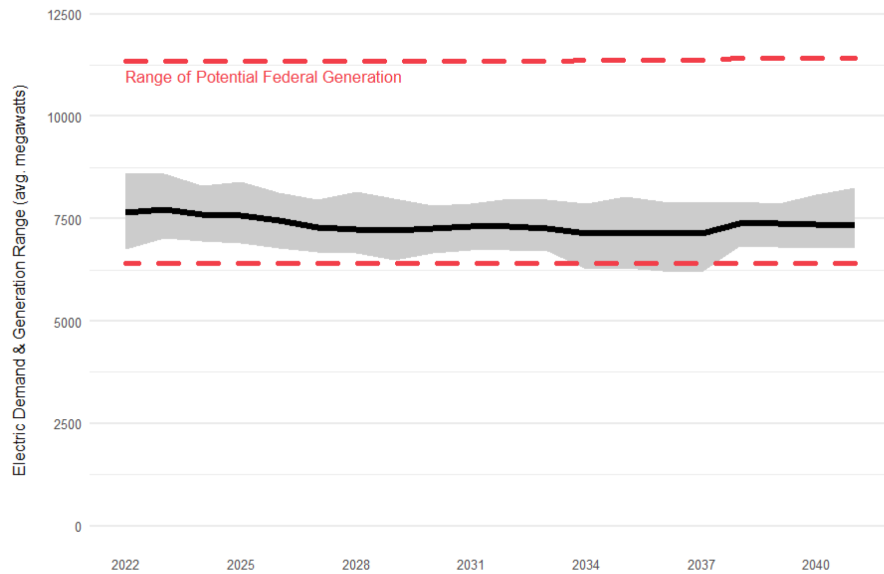
	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4[72]	43.2%	42.5%	43.0%	42.8%
Q1	41.8%	41.5%	42.2%	41.9%
Q2	46.4%	45.9%	47.4%	47.7%
Q3	45.3%	45.1%	46.2%	46.6%

Forecast of Electricity Produced by Federal Resources and Marketed by Bonneville

The Council estimates that generation from the Federal Columbia River Power System generally varies from a minimum of just over 6,400 average megawatts to a maximum of over 11,000 average megawatts. This range is mostly a function of the change in hydroelectric generation from year to year. In a year with plentiful water from regional rain and snowpack, the amount of generation from the system far exceeds Bonneville's obligations. In these situations, the excess electricity would either be sold, scheduled[73] in the secondary markets, or spilled at the federal dams without generating electricity.

[72] The Bonneville and Council fiscal year is October 1 to September 30. The quarters indicated are the calendar year quarters. Thus, Q4 is the first quarter of the fiscal year and contains the months of October, November, and December. The first month of the 2023 fiscal year is October 2022.
[73] There are some times when the generation from the federal system is not sold in the secondary market but is still scheduled to be exported. See Bonneville's Oversupply Management Protocol, https://www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx.

Electricity Produced by Federal Resources Compared to Electric Demand



Estimated Bonneville Need for Electricity

While it is clear that under many circumstances Bonneville has surplus electricity relative to its obligation, there are some infrequent circumstances where the electricity produced by the federal system is less than the amount of power Bonneville is obligated to supply. For this analysis, the Council worked with Bonneville staff to adapt the approach taken in the Bonneville Needs Assessment.[74] This approach uses a "critical" energy amount[75] from the federal hydroelectric system to establish a risk preference on the amount of energy from that system set aside to meet the Bonneville obligation. This is added to the non-hydro-based resources in the federal system, and contracts and transmission losses are subtracted to determine the federal system's capability to supply electricity under "critical" circumstances. Bonneville, in coordination with the Council, ran simulations using models tuned to estimate the federal system output. These simulations were adapted to the methods the Council uses in its regional modeling. Four years were run through the simulation, as detailed in the table below.

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[74] The Bonneville Needs Assessment is included in the BPA Pacific Northwest Loads and Resources Study, commonly referenced as the "White Book". https://www.bpa.gov/p/Generation/White-Book/Pages/White-Book.aspx.

[75] In this case, "critical" is defined by looking over the range of simulated generation when using regulated flows defined by the climate-change-based precipitation estimates for each of 14 periods, corresponding to the calendar months except April and August are split at the end of the 15th day to form two periods each. In each of these periods, we take an amount of generation that only one out of every 30 simulations would be below (or the 3.33 percentile of the simulated generation for each period).

Expected Federal System Generation under Critical Circumstances in Average Megawatts

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	7157	7107	6995	7233
Q1	7000	6991	6845	7348
Q2	6007	6037	5843	5521
Q3	7086	7205	7091	6222

The Council's estimate of Bonneville's need for electricity is based on the difference between the Council's forecast of the electricity demand Bonneville is obligated to serve and the expected federal system generation under critical-energy circumstances. The analysis assumes limited market purchases to meet load variation in a particular quarter or season. This results in an estimated margin between critical-energy generation and electricity demand.

For example, in the first quarter of the 2023 fiscal year (October to December of 2022), the Council estimates Bonneville would have sufficient electricity as long as the federal generation under critical circumstances (estimated at 7,157 average megawatts) can meet 88.5 percent or more of Bonneville's need for electricity.

Margin of Critical Resource to Electric Demand

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	88.5%	88.8%	93.7%	98.0%
Q1	81.6%	83.3%	86.6%	94.0%
Q2	86.6%	88.3%	89.8%	84.1%
Q3	94.6%	96.8%	98.8%	86.6%

When the available federal generation is less than the estimated margin, we project Bonneville would need electricity.

Using this approach, the Council forecasts Bonneville will have a minimal need for electricity. The average expected need is under 7 average megawatts for the first decade of the forecast and under 28 average megawatts for the second decade[76]. However, those expected loads reflect a range of simulations. Within this range, there are some circumstances where the need could be larger than 60 average megawatts in the first decade and almost 145 average megawatts in the second decade. Seasonally these needs are more likely to occur in the summer, with the upper end of the range of forecast being around 300 average megawatts.

[76] Assuming Bonneville customer utilities sign substantially similar contracts

Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation

Resource Recommendations

Energy Efficiency

Public power has played an important role in the Northwest energy efficiency achievements over the last 40 years. Since 2008, Bonneville utility customers have acquired roughly 36 percent of the region's energy efficiency savings. Looking forward, the Council estimates that 36 percent of the remaining available energy efficiency is within the Bonneville utility customer service territories. It is clear that Bonneville's energy efficiency program will continue to be an important piece of our regional power system infrastructure.

To support both Bonneville's and the regional power system's needs, the Council recommends that Bonneville acquire between 270 and 360 average megawatts of cost-effective energy efficiency by the end of 2027 and at least 865 average megawatts by the end of 2041. Aligning with the Council's analysis of remaining potential and historical achievements, this level represents 36 percent of the overall regional target.[77] Within the first six years, the Council recommends that Bonneville plan to acquire a minimum of 243 average megawatts of cost-effective efficiency from programmatic savings. This includes savings currently funded through Bonneville's program, whether via the Energy Efficiency Incentive or self-fund utility contributions, as well as the Northwest Energy Efficiency Alliance (NEEA) market transformation initiatives. The remaining efficiency may come through additional programmatic activity, market change, or codes and standards. Bonneville should use the Council's methodology for cost-effectiveness to identify efficiency opportunities at levels that are cost-effective for the region. This target recognizes the value that Bonneville can provide the region to ensure a reliable power system and achieve decarbonization goals. Additionally, it can mitigate some of the risk associated with potential changes in obligations post-2028 when the current contracts expire.

The Council understands that although Bonneville produces an annual budget, it forecasts its revenues and expenditures on a biennial basis as part of its rate setting process. For the first two years of the 2021 Power Plan, the Council assumes that Bonneville has budgeted appropriately for the agency to successfully achieve the energy efficiency target in this plan. For the remaining years

[77] The determination of 36 percent as the Bonneville portion of the regional target represents the portion of cost-effective energy efficiency potential located within the Bonneville customer utilities territory.

of the 2021 Plan, Bonneville should work with the Council to ensure that a budget is established to successfully meet the Plan's energy efficiency targets.

If evaluation of the energy efficiency achievements through the Council's annual Regional Conservation Progress report indicates that Bonneville's achievements fall short of the Council's recommendation, Bonneville and the Council should work cooperatively to understand and address the underlying cause of this shortfall. The Council will continue to work with Bonneville, the NEEA, and the regional utility community to ensure the Regional Conservation Progress report that the Council was directed by Congress to produce annually accurately reflects the regional energy efficiency achievement.

The Council's recommendation for acquiring energy efficiency does not distinguish between energy efficiency funded through money collected by Bonneville and energy efficiency funded directly by customer utilities. Nor should the Council's recommendation be seen as a recommendation for maintaining or changing the structure of how energy efficiency is funded between Bonneville and its customer utilities. Further, this recommendation is not intended to be proportional to the customer utilities, based on load or potential or any other manner. Our intent is that this recommendation assists individual utilities in determining for their service territory how they can best structure their programs to acquire energy efficiency; our recommendation is not prescriptive on how individual utilities should run their energy efficiency programs.

The Council recognizes that there are diverse challenges to acquiring energy efficiency across Bonneville's customer utilities. Achieving the efficiency targets will require that Bonneville work to meet each of those utility challenges within the cost-effectiveness considerations. Many of the public utilities with a rural—and primarily residential and agricultural—customer base have fewer energy efficiency opportunities. Additionally, these utilities may lack resources—such as staff, contractors, retailers—and thus have significant challenges implementing cost-effective efficiency programs. To meet its programmatic efficiency goals, Bonneville must work with these utilities and provide territory-wide programmatic opportunities to enhance the infrastructure for the small and rural utilities. Continued funding of NEEA initiatives will also provide necessary support for training and other infrastructure to address implementation barriers across its customer utility footprint.

