The 9th Northwest Power Plan

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Northwest Power and Conservation Council

Introduction to the Ninth Northwest Power Plan

The Northwest Power Act of 1980 established the Northwest Power and Conservation Council (Council) at a time of crisis in energy planning. Errors in demand forecasting led to an overinvestment in unnecessary power plants, a costly mistake that the Pacific Northwest is still paying for today. The Council's Ninth Northwest Power Plan comes at another critical time in our power system history, with energy policy once again dominating the regional conversation. Demand for electricity is expected to grow significantly due to a variety of factors including increased tech load from data centers and chip fabrication and new loads from electrification. Concerns about affordability and reliability have gained prominence in media coverage and policy discussions, and consumers are paying close attention.

The Council was created in part to avoid making the same costly mistakes of the past when planning for the future. The Power Act instructs the Council to provide direction to the Bonneville Power Administration (Bonneville) and the broader region on how to meet future energy needs in a way that assures the region of an adequate, efficient, economical, and reliable power supply, while also protecting, mitigating, and enhancing the fish and wildlife of the Columbia River and its tributaries. The Council must produce a power plan at least every five years that guides the acquisition of new resources to meet forecasted energy demand.

This Ninth Northwest Power Plan rises to meet the moment, providing a clear path forward while recognizing the significant uncertainty ahead. Load growth is one of the greatest areas of uncertainty both regionally and nationally. While predicting future energy demand has always been challenging, changes in electricity use are significantly increasing that uncertainty. Data centers, and other high-tech industries, are one of the main drivers of this uncertainty in load forecasting. Electrification of transportation, building, and industries, is another. Developing a forecast is critical to ensure that the region develops sufficient resources to meet the need without overbuilding. For the Ninth Plan, the Council significantly enhanced its modeling capabilities for forecasting demand. This allowed the Council to account for this uncertainty by developing a suite of forecasted load trajectories, representing a range of possible conditions for total load growth, the pace of that growth, and the shape of future demand. The updated modeling approach also allows the Council to reflect the diversity of the region, recognizing that not all parts of the region are experiencing the same amount or type of load growth.

Extreme weather events are another significant challenge and source of uncertainty considered in the Ninth Plan. These events have become more frequent across the West in recent years and include periods of very low or very high temperatures, as well as the added risk of wildfire across the region. Since the 2021 Power Plan, the Council's analysis has leveraged climate model data to capture a range of potential future weather conditions, including changes in temperature and precipitation patterns. As temperature and precipitation change from year to year, so too does the amount of and timing of hydropower and wind resources that rely on natural fuel sources. The Council improved this analysis for the Ninth Plan, expanding the use of climate model data to inform availability of resources such as wind and solar. Temperature also impacts the demand for electricity, changing the amount of heating or cooling needed for homes and businesses. By accounting for a range of potential future weather conditions, including extreme temperatures, the Council can make recommendations that consider these uncertainties and risks.

The regional resource strategy of the Ninth Power Plan is intended to build on the region's existing power system, the foundation of which is the Federal Columbia River Basin hydropower system. This system provides roughly half of the electricity generated today for the Pacific Northwest; the other half is generated from a roughly equal mix of thermal resources (primarily natural gas) and renewable resources (primarily wind). Energy conservation is also a significant resource – the region's long-term investment in conservation makes it the second largest resource in terms of energy. Conservation has saved the region more than 8,000 average megawatts.

Accounting for the existing power system capabilities, and for the forecasted growth in loads, the Council determined that the region has a significant need for new resources. New resources are needed to provide flexibility and address peaking challenges throughout the year, as well as provide energy, particularly during the winter months. To provide a robust approach to addressing these needs, the Ninth Plan scenario modeling included a range of sensitivities that explored uncertainty around new resource availability and costs. This included a range of potential transmission buildouts, as transmission is critical for delivering electricity to where it is needed. The Council's scenario modeling also included four sensitivities that tested changes to future resource needs to accommodate different hydropower system operations to benefit fish. The Council scoped these sensitivities to understand different levels of risk and uncertainty from which the Council could develop its resource strategy.

The regional resource strategy, outlined in Chapter 4 of this Plan, provides a portfolio approach to meeting future needs, with a focus on 2027 through 2032. This strategy includes a mix of demand and supply side resources, including 1,060 average megawatts of conservation, 590 megawatts of demand response, 220 megawatts of voltage regulation, 9,000 megawatts of renewables, 5,200 megawatts of storage, and 2,100 megawatts of natural gas. Through its enhanced modeling suite, the Council was able to glean insights on the locational value of different resources, which provides valuable insights into this strategy. It is this suite of resources together, in the recommended amounts, that collectively provide for a cost-effective and adequate approach. The demand side resources provide benefits to the system by reducing loads, particularly in key times. This, in turn, defers the need to acquire more expensive generating resources, as well as the need to expand the capacity of both the transmission and distribution system. The recommended supply side resources provide further value to the system, ensuring that remaining load growth is met in a cost-effective way. The renewables and storage provide energy and reserves to the system, while meeting state and utility clean targets. Natural gas provides seasonal reserves, which are an important hedge in years with reduced hydropower due to low water conditions. These resources can be effectively integrated into the existing system. Collectively, they provide for adequacy, meet clean requirements set by states and goals set by others, and allow for Bonneville and others to implement the Council's 2026 Columbia Basin Fish and Wildlife Program.

In addition to guiding regional resource acquisition, the resource strategy provides recommendations to Bonneville. Core to this is the recommendation for Bonneville to acquire its share of the cost-effective conservation resource. Bonneville's energy conservation program has been a cornerstone of conservation in the region over the years, and the Ninth Plan looks to Bonneville to continue to play an important role. This conservation will extend the value of the existing hydropower system and defer the need for acquiring other resources. Should the need arise for Bonneville to acquire resources beyond conservation to meet its obligations, the Ninth Plan provides recommendations that Bonneville pursue renewables to support energy needs and assess the cost-effectiveness between storage and natural gas in meeting capacity needs. These recommendations are designed to support Bonneville ensuring sufficient power delivery under its new Provider of Choice contracts, as well as enabling Bonneville to meet its obligations of implementing the Council's 2026 Columbia Basin Fish and Wildlife Program.

The Ninth Power Plan calls for the region to acquire new generating resources at a level that has not occurred in recent years. Achieving this resource strategy will require collaboration. States, utilities, transmission providers, and developers will need to find ways to streamline the processes required to develop new resources, including developing new transmission and siting. The region will also need to further develop ways to maximize the capacity of the existing system. Working with new partners, including data centers and others in the high-tech industry, will be critical to integrating new loads without creating burdens for the power system and other ratepayers.

This is a very dynamic time for the power system. The Council will continue to monitor changes on the ground, as well as progress towards implementing the Ninth Plan regional resource strategy, through annual studies assessing changes to load growth, market depth, and adequacy. The Council will also track the acquisition of resources on both the supply and demand sides. These annual studies will provide important information to help inform the mid-term assessment of the Ninth Power Plan, so that the Council can refine its direction to the region and Bonneville as needed.

Contents

Chapter 1: Northwest Power Act Requirements

Context for the Power Act

In the wake of a regional power system planning failure and facing mounting concerns over declining salmon and steelhead runs in the Columbia Basin, Congress passed the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) in 1980. The Northwest Power Act provides a path for regional planning around fish and wildlife and power needs, focusing on ensuring both are met and the region maintains an adequate, efficient, economical, and reliable power supply.

The origin of the Power Act begins decades earlier, at the outset of a boom in electricity consumption that occurred in the Pacific Northwest and across the U.S. Beginning in the late 1930s and continuing until the mid-1970s, national and regional electricity use experienced sustained, unprecedented levels of growth. Energy systems scaled rapidly to keep pace. In the Northwest, this trend was particularly evident in the growth of electricity demand post-World War II, and in the extensive development of hydropower in the region, including in the Columbia Basin. Between 1960 and 1970, regional electricity consumption approximately doubled.

By the late 1960s and early 1970s, however, the energy potential of the Columbia River hydropower system had been mostly developed, yet regional demand forecasts continued to predict large-scale growth extending well into the future. Forecasters warned of looming power supply shortages. Recognizing that the power from new plants would be more expensive than that from the existing hydropower system, an allocation dispute developed over who would have access to the low-cost federal hydropower. This debate was in the background of the development of the Power Act.

Based on these demand forecasts, the region embarked on ambitious plans to develop a large fleet of nuclear and coal power plants in the coming decades called the Hydro-Thermal Power Program. As will be discussed more in Chapter 2, this program included the planned development of five nuclear power plants to be built in Washington state by the Washington Public Power Supply System, as well as other coal and nuclear projects to be developed by other utilities. However, by the late 1970s, it was clear that the earlier demand forecasts were inaccurate. Construction of the nuclear plants also encountered a host of problems, including significant cost overruns. Ultimately, only one of the five Washington Public Power Supply System projects ever reached operation, resulting in one of the largest bond defaults in the country's history. Meanwhile, new studies showed that conservation of electricity could be a cost-effective alternative to building new power plants. This situation drove an interest in broader public engagement in resource planning decisions.

Another motivating factor was the increasing recognition that salmon and steelhead runs in the Columbia Basin were declining, most notably in the Snake River. While not the only factor, the hydropower projects were considered a significant cause for these declines. State fish and wildlife agencies, the region's Tribes, and environmental and fishing groups in the Pacific Northwest expressed concerns about not being sufficiently involved in the decisions up to that point and wanted pathways to address the impact of the hydropower system on salmon and steelhead.

What resulted was the Northwest Power Act, a unique piece of legislation created to respond to these multiple challenges. The Act authorized the states of Washington, Oregon, Idaho, and Montana to form an interstate compact agency, the Northwest Power and Conservation Council (Council), to address these challenges by protecting and mitigating for the impacts of hydropower on fish and wildlife, while also assuring the region an affordable and reliable electricity supply. The Council develops these plans based on robust and transparent public engagement from across the four-state region.

Purposes of the Power Act

The main intentions of the Northwest Power Act can be traced back to the events that led up to the Act's passage. There was regional interest in an open, public, and transparent process that would ensure a reliable and economic power supply, while also mitigating impacts from the hydropower system on the region's salmon runs. To address these connected challenges, the Northwest Power Act outlines the following purposes:[1]

- To encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest,
- To assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply,
- To protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat.
- To provide for the participation and consultation of the 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 for energy conservation and new generating resources; protecting, mitigating and enhancing fish and wildlife resources; facilitating the orderly planning of the region's power system; and providing environmental quality.

[1] Northwest Power Act, Sections 2(1), 2(2), 2(3), and 2(6).

Power Plan Provisions in the Power Act

Timing of the Ninth Power Plan

The Council is required to adopt and transmit to the Bonneville Power Administration (Bonneville) a power plan and to review the plan at least every five years.[2] The Council adopted its last power plan, the 2021 Power Plan, in February of 2022. Since then, the region has experienced several changes. First, the Council's 2021 Power Plan Mid-Term Assessment highlighted the risk of near-term, fast-paced load growth driven by data center development and noted that the 2021 Power Plan's resource strategy would not be sufficient if that load materialized.[3] This high-tech load is anticipated to be in addition to the already forecasted electrification loads in the region. Second, over the past several years, Bonneville has been working with its customers and the region on developing a new set of contracts set to start October 1, 2028. With these new contracts comes the potential that Bonneville may need to acquire resources beyond conservation. With Bonneville resource decisions being guided by the Council's power plans, an updated plan would prove timely. Additionally, there have been changes in how the region is organized in terms of markets and adequacy programs, creating opportunities for resource and reserve sharing that will shift power system planning and operation in the Northwest. These changes, as well as other factors discussed more in Chapter 2, led the Council to initiate the review of the 2021 Power Plan in February of 2025.

The timing of the Council's power plan development is also directly connected to the Council's fish and wildlife responsibilities under the Northwest Power Act. The Act requires that, prior to reviewing the power plan, the Council must first initiate the fish and wildlife program amendment process with a call for recommendations to amend the Program.[4] The Council's final amended fish and wildlife program then becomes a required element included within the power plan,[5] requiring that the program be completed and adopted before finalizing the power plan. The two processes and responsibilities are further connected in substantive ways, described at the end of this chapter. The Council initiated its amendment of the 2014/2020 Columbia River Basin Fish and Wildlife Program in January 2025, just prior to the Council starting review of the power plan. After the adoption of the Council's 2026 Fish and Wildlife Program in June 2026, the Council incorporated the revised Fish and Wildlife Program into this draft power plan as required.[6]

[2] Ibid., Section 4(d)(1).
[3] 2021 Power Plan Mid-Term Assessment is available at https://www.nwcouncil.org/2021-northwest-power-plan/mid-term-assessment.
[4] Northwest Power Act, Section 4(h)(2).
[5] Ibid., Section 4(e)(3)(F).
[6] 2026 Columbia Basin Fish and Wildlife Program is available at https://www.nwcouncil.org/reports/2026program/.

Power Plan Elements

The power planning provisions in the Northwest Power Act are primarily focused on key elements required in the power plan, many of which can be traced back to the context that led to the Act.[7] This section outlines these main elements, providing a foundation for the work to come in the following chapters of this Plan.

The Council must put forth a "regional conservation and electric power plan." The power plan must prioritize "cost-effective" resources, with priority first to conservation, then renewable resources, then generating resources utilizing waste heat or with high fuel conversion efficiency, and finally all other resources. [8,9] The emphasis on cost-effectiveness stems from the origin and purpose of the Act, when there were concerns about the investment in higher cost thermal resources over lower cost alternatives. Under the Northwest Power Act, cost-effective is defined as a comparison between two resources, ensuring that the cost-effective resource is available and reliable at a cost lower than that of a similarly available and reliable resource.[10,11]

Prior to adoption of the Act, several studies demonstrated that conservation benefits could be achieved at a lower cost than other resources. The environmental movement at the time influenced this resource prioritization, as well as other elements of the Power Act. This was a novel approach, particularly the treatment of conservation as a resource to be considered alongside generating resources in power planning, and it has resulted in a legacy of conservation investment in the Pacific Northwest.

The Council's power plan is to set forth a "general scheme for implementing conservation measures and developing resources" to reduce or meet Bonneville's obligations.[12,13] In defining these resources, the Council is to give "due consideration" to (1) environmental quality, (2) compatibility with the existing power system, (3) protection, mitigation, and enhancement of fish and wildlife and related

[7] Sections 4(e) and 4(f) of the Power Act walk through these required priorities, considerations, and elements of the Council's power planning.
[8] Conservation is defined under the Power Act in Section 3(3) as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution." Energy efficiency is often used to describe conservation as defined under the Act.
[9] Northwest, Section 4(e)(1).
[10] Ibid, Section 3(4).
[11] The definition goes on further to define all aspects included in resource costs, focusing on total lifetime costs of related power system costs of a resource and quantifiable environmental costs and benefits that are directly attributable to that resource. More discussion of the cost comparisons of resources is available in Chapter 3 under the discussion of new resource potential, and in Technical Appendix A – Global Assumptions and Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits.
[12] Northwest Power Act, Section 4(e)(2).
[13] As discussed more below, Bonneville's obligations as laid out in Section 6 of the Power Act include implementing a conservation program consistent with the Council's plan and then, after taking into account those planned savings from conservation, acquiring resources to meet contract loads and the implementation of the Council's Fish and Wildlife Program.

spawning grounds and habitat, and (4) other criteria that the Council might set forth in the power plan. These considerations are rarely able to be quantified, but the Council must weigh them seriously as it develops a resource strategy guiding future resource investment.