To help ensure the necessary levels of cost-effective conservation are acquired, the Council recommends that Bonneville contribute to all aspects of the regional conservation program, as described in *Section 5: Energy Conservation Program*. This includes continued funding and support in the following areas at levels commensurate with 2020 levels or greater: NEEA; research including regional market research, stock assessments, evaluation, and related analysis; and codes and standards development.

The Council's conservation program also identifies two key opportunities to ensure equitable distribution of energy efficiency. The Council recommends Bonneville continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. We recognize that these measures, while historically cost-effective, may not be cost-effective under our current paradigm. Nevertheless, the Council believes they are critical to provide livable homes for all people. Bonneville and its customers should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes. Additionally, the Council recommends Bonneville work with its utilities with large commercial loads to utilize energy-use intensity data to identify those buildings with significantly higher consumption than comparable buildings. The Council believes leveraging this data will provide a way to identify those commercial consumers in the greatest need of efficiency measures that were previously missed by programs.

Demand Response

In *Section 6: Resource Development Plan,* the Council recommends that utilities pursue demand response that can be frequently deployed and obtained at a low cost. We identified that Demand Voltage Regulation (DVR) and Time-of-Use (TOU) rates can help substantially in ramping and peak periods. Additional value may also be obtained to relieve transmission constraints and defer transmission and distribution system upgrades.

Bonneville should work to enable and encourage its customer utilities to pursue these and other low-cost and high-value demand response measures in an equitable manner.

Market Purchases

The Council anticipates that regional wholesale electricity prices will have substantial downward pressure from expanded renewable generation additions throughout the West. We recommend that Bonneville, when it has needs beyond the recommended energy efficiency and demand response resources, look to mid-term and long-term market resources for additional energy.

When Bonneville has needs for electricity in specific locations where the ability to deliver power from the federal system is limited, the Council still anticipates the mid-term and long-term market resources will likely be the low-cost resource alternatives.

Renewable Resources

Costs for renewable resources have substantially fallen. While the Council recommends purchasing market resources to meet Bonneville's needs for additional energy, we recognize that there may be situations where a more general market resource may be more expensive that a direct power purchase agreement, or similar arrangement, tied to a specific renewable resource. The Council recommends that Bonneville compare power purchased in this manner to alternative market products, both in price and capability, to ensure that the lowest-cost product that suffices to meet any need identified is purchased on behalf of the region's electricity consumers.

Supporting Recommendations

Regional Hydro Generation System

The Council's analysis shows a rapidly shifting market dynamic in the Western electricity grid. The impacts, both challenges and opportunities, need to be better understood and explored by all regional entities that have a role in operating the hydro system.

The Council recommends Bonneville play a central role in these future efforts. Bonneville can do this by both incorporating these impacts into its analyses and supporting broader regional efforts, at the Council and other organizations, to study and understand these impacts.

Future Contracts

The Council's recommendations to the administrator on what power to acquire depend on the obligation placed on Bonneville. Current contracts allow customer utilities to reduce or abandon service from Bonneville at the end of the contract. Currently all contracts end at the same time, leaving an acute risk that could be aggravated by the Council's recommendations. Our analysis shows the lowest-cost strategy for the Bonneville portfolio changes within the action plan period based on whether or not regional utilities contract for power from Bonneville in the future.

Further, Bonneville's resource decisions may be limited based on this risk. When all the contracts expire at the same time, decisions made close to the end of the contract period are less likely to favor long-term commitments. This could disadvantage lower-cost but longer duration power acquisition.

Bonneville should consider in its next contract negotiations how to mitigate the financial risk of acquiring power that may be least-cost but longer duration. Further, it should explore how a wide range of potential future Council recommendations on resource acquisition could be contractually accommodated without substantial risk of shifting costs among regional consumers of electricity at the end of contract periods.

Additionally, in the current contracts, many Bonneville customer utilities see little value in pursuing demand response and are limited in the ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. In future contracts, Bonneville should consider provisions supporting its customer utilities' development and export of demand response resources.

Section 9: Cost Effective Methodology for Providing Reserves

Reserves in the Act

The Power Act indicates the Power Plan should include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost. Additionally, the Power Act explicitly recognizes that reserves can come either from generating resources or non-generation alternatives, including conservation measures and contract rights to curtail or interrupt power supplied to customers.

Reserves on the power system are held to account for the uncertainty about the expected amount of electricity demand and power generation. The wholesale power market can help address a significant amount of uncertainty in generation and load, however most often individual utilities or collections of utilities take actions like holding back some existing resources from the market or adding additional generating resources or non-generation alternatives to address these uncertainties from a second to second, hour to hour and year to year basis.

Types of Reserves

The growth of electricity demand due to changes in the economy or amount of water available for hydro generation in a year based on precipitation are forecasted, but due to the uncertainty of those forecasts, reserve power generation capability is held on a planning basis. These types of reserves are often called planning reserves.

Uncertainty in the forecasted speed and direction of the wind hitting turbines or the forecast of households who will have their lights on or air conditioning running at any certain time are examples of shorter term uncertainties that may cause an imbalance between power scheduled to be delivered to demand. Additional power system capability to meet these schedule imbalances are often referred to as balancing reserves[78].

While having less fuel uncertainty than solar, wind or hydropower, coal or gas plant generators have the possibility that some aspect of the controlled combustion that creates the power in those plants will go wrong and the entire plant will shut down unexpectedly. Additional power system capability to address these unexpected plant outages are often called contingency reserves[79].

Since planning for future resources strategies in the power system must explicitly account for these uncertainties, the discussion of the methodology for including reserves in the analytical framework of

[78] Used maximum of the regional sum of balancing reserves in any hour in the Northwest Power Pool Energy Imbalance Market work as planning assumption for the region.
[79] Northwest Power Pool reserve sharing group for contingency reserves

the resource strategy started with a description of the types of reserves considered: planning, balancing and contingency reserves. Balancing reserves are held by generating resources that are positioned to ensure that if any errors are made in forecasting load and generation on an hour-to-hour basis that there is enough of a buffer within the region to make sure generation matches load at all times by increasing or decreasing the amount of electricity being generated. Contingency reserves are held back to make sure if contingencies like large unexpected forced outages on generators happen that there are enough reserves to make sure generation always matches load by increasing electricity generation to replace electricity that becomes unavailable[80]. These operational reserves are part of what makes up planning reserves. The rest of planning reserves account for year-to-year variation in generation and load, such as planning to be able to keep the lights on even during low hydro conditions. All these reserves are incorporated into the calculation of additional resource requirements to maintain the Council's adequacy standard[81] throughout the planning period.

Operating Reserves

Type	Amount Held
Balancing Up	2,900 megawatts
Balancing Down	3,345 megawatts
Contingency Reserves	3% of load and 3% of generation

Providing Reserves Using New and Existing Resources

Traditionally, additional reserve requirements have more directly translated into needs for additional generating resources, energy efficiency or demand response, but the current analysis indicates that the operations of the existing regional generators may play a larger role. In the past, in our region, coal and natural gas generators have complemented the regional hydro generation by providing a significant amount of system flexibility. Since the wholesale market electricity price was set by coal or gas generation near times of scarcity, the expectation that those plants would operate if available was a decent assumption.

More Conservative Operation of Existing System to Provide Reserves

In the current and predicted future power system, significant amounts of solar generation throughout the western grid contributes to very low prices for power midday. These low midday prices can be

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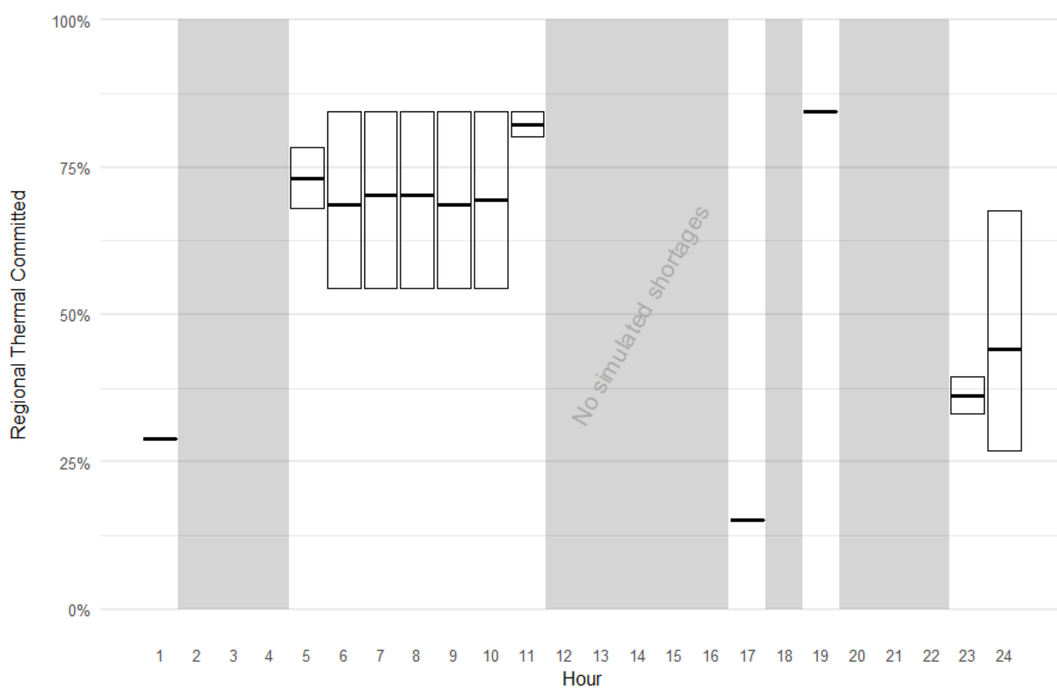
[80] Increases in load require increases in generation, called *balancing up reserves* often referenced in the electric industry as *INCs*. Conversely, decreases in load require decreases in generation, called *balancing down reserves* often referenced as *DECs.*

[81] 5% Loss of Load Probability

low enough that coal and gas plants can appear uneconomic to run during the day and plan to shut down to lower overall system cost. However, during the periods around when the sun goes up and down, and when demand for power ramps up in the morning and down at night there is now significant uncertainty about available generation to go along with the uncertainty associated with electricity demand and that uncertainty introduces some operational challenges. For example, much of the regional fleet of coal and gas generation need a few hours to ramp up to or ramp down from full generation, and the fueling of the larger gas plants requires significant notice ahead of time to order the fuel. Depending on overnight pricing of wholesale power this could mean that some of these plants might not be seeing an economic signal[82] to stay online or start up with enough time to respond to a potential shortage during those early morning or evening hours where there is significant uncertainty about the amount of electricity demand and generation available. These types of operational issues appear to be accounting for almost all the simulated system shortages in the analysis. These issues are due to not a shortage of resources, but in having enough information to operate the existing system economically but adequately.

Maximum Available Thermal Generation During Simulated Shortages[83]



[82] In general, most power plants generate when the cost of producing power is below the price they can receive on the wholesale market for selling power.
[83] This graph shows the maximum and average percentage of total thermal generation online during the shortfalls in winter by hour of the day.

One way to mitigate some of these challenges is to create a signal, in the form of additional reserves, to operate more of these plants to maintain adequacy. This effectively utilizes the existing generators in a way that results in higher overall system cost but less risk of being short generation at a critical time. Plan analysis showed that holding additional reserves overnight does seem to address most of the issues at a slightly higher cost merely by operating the existing system[84] more conservatively.

Additional Resources as a Reserve

Another way to address this issue is to add additional power generation, demand response or energy efficiency. Since the reserves are accounted for implicitly in the resource strategy analysis[85], this approach is considered to some extent along with all the other reasons to make further investments in the regional power system. Generation resources with uncertain fuel like wind and solar tend to cause the need for more reserves without significant diversity. Generating resources like combined cycle gas plants have some of the same operational challenges as the existing fleet. Demand response, batteries and pumped storage all can contribute to a solution, but without an explicit reserve signal often are positioned imperfectly to address adequacy issues. Energy efficiency is the most effective resource at creating more reserve capability in the region, however it is more expensive than in the past.

Additional Market Reliance

The wholesale electricity market is a valuable tool to take advantage of the diversity of the pool of resources in the western power grid. Currently, the region has chosen to plan to only rely on resources outside the region on a limited basis (2,500 megawatts per hour in the winter and fall and 1,250 megawatts per hour in the spring and summer). Since the Northwest utilities have a limited say in the governance and planning in other region in the west and due to recent historical events[86], there has been reluctance on a planning basis to rely to more heavily on other regions generation as a hedge against regional uncertainty despite the cost advantages.

Cost Effective Reserves as Part of the Resource Strategy

Similar operational issues as seen in the analysis have occurred in California power system operations for the last ten years or so, and the market operator in California[87] has multiple strategies[88] to address this issue, of which at least one is a more conservative operation of the existing system power generators incentivized by paying extra money to plants with flexibility to stay

[84] The existing system providing more reserves is referring mostly to regional hydro, coal and gas generation operated more conservatively
[85] See Section 6: Resource Development Plan for more details on how these investment decisions are approached.
[86] 2001 Western Power Crisis
[87] California Independent System Operator
[88] Market mechanisms to hold more reserves and procure more resources.

online. The Pacific Northwest region currently has no such market operator[89] and leveraging off regional collaborations[90] such as the Northwest Power Pool Resource Adequacy effort to try to achieve a similar mitigation strategy to these operational challenges as California may be advantageous. Additionally, a slightly more expensive, but effective alternative to this would be to invest in further resources like energy efficiency than what was identified within the resource strategy analysis. Also, a riskier but less expensive mitigation method that could be effective would be to rely more on the market outside the region.

The few major takeaways from the analysis are as follows:

1. The least cost option to maintain an adequate, cost-effective regional system is to couple the investment recommendations (per the listed amounts of renewable generation, energy efficiency and demand response) in the resource development plan with some sort of reserve pooling effort via an organized market or regional collaboration that ensure that sufficient reserves[91] can be held to mitigate the increasing uncertainty brought about by the increased investment in renewable generation. Part of the reason this method is recommended as the most cost-effective is that the amount of the reserves necessary to maintain an adequate system could be changed to match needs over time.
2. Another more expensive, but effective, alternative is to invest in further energy efficiency than identified in the resource strategy analysis. This will increase the fixed cost investments required by the region but may be necessary to maintain adequacy should the regional coordination to provide additional reserves prove unsuccessful.
3. Another less expensive, but riskier alternative is to plan on more external to the region generation to support the region in times of need. Other regions have varying policies, requirements and northwest regional stakeholders have less say in their planning processes. Without a more formalized collaborative process like an organized market, this strategy, while taking advantage of the diversity of a large pool of existing resources, would likely expose the region to significantly more risk

[89] Other than the limited volume of market trades that are governed within the Western Energy Imbalance market structure

[90] Other options include leveraging off the current Western Energy Imbalance Market structure and/or further coordinating throughout the west for the day-ahead market via the Enhanced Day-Ahead Market.

[91] Analysis showed that over 3,000 megawatts of additional reserves may be required by 2023 to sufficiently incentivize enough generation to be online and have order enough fuel to meet the morning and evening ramps.

Section 10: Recommendations for Research and Development

The Northwest Power Act directs the Council to include within the plan a "recommendation for research and development." Given the vastly different and rapidly evolving power system, it is important that the Council reflect not only on what we know today, but on what we need to continue to understand to ensure we meet the needs of all the region's consumers. To that end, the Council recommends additional research and development in four key areas:

1. Research to support effective implementation of the conservation program
2. Exploration into alternative approaches to power system operation
3. Research of emerging technologies to support development of future resource options
4. Development of data and tools to enhance future power planning analysis

These recommendations are for entities across the region, with the Council at times providing a supporting role.

Implementing the Conservation Program

The Council is recommending 2,400 average megawatts of energy efficiency be acquired by 2041. Energy efficiency is a slow-build resource. Achieving this goal requires ongoing research to ensure that it is available, reliable, and acquired at the lowest cost. It requires steady investment to identify opportunities, design programs to deliver efficiency to consumers, evaluate effectiveness, and then refine and repeat. Therefore, the Council recommends that the region continue to invest in research in the areas of evaluation, market research, regional stock assessments, and end-use load research. In addition to supporting the *Section 5 Energy Conservation Program*, we believe this research provides important insights for identifying demand response opportunities and ensuring effective delivery of those products. The Council recommends the region consider these wider benefits when determining appropriate investment levels for research.

Evaluation

Evaluation is a critical component of understanding the impacts of energy efficiency measures and demand response products. It conveys whether the planned savings were realized, and it can provide insights on how to improve program effectiveness. Many of the region's efficiency programs—including the Bonneville Power Administration's on behalf of its customer utilities—have robust evaluation efforts. The Council recommends continued investment in energy efficiency evaluation, at levels commensurate with today's investment. This research should include collecting all measure information required to support cost-effective and equitable application of ratepayer funds. Additionally, we recommend that efficiency programs develop evaluations in accordance with the Regional Technical Forum's guidelines, which support consistent and reliable determination of energy efficiency across all measure types.

Market Research

Market research provides thoughtful insights to characterize the prevalence of efficient products available in the market, the availability of contractors and other experts needed to install efficient products (including those with controls that could be used in demand response programs), and where the largest gaps in efficiency adoption exist. Over the past several years, the region has increased its investment in market research, providing the information needed to refine and focus efficiency programs on the most promising opportunities. NEEA plays a critical role in market research, as it can leverage its market expertise and take advantage of the economies of scale that come with being a regional entity. Bonneville, the Energy Trust of Oregon, and the region's utility programs also have an important role, particularly as it comes to gathering insights to address specific local questions or needs. The Council recommends that NEEA, Bonneville, and the region's efficiency programs continue to invest in market research.

Regional Stock Assessments

Through NEEA, regional stock assessments have been conducted that provide snapshots of the existing building stock. This includes information on numbers of buildings, size, use, types of equipment installed, availability of products with controls, and more. Stock assessments are an important complement to market research, as they provide another lens for identifying efficiency opportunities and tracking regional progress. The Council recommends that the region's utilities, through NEEA, continue to invest in regular stock assessments for the residential and commercial sectors. Ideally, these would be completed at least once every five years. As part of this effort, NEEA should explore new data techniques for providing more timely information about fast-evolving changes in the stock.

Additionally, for commercial buildings, the Council recommends that NEEA, with support of Bonneville, Energy Trust of Oregon, and regional utilities, develop a reliable commercial building energy use intensity dataset. The starting point should be the commercial building stock assessment and other publicly available data sources. This dataset will enable efficiency programs to identify those buildings that provide the greatest opportunity for significant investment.

The Council also recommends the region's utilities invest in another stock assessment for the industrial sector (including water and wastewater), with particular focus on motors and motor-driven systems. To the extent practical, data gathered on motor and motor-driven systems should also include the agricultural sector, as the region has a long-standing gap of information on this sector. For this work, we recommend that the region build on existing utility data and leverage efficiency program experts knowledgeable with these facilities as a starting point for this assessment.