The power plan must include several specific elements, including:[14]

- Conservation program to be implemented, which is described in Chapter 5.
- Recommendations for research and development, which are included in the Action Plan (Chapter 4) and as elements of the conservation program in Chapter 5.
- Methodology for determining quantifiable environmental costs and benefits, which connects to the definition of system cost and is described in more detail in Chapter 3 and Technical Appendix C.
- Demand forecast of at least 20 years, included in Chapter 3, and a forecast of resources required to meet Bonneville's obligations, included in the Action Plan (Chapter 4).[15]
- Analysis of reserve and reliability requirements, including a cost-effective method for providing reserves, which is discussed in the Action Plan (Chapter 4).
- Council's fish and wildlife program, which for the Ninth Power Plan is the 2026 Columbia Basin Fish and Wildlife Program.
- Model conservation standards and the related surcharge methodology, which are discussed more in the conservation program in Chapter 5 and detailed in Technical Appendix P.

Public Engagement in the Power Plan Development

One of the key purposes of the Northwest Power Act is to promote broad engagement in the Council's power planning activities by providing for the participation and consultation of many different entities. This includes widespread public involvement in developing regional power policies, consulting with Bonneville's customers and others in the development of the plan and in the ongoing implementation of the plan, and engaging with federal agencies, states, tribes, and local governments.[16] Throughout the process, the Council and Bonneville must "recognize and not abridge the authorities" of the states, local governments, utilities, and others responsible for the planning and operation of the power system. Collectively, these provisions in the Northwest Power Act call on the Council to engage the public and key regional stakeholders throughout the power plan process.

[14] Northwest Power Act, Sections 4(e)(3) and 4(f).
[15] The forecast of resources are to include reserves and reliability requirements, must take into account the Council's fish and wildlife program, and should include approximate amounts and of what types of power to be acquired by Bonneville on a long-term basis.
[16] Northwest Power Act, Section 4(g).

There are many ways the Council fulfilled these public engagement responsibilities during the development of the Ninth Power Plan. The first is through the Council's regular public meetings, during which the Council discussed substantive issues around analytical methods, data and assumptions, results, and ultimately the development of the findings and recommendations in the power plan. For the Ninth Power Plan, the Council began the public process in March 2024, with the release of an Issue Paper on Preparation for the Ninth Plan.[17] Public comment on this paper and additional input provided via consultations helped to shape early scoping of the Ninth Power Plan.

Throughout the development of the Ninth Plan, the Council used its advisory committees to engage experts and key regional partners.[18] These advisory committees cover a range of topics, from understanding the existing system, to developing forecasts of load and new resource potential, and discussing the analytical approaches used to develop the power plan. Like the Council meetings, these advisory committees meet in public, and the materials are available on the Council's website. The Council uses its website to provide data and analysis throughout the development of the power plan.[19]

Another form of broad public engagement is the release of a draft power plan for public comment. While the Northwest Power Act does not explicitly require it, the Act does call on the Council to hold public hearings in each state prior to adopting the final power plan.[20] In practice, this results in the Council releasing a draft for public comment. During this time, the Council will hold multiple public hearings, schedule consultations with key regional entities, and accept written and oral comments on the draft power plan. The Council will consider all comments received during this period in the development of a final Power Plan to be released later this year. After completion of the plan, the Council will also develop a response to comments, explaining how it considered comments in the development of a final plan, including any changes between draft and final.

Role of the Power Plan in the Region

Relationship to the Bonneville Power Administration

The Council's power plan has the most direct connection to Bonneville and its decisions around acquiring new resources to meet its obligations. At the time of the Northwest Power Act's passage, Congress envisioned that Bonneville would be the major engine for new resource development in the Northwest, and therefore that the purposes of the Act would be achieved through Bonneville and the

[17] The full issue paper is available at https://www.nwcouncil.org/reports/2024-1.
[18] Section 4(c)(11) of the Power Act requires the Council to establish a "scientific and statistical advisory committee" to assist with the development of the plan, and Section 4(c)(12) allows the Council to develop additional advisory committees as appropriate. In practice, the Council used eight advisory committees covering a range of specific expertise to support the development of the Ninth Plan. More information is available at https://www.nwcouncil.org/energy/energy-advisory-committees.
[19] More information is available at https://www.nwcouncil.org/energy/ninthpowerplan.
[20] Northwest Power Act, Section 4(d)(1).

use of the federal system. The Act sets up Bonneville to offer power sales contracts to utilities and others in the region, without limitation to the available power of the federal base system.[21] Then, the Act authorizes and obligates Bonneville to acquire conservation and generating resources to meet or reduce its obligations, which include contractual obligations for power and obligations to meet the requirements for fish and wildlife protection and mitigation.[22] As Bonneville acquires resources, it must do so in a manner consistent with the Council's current power plan, as determined by Bonneville, and with several exceptions that still tie Bonneville to the power plan standards.[23]

The Act includes several provisions for the Council in developing the power plan that point directly to Bonneville. For example, the power plan must put forward a scheme of resources to "reduce or meet [Bonneville's] obligations," must include an energy conservation program to be implemented by Bonneville, and must include a forecast of resources, reliability, and reserves requirements to meet Bonneville's obligation.[24]

Taken together, these provisions in the Northwest Power Act closely tie the Council and Bonneville. The Council must plan for resources to meet Bonneville's obligations and, in meeting its obligations, Bonneville must acquire resources, including conservation, consistent with the Council's plan. While the original vision of Bonneville as the major engine of new generating resource development in the region has not come to fruition, Bonneville and its customer utilities have played a key role in the acquisition of conservation over the years. Under its new contracts, Bonneville may be in a position where generating resources are needed to meet its obligations.[25] The Ninth Power Plan includes actions specifically targeted to Bonneville in the Action Plan (Chapter 4) and conservation program (Chapter 5).

Relationship to Others

The Council is required to develop a power plan for the region. While the only direct obligation on resource acquisition under the Northwest Power Act is to Bonneville, this regional power plan is influential in resource decisions of others throughout the region. 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. Chapters 4 and 5 of the Ninth Power Plan include recommendations for the broader region, identifying actions of others outside of Bonneville necessary for supporting the purposes of the Act. While there is no legal obligation under the Northwest Power Act for entities other than Bonneville to act consistent with the Council's plan, state energy agencies,

[21] Ibid., Section 5.
[22] Ibid., Section 6(a)(2).
[23] Ibid., Section 4(d)(2) and Sections 6(a) through 6(c).
[24] Ibid, Sections 4(e)(2), 4(e)(3)(A), and 4(e)(3)(D), respectively.
[25] Sections 6(a) through 6(c) discuss implementation of conservation and resource acquisition. Section 6(c) specifically pertains to the acquisition of a "major resource", which is defined in the Power Act as being any resource that is greater than 50 average megawatts and is acquired for more than a five-year period. Any major resource acquired by Bonneville must go through a process (described in Section 6(c)) to determine consistency with the Council's current power plan.

regulatory agencies, investor-owned utilities, public utilities that hold their own generation, and others look to the Council's plan for guidance. Additionally, the State of Washington passed its own legislation, the Energy Independence Act, that requires utilities in that state to plan for conservation consistent with the Council's methodologies.[26, 27] Broadly, entities throughout the region recognize the Council as the only entity tasked with taking a region-wide, independent, long-term perspective to power planning. The power plan remains the venue for examining the potential implications of policy decisions on the regional system, and how to plan and manage in the face of uncertainty.

Relationship to the Council's Fish and Wildlife Program

As noted above, the Council's Columbia River Basin Fish and Wildlife Program is a required element of the power plan. Prior to reviewing the power plan, the Council must first initiate a fish and wildlife program amendment process by calling for recommendations for program amendments. Section 4(h) of the Power Act defines the Council's role in developing or amending the fish and wildlife program, a process that is highly circumscribed under the Act.

The first step of the fish and wildlife program amendment process is to request recommendations from the region's state and federal fish and wildlife agencies and Tribes for "measures … to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric project on the Columbia River and its tributaries" and "objectives for the development and operation of such projects on the Columbia River and its tributaries in a manner designed to protect, mitigate, and enhance fish and wildlife."[28] These recommendations form the raw material from which the Council builds the Program. The final Program must include measures to benefit salmon and steelhead and other fish and wildlife affected by the hydropower system. This includes a combination of changes in hydropower operations to improve flows, passage, and reservoir levels to benefit fish affected by the system, as well as offsite habitat and production mitigation measures.

The Fish and Wildlife Program operations inherently reduce the generating capacity of the hydro system. The program decision around any operation must continue to ensure that the region has an adequate, efficient, economical, and reliable power supply.[29] This standard is one of the factors in the Act connecting the Fish and Wildlife Program process to the power plan process. It is in the power plan that the Council has the responsibility to plan for resources that will allow Bonneville to meet or reduce its obligations. This includes resources to meet its contractual operations, as well as any

[26] Energy Independence Act, Chapter 19.285 RCW. https://app.leg.wa.gov/rcw/default.aspx?cite=19.285.
[27] Details on the Council's methodology are in Technical Appendix H – Conservation Methodology and Potential.
[28] Northwest Power Act, Section 4(h)(2)(A) and 4(h)(2)(B).
[29] Ibid., Section 4(h)(5).

resources that are required to keep the system adequate while implementing the operations required for fish and wildlife.[30]

In January 2025, the Council initiated its Fish and Wildlife Program amendment process with a call for recommendations. As part of the Ninth Plan, the Council conducted scenario modeling exploring different hydro operations. The Changing Hydro Operations scenario included sensitivities that tested some of the operations recommended by some of the states and tribes.[31] The New Resource and Transmission Risk scenario included operations as defined in the Draft 2026 Columbia River Basin Fish and Wildlife Program, released for public comment in December 2025. Collectively, the Council used this analysis to inform both the 2026 Columbia River Basin Fish and Wildlife Program development and the Ninth Plan. Appendix H to the 2026 Fish and Wildlife Program describes the Council's preliminary conclusions, leading into the power plan, about the implementation of the program and the adequacy, efficiency, economical character, and reliability of the region. Chapter 2 of this power plan then includes more discussion of the integration of the 2026 Columbia River Basin Fish and Wildlife Program into the Ninth Plan. Chapter 4 includes recommendations for resource development that ensure the region maintains an adequate, efficient, economical, and reliable power supply, while also meeting the requirements for fish and wildlife as outlined in the Council's 2026 Columbia River Basin Fish and Wildlife Program.

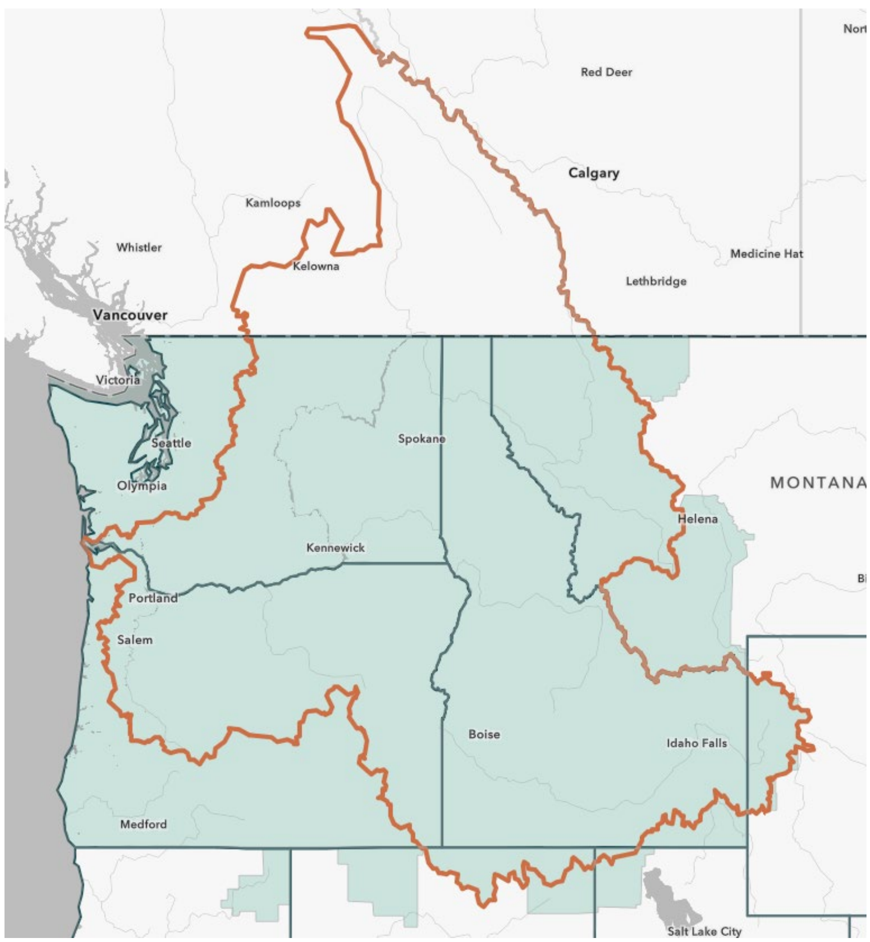
[30] Section 4(e)(3)(F) requires the inclusion of the fish and wildlife program into the plan. The Council's responsibilities under Section 4(d)(2) and 4(e)(2) connect to Bonneville's obligations in Section 6. In Section 4(h)(10)(A), the Act lays out Bonneville's obligation to use its funds and authorities to "protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries in a manner consistent with the … the program adopted by the Council."

[31] Specifically, the Council tested a sensitivity that explored limiting the daily flexibility of the hydropower system and a separate sensitivity looking at the specific spill and elevation operations recommended by some of the states and tribes. More information on these, and other sensitivities, is included in Chapter 3 and Technical Appendix N – Scenario Modeling and Results.

Chapter 2:
Existing Northwest Power System

The Northwest Power Act directs the Council to develop a regional plan to add new conservation and generating resources to the Pacific Northwest electric power system. The "region," as defined by the Act, is the geographic area of the Columbia River Basin, plus areas outside the basin where the Bonneville Power Administration (Bonneville) sells firm power. This includes the states of Oregon, Idaho, Washington, Western Montana (the portion west of the Continental Divide), and portions of California, Nevada, Utah, and Wyoming served by rural electric cooperative customers of Bonneville. Figure 2 - 1 shows the Columbia River Basin (outlined in orange) and the region as defined by the Act (shaded in blue).