End Use Load Research

Understanding the timing of energy use, as well as the timing of energy savings, is critical for identifying those measures that provide more value for the power system. Today, the region continues to rely heavily on the results from the End-Use Load and Consumer Assessment Program (ELCAP), which was conducted in the late 1980s to characterize the timing of energy use. Recently, through coordination at NEEA, the region has undertaken a new effort to meter and characterize energy use in residential and commercial buildings. The findings from this research shine light on how we use energy today and provide insights on how new technologies might shift and reduce the timing of energy use. With the recent Covid-19 pandemic changing how people live and work, this research will answer questions around how energy use has shifted and whether any of those shifts will continue as the “new normal”. The Council recommends the region continue to fully fund this research and ensure that the knowledge gained is shared broadly for effective investment in all demand-side opportunities. Additionally, the Council recommends that the Regional Technical Forum use this data to create load shapes for efficiency measures that can be leveraged by the region’s utilities to understand the timing of energy efficiency savings.

Exploring Alternative Approaches to Power System Operation

The rapidly decreasing cost of renewable resources, coupled with various state and utility clean policies and emissions goals, are driving large renewable builds across the west. The result: a very different power system. The system requires flexibility, with resource options that can fill in those valleys when renewable energy is not available and support ramping needs when the sun goes down and the lights come on. Our modeling suggests that we need to rethink power system operations to ensure not only an adequate, efficient, economical, and reliable power supply, but one that continues to protect, mitigate, and enhance the important fish and wildlife in the region. To that end, the Council recommends the region undertake the following explorations aimed at broadening our thinking of power system operation.

Renewable Generation Impacts on Regional Hydropower Operations

The substantial increases in renewable generation across the West shifts power system generation and transforms power markets. The oversupply of renewable generation during the day rapidly shifts to a need for other resources during the evening when the sun is down. Since hydropower has a low variable cost and is flexible, our analysis shows that it is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region. However, it is unclear how these daily river flow fluctuations will affect environmental conditions for fish in the river, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat. The Council’s 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on the system operators to minimize or reduce daily flow fluctuations, and yet the analysis suggests a need for increasing fluctuations for adequacy. The Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together Bonneville, system operators, the federal and state fish and wildlife agencies, and the region’s tribes. The goal will be to explore the possible benefits and consequences of different hydropower system operations to identify a path forward that provides greater benefit to both power and fish.

Alternative Approaches to Support Renewable Integration

Our analysis suggests other approaches might provide low-cost solutions to support integrating renewables into the existing system. One example is the role of holding reserves. Plan analysis shows that more regional collaboration on holding reserves can provide a lower cost approach to system adequacy. When a utility holds more reserves, it has more of its existing generation ready if needed to address unexpected loads. Alternatively, with lower reserve amounts, the market prices diluted by the influx of renewables might not provide a sufficient signal to ensure those existing resources are otherwise available if needed. To better understand the tradeoffs around holding more or less reserves, the Council recommends that the region's utilities, regulators, and Bonneville conduct a study to explore how market liquidity by season and time of day can create price barriers for flexible resources, and the cost of mitigating those barriers through greater reserves. This analysis should take into account different hydro conditions.

Another approach to supporting adequacy is demand response. As described above, balancing this system requires that resources are available to quickly meet loads as they come onto the system and can be curtailed as those loads go away. Demand response is a resource that can shift loads away from those high peaks to other times of the day when loads are otherwise low. The Council recommends that Bonneville and utilities research opportunities to use demand response to support system balancing. This effort should provide insight on how to improve modeling of these opportunities for future regional and utility power planning efforts.

Transmission and Non-Wires Alternatives

With a potential significant deployment of cheap, new resources vying for access to the transmission system and competing with established, oftentimes more expensive resources for dispatch to the grid, it is time for the region to reconsider how we contract, reserve, and schedule transmission access. It is common for a given transmission path to be fully contractually encumbered on a long-term firm basis while still having substantial available physical capacity most or all hours of the year. New resources may face transmission access queues up to several years, creating a barrier to, or slowing, development. While any unused transmission capacity must be marketed for short-term utilization, this can have limited value to project developers who require deliverability guarantees in order to receive financing. The Council recommends that the region's transmission providers work with utilities, load serving entities, NorthernGrid, and others to develop a comprehensive review of the existing state of the transmission system, research potential short-term and long-term solutions to alleviate new resource development barriers while balancing existing long-term contracts and compensation to transmission providers, and explore the potential benefits of implementing a regional transmission operator in the Pacific Northwest.

Additionally, the region should continue to explore non-wires alternatives to address transmission and distribution constraints. Battery storage and targeted demand response, for example, can provide significant value to deferring the need for adding transmission. The Council recommends that the region consider the role of battery storage, targeted demand response, and other demand-side resources to address existing transmission capacity challenges. This research should speak to the role of these resources in alleviating some of the new resource development described above. Additionally, the Council recommends that the utilities and Bonneville consider the value of these opportunities on a case-by-case basis to address local needs.

Role of Hydrogen and Fuel Cell Technology

Finally, the 2021 Power Plan is the first to explore the use of hydrogen fuel cell technology as a potential clean energy resource. Hydrogen may be especially promising as a replacement for diesel fuel in heavy duty freight transportation[92] and for some high-heat industrial uses. Currently there is limited demand and production in the region, however this may change in the future with the various clean electricity grid and emission reduction goals.

The Council recommends study of the impacts, benefits, and challenges that large-scale demand and production of hydrogen in the region might have on the power system overall; and in particular, hydro and renewable power. For instance, one hydrogen production method—electrolysis—can be turned on and off; which maybe be useful for balancing load and soaking up excess renewable generation.

Emerging Technology

In developing the recommended resource strategy, the Northwest Power Act requires the Council to give priority to resources that are cost-effective. This includes resources that are “reliable and available within the time [they are] needed, and to meet or reduce the electric power demand […] at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource.” We recognize that while the resource strategy must focus on those resources available today, there are many potential opportunities that might meet future power system needs at lower costs. To this end, the Council recommends that the region continue to invest in researching emerging opportunities.

As states and utilities progress toward clean, non-carbon emitting energy portfolios, there are opportunities for new, emerging supply-side technologies to compete with established renewable resources—such as onshore wind and solar photovoltaic—and that will play a critical role in the future power system. The Council recommends that the national labs, research institutions, trade allies, and utilities continue to work with developers and manufacturers to research and explore the regional resource potential of supply-side emerging technologies such as offshore wind, small modular nuclear, enhanced geothermal systems, energy storage, carbon sequestration technologies, and other carbon-free resources. In addition, the Council urges the region to identify potential barriers to deployment, including costs, transmission, siting, etc., and work together toward solutions when it is in the best interest of the region.

On the demand-side, new innovations in efficient technologies provide paths to lower cost energy efficiency. To ensure that efficiency measures are readily available and reliable, research is needed to understand the efficacy and applicability of potential technologies. The Council recommends that efficacy programs, through NEEA, regional universities, national labs, and others should continue to invest in emerging technology research for efficiency measures. This effort includes scanning for emerging technologies, pilot studies to provide case studies for program opportunities, and field research to verify real-world savings. With less lower cost energy efficiency potential than in prior years, and greater competition with generating resources, this research should also explore opportunities for cost reduction and paths forward that provide the most efficiency benefit at the lowest costs. The Council also recommends the Regional Technical Forum increase the rigor of its

[92] https://www.nwcouncil.org/energy/energy-advisory-committees/demand-forecast-advisory-committee

measure cost analysis to support improved comparison with alternative resources in future resource planning. Further, the Council recommends additional research around demand response opportunities. Our analysis for this plan demonstrates that demand response products that can be frequently deployed at low cost provide significant value to the power system to maintain adequacy and reduce emissions. As utilities and Bonneville explore the value of demand response, the Council recommends that the region continue to develop these “non-traditional” applications that may provide more value than the standard peak-reducing product.

Development in Support of Future Power Planning

The Council recognizes that power planning is an ongoing effort. This power plan reflects our recommendations based on our understanding of the system today, the availability and costs and benefits of new resources, and the existing modeling tools. We recognize, however, that there are enhancements needed to continue to improve our power planning in the future. To that end, the Council recommends development of data and tools in the areas of equity, the valuation of model inputs, and enhanced metrics and tools for improved modeling.

Equity

Through its development of the power plan, and in particular discussions in the System Integration Forum[93] on diversity, equity, and inclusion in the power planning process, the Council identified a gap in equity data that are informative to supporting equitable representation and accountability in regional and utility resource plans. The Council recommends that the region convene a series of workshops to investigate existing equity data—encompassing generation, transmission and distribution, and demand-side resources—, share publicly available data sources, and perform a gap analysis to identify areas where further research and data are needed. The goal of this workshop is to develop a regional framework to improve future power planning analysis, including future Council power plans and regional utility integrated resource plans. The workshop participants will need to identify the appropriate entities to manage these efforts long-term. Regional cooperation and collaboration—broad representation across the region, including many agencies and utility groups—is crucial to the success of this effort. The Council will use its role as convener to assist in launching the first workshop.

Improved Valuation of Model Inputs

Upstream Methane

Despite the focus on renewables, natural gas continues to play an important role in providing energy to the Northwest. Methane, the primary component of natural gas, is an especially potent greenhouse gas, and measures of atmospheric levels have been rising significantly in recent

[93] The System Integration Forum brings together multiple Council advisory committees to explore cross-cutting topics. The Forum on diversity, equity, and inclusion was held on February 19, 2021. https://www.nwcouncil.org/meeting/sif-2021-power-plan-and-dei-february-19-2021

years.[94,95] The 2021 Power Plan is the first to include an estimate of upstream methane emissions from the natural gas system directly in the planning process. For this Power Plan, the Council—leveraging the expertise within the Natural Gas Advisory Committee—developed an estimate for methane release rate of the natural gas consumed in the Northwest, which is drawn from Western Canada and the Western United States. While we are confident in the approach and assumptions for this analysis, we recognize that there are gaps in our understanding.

Assessing the upstream methane emissions related to the extraction, processing, transportation, and storage of natural gas is a complex undertaking. This has emerged as an important topic, spurring a number of studies that use new methods to assess the overall emissions from natural gas activities in the United States. However, the level of methane releases can vary among specific gas basins. To add a further level of complexity, estimates for the same gas basin can vary depending on the methods and tools that were used to develop the estimate.

The Council recommends working with the Northwest Gas Association and other interested regional bodies to design a study and define a course of action with the goal being to more fully quantify the upstream methane emissions related to the natural gas consumed within our region. We also recommend a follow-up study on how best to limit the intended and unintended methane releases related to the natural gas consumed in the region.

Valuation of Resilience and Flexibility

Energy efficiency provides values to the power system not readily captured in today's modeling. Two important attributes are resiliency and flexibility. In these terms, resiliency is focused on home and building resilience. For example, some energy efficiency measures provide the ability to ride-through extended power outages or extreme weather events. Recent events, like the historic wildfires across the West and the Texas freeze, have demonstrated the importance for home and building resilience during extended outages. Energy efficiency can also support flexibility. While energy efficiency itself is not a flexible resource, there are many measures that support load management for grid flexibility, whether through integrated control or reducing the impacts on end-users from other load-management efforts. For both resiliency and flexibility, the Council considered proxy values in the cost-effectiveness valuation to highlight those beneficial measures. The Council recognizes the need to improve this valuation for future efforts. The Council recommends that the Regional Technical Forum investigate methods for quantifying the value of flexibility and resiliency for energy efficiency measures. To ensure symmetrical treatment of energy efficiency with other demand-side and supply-side resources, the Regional Technical Forum should work with other regional experts in development of these values.

Efficacy of Voltage Regulation

[94] https://gml.noaa.gov/ccgg/trends_ch4/

[95] https://research.noaa.gov/article/ArtMID/587/ArticleID/2742/Despite-pandemic-shutdowns-carbon-dioxide-and-methane-surged-in-2020

The Council recommends that Bonneville, the national labs, NEEA, and regional utilities study the impacts of voltage regulation under current conditions and explore how these results might change with future expected loads. Utilities may regulate the voltage along the distribution system as a way of changing total energy demand. Reducing the line voltage will reduce the resistive losses in the system, resulting in energy or peak demand savings. The efficacy of voltage regulation is determined by the amount of resistive load on the system. New technological advances and efficiency gains—for example compressor-based equipment replacing electric resistance technologies—have the potential to change the amount of savings from voltage regulation. Current data for voltage regulation effectiveness are based on older studies that do not represent today's technology mix, nor do they reflect future load sources such as electric vehicles. As the Council and regional utilities base estimates of energy efficiency (conservation voltage regulation or CVR) and demand response (demand voltage regulation or DVR) potential on these studies, updated research will provide more accurate assessments of potential. [96] The analysis for this plan demonstrates the importance of this regulation, particularly DVR as a non-intrusive and regularly available demand response product, for addressing future power system needs.

Valuation of Non-Energy Based Emissions, and Potential Regional Emissions, Sinks, or Offsets

This plan attempts to explore paths toward meeting various economy-wide decarbonization goals. While not in the direct purview of the Council, understanding non-energy sector emissions, and viable paths for reducing emissions, is important for understanding the interaction between the power sector and these other sources. The Council estimated rough targets in the Pathways to Decarbonization scenario to explore the tradeoffs between the power sector and other emissions sources in meeting economy-wide emissions goals, but more data would improve future modeling. The Council recommends that the region—including national labs, universities, and state agencies—analyze emissions sources and sinks that may have implications for future power system planning. This data and analysis should be made available to regional stakeholders to support future analysis.

Improved Modeling

Adequacy Metrics for Power Systems with High Renewable Penetration

The Council, and others in the region, have historically used the annual loss of load probability as a measure of power supply adequacy. The changing power system with more prominent seasonal issues requires that the region rethink its assessment of adequacy. Specifically, the Council believes that a set of more detailed adequacy metrics is warranted. Therefore, the Council recommends that Bonneville and the region's utilities investigate adequacy standards that capture the frequency, duration, and magnitude of potential shortfall events to better understand issues that occur in a system with high renewable generation penetration. Also investigate underlying system conditions

[96] Demand voltage regulation (DVR) is a product that allows utilities to reduce voltage during peak periods of need and increase it for periods of load building as a way of balancing the system. Alternatively, a consistent reduction in voltage throughout the year can serve as a conservation measure, also known as conservation voltage regulation (CVR).

during shortfall events and how adding resources or changing reserves impacts these events. The Council plans to support this effort, with a goal of incorporating improved metrics into future power planning.

Revisit Analytical Approaches to Planning for the Electric System

The models and analytical approaches used by the Council and the regional utilities for power planning reflect standard industry practice. These standard industry practices are based on a historic electric system that is different than our present-day electric grid. Further, we expect the present electric grid is on the cusp of substantial transformation that will diverge further from the electric system these models and approaches were designed to simulate. While the timing and extent of this transformation is unclear, the Council recommends the region, including national labs, universities, and other experts, research how effective the current models are at forecasting or simulating system operation and at projecting the future drivers of the demand for electricity. This research should focus on production-cost models, load-forecasting models, and capacity-expansion models.

Production-cost models, the computer programs most-often used to estimate electricity prices, use the marginal pricing theory from economics, which in the current electric system means electricity prices are largely forecast and formed based on what it costs to operate fossil-fuel-based generation. However, fossil-fuel-fired generation is being rapidly retired and will likely make up a smaller portion of the future electric system. With fewer fossil-fuel power plants in the system there will be fewer power plants ready to respond to market prices and more generators that have minimal or even negative operating costs, such as wind and solar plants. This shift in generation results in prices being more volatile, likely leading to inefficiencies in the market and possibly a breakdown in the economic theory on how electricity market prices are formed. This impacts the accuracy and efficacy of widely used production-cost models. Since forecasting future electricity prices is fundamental to the Council's analysis, we recommend the next generation of production-cost models directly address this challenge.

In load-forecasting models, we have made progress toward incorporating climate change into our analysis, but would also encourage a broader regional conversation on methods that adapt our forecasts to a changing climate. We also see that future demand for electricity depends on the interaction of the electric system with purposes that have historically been served by other forms of energy, such as electric vehicles replacing those previously powered by gasoline. The interaction between the different forms of energy used in our region or in the broader Western electric grid could have wide-ranging impacts on our future power plans. In this plan, we have shown the range of potential future electric loads is extremely large depending on the extent of electrification of transportation and buildings that occurs. We recommend the next generation of load-forecasting models focus on improving estimates of these interactive effects.

Capacity-expansion models generally assume a static demand for electricity is met by adding differing types of generating technologies, while minimizing the capital cost and fixed and variable costs of operating the resulting system. The next generation of capacity-expansion models will likely need to assess trade-offs between different technologies on the demand-side, particularly hydrogen produced by electrolysis, an energy-intensive process. Also, in using models to test capacity expansion, it's important to capture the impacts on the existing system from dynamically adjusting reserves and storage deployment for different generating technologies. Finally, capacity-expansion models are computationally intensive, therefore we recommend that future models focus on those questions that result in a meaningful difference, recognizing that these may be different questions than in the past.

The Council recommends that analysis of the current generation of models should both address these concerns and explore further implications of how transformation of the electric system will impact our ability to appropriately capture future risks and requirements for power planning.

Section 11: Methodology for Determining Quantifiable Environmental Costs and Benefits and Due Consideration for Environmental Quality, Fish and Wildlife, and Compatibility with the Existing Regional Power System

The production, generation, and distribution of electricity impacts the environment, and the associated environmental effects will vary in type and magnitude based on a number of factors, including the resource type and technology, fuel use and extraction processes, the facility size and footprint, and location. Pursuant to the Northwest Power Act, in its power planning, the Council must consider the environmental effects related to the power system and integrate these considerations into its analysis through various statutory vehicles. For example, perhaps reflective of the time in which the Act was drafted when natural resource policymaking shifted to recognize the importance of internalizing environmental externalities, Section 4(e)(3)(C) of the Act requires the Council include as an element of the power plan a "methodology for determining [the] quantifiable environmental cost and benefits" of new generating and conservation resources. Further, Section 4(e)(1) of the Northwest Power Act requires that the Council's regional power plan give "priority to resources which the Council determines to be cost-effective." And, the definition of cost-effective, found in Section 3(4) of the Act, requires that the Council estimate and compare the incremental "system costs" of different generating and conservation resources, with system cost defined as:

> "an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and *such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource."*

Consequently, the methodology for determining environmental costs and benefits not only represents one of the vehicles available to the Council to analyze and integrate environmental effects into its planning, it is also a significant component of the Council's work to estimate and compare the system costs of a particular resource and ultimately determine those resources that are most cost-effective for the region. In addition, Section 4(e)(2) of the Act requires that the Council set forth a general scheme for implementing conservation measures and developing resources with due consideration for, among other things, environmental quality, and the protection, mitigation and enhancement of fish and wildlife. Therefore, this statutory vehicle introduces a broader set of environmental considerations for the Council to deliberate upon as it analyzes new generating and conservation resources, and, importantly, as it assembles those new resources into a regional resource strategy.

The first part of this section describes the Council's methodology for determining environmental costs and benefits for the 2021 Power Plan. Implementation of this methodology is then reflected in the resource strategy discussed in Section 6, with the supporting materials providing additional analysis regarding the resource cost assumptions and analysis (See the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials). The second half of this section describes how the Council, in developing its resource scheme, gave due consideration for environmental quality, compatibility with the existing regional power system, protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and other criteria as set forth in this plan. This last part of the section, describing how the Council gave due consideration to each of these listed factors, captures how the Council grappled with and used these considerations to shape its final resource strategy and planning decisions.