Figure 2 - 1: Region as Defined by the Northwest Power Act



To develop the regional power plan, it is important to first understand the system as it is today. This chapter delves into that background, providing context of the existing resource base and how it has evolved over time, a description of key issues impacting the power system, and a discussion of the Council's 2026 Columbia River Basin Fish and Wildlife Program, which provides a basis for operations and actions to be implemented and informs the existing system capabilities.

Existing Resource Base

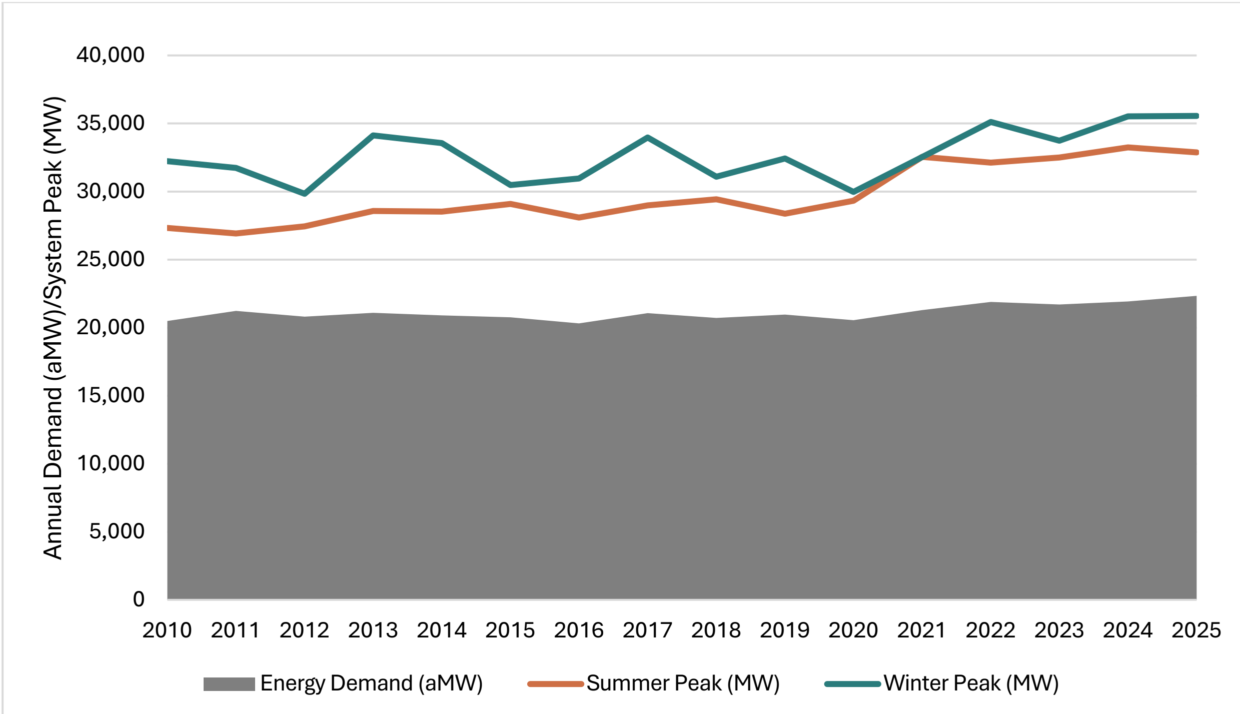
Historical Load Growth

Prior to the passage of the Northwest Power Act, total regional electricity demand had been growing significantly. In 1970, regional demand was around 11,000 average megawatts. In that decade, the region added nearly 4,700 average megawatts of demand. Demand forecasters continued to assume the rapid demand growth would continue. This resulted in investments in the planning and construction of coal and nuclear power plants. As discussed in Chapter 1, the forecasted load projections never materialized. As a result, the region overinvested in resource development, which was one of the main drivers for the passage of the Act.

In the 1980s, the pace of demand growth slowed significantly, dropping to roughly 1.5% per year over the decade. This resulted in approximately 2,300 additional average megawatts of demand by the end of that period. In the 1990s, growth slowed further, to a rate of around 1.1% per year over the decade, with around 2,000 average megawatts added to the regional demand. Things changed in the early 2000s. As a result of the West Coast energy crisis of 2000-2001 and the recession of 2001-2002, regional demand decreased by 3,700 average megawatts in this period, a decline of around 0.5%. A significant cause of this decline was the closure of many industrial plants, including the direct service industries, such as the aluminum smelters, served by Bonneville. After this period, regional energy demand grew by less than 1% per year, ultimately ending the decade lower than it started.

Figure 2 - 2 shows the region's annual energy demand over the last decade and a half. In the 2010s, annual electricity demand continued to stay relatively flat, with an annual average growth rate of 0.1% per year. This was driven by continued investment in conservation (discussed more below) and further loss of industrial loads. There has been a shift in the last five years, as electricity demand has increased roughly 1.7% per year. As of 2025, regional electricity demand in the Northwest is more than 22,000 average megawatts. The primary driver of this new demand growth is the introduction of new loads, including new air conditioning demand in response to recent summer heat events, electric vehicles emerging on the market, and the growth of data centers.

Figure 2 - 2: Annual Energy Demand and System Peaks Since 2010



During this same time, the regional system's peak demand has been growing, particularly in the summer. In the past couple of years, the winter peak has reached over 35,000 megawatts, and summer peak has been roughly 33,000 megawatts. The power system for the Northwest was primarily built to serve winter peak needs. While meeting winter peak needs continue to be important, this growth in summer peak is a key consideration for power system planning.

While electricity demand has increased regionwide, this growth is not universal. Some parts of the region, particularly urban areas of the west side, have seen negative to low load growth (less than 1%), likely driven by shifting populations and continued investments in conservation. Other parts of the region have seen load growth of over 1%, in some areas over 2%. These areas, primarily on the east side of the Cascades or in urban areas with high technology loads, are experiencing a mixture of growing populations and the introduction of data center loads. The Council's forecast for future demand continue to show growth across the region. This is discussed more in Chapter 3.

Demand Side Resources

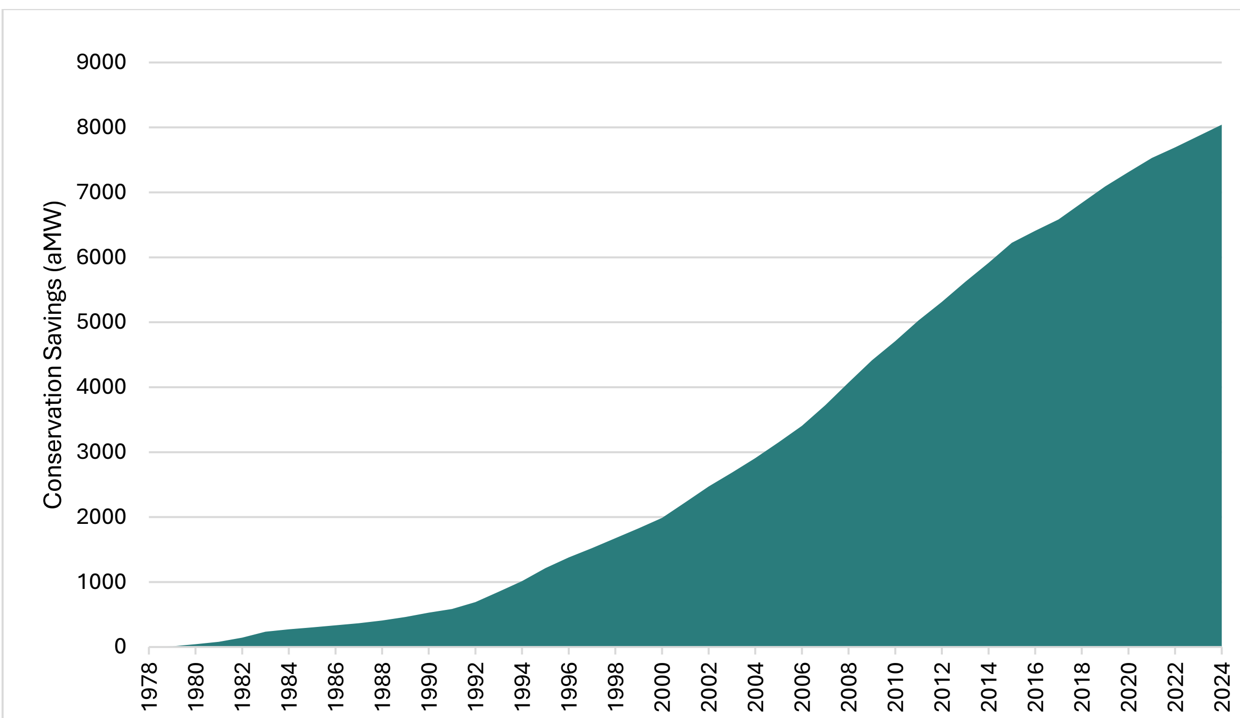
Demand side resources are those that can be acquired on the consumer (or demand) side of the meter. These include conservation, renewable resources such as rooftop solar, and demand response, or the ability to shift demand to support broader power system needs. Because these resources are on the consumer side of the meter, they have a direct impact on overall load growth. As demand side resources are added to the system, they offset electricity load, which in turn reduces the need for generating resources to serve that load.

Conservation

The Northwest Power Act identifies conservation as a priority resource to meet power system needs. Conservation is defined as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution."[32] The term "energy efficiency" is often used to describe this resource.

Conservation consists of many small decisions made by individuals and businesses, such as adding insulation to a home, installing a heating system that uses less energy, using more efficient lighting, upgrading industrial practices, or changing irrigation sprinklers to use less water, thereby reducing the associated pumping energy. Since the 1980s, Bonneville, the region's utilities, and others have been running conservation programs to support these actions. This collective effort has resulted in conservation becoming the second largest resource in the Pacific Northwest in terms of annual average megawatts, behind hydropower. As of the end of 2024, the region has achieved over 8,000 average megawatts of conservation. For scale, 8,000 average megawatts is enough energy to provide continuous power to seven cities the size of Seattle.

Figure 2 - 3: Northwest Conservation Savings Since 1978

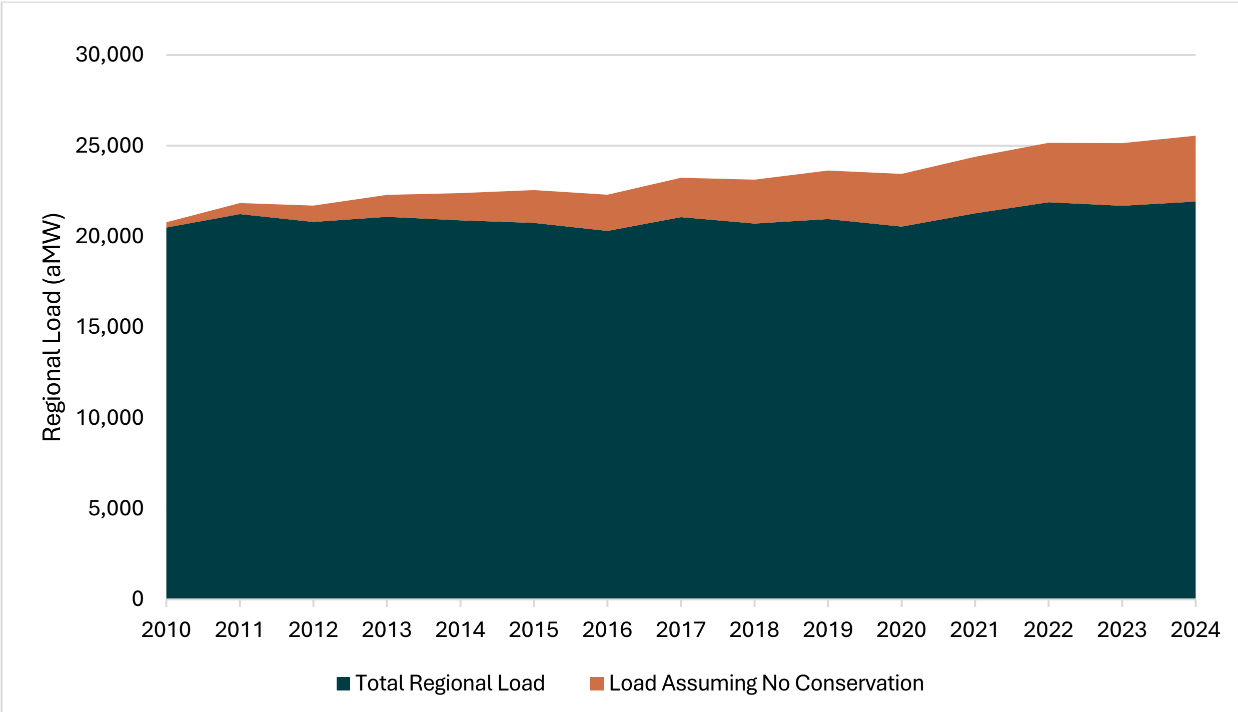


Conservation has reduced the electricity need in homes, businesses, industries, and farms throughout the region. This, in turn, has reduced the amount of load growth since 1980, helping to keep electricity demand relatively flat in recent years. Figure 2 - 4 shows the role conservation has

[32] Northwest Power Act, Section 3(3).

played in dampening load growth. Without conservation, regional loads in 2024 would have been closer to 25,000 average megawatts, or roughly 17% higher.