Methodology for Determining Quantifiable Environmental Costs and Benefits

As provided above, Section 4(e)(3)(C) requires the Council develop and include as an element of the power plan "a methodology for determining quantifiable environmental costs and benefits" of new generating and conservation resources. The Act does not prescribe a particular procedure or method that the Council must undertake in developing its methodology; however, the sum of the provisions of the Act addressing the methodology, Section 4(e)(3)(C) and Section 3(4)(B), are specific in that the methodology is to consider costs and benefits to the *environment*, not to any other type or category of costs and benefits, and that those environmental costs and benefits must be *quantifiable* and *directly attributable* to the new resource. These terms, "environmental," "directly attributable" and "quantifiable," are not defined in the Act; therefore, the Council has used a common-sense understanding of the terms, guided by the context in the Act, discussions included in the legislative history, and at times, the Council has exercised its judgment on a reasoned basis in making determinations as to what these terms mean and how they apply for purposes of the methodology.

For the 2021 Power Plan, and consistent with previous plans, the Council has identified four primary components to serve as the base of the methodology: 1.) compliance with existing regulations; 2.) environmental effects beyond regulatory controls, including both residual and unregulated; 3.) compliance with proposed environmental regulations; and, 4.) environmental benefits. Each component is discussed in detail below. However, before discussing each component it should be understood that Section 3(4)(B) of the Act requires a back and forth between the Council and the Bonneville Power Administration's administrator to develop and then apply the methodology that is not workable in practice for development of the power plan. Under the precise language of the Act, as part of the plan, the Council must develop a methodology for determining quantifiable environmental costs and benefits, then on the basis of that methodology, Bonneville's Administrator is to determine such quantifiable environmental costs and benefits directly attributable to each resource, and then the Council is to incorporate the Administrator's determinations into the estimated system cost of each new measure or resource for use in determining the cost-effective resource strategy for the power plan. Following this specific direction does not work, as the Council cannot issue a power plan that includes the cost-effective resource strategy without first estimating and comparing the resource system costs, which necessarily requires consideration of such quantifiable environmental costs and benefits. Therefore, to make these provisions work together, the Council has provided Bonneville (along with others, including various advisory committees) the opportunity to examine and comment on the Council's methodology and the environmental costs and benefits attributed to each resource both prior to and following issuance of the draft plan. Any concerns identified in comments on the draft plan will be considered and addressed in the final plan.

Components of the Methodology

Cost of Compliance with Existing Regulations

The Council's planning assumes that all new (and existing) generating and conservation resources will comply with existing federal, state, tribal, and local environmental regulations. This includes, for example, compliance with environmental regulations governing air and water emissions, siting and licensing, waste disposal, fuel use (extraction and production), and fish and wildlife protection and mitigation requirements. Existing regulations reflect policy decisions already agreed upon regarding the environmental costs and the appropriate level of protections to redress that harm, the costs are directly attributable to the resource, and largely quantifiable as a component of capital installment costs and fixed and operating costs. Thus, the estimated cost of compliance with existing environmental regulations is the primary method the Council has used to quantify environmental costs of generating and conservation resources in past plans, and it is again the primary method for the 2021 Power Plan. While the cost of compliance may seem most obvious for generating resources, the costs of compliance also factor into the total system cost of new conservation measures to the extent there are applicable environmental compliance costs that are quantifiable and directly attributable to the measure. The generating resource reference plant section of the new generating resource supporting materials describe the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information regarding the environmental effects of generating resources and outlining the existing environmental regulations to address those effects. In addition, the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials, describe and assess resource system costs, including costs of compliance. Further, the supporting materials for the methodology also expound on how the Council applies this method using an existing regulation as an example.

Cost of Compliance with Proposed Environmental Regulations

The Council has typically dealt with the cost of compliance with proposed environmental regulations on a case-by-case basis depending on the proposal, the effects the proposal addresses, and the quantitative data available. The Council is again deciding to address and consider costs of compliance with proposed regulations on a case-by-case basis for the 2021 Power Plan. However, at the time of drafting this plan, there were no environmental regulations proposed that set stricter standards than those previously established for new resources. Consequently, there were no costs of compliance with proposed regulations added to any new resource system costs.

Environmental Effects Beyond Regulatory Controls

Existing environmental regulations control or mitigate for some amount of the targeted environmental effects from generating or conservation resources, but existing regulations do not control or mitigate for all environmental effects of resources and these remaining effects represent environmental effects beyond regulatory control—residual as well as unregulated effects. Residual effects refer to those environmental effects predicted to remain after compliance with current regulations. For example, not all discharges from an electric generating facility, whether to the air or water, are controlled or prevented by the limitations and standards established pursuant to the Clean Water Act or the Clean Air Act, nor are all bird kills from wind turbines prevented by current regulations. These effects that remain after regulation are residual effects. In addition to residual effects, there are also unregulated effects, which are environmental effects not yet regulated or not currently under regulation. The social cost of carbon emissions is an example of an associated environmental effect of a resource that is currently beyond regulation.

The Council acknowledges there are environmental effects beyond regulatory control and that these associated effects of various resource choices should be considered in the Council's planning; however, quantifying costs for these effects for inclusion in a resource's system cost is difficult if not impossible due to the persistent lack of adequate data and methods to determine reasonable quantitative costs for these effects. Moreover, while sufficient data is available for a few effects (e.g. the social cost of carbon) data largely remains deficient for the whole of these effects, and to add the determined costs of some effects to some resource costs, but not the costs of all known effects to all resources due to an inability to reasonably quantify could lead to an inappropriately skewed resource cost comparison. Further, when estimating and comparing resource system costs, it is most useful for the Council to consider costs reasonably anticipated or appropriate to be borne by the power system, and considering social or damage costs in the direct costs of a few resources could lead to potentially applying costs to some resources that are extraneous to the power system, resulting in inconsistent resource cost comparisons. Therefore, consistent with previous power plans, for the 2021 Power Plan, the Council is continuing to acknowledge and examine residual and unregulated effects qualitatively in the resource analysis and in development of the resource strategy because it remains infeasible for the Council to develop quantitative cost estimates for these effects, especially in a systematic or consistent way across resources, and then add them to the new resource system costs. The methodology supporting materials provides additional detail regarding the data insufficiency and the hinderance it presents to the Council in estimating the costs of these environmental effects beyond regulation. The Council's qualitative assessment of these effects is described in the generating resource reference plant section of the new generating resource supporting materials, with the environmental effects of generating resources found in the existing systems and policies supporting materials providing additional information.

In addition, as noted above, there are other vehicles for the Council to consider and integrate environmental effects into its power planning, and unregulated environmental damages are considered by the Council through the lens of Section 4(e)(2)—the provision requiring that the Council give due consideration to, among other factors, environmental quality and the protection and mitigation of fish and wildlife. One prime example of this consideration is the continued implementation of "protected areas." Protected areas were first adopted by the Council in 1988 as an element of the Council's fish and wildlife program, and represent river reaches where the Council believes new hydroelectric facilities would have unacceptable risks of loss to fish and wildlife species of concern or their habitat. Thus, their designation, and continued implementation and enforcement, is an explicit expression of the Council's due consideration to the effects of new energy resources on environmental quality and fish and wildlife resources. Further, in this power plan, the Council has included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation, with upstream methane emissions factored into that cost calculation as well. While these environmental effects are not added as a direct cost of the resource via the methodology, these effects are considered and integrated into the Council's planning, and the impact of that consideration is reflected in the Council's resource decisions as detailed in the resource strategy (Section 6).

Quantifiable Environmental Benefits

In addition to quantifiable environmental costs, the Act also requires the methodology address quantifiable environmental benefits of new generating and conservation resources. When considering environmental benefits, a key issue for the Council is whether and how to factor into the system cost of a new resource the benefit of being able to reduce an existing activity that has an environmental cost. The Council acknowledges that the environmental benefit of a resource should be recognized and considered within the resource analysis in some capacity; however, for the methodology the question for the Council is whether these environmental benefits can be quantified and determined to be "directly attributable" to the new resource. For the reasons outlined below, the Council is deciding again to not attempt to include quantified environmental benefits in new resource costs beyond a few historic examples, and instead recognize and emphasize in the resource strategy in other ways the value of certain resource choices in helping to mitigate for other harmful environmental effects.

Except for a few minor exceptions (e.g. the clothes washer example discussed below), the Council has not been able to quantify environmental benefits of new resources because information and data on environmental benefits is not available, sufficient, or well understood, and quantification of the financial aspects of the reduction in environmental harm is often missing or quite speculative in the data that is available. Additionally, it is difficult to determine that a reduction in environmental harm is directly attributable to the new resource or, rather, the environmental benefit is a direct result of the resource, and not simply incidental or indirect. And, as noted above regarding the effects beyond regulatory control, while it may be possible to capture quantified environmental benefits for a few resources, the Council is reluctant to engage in a piecemeal quantification of benefits, which could result in a skewed resource cost comparison.

To use a familiar example, installation of an efficient washing machine saves energy as well as reduces water consumed, which is an environmental benefit. The reduction in water consumed is a direct benefit of the installation of the efficient clothes washer and the Council is able to quantify this direct environmental benefit by utilizing consumer water and wastewater bills as data to support the quantification. The Council is able to do a similar analysis for other water-saving measures, such as dishwashers, showerheads, and aerators However, to walk through another familiar example, installation of a ductless heat pump in the main living area of a house may result in less wood burned. With less wood burned, particulate emissions are reduced, which is a benefit to the environment (air quality) as well as a benefit to human health. However, in this example it is more challenging for the Council to say whether the environmental benefit (reduced particulate emissions) is directly attributable to the installation of the ductless heat pump or a result of a behavior choice and thus incidental to the installation of the measure; and, the environmental benefit is more difficult to reasonably quantify due to a lack of appropriate data and tools for quantification. Therefore, the Council has not added this benefit to the cost of the measure.