Figure 2 - 4: Load and Conservation Savings Since 2010

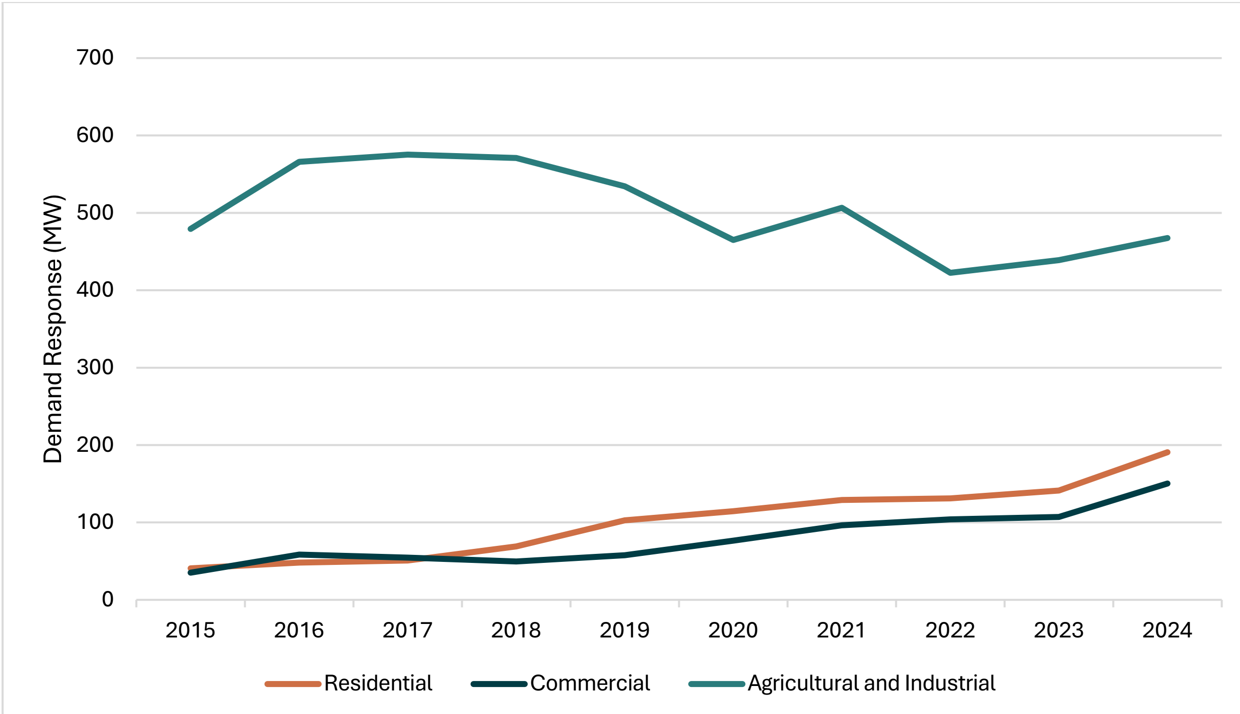


Demand Response

Demand response is a mechanism by which utilities can adjust the electricity demand of consumers at specific times to help reduce overall system demand. This can be done through direct adjustments, such as shifting the time of electric vehicle charging to later in the evening when less electricity is needed elsewhere in the system, or through the use of price signals to encourage consumers to shift the timing of their electricity use. Because the Northwest as a region has traditionally been capacity-rich, there has not been as much of a need for resources that target peak needs, like demand response. That is changing.

Historically, the use of demand response as a resource has been concentrated in the agricultural and industrial sectors. Irrigation demand response focuses on curtailing the load from pumps used for irrigation during some days in the summer months when there is significant energy demand. This has been an important resource in some parts of the region. For example, Idaho Power has maintained an irrigation demand response program for over two decades to support summer capacity needs. Industrial demand response targets large customers who can temporarily reduce operations or shift processes to lower energy use in response to a call from the utility.

Figure 2 - 5: Demand Response Savings by Sector Since 2015[33]



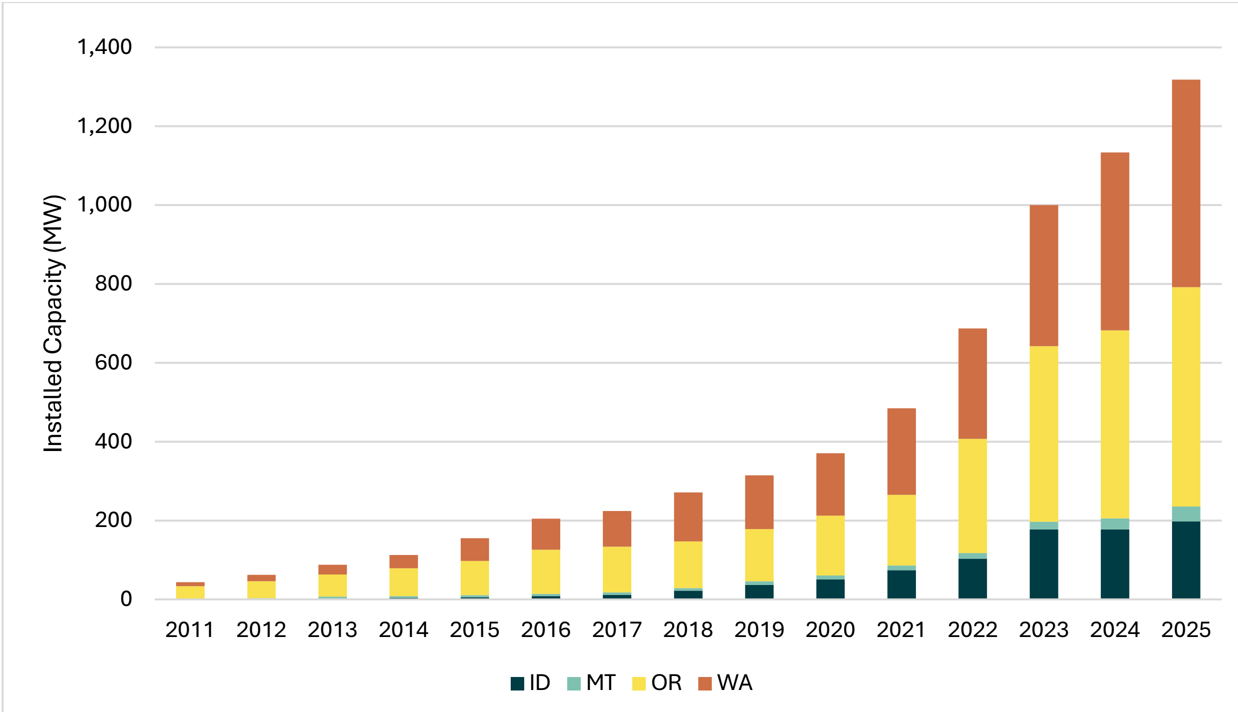
While the region's demand response resource is still dominated by irrigation programs, there has been a shift in recent years to explore more opportunities in other sectors, starting with the residential sector. These newly established programs and pilots consider a range of opportunities, including managing water heating loads, shifting electric vehicle charging times, and establishing rate structures to guide consumer electricity use. Collectively, these demand response programs help to offset regional energy demand during times of peak need on the system.

Rooftop Solar

Rooftop solar is similar to its utility-scale counterpart, but sized to address the needs of the specific residence or business on which it is located. Rooftop solar is a relatively small resource in this region, but there has been recent growth in the market that is consistent with national trends (see Figure 2 - 6). Rooftop solar growth in 2023 was particularly significant, with over 300 megawatts of new installations. This single year represents over 20% of the region's total installed capacity of around 1,300 megawatts as of 2025.

[33] Energy Information Administration Demand Response Data, Form 861.

Figure 2 - 6: Rooftop Solar Installations, by State, Since 2011[34]



Similar to other demand side resources, rooftop solar ultimately reduces overall regional load growth. Given the relatively small size of this resource to date, the Council has typically accounted for rooftop solar in its load forecast. For the Ninth Power Plan, the Council developed an estimate of rooftop solar potential, which is included in the suite of new resource options discussed in Chapter 3.

Supply Side Resources

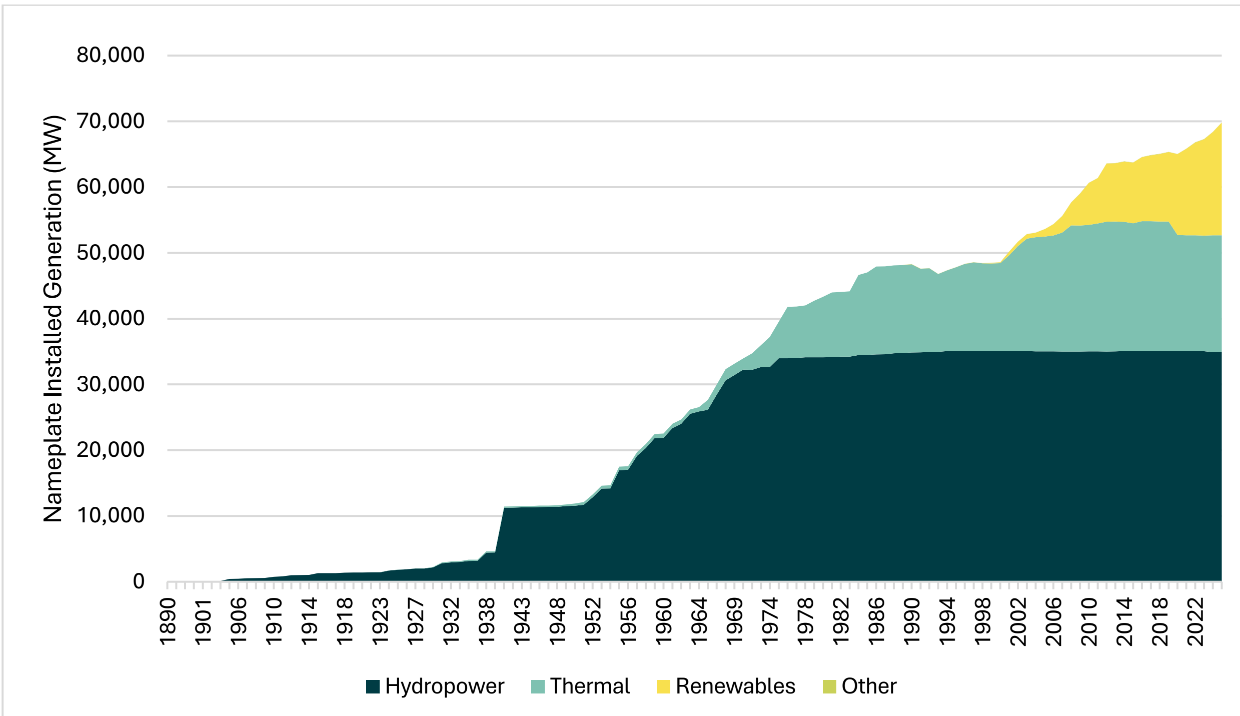
Large generating resources, also referred to as supply side resources, make up the bulk of the power system. The Council maintains a database tracking all generating projects in the region, including those projects built outside the region but serving the region's load.[35] This section provides context on historical development of supply side resources in the Northwest. More detail on the existing system is available in Technical Appendix B – Existing System Parameters and Policies.

The history of generation in the region can be characterized by three phases of development. First, the growth of the hydropower system, followed by a shift to new thermal plant development, and then the third phase of significant renewable development. Hydropower system development started in the late 1800s, with the bulk of development occurring from the 1930s through the 1970s. The hydropower system continues to provide the foundation for the Northwest's energy landscape.

[34] Energy Information Administration Data, Form 861.
[35] The Council's Project Database is updated regularly and is available at https://www.nwcouncil.org/energy/energy-topics/power-supply.

Around the 1970s, the region started to invest more in the development of thermal resources, starting with coal and nuclear power. In the late 1990s, the region transitioned to natural gas as the primary thermal resource to meet new load growth. The third phase started in the mid-2000s, with the shift towards renewable resources beginning with investment in wind development before shifting more to solar in recent years. More detail on each of these phases is described in the sections below.

Figure 2 - 7: Resource Development in the Northwest Since 1890



Hydropower

The Columbia River and its tributaries comprise one of the major economic and environmental resources in the Pacific Northwest. Originating in the Rocky Mountains in Canada, the mainstem of the Columbia River extends a total of 1,243 miles to the Pacific Ocean. The major development phase of hydropower in the Columbia River Basin began in the 1930s and extended through the 1970s. The development across the system included over 250 hydropower dams and about 200 non-power dams, which were built for purposes such as irrigation and flood control. Today, the Columbia River Basin hydropower system delivers carbon-free, renewable energy that, on average, supplies roughly half the electricity generation in the region.

In addition to providing electricity, the dams meet many needs for the Northwest. These include operations to support flood control, irrigation, recreation, and transportation. More importantly for the Council's work, the operational flexibility and generating capability of the hydropower system has been reduced to protect fish and wildlife from the impacts of the system. As discussed in Chapter 1, one of the Council's key purposes is to protect, mitigate, and enhance fish and wildlife impacted by the Columbia River Basin hydropower system. The Council's 2026 Columbia River Basin Fish and Wildlife Program details measures and objectives to protect and benefit fish and wildlife. This includes measures that directly impact hydropower development, require minimum flows and flow augmentation to support fish migration, and offsite protection and mitigation actions to support affected species. From the inception of the Program, the Council has also supported the concept of protecting some streams and wildlife habitats from further hydropower development. In the late 1980s, the Council designated 44,000 miles of river reaches as “protected areas,” where the Council determined that development would have major negative impacts that could not be reversed. These protected areas have proven effective at limiting new hydropower development in important fish and wildlife habitat.

More detail on the Council’s current Fish and Wildlife Program and its relationship to the Ninth Power Plan is included later in this chapter.

Thermal Resources

Following the development of the hydropower system, there was a shift to thermal resource development to meet new load growth, including nuclear, coal, and natural gas. These came into the region in two waves. First, there was a focus on nuclear and coal, driven in part by the Hydro-Thermal Power Program. The second came later with the advancement of natural gas.

Nuclear and Coal Development

Congress authorized the region’s first nuclear project in 1958 in Hanford, Washington, on the site of plutonium production for atomic weapons used in World War II. The Hanford Generating Project came online in 1966. Hanford operated until 1987, when it was placed on standby and ultimately shut down in 1994.

In the 1960s and 1970s, the region faced significant load growth forecasts and sought to address these impending projected shortfalls with new generation, specifically nuclear and coal plants. This effort, launched in 1968, was organized and spearheaded by the Hydro-Thermal Power Program, a comprehensive action and planning proposal for hydro-thermal power development. The program laid out the plan for Bonneville and its customers to build 21,400 megawatts of new thermal power (20 new thermal plants, 18 of which were nuclear) and 20,000 megawatts of new peaking hydropower by February of 1990. Phase 1 of the program proposed seven new generators, including Centralia coal plant in Washington, Trojan nuclear plant in Oregon, and three nuclear plants built and operated by Washington Public Power Supply System (WPPSS).[36] WPPSS was already the non-federal operator of the steam generator half of the Hanford nuclear project. Phase 2 included two additional nuclear projects to be built by WPPSS.

Ultimately, after significant cost overruns and load growth not materializing as forecast, only one of the five WPPSS nuclear plants was ever built, the Columbia Generating Station (CGS), at the Hanford

[36] The Washington Public Power Supply System was a joint operating agency that organized Bonneville utility customers in Washington to share the risks and rewards of building and operating new electric generating facilities.

site in 1984. As discussed in Chapter 1, this experience was a major driver for the development of the Northwest Power Act.