Since the Seventh Power Plan, additional information and data for quantifying environmental benefits has been developed, but the additional information does not support or allow for the Council to quantify environmental benefits to a broader degree. Specifically, the U.S. Environmental Protection Agency issued a report in July 2019, *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report,* addressing the public health benefits associated with conservation and renewable resources, and Washington investor-owned utilities (IOUs) issued studies analyzing how to monetize the benefits of reduced wood smoke from the installation of ductless heat pumps. The Washington IOU studies did provide new location-specific information for quantifying the environmental benefits of reduced wood smoke; however, these studies do not resolve the Council's concerns, noted above, in that it remains difficult to say to what extent reductions in particulate emissions are directly attributable to the installation of the efficiency measure, nor does this additional data address lingering concerns regarding piecemeal quantification, leading to a skewed resource cost comparison. To be clear, the Council recognizes that particulate emissions from wood burning are a well-documented health concern, and the installation of a new electrical measure in the right circumstances may lead to reduced emissions. The Council will continue to exercise its discretion on the basis of the data currently available and not apply these benefits to the cost of new conservation resources. Nonetheless, state and local government, regulatory commissions, and utilities are more than justified in continuing to pursue these measures based on the health and societal benefits.

EPA's report recognized energy efficiency and renewable resources reduce emissions. The report quantified near-term benefits of reduced emissions using avoided emissions rates based on 2017 electricity generation, which resulted in dollars per kilowatt values for conservation and renewable resources. EPA advised, however, that the values should not be used to estimate benefits beyond 2022 given the emission rates underpinning the values.[97] Thus, capturing these benefits in new resource system costs for the 2021 Power Plan, would require significant analysis by staff to extend the values through the 20-year planning period. More importantly, however, as evidenced throughout this plan, there is a significant transformation occurring in the mix of technologies relied

[97] EPA issued an update to the 2019 report in May 2021. However, data for the 2021 Power Plan was frozen in April 2020; moreover, the May 2021 update recommends its values not be used beyond 2024.

on for electricity generation in the western electric grid, with a significant amount of renewable resources being added in the region as well as WECC-wide. This is being spurred by lower resource costs, coal retirements, and clean energy policies. Thus, emissions will be changing over the next five to 10 years and beyond, and with an increased reliance on zero-emitting resources, the avoided emissions rate for the region will also be changing. This will lead to an even lower dollars-per-kilowatt-hour benefit in future years. The potential for the benefit value to become less significant over the course of the planning period compounds the Council's concern regarding 1) applying these benefits piecemeal, and 2) the risk of inappropriately skewing the resource cost comparison. Moreover, as discussed above, there are other vehicles provided under the Act for the Council to consider the environmental effects of resources, and one of those is through its due consideration of environmental quality. In development of this power plan, the Council considered greenhouse gas emissions as well as climate change and integrated each of these into its analysis. Climate change impacts on temperature and precipitation, which affect loads and river flows, were integrated throughout our quantitative analysis and modeling, and the Council included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation in the Regional Portfolio Model, with upstream methane emissions factored into that cost calculation as well. Thus, while the environmental effects of carbon were not added as a direct cost or benefit of a new resource via the methodology, its effects were considered and integrated into the Council's planning, and the impact of that consideration is reflected in the Council's resource decisions. These environmental quality effects and considerations are addressed in more detail below.

Therefore, for these reasons and consistent with the Council's previous application in past power plans, the Council did not attempt in this plan to include quantified environmental benefits in new resource costs beyond the few historic examples, and instead recognizes and emphasizes in the resource analysis the value of certain resource choices in helping to mitigate other harmful environmental effects. See, the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials for additional information on benefits included in resource system costs. And the generating resource reference plant section of the new generating resource supporting materials describe the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information regarding the environmental effects of generating resources.

Due Consideration for Environmental Quality, Fish and Wildlife Protection, Mitigation and Enhancement, and Compatibility with the Existing Regional Power System

The Power Act calls on the Council to develop the conservation and generation resource strategy for the plan "with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan." The purpose here is to provide a brief statement documenting how the Council has provided "due consideration" for these matters in developing this Power Plan, with particular focus on considerations of environmental quality and fish and wildlife. There are certain matters the Council considers with every power plan that are relevant here, and other matters particular to this plan. Both are highlighted as follows:

Fish and Wildlife Program/Hydropower System Operations for Fish and Wildlife

The Act requires the Council to call for recommendations and amend the fish and wildlife program prior to the power plan. The Act then makes the fish and wildlife program a mandatory element of the power plan. See *Section 12: Fish and Wildlife Program.*

One of the reasons for this is so that the Council, in developing the power plan, can assess the effects of dam operations to benefit fish on hydropower generation in terms of both the amount and timing and then design a new resource strategy that accounts for this generation. The Council in turn designs the regional resource strategy in part to facilitate the reliable implementation of the system operations for fish while continuing to assure the region an adequate, efficient, economical and reliable power supply.

The Council's analytical models and scenario analyses for this Power Plan incorporated all of the latest system operations recognized in the Council's fish and wildlife program. This includes reservoir operations and spill and other passage operations, including the flexible spill operation for juvenile fish, incorporated into the program from decisions external to the program and program amendment process, such as the most recent Columbia system biological opinions. These operations are all incorporated into the Council's modeling and analytical work on the scenarios as well as the baseline conditions. The Council's resource strategy is developed in part to assure an adequate and reliable power supply that will also allow for reliable implementation of those fish operations.

Environmental effects from the generation of electricity and from conservation

The Council identifies the various environmental effects that result from the generation of electricity from all phases of the life-cycle of a new generation resource. The include, for example, the effects on land, water, habitat and fish and wildlife during construction; environmental effects of key parts in manufacturing; fuel development and transportation; operational effects such as air and water emissions or harm to wildlife or fish; waste disposal; and end-of-life decommissioning and similar matters. The Council also identifies environmental effects to the extent possible for conservation measures and other non-generation alternatives.

The Council described these effects in a comprehensive way for the Seventh Power Plan, especially in Appendix I. The Council reviewed and updated this information as necessary for consideration in the 2022 Power Plan. See the supplemental material for generating resources, especially the discussion of environmental effects in the generating resource reference plant section as well as the environmental effects of generating resources.

To the extent these environmental effects can be quantified in dollar terms, the Council includes these values as resource costs for the new resource cost comparison, as described above with regard to the environmental cost and benefit methodology. Environmental effects and damage that cannot be quantified in the same way are still recognized and considered in developing the resource strategy. The existence of unquantifiable environmental impacts and damage from utility-scale generating developments has always been an additional consideration for the implementation of conservation measures and for other power system efforts that avoid construction and operation of major facilities, including demand response measures and in certain cases more efficient use of existing generation facilities. Specific environmental considerations particular to this plan are described further below.

Protected Areas

Beginning in 1988, the Council adopted what are called the “protected areas” as an element of the Council’s fish and wildlife program and power plans. In these provisions, the Council calls on the Federal Energy Regulatory Commission (FERC) not to license a new hydroelectric project in river reaches with valuable fish or wildlife resources that the Council identified and mapped in a “protected areas” database by the Council. The protected areas provisions also call on Bonneville not to acquire the output of, or provide transmission support for, such a project assuming it were to receive a license. To date, FERC has not licensed a new hydroelectric project in a protected area identified by the Council.

In the power plan context, protected areas represent a judgment by the Council that due to potential effects on habitat, flows, and passage, the adverse effects on and environmental costs to important fish and wildlife resources are too great to justify including new hydroelectric projects in these areas except under certain limited conditions. The existing power system is already bearing substantial costs to protect and mitigate for its impacts on fish and wildlife resources. The power plan context is also important in that the protected areas designations extend throughout the entire Pacific Northwest (essentially the same as the Bonneville service territory), not just within the Columbia River Basin, representing a part of the resource strategy for the region’s power system as well as a comprehensive plan for the region’s waterways and new hydroelectric development. As the Council evaluates the potential and cost-effectiveness for new hydroelectric development in each power plan, it includes the effects of protected areas in limiting the extent of that potential. The Council also gives due consideration to fish and wildlife and the quality of their environment by including a set of development conditions to protect fish and wildlife as new hydroelectric projects are licensed and developed in areas outside of the protected areas.

Greenhouse Gas Emissions/Climate Change

The environmental quality topic of primary interest in this plan, as in the last two, was the issue of greenhouse gas emissions and climate change. The Council has considered this topic in a number of ways in formulating the plan’s resource strategy, including:

- The Council closely tracked state and other legal and policy developments in the region and across the West that require the retirement of, or reduced emissions from, coal-fired generation; the scheduled retirements of coal plants; the addition of renewable resources through renewable portfolio standards; and clean energy standards and greenhouse gas reduction goals from the electrical power system. The Council designed a resource strategy for a power system consistent with the effects of these laws, policies and commitments. Part of the Council's aim in this power plan is to help the region understand a least-cost way to make this transition and retain an adequate and reliable system.

- As noted above, the Council included greenhouse gas emissions considerations in new resource costs whenever possible to quantify, and also tracked emissions and effects to the extent possible. This includes upstream methane emissions from natural gas production.
- The Council also integrated climate change effects into the baseline conditions and analyses, including climate change impacts on river flows for hydropower generation and on loads from changing temperatures.
- The Council included a cost of carbon in the baseline analyses as a damage cost on emissions from existing and new fossil-fueled generation. The Council also ran several scenarios or variants to test different aspects of this issue – removing the social cost of carbon; accelerating the retirement of coal plants; restricting the build of renewable resources; restricting the build of new natural gas plants; assessing the emissions reduction effects of a demand response sensitivity case; assessing in several different ways the power system effects of an economy-wide effort to decarbonize; and more. One result tracked for all model analyses was the resulting change in system emissions of greenhouse gases.

More details on how the Council considered this topic can be found in several different sections of the plan and supporting materials, including the resource development plan, the global assumptions in the power plan, the generating resource reference plants and environmental effects of generating resources.

Protecting Environmental and Cultural Resources from the Impacts of New Generating Resource Development

The siting, construction and operation of any generating facility has impacts on land and land uses; water resources; wildlife and wildlife habitat conditions; cultural resources; traditional uses; and local landowners and communities. Environmental effects of any proposed development are analyzed as part of state energy siting processes (if on private land) or by state or federal land management agencies (if on public land) through an array of different criteria and procedures. State fish and wildlife agencies and tribes have commented throughout this and the last power planning process with concerns that energy siting decisions for renewable facilities are not or may not be as protective of wildlife, habitat, cultural resources, and traditional uses as optimally needed. As the scale of development increases, so do the concerns – about the impacts of a host of individual decisions and about the cumulative impacts.

As noted above, the Council's Fish and Wildlife Program has a set of standards and conditions for developing new hydroelectric projects outside of protected areas. The purpose is to "ensure that new hydroelectric development is carried out in a manner that protects the remaining fish and wildlife resources of the Columbia River Basin and the Pacific Northwest and does not add to the region's and ratepayers' mitigation obligation." The Council has been asked to consider including in the power plan a similar set of development conditions for renewable resources. The Council is continuing to consider the value of directly recommending such a set of development conditions in the plan, given that the siting authorities have no particular obligations to the Council's power plan, unlike the situation with regard to the Federal Energy Regulatory Commission and hydroelectric project licensing.

Whether or not the Council develops and includes such a set of conditions, it seems obvious that siting authorities should work to ensure that new renewable resource development is carried out in a manner that also protects the wildlife and fish resources and cultural resources of the Pacific Northwest. The emphasis should be to incorporate "least impact, less conflict" siting principles to push development away from high value lands; ensure deliberate, strategic outreach and engagement in siting processes with fish and wildlife agencies and tribes, and with communities directly impacted by development; and ensure tribes are consulted to understand and preserve cultural resources and traditional uses in the vicinity of developments.

Hydrosystem Flexibility and Possible Impacts to Fish

The substantial increases in renewable generation across the West shift power system generation and transform power markets. The increasing supply of especially solar generation during the day rapidly shifts to a need for other resources during the evening when the sun is down. Since hydropower has a low variable cost and is flexible in its use (within certain established parameters noted above), the Council's analyses – and current actual practice – indicate that the hydropower system is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region. However, it is unclear how these daily river flow fluctuations – which are already evident and will likely increase if power considerations drive river operations - will affect environmental conditions for fish, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat. The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on the system operators to minimize or reduce daily flow fluctuations, and yet the power system analyses indicate a system adequacy benefit from increasing generation and flow fluctuations.

As described in the research recommendations in *Section 10: Recommendations for Research and Development*, the Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together the Council, Bonneville, system operators, the federal and state fish and wildlife agencies, the region's tribes, and others. The goal will be to explore the possible benefits and consequences of different hydropower system operations to try to identify a path forward that provides greater benefit to both power and fish.

Compatibility with existing power system/retirement of coal existing coal plants/lower Snake River dams

As noted elsewhere, the point of the Council's work on the power plan under the Northwest Power Act is to analyze and recommend what new conservation and generation resources should be added to the region's power supply. The Council is to do so while taking into consideration not just matters of environmental quality and fish and wildlife impacts, but also the compatibility of the new resources “with the existing regional power system.” The Council has done so in a number of ways, including analyzing and noting how the existing hydropower and gas plants have a valuable role in assimilating the addition of significant amounts of renewable resources in a cost-effective manner while preserving an adequate system.

The Council’s task is not to analyze or decide whether elements of the current system should remain or be retired, for environmental or economic or other reasons. The Council does need to take into account decisions made by others to retire or reduce the output of existing resources or constrain what types of new resources may be added. This includes, for this power plan, the current set of decisions by utilities to retire coal-fired generating units for reasons of economics and state law, as well as the new state law requirements requiring the addition of renewable or clean resources, both part of a policy effort to reduce the output of greenhouse gas emissions from the existing system. In this instance the Council needs to analyze the effects of those plant retirements on the existing power system during the power plan process, as part of being able to analyze and decide what resources in what amounts need to be added to assure the region retains an adequate, efficient, economical and reliable power supply.

In this plan period, numerous comments have been submitted asking the Council to analyze or recommend the removal of the four federal dams on the lower Snake River. There are as yet no planned retirement dates for any mainstem dams on the Snake and Columbia. So, the Council does not need to analyze the effects of the retirement of those plants for this power plan in order to develop the power plan’s new resource strategy and fit that strategy to the existing if changing power system. And it is not the Council’s task under the Act, in the power planning process, to analyze or recommend the retirement of existing system resources.

There may be value to the region in having the Council analyze the power system effects of the retirement of those dams. Such an analysis could provide information to decisionmakers considering the future of the projects. The Council has done similar analyses in the past for the purposes of information, and could analyze the retirement of the Snake River dams after the conclusion of this power plan if entities in the region and the Council decide at that time that such an informational analysis would be a prudent use of Council staff resources. But, there is no need at this time to do that analysis as part of this power plan, and there is no authority under the Act for the Council to analyze and decide on its own that the removal of those projects should be part the plan’s new resource strategy.

Pre-Decisional Draft Section: Not for Public Release

Section 12: Fish and Wildlife Program

The Council's *Columbia River Basin Fish and Wildlife Program* is one of the required elements of the power plan under the Northwest Power Act. The 2014 Fish and Wildlife Program, supplemented by a 2020 Addendum, is the Council's current version of the program. https://www.nwcouncil.org/reports/2014-columbia-river-basin-fish-and-wildlife-program

The Act requires the Council, prior to the review of the power plan, to call for recommendations to amend the fish and wildlife program and then follow the process described in the Act for deciding on program amendments. The Council did so, initiating a fish and wildlife program amendment process in 2018 that culminated in a final decision on the 2020 Addendum to the existing program toward the end of 2020. Section 11 includes a discussion of the role of the fish and wildlife program in the development of the 2021 Power Plan, as part of the required fish and wildlife and environmental considerations.

The Council's fish and wildlife program has evolved through time. Early programs focused largely on improving juvenile and adult fish survival at and through the mainstem Columbia and Snake river dams, including water management and fish passage provisions for anadromous fish and reservoir operations to benefit resident fish. Early program developments also included the anadromous fish loss assessments and systemwide goal, the wildlife loss assessments and the beginning of mitigation for those losses, and the designation of protected areas to protect the region's fish and wildlife resources from new hydroelectric development. Over time the Council built up other portions of the program, especially expanding the off-site mitigation activities of the program with habitat improvements and fish hatcheries in the tributaries off the mainstem and in the lower Columbia River and estuary.

The 2014 Program reflected all this work built up over the last 36-plus years of program development and implementation, with a continued emphasis on both mainstem water management, passage improvements, and spill and offsite habitat and hatchery mitigation improvements. The 2014 Program also identified a set of emerging priorities and called on Bonneville, the other federal agencies, and the region to integrate these emerging priorities into program implementation. These emerging priorities included, for example, providing funding for long-term maintenance of program assets; integrating climate change considerations; expanding efforts to deal with predation and invasive species; increased focus on addressing the needs of sturgeon and lamprey; increased attention to toxic contaminants; investigating blocked area mitigation options through a number of activities; and continuing efforts to support ecosystem function through improved floodplain habitats.

When it came time under the Act to call for recommendations to amend the 2014 Program, the Council, in consultation with other program participants, concluded that a wholesale revision of the 2014 Program did not seem necessary. The Council asked the region to focus on two key program needs: 1) how to improve the way the Council and others assess and report on program performance and how to further develop and utilize the program's goals, objectives, and performance indicators to that end; and 2) a small set of near-term needs regarding program implementation. The Council worked with the resulting program amendment recommendations and further public participation over most of two years to focus the resulting 2020 Addendum to the 2014 Program on those two topics.

Thus, based on the recommendations received, the region's experience with implementation following the 2014 Program, and the development work with the region, the 2020 Addendum is structured in two parts. Part I focuses on program performance, reorganizing and supplementing the goals, objectives, and indicators provided in the 2014 Program to enable the Council and others to evaluate program performance in an effective manner. The Council granted requests to extend the scheduled conclusion of Part I for approximately six months to further engage the state and federal fish and wildlife agencies and the region's Indian tribes in a series of workshops on the program goals, objectives, and performance indicators.

Part II of the 2020 Addendum covered a small set of program implementation needs consistent with the existing and emerging priorities identified in the 2014 Program. These included, among others, re-emphasizing the need to integrate climate change impacts and considerations into all areas of implementation; continuing the asset management effort; increasing the scope of mitigation in the blocked areas, especially the work to mitigate for the loss of anadromous fish and the losses to other fish and wildlife species in the areas of Grand Coulee and Chief Joseph dams; implementation of refinements in operations at Libby and Hungry Horse dams; restoring and sustaining the implementation of ocean research studies identified by the Council; sustaining ongoing efforts to reduce predation and increase or revise those efforts as necessary; research to assess benefits of estuarine use by salmon stocks from the interior Columbia River Basin; and more.