Regional utilities also developed the Centralia coal plant and Trojan nuclear plant identified in Phase 1 of the Hydro-Thermal Power Program. In 1976, Portland General Electric connected Trojan nuclear plant near Rainer, Oregon. The plant was permanently shut down in 1993, when it was deemed no longer cost competitive, and was eventually demolished in 2006. Trojan's retirement and eventual demolition was also a reaction to years of organized anti-nuclear pushback against the plant. These sentiments were codified into law in 1980 by Oregon's Ballot Measure 7, which banned the construction of new nuclear reactors without a permanent, federal repository for high-level nuclear waste and the approval of Oregon voters.[37]

Today, CGS is the only remaining nuclear plant operating in the region. WPPSS was renamed Energy Northwest in 1998. CGS is owned and operated by Energy Northwest and is licensed to run through 2043, since the Nuclear Regulatory Commission granted a 20-year renewal to CGS's original 40-year operating license. CGS has a capacity of about 1,200 megawatts and provides on average between 950–1,100 average megawatts of energy to the region annually, depending on the refueling schedule. In May 2025, Bonneville approved an extended power uprate to CGS, which will increase generating capacity by around 160 megawatts by 2031. The recent need for new resources, especially the perceived need for new baseload resources, has created interest in nuclear energy. Plants in other parts of the U.S. are being repowered, and there is ongoing interest in new applications of nuclear technology. These emerging technologies are discussed further in Chapter 3.

In the late 1960s, the region also looked to coal as another economical source of electricity. In addition to the Centralia plant in Washington, Northwest utilities brought into service 14 coal-fired units across six sites between 1968 and 1986. These include Boardman (Oregon), Colstrip (Montana), J.E. Corette (Montana), Jim Bridger (Wyoming), and North Valmy (Nevada). At its height, the region's coal capacity (including several smaller coal units) totaled around 7,300 megawatts.

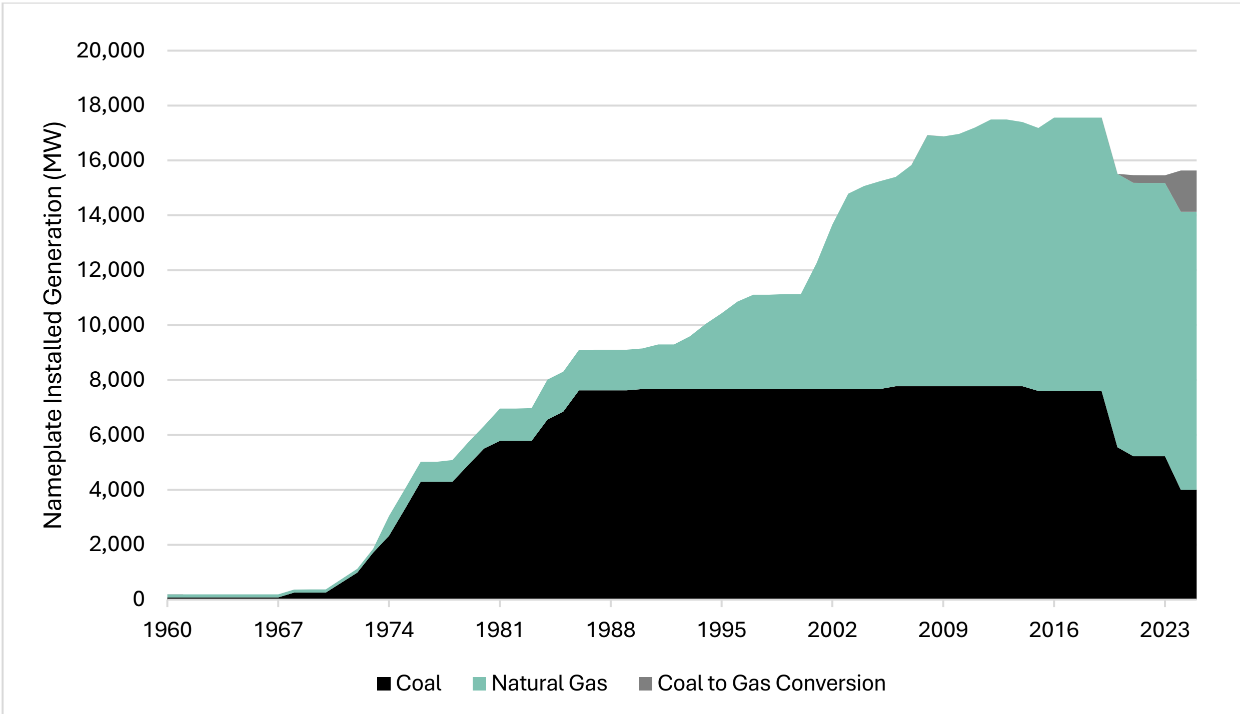
Natural Gas

Natural gas development started in the region in 1974 with the first natural gas-fired baseload plant, the 600-megawatt Beaver combined cycle plant. This was followed by a few gas peaking plants in the early 1980s. The real shift towards natural gas development started in the late 1980s (see Figure 2 - 8). This was driven in large part by General Electric's release of its F-class frame unit, a machine with increased reliability and efficiency, as well as low gas prices. A second wave of gas plant development by independent power producers came in response to the West Coast electricity crisis in the early 2000s. In recent years, the development of gas peaking plants (simple cycle and reciprocating engines) in the Pacific Northwest and elsewhere can be attributed, in part, to the need

[37] Siting of Nuclear-Fueled Thermal Power Plants, ORS 469.590 to 469.599. https://www.oregonlegislature.gov/bills_laws/ors/ors469.html

for additional flexibility in the power system to supplement and integrate variable energy resources such as wind and solar.

Figure 2 - 8: Coal and Gas Development in the Northwest Since 1960



A combination of new clean policies and the decreasing costs of alternative resources, including natural gas and renewables, has reduced the role of coal in the region. In the mid-2010s, several coal plant owners announced planned retirement of their projects. In 2020, around 2,050 megawatts of coal were retired from the system.[38] Since then, driven by recent load growth and resource development challenges, coal plant owners have reversed decisions on plant retirement, with many instead shifting to coal-to-gas conversions. Table 2 – 1 outlines the owner-announced plans for the remaining coal plants serving Northwest loads.

[38] This includes Colstrip 1 and 2 in Montana, Boardman in Oregon, and Centralia 1 in Washington.

Table 2 - 1: Owner-Announced Plans for Remaining Coal Plants Serving the Northwest

Coal Unit	Nameplate Capacity (MW)	Owner-Announced Plans
Centralia 2	730	Gas conversion expected in late 2028
Colstrip 3	778	Remaining coal
Colstrip 4	778	Remaining coal
Jim Bridger 1	608	Converted to gas in 2024
Jim Bridger 2	617	Converted to gas in 2024
Jim Bridger 3	608	Adding carbon capture sequestration in 2030
Jim Bridger 4	608	Adding carbon capture sequestration in 2030
North Valmy 1	277	Gas conversion expected in 2026
North Valmy 2	289	Gas conversion expected in 2026

Other Thermal Resources

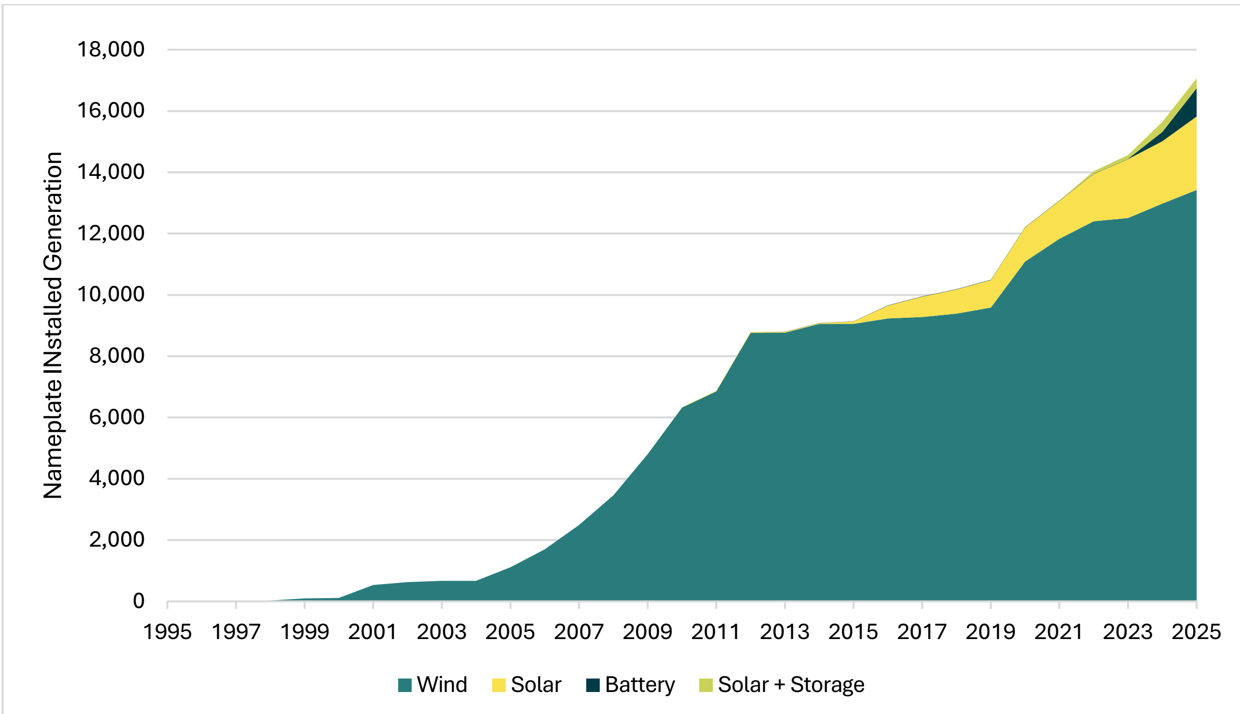
Other thermal resources exist in the region but play a smaller role in the overall regional power supply. For example, the region has around 750 megawatts of installed biomass plants, which run on a variety of fuels. The majority of the region's biomass capacity burns fuels from spent pulping liquor and woody residues. The economic recession in the late 2000s resulted in several of the region's paper and textile plants shutting down, leading to a reduction in the supply of this fuel for biomass plants. More recently, the region has also added several small animal waste and landfill gas plants developed on existing dairy farms and landfill operations.

Another thermal resource is cogeneration, or combined heat and power, which produces both electricity and thermal or mechanical energy for industrial processes, space conditioning, or hot water. Section 4(e)(1) of the Northwest Power Act gives priority first to conservation, second to renewable resources, and third to generating resources using waste heat. Industrial cogeneration falls under this third priority category. In the Pacific Northwest, there are different types of industrial cogeneration, namely biomass and natural gas plants. Industrial cogeneration in the forest products industry has long been a component of Pacific Northwest electric power generation. These plants include chemical recovery boilers in the pulp and paper industry, and power boilers fired by wood residues, fuel oil, and gas in both the pulp and paper and lumber and wood products sectors. Gas-fired combustion turbines have also been installed as industrial cogeneration units, oftentimes with the waste heat (steam) being used for secondary heating purposes. Many of these industrial cogeneration plants do not sell power offsite, or generate only when fuel costs are favorable, and therefore the Council does not have a precise inventory of these plants in the region.

Renewables

The region's investment in renewable energy started with wind in the late 1990s and early 2000s. When states began adopting renewable portfolio standards in the mid-2000s, wind development picked up. This started in areas with both a good wind resource (e.g. higher speeds) and accessibility in the region, primarily along the Columbia River Gorge.[39] Advancements in wind technology and lower costs have enabled the region to expand its wind resource by broadening the potential locations of projects. This includes additional wind throughout the Gorge, parts of central and eastern Washington, and expansion into Montana and Idaho. There has also been significant development of wind in Wyoming to serve loads in the region. Wyoming has a particularly good wind resource.

Figure 2 - 9: Renewable Development in the Northwest Since 1995



The next wave of renewable development in the region has been solar generation. Solar is a relatively newer technology. Early development primarily occurred in parts of the country with a better solar resource (e.g. more reliable sunshine), such as California and the desert Southwest. The investment in solar in those locations ultimately flooded the market with cheap power, which in turn discouraged early solar development in the Northwest. As clean policies got more stringent and the cost of solar continued to decline, the region started to invest more in this resource. The region now has around 2,400 nameplate megawatts of solar resources, with the bulk of that investment occurring in the last five years.

The most recent phase of renewable development is storage. Storage resources capture and store energy generated at one time to be discharged and used at another time. While not strictly a renewable resource, utilities are adding storage to balance renewables and foster further renewable

[39] Part of accessibility included transmission availability, with early projects being cited in areas with both a good wind resource and transmission access.

development. The most common storage resource in the Northwest is lithium-ion batteries. The first wave of battery storage in the region was an investment in standalone facilities, but the region is seeing an increase in the colocation of battery storage with other renewable resources. In 2024 and 2025, the region built 1,000 megawatts of battery storage.

In addition to wind, solar, and storage, the region has also invested in some geothermal resources. The Northwest is home to a significant, naturally occurring geothermal resource, especially in southern Oregon and Idaho. Despite this resource potential, the significant cost of geothermal has limited the amount of development in the region. There are currently only four geothermal projects with a total nameplate capacity of around 50 megawatts, three of which are in southern Oregon and one in southern Idaho. Entities are exploring enhancements in geothermal that would broaden the geographic potential of this resource.

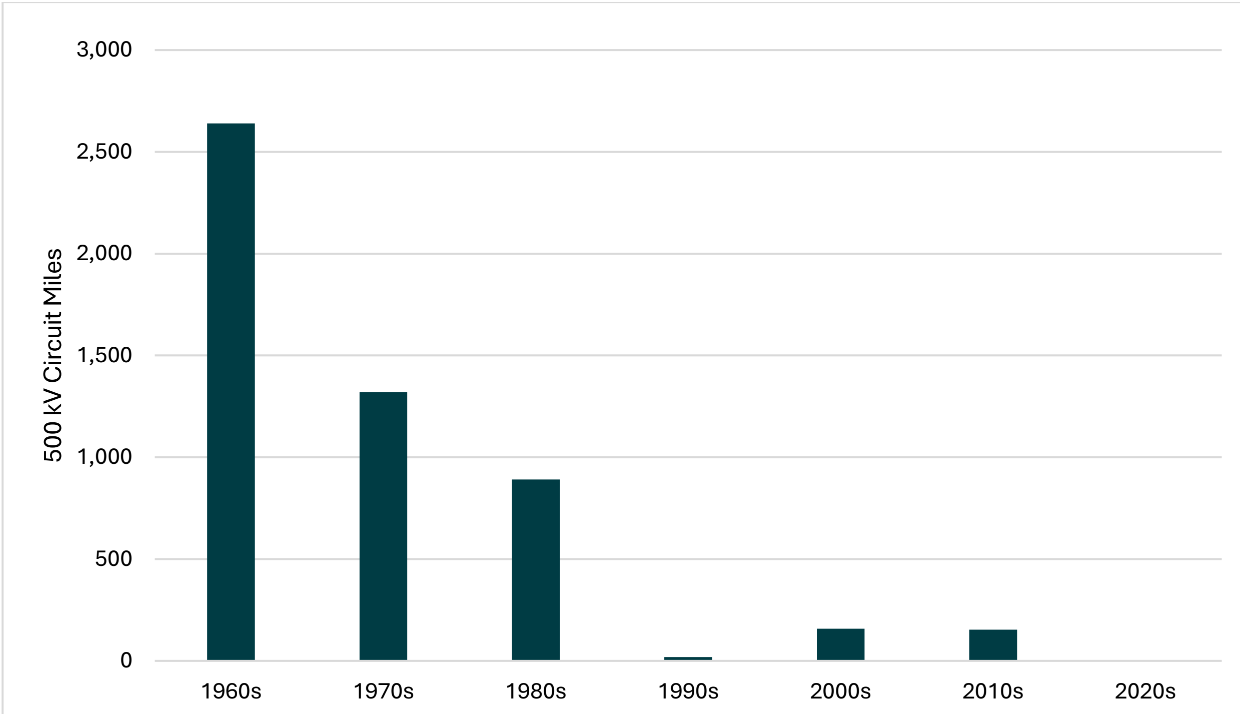
Transmission

The Pacific Northwest transmission grid is part of the Western Interconnection, one of three major National Energy Regulatory Commission (NERC) grid interconnections in the continental United States. The Western Interconnect encompasses all or parts of states and provinces west of the Rocky Mountains to the Pacific Ocean and Northern Baja, California. Via this system, Northwest utilities are connected to the greater West through interties into California, British Columbia, and the Rocky Mountain Area. According to the Western Electricity Coordinating Council (WECC), the Western Interconnect comprises roughly 136,000 miles of transmission lines.[40] The system was strategically developed to connect the major load centers with remote resources, and, in particular in the Pacific Northwest, to connect the hydropower dams to high-voltage transmission lines in order to support the transfer capability of seasonal energy.

Bonneville owns roughly 70% of the transmission system in the region, with other utility and energy service supplier owners accounting for the rest. As shown in Figure 2 - 10, the bulk of the Bonneville transmission system was developed in the 1960s through 1980s. Since then, there has been little investment in transmission expansion in the region. This stagnation in new transmission development has become increasingly pressing in recent years, as increasing loads and more dispersed generation asks more of the aging system.

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

Figure 2 - 10: Transmission Development in the Bonneville System over the Decades[41]



Recognizing the need for new transmission in the region, Bonneville, utilities, and others have come together through the Western Transmission Expansion Coalition (also known as WestTEC). This is a west-wide voluntary effort to conduct long-term transmission planning for the west. WestTEC recently released the results of its 10-year study and is now working on a 20-year analysis.[42] The Council leveraged publicly available information from this analysis to inform the scenario modeling discussed more in Chapter 3.[43]

Resources Across the West

With the region being part of the broader Western Interconnect, it is important to understand the resource mix across the West. This ultimately provides information on the available market on a short-term basis. The Council's adequacy, production cost, and capital expansion models all include load and resource information for the broader West.[44]

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[41] Data for this chart was provided by Bonneville, as shared with the Council at its August 2023 meeting. More information is available at https://www.nwcouncil.org/fs/18429/2023_08_3.pdf.

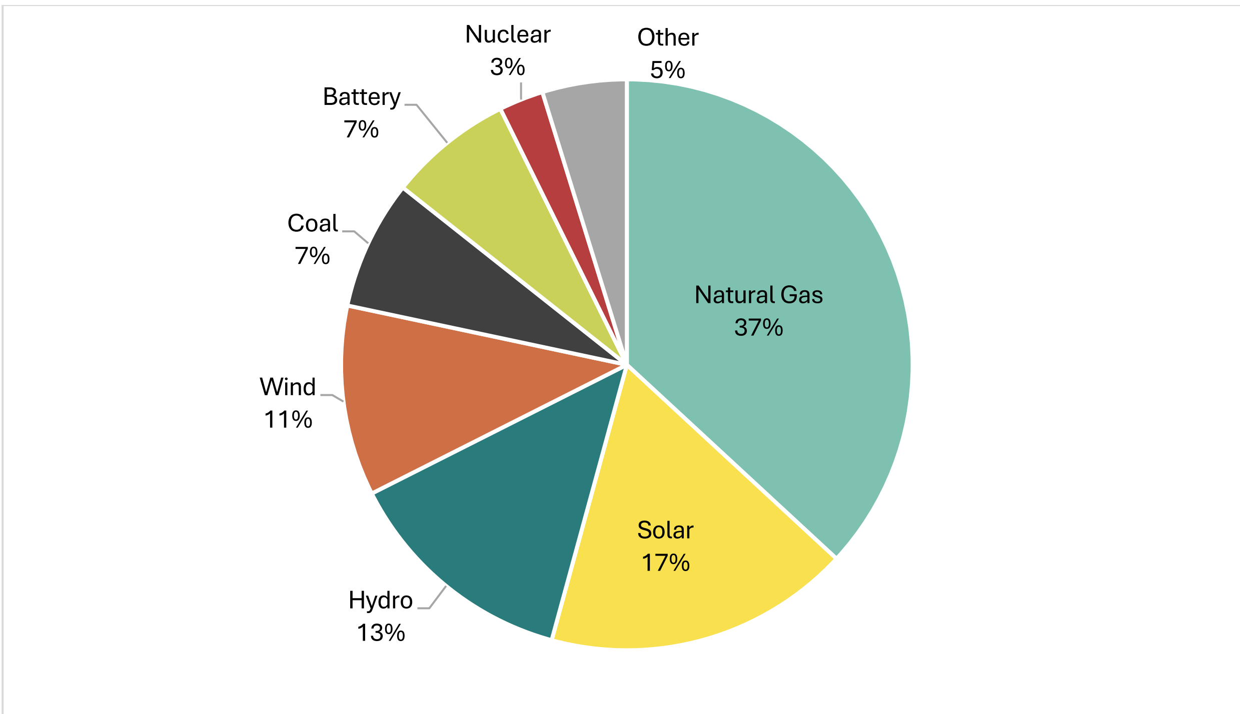
[42] More information on the work of WestTEC, including the 10-year report, is available on its website: https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition.

[43] More detail on the existing transmission system is available in Technical Appendix B – Existing System Parameters and Policies.

[44] The Council's three models for scenario modeling include GENESYS (hydro modeling and adequacy), OptGen/SDDP (regional capital expansion and resource optimization, and Aurora (west-wide market availability).

The resource mix across the Western Interconnection is different than that of the region. While hydropower is dominant in the Northwest, it represents around 13% of the installed generation for the broader West. Instead, natural gas is the most dominant resource in terms of installed capacity, followed by solar. Figure 2 - 11 shows the resource mix of the Western Interconnect, excluding the resources serving the Northwest. The total nameplate capacity of the West outside of this region is around 248 gigawatts. This compares to approximately 70 gigawatts in the Northwest. The resources that make up the “other” category depicted in Figure 2 - 11 include around 4,700 megawatts of pumped storage (1.9% of total) and 3,700 megawatts of geothermal (1.5% of total).

Figure 2 - 11: West-Wide Resource Mix in 2025, Excluding Northwest Resources



Coal generation currently represents around 7% of the installed capacity for the West. As in the Northwest, states across the West are shifting away from their coal fleets due to rising costs, aging plant efficiency, and policies targeting carbon emissions. Roughly 75% of the installed coal fleet capacity is announced for either retirement or conversion to natural gas.[45]

Current Issues Impacting the Northwest Power System

The power system is dynamic. Changes in the consumer base, whether it be a growing population, emerging industry, or other shifts in the economy, result in changes in power needs. Policies at the federal, state, and local levels may impact decisions around power planning, siting of resources, and operations of the existing system. As the Council embarks on the Ninth Power Plan, Bonneville, the region, and the broader power system are undergoing a period of rapid change. The following section highlights some of these key shifts.

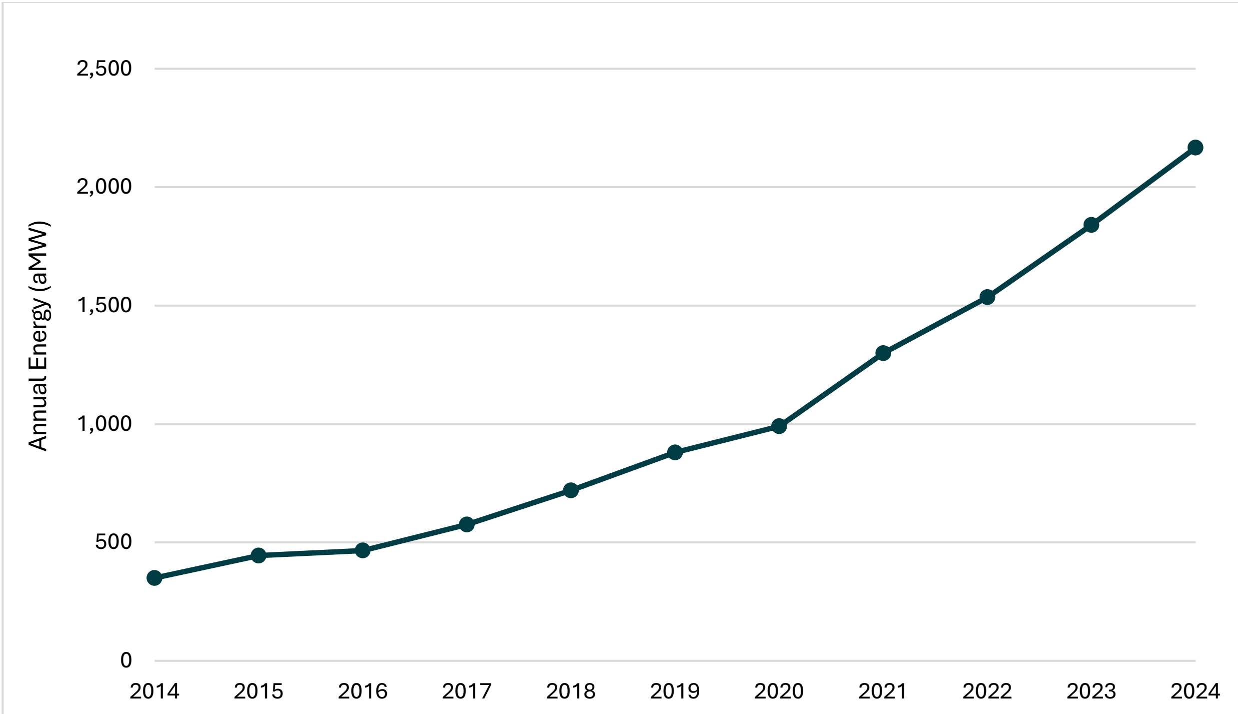
Recent Load Growth

As discussed above, the rate of load growth in the last five years has increased, driven by new load segments including data centers and electrification. Over the next 20 years, overall regional load growth is expected to grow significantly, although there remains much uncertainty around exactly how much, in what sectors, and where in the region this growth will occur.

One of the largest drivers of recent load growth is the increase in data centers and high-tech industries. This type of load is unique from other sectors. These are very large and relatively flat loads that come on rather quickly. They are also highly concentrated in some parts of the region. Figure 2 - 12 shows the estimated recent data center growth in the region. It is important to note that this specific data does not include the growth of other high-tech industries, such as chip fabrication, which are also important drivers of electricity demand. Planning for the growth in these large loads is one of the biggest challenges facing the region. Chapter 3 provides more information on the Council's approach to forecasting this data center and other high-tech growth over the next 20 years.

[45] A full list of west-wide coal plants and information on announced retirements or conversions is available in Technical Appendix B – Existing System Parameters and Policies.

Figure 2 - 12: Estimated Data Center Demand Since 2014



Another driver of recent load growth is the electrification of vehicles. Unlike data centers loads that are relatively large and flat, these loads grow more slowly over time as consumers make decisions to purchase electric vehicles. The demand for electricity only occurs when the car is charging, which can strain the power system if everyone comes home and plugs in to charge at the same time. Table 2 - 2 shows the estimated number of electric vehicles in the region, and the growth since 2021. Most of this growth is concentrated in Oregon and Washington. Currently, electric vehicles represent only a small share of total vehicles in the region. As described in Chapter 3, the Council expects electric vehicles to become a larger part of the economy, particularly in the states of Washington and Oregon where policies are targeting increased sales of these vehicles.

Table 2 - 2: Estimated Electric Vehicle Counts, by State

State	Number of EVs as of 2025	Growth since 2021	Estimated Share of EVs as of 2024	Percent Mix of BEV/PHEV[46]
Idaho	20,133	14,133	0.9%	67/33
Montana	4,754	4,544	1.0%	66/34
Oregon	134,425	102,212	2.8%	72/28
Washington	278,490	190,456	4.3%	80/20

Bonneville Power's Post-2028 Contracts

As described in Chapter 1, Bonneville is required to offer power sales contracts to utilities and others in the region.[47] Bonneville's current contracts with preference customers are known as the Regional Dialogue contracts. These contracts are set to expire on September 30, 2028. Bonneville has been working with the region on a new set of contracts, known as the Provider of Choice contracts, to support power services for a 19-year period starting October 1, 2028, and ending September 30, 2044. More than 130 customer utilities signed these contracts, and Bonneville is now working with its customers and the region on implementation details to be ready to provide service in October 2028.

Bonneville may need to acquire new resources beyond conservation to meet the power service obligations of these contracts, while also continuing to meet its obligations to meet requirements for fish and wildlife mitigation. Bonneville sells power to its preference customers under a tiered rate approach. Under these new contracts, Bonneville has committed to deliver up to 7,250 average megawatts to customers at the Tier 1 rate, which represents the costs of the existing system and any new resources that may need to be acquired to meet that obligation. The amount of power that Bonneville will provide to each customer at the Tier 1 rate is known as the contract high water mark. Customers may then elect to have Bonneville serve additional load beyond that contract high water mark, which is provided at the Tier 2 rate. As customers' loads grow, and the obligation for power sales increases, Bonneville may need to acquire resources to serve those customers. The Ninth Power Plan provides recommendations for Bonneville to guide its resource decisions. More information is provided in the Action Plan (Chapter 4) and Conservation Program (Chapter 5).

Extreme Weather Events

The region, and broader West, have experienced several extreme weather events over the years that have strained the power system and significantly impacted communities. Two recent events of note were the 2021 heat dome where temperatures in the region were significantly above normal (reaching

[46] BEV stands for battery electric vehicle, which is an all-electric vehicle. PHEV standards for plug-in hybrid electric vehicle, which combines a rechargeable electric motor with a traditional gasoline engine.
[47] Northwest Power Act, Section 5.

116 degrees in Portland) and the January 2024 cold event (also referred to as the MLK event). Beyond extreme temperature events, the Northwest has been experiencing an increase in the amount and intensity of wildfires. As the Council embarked on the development of the Ninth Plan, many entities throughout the region asked that the Plan provide a robust solution to account for extreme weather events in the future.

Weather, and particularly weather 20 years into the future, is a significant area of uncertainty for power planning. Temperatures have a direct impact on how much power people will use in their homes and businesses for heating and cooling. Temperatures and precipitation impact rainfall and snowmelt, which is important in a region dominated by hydropower. The weather can even impact resource availability by changing the efficiency or capacity of a specific resource. Since the development of the 2021 Power Plan, the Council has leveraged climate model data to help forecast the very uncertain future weather, including temperatures, precipitation, and wind regimes.[48] The temperature data from these climate models informs the Council's forecasts of future load. These same temperatures also inform wind and solar availability, as there is a relationship between temperature and the capacity factors of those resources. Precipitation data informs streamflow, which in turn informs hydro conditions. In total, the Council models 90 pairings of future hydro, wind, solar, and loads connected by data from three climate models, to provide a range of uncertainty.

Given the importance of ensuring the Ninth Power Plan accounts for extreme weather, the Council reviewed how well the climate model data captures extreme weather events by comparing temperatures from recent events to those in the climate data. This analysis shows that the climate model data captures extreme events, both hot and cold. The climate models generally show a shift to warmer temperatures. This shift is captured in the frequency of heat events, where there are more consecutive days of high temperatures across the climate model years than in historical data. While the data shows an overall shift towards warmer temperatures, the models continue to capture long-duration cold events, with temperatures getting as low as those seen in the historical data.[49]

Wildfires are another risk area across the West, impacting the daily lives of many. The Ninth Power Plan is the first Council plan to consider the impacts of wildfire on the power system. The Council focused on the operational risks of wildfires, specifically the impact on solar generation from nearby smoke.[50] The Council used data on particulate matter from recent events to develop information on

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[48] The Council uses global climate models analyzed by the Intergovernmental Panel on Climate Change as part of its Fifth Assessment Report. The River Management Joint Operating Committee downscaled these models to provide more granular information for the Pacific Northwest. The Council has selected three of these models that represent a range of future temperature and hydro conditions. More information on the models and the Council's selection process is available in Technical Appendix D – Climate Model Data and Assumptions.

[49] More information on the use of climate model data and the analysis of extreme weather events is available in Technical Appendix D – Climate Model Data and Assumptions.

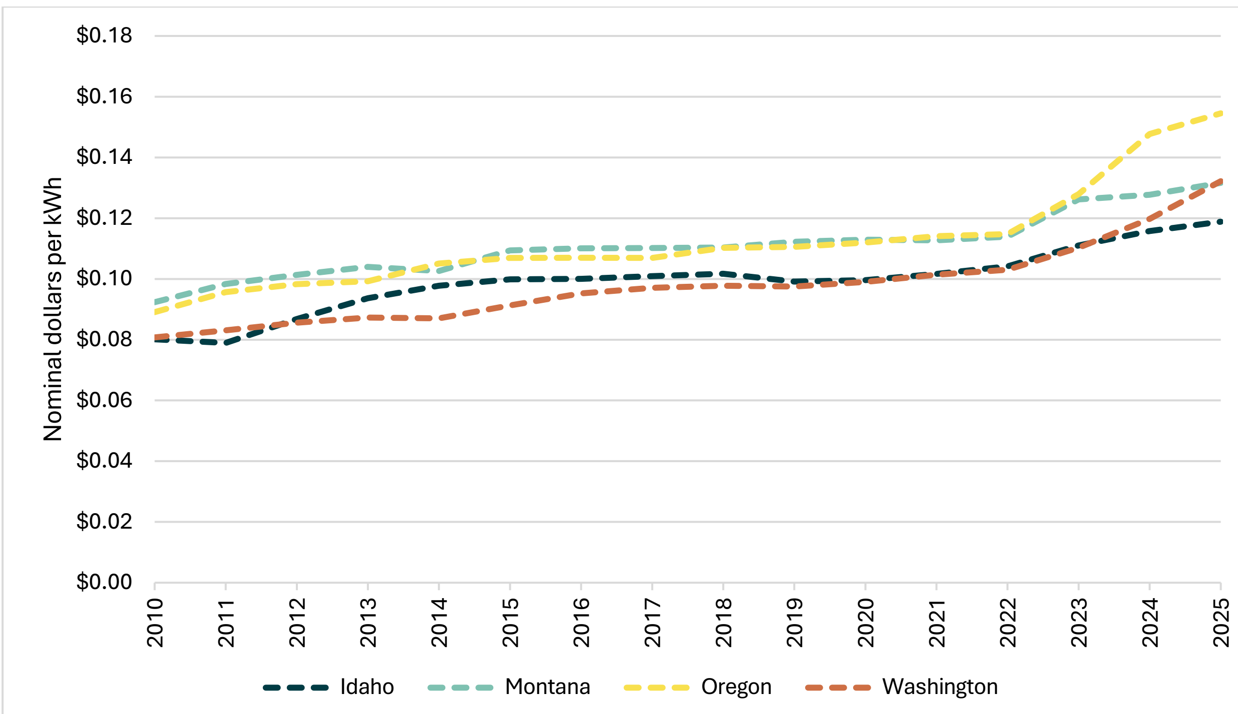
[50] The Council also considered a modeling approach to capture the operational risk of transmission derates from wildfires. This approach was discussed at a multi-advisory committee meeting on March 7, 2025 and with the Council at its May 2025 Council meeting. Ultimately, the Council determined that there was not an effective way to incorporate the proposed

"wildfire smoke days" during which the capacity factors for a specific solar shape is reduced by roughly 10%.[51] This approach provides an important step forward in power system modeling, as the risk of wildfire continues to grow for the region.

Bonneville and Retail Electricity Rates

Northwest electricity rates have increased for consumers in nominal dollar terms in recent years, with steeper increases in the early 2020s. Figure 2 - 13 shows average annual retail electricity rates for residential customers from 2010 through 2025. General trends for the commercial and industrial sectors are similar to those in residential, albeit at lower prices. It is important to note that these data are state level aggregates. Individual utilities may have different patterns of rate change.

Figure 2 - 13: Residential Retail Electricity Rates, nominal dollars[52]



One factor that impacts retail electricity rates shown in Figure 2 - 13 is inflation. The U.S. experienced a high level of inflation in the early 2020s. After adjusting for this inflation, the picture shifts slightly. Figure 2 - 14 shows retail electricity rates in real dollars after adjusted for inflation. As shown, retail

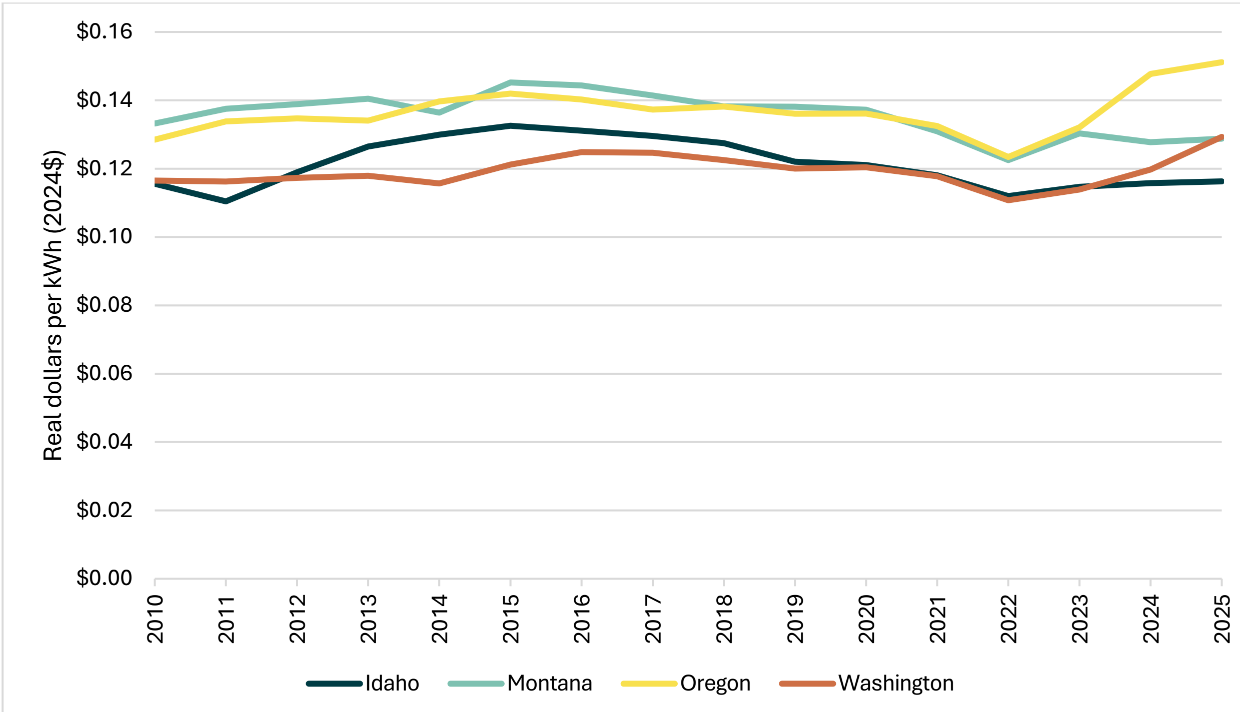
transmission derates consistent with the effect on solar generation, and therefore it did not implement the approach in the Ninth Plan.

[51] More information on the development of the wildfire informed solar profiles is captured in Technical Appendix G – New Generating Resources.

[52] Data from U.S. EIA, averaged from monthly data to annual: https://www.eia.gov/states/data/dashboard/prices-rates-revenues-costs-expenditures.

rates in real dollars declined between 2015 and 2022. These rates in real dollars have since increased, particularly in Oregon and Washington.

Figure 2 - 14: Residential Retail Electricity Rates, real (2024) dollars[53]



This increase in electricity rates has been driven by a variety of factors, including the investments needed to maintain aging distribution and transmission system infrastructure, as well as the development of new resources to address load growth and support clean policies. Extreme weather events have also led to increases in electricity rates in some areas, like investments for wildfire mitigation, insurance costs, and costs associated with liabilities and awarded damages. Some portions of the region have also seen increases in rates due to storm recovery, such as distribution system repairs after an ice storm.

In the Northwest, public utilities have access to power from Bonneville at contractually set preference rates. This includes power sold at the Tier 1 rate for contract high water mark load and power sold at the Tier 2 rate for additional load. Similar to the trends seen across the region, when accounting for inflation, Tier 1 rates showed a general decline between 2018 and 2023, with sharp increases in the past few years.

Bonneville's Tier 2 rates tend to be higher than Tier 1 rates. Bonneville's Tier 2 rate is currently connected to market prices, and recent increases and variability in market prices (discussed more below) have driven up this rate. The increase in Bonneville rates has a direct impact on the retail

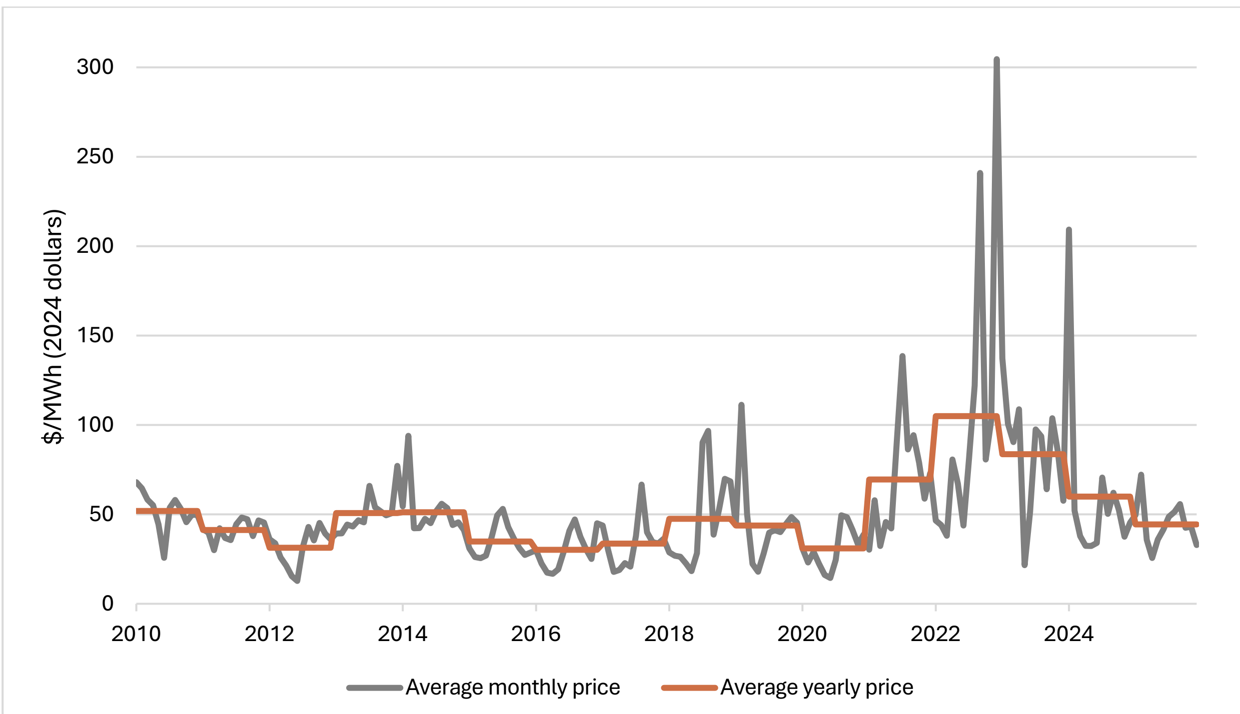
[53] Ibid.

electricity rate for consumers. As Bonneville customer utilities forecast load growth, they are weighing the uncertainty and risk of future Bonneville rates as part of the decision-making process when deciding how to meet needs while ensuring affordability.

Market Prices and Economic Risk

Power market prices, and the variability of market prices, create economic risk for utilities relying on the market as part of their resource needs. The market price is typically connected to the marginal resource for energy. For the 2010s, annual average market prices remained relatively low. This was driven, in part, by relatively low and stable natural gas prices, with natural gas often the marginal resource for the system. In recent years, the market has experienced volatility and periods of high prices. This is due in part to power system load growth, increased volatility in natural gas prices driven by pipeline system constraints and outages, and extreme weather events. The increase in variable energy resource penetration is also driving more intraday volatility in market prices.

Figure 2 - 15: Average Monthly and Annual Market Prices Since 2010[54]



Power market conditions can shape new resource decisions. New resources become a more attractive way of meeting loads when market prices are high or when supply is tight during peak demand hours. High prices can also make new resources more valuable because they reduce a

[54] These prices are for day-ahead heavy load hours at the Mid-Columbia hub. The volume at the Mid-Columbia hub has declined in recent years, due in part to the introduction of the Western Energy Imbalance Market discussed more in the next session. That being said, these prices continue to provide good information to show general trends for the region.

utility's exposure to market purchases, and these same resources can provide economic gains by selling excess power into the market when available.

This recent exposure to increased market prices, and particularly the increased volatility of market prices, is changing utility resource decisions. Utilities have been planning for the development of more resources and reducing their reliance on the market. The extreme weather events experienced in the last five years have further heightened utility interest in reducing market reliance. The Council was mindful of this risk when developing the resource strategy included in Chapter 4 of this Plan.

State of Power Markets

Unlike other parts of the country, the Northwest power system generally operates within a bilateral (decentralized) market where electricity buyers and sellers directly negotiate contracts for power. Over the past decade, the region has been exploring shifts towards more organized markets. This shift started with the launch of the Western Energy Imbalance Market (WEIM) in 2014, operated by the California Independent System Operator (CAISO). This is a real-time market that seeks to optimize operations across its footprint to balance immediate demand within the hour. Between 2014 and 2022, Bonneville, the investor-owned utilities in the region, and a couple of the larger public utilities joined the WEIM.[55]

In recent years, the region has explored additional opportunities for market development with two potential day-ahead markets: the Extended Day Ahead Market operated by CAISO and Markets+ operated by the Southwest Power Pool. As suggested by the name, these markets will seek to optimize operations a day ahead of need. The Extended Day Ahead Market is already in operation as of May 2026, and Markets+ intends to go live in 2027. Bonneville and many of the utilities throughout the region are joining one of these two markets, which will provide for optimization of resources in the day ahead across larger footprints than currently happens under the bilateral market of today.

In addition to these markets, there are adequacy programs forming in the West. These programs seek to address resource adequacy needs by setting common standards for planning of resources and allowing the ability for participants to pool and share resources during tight power system operations. One such program is the Western Resource Adequacy Program (WRAP), which has been functioning for the past couple of years in a non-binding, voluntary manner, with plans to have a fully binding program in the winter of 2028. Many utilities in the region and across the West are participants of WRAP. Several regional utilities who are not a part of the WRAP are currently developing an alternative resource adequacy program. Collectively, it is expected that the bulk of the region's utilities and Bonneville will be participating in a resource adequacy program in the coming years.

All these advancements provide broader footprints for planning and operating, which can provide efficiencies for meeting future load growth and resource needs. The rules and footprints for these markets and programs were not established early enough to be incorporated directly into the Ninth

[55] More information at: https://www.westernenergymarkets.com/western-energy-imbalance-market-weim.

Plan analysis. The Ninth Plan does, however, attempt to reflect what was known about these markets in its modeling for resource adequacy within the regional footprint.

Existing State and Federal Policies

Energy policy is one of the key drivers of future resource development in the region and across the country. Policies impact the power system, and therefore the Council's planning, in multiple ways. Some policies impact the potential for future electricity demand. Examples of this are policies that target an increase in electric vehicle sales or encourage the development of certain industries. The actual impact of these policies over the next 20 years is uncertain. There is also uncertainty about what new policies impacting load growth will be established in the next 20 years. The Council's approach to modeling a range of future potential load growth, as described more in Chapter 3, is one way of accounting for the significant uncertainty driven by future policies.

Other policies have a direct impact on resource options for development, resource costs, or other considerations around resource operations. The Council accounts for these policies in multiple ways. One aspect is compliance with applicable environmental laws, which is incorporated as a cost of compliance impacting resource costs. As described in Chapter 1, the Northwest Power Act requires that the Council put forward a strategy for the development of new conservation and generating resources with due consideration for environmental quality, among other things. The Power Act also requires that the Council develop a methodology for quantifying environmental costs and benefits directly attributable to a resource. Chapter 3 of this Power Plan provides more detail on how the Council accounts for the cost of compliance with these environmental laws.

Policies can also impact which resources are developed and/or how those resources are operated. The main policies driving resource decisions in this region exist in Washington and Oregon. Washington's Clean Energy Transformation Act (also known as CETA) sets a statewide goal of 100% clean energy by 2045.[56] This goal is paired with the Climate Commitment Act, which sets an economy-wide, declining cap on greenhouse gas emissions and establishes a cap-and-invest program creating a carbon price for the state.[57] Oregon's Clean Energy Targets Bill requires Portland General Electric, PacifiCorp, and electricity service providers to reduce greenhouse gas emissions from the electricity sold to consumers in Oregon.[58] Oregon also has a renewable portfolio standard, which applies to consumer owned utilities not impacted by the Clean Energy Targets Bill.

Outside of these policies, utilities and jurisdictions in other parts of the region have created clean goals that guide decision making. Both Idaho Power and Avista have set goals to be 100% clean by

[56] Washington Clean Energy Transformation Act, Chapter 19.405 RCW. https://app.leg.wa.gov/rcw/default.aspx?cite=19.405.

[57] Greenhouse Gas Emissions – Cap and Invest Program, Chapter 70A.65 RCW. https://app.leg.wa.gov/rcw/default.aspx?cite=70A.65.

[58] Oregon Clean Energy Targets Bill, HB2021. https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled.

2045, which together represent roughly 75% of Idaho's electricity sales.[59] NorthWestern Energy in Montana has a 100% clean electricity by 2050 goal. Additionally, the cities of Bozeman, Missoula, and Helena have their own 100% clean electricity goals with a target date of 2030. Collectively, these jurisdictions represent approximately 58% of Montana's electricity sales. Between the policies in Washington and Oregon and the voluntary goals by utilities and communities in Idaho and Montana, approximately 88% of the region's electricity sales are impacted by a clean target or goal by 2050.[60] All of these policies and goals are reflected in the Council's Ninth Power Plan development.

The uncertainty around future policy changes and the durability of existing policy creates uncertainty for power planning, particularly at the federal level. For example, the changes in policy between the Biden Administration and Trump Administration send starkly different signals for resource development. Biden-era policies, like the Inflation Reduction Act, incentivized investment in clean technologies generally. The One Big Beautiful Bill Act passed under the Trump Administration removed those incentives for specific clean technologies — wind, solar, and conservation. Federal regulation of greenhouse gas emissions under the Clean Air Act has also caused significant uncertainty for new resource development. The Biden-era rules set strict emissions limits for new natural gas plants that would have had a meaningful effect on the utilization of high-capacity factor gas plants. The Trump Administration reversed those requirements. Policy shifts like these create uncertainty, making it challenging for planning and investing in certain resources. Recognizing this uncertainty, the Council developed scenarios to explore the impacts of differing federal policies on local resource decisions, with the aim of developing a Ninth Plan that is robust despite this uncertainty.[61]

The Council's 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 2026 Columbia Basin Fish and Wildlife Program is the Council's current version of the program. Prior to reviewing the power plan, the Act requires the Council to call for recommendations and then follow the process described in the Act to decide on program amendments. The Council did so, initiating this amendment process in January 2025 that culminated in the final decision to adopt the 2026 Fish and Wildlife Program in June 2026. As discussed in Chapter 1, one of the reasons for this ordering of the fish and wildlife program and power

[59] The City of Boise also has a 100% citywide clean energy goal by 2035. Idaho Power serves much of the electricity for Boise.
[60] More information on these policies and the representation across the region is provided in Technical Appendix B – Existing System Parameters and Policies.
[61] For the Ninth Power Plan, the bulk of analysis assumes all policies in effect as of December 31, 2024. With the change in Federal administration in January 2025, the Council made the decision to update its modeling to reflect the updated policies of the Trump Administration in its modeling. To test the impact federal policies have on regional decisions, the Council used a mix of Biden-era and Trump-era policies in its scenario analysis. The scenarios are described more in Chapter 3. Full description of the existing policies assumed in the Ninth Power Plan analysis is included in Technical Appendix B – Existing System Parameters and Policies.

plan process is that while developing the power plan, the Council can assess how dam operations that benefit fish impact hydro generation, and then design a regional resource strategy that accounts for any reduction in this generation.

The Council's fish and wildlife programs have evolved over the last 45 years. Early programs focused largely on improving juvenile and adult fish survival at and through the mainstem Columbia and Snake River dams. This included water management and fish passage provisions for anadromous fish and reservoir operations to benefit resident fish. The early programs also focused on anadromous fish loss assessments and systemwide goals, as well as wildlife loss assessments and the beginning of mitigation for those losses.

In 1988, the Council adopted protected areas as an element of the Council's fish and wildlife program and power plan. These provisions call on the Federal Energy Regulatory Commission (FERC) to not license new hydropower facilities in the river reaches with valuable fish or wildlife resources, which the Council identified and mapped in a protected areas database. These protected areas are not just limited to the Columbia River Basin but extend throughout the entire region. These provisions also call on Bonneville to not acquire the output of, or provide transmission support for, any such project, assuming it were to be licensed. To date, FERC has not licensed any new hydroelectric projects in these defined protected areas. In the context of power planning, these protected areas represent judgment by the Council that the potential effects on habitat, flows, and passage, as well as the adverse effects on and environmental costs to important fish and wildlife resources, are too great to justify new hydro development in these areas.

Since the early years of the Fish and Wildlife Program, the Council has expanded offsite mitigation activities with habitat improvements and fish hatcheries in the tributaries off the mainstem and in the lower Columbia River and estuary. The 2026 Columbia Basin Fish and Wildlife Program reflects work built over many years of program development and implementation. It has a continued emphasis on mainstem water management, passage improvements, and spill, as well as offsite habitat and hatchery mitigation improvements. The 2026 Program builds on a wealth of recommendations, comments on recommendations, and comments on the draft Program from federal and state agencies, including fish and wildlife agencies, tribes and tribal agencies, customers of Bonneville, river system users, and others. Given the broad scope of activities included in the Program, the Council identified and articulated a suite of priorities for near-term implementation. These include preserving program integrity, hydropower system operations, predator management, and habitat protection and restoration.

Of particular relevance to the Ninth Power Plan is the near-term priority of hydropower system operations. The Council placed particular focus on the importance of consistent and stable operations over a longer period of time to allow for better assessment of the effectiveness of those operations. This includes prioritizing operations that keep water flowing, increase velocities, and minimize fluctuations during peak juvenile migration. The Council also committed to help establish one or more work groups to investigate further changes in operations, including updating flood risk management for reservoir operations, evaluating specific parameters of limiting or allowing system flexibility to alter flow regimes, considering additional changes to system operations to increase velocities, and planning for preserving and rehabilitating passage infrastructure.

Many of these priorities are not new but reflect a continuation of measures included in previous Council programs. The Council's 1994 Fish and Wildlife Program introduced flow objectives designed to increase water flow and velocity, with the goal of reducing downstream migration time for juvenile anadromous fish and making conditions less favorable for predatory and competing fish. Also in the 1994 Program, the Council considered measures to reduce daily flow fluctuations by calling on the region to evaluate recommendations for developing ramping rates. In subsequent programs, the Council developed a suite of measures seeking to manage flows to more closely approximate natural hydrographic patterns and minimize daily fluctuations in flow. This issue of hydropower flexibility, particularly daily flexibility, has become one of increased focus with the addition and integration of new variable energy resources into the system.

The federal agencies that operate, manage, and regulate the Columbia system hydroelectric facilities all have responsibilities toward the Council's Fish and Wildlife Program and to the Act's purpose to protect, mitigate, and enhance fish and wildlife affected by the facilities. This includes Bonneville, the Army Corps of Engineers, and the Bureau of Reclamation. The Council's Program has been a foundation for both system operations and for the funding and implementation of off-site mitigation. While federal hydro system operations overlap substantially with measures in the Council's Program, the agencies have other influences on their operations and funding. The focus of the Council's 2026 Program is to move the federal system operations in certain directions, as described above. It remains to be seen, however, how much the new Program will affect actual operations. For power planning purposes, it is important to understand both what the Council's Program calls for and how the federal agencies are currently operating the hydropower system, as well as any differences between the two. Between the Endangered Species Act biological opinions, litigation settlements, and court orders, the federal system operations, specifically those targeting juvenile passage, have been on a roller coaster for over a decade.

The Council is mindful of these dynamics and the shifting, uncertain future for hydro operations. As discussed more in Chapter 3, the Council created space in the Ninth Plan scenario modeling to explore a variety of operations. This included testing different spring and summer spill regimes, exploring operations that reduced and held more consistent reservoir elevations during the spring and summer migration, and limited the fluctuations in the lower Columbia and Snake River systems at various portions of the year. The results from this analysis provided information to the Council on the impact of these different operations on future power system needs and a robust approach to adding new conservation and generating resources to ensure system adequacy across a range of potential hydropower operations. Further, as part of the Ninth Power Plan, the Council specifically analyzed the operations as recommended by the Council in the 2026 Fish and Wildlife Program. These operations included reservoir operations, spill, and other passage operations. The resource strategy and related recommendations included in Chapter 4 of this Power Plan provide for sufficient resources to both facilitate the operations required for the protection and mitigation of fish and wildlife impacts of the hydropower system and ensure the region maintains an adequate, efficient, economical, and reliable power supply.

Chapter 3: Future Electricity Needs and New Resource Potential

With Chapter 2 providing the foundation for where the system is today, Chapter 3 transitions to looking into the future. This chapter explains the Council's approach to forecasting future electricity demand, the resulting power system needs from that forecasted growth, and the suite of potential new resources available to serve those needs. Because each piece of this is inherently uncertain, this chapter also discusses the Council's approach to assessing that uncertainty in the Ninth Power Plan.

Planning Under Uncertainty

While the Council's methodologies have evolved over time, one underlying principle has always been to plan under uncertainty. This approach has allowed the Council to develop recommendations to the region around new resource additions, recognizing the future is hard to predict, and seeking to minimize the cost and risk of adding new resources despite that uncertainty. Over the past several years, as part of implementing power plans, the Council has conducted annual studies. These studies allow the Council to continually assess this uncertainty by updating known factors and exploring implications of new dynamics.

Practically every assumption used in power planning carries with it some uncertainty. For the Ninth Plan, the Council weighed the risk of being wrong on these assumptions, and then it developed a suite of "futures" and conducted scenario modeling on those priority factors that were most likely to have the largest impact on future system needs, costs, and reliability. In doing so, the Council sought to frame the questions broad enough, creating a large distribution of risk. This approach provided important insights to inform the recommendations included in Chapters 4 and 5 of this Plan. It also provides valuable analysis that the Council can leverage during its annual studies and mid-term assessment of the Plan to refine direction to the region and Bonneville, if needed. This section explains these approaches and the types of information captured by each.

Futures

The Council created a series of "futures" to represent uncertainty around several factors outside of the region's control that could affect resource decisions. The uncertainties reflected in the Ninth Plan futures are load growth, natural gas prices and potential for volatility in those prices, and the fuel availability for hydropower, solar, and wind.[62]

Load Forecast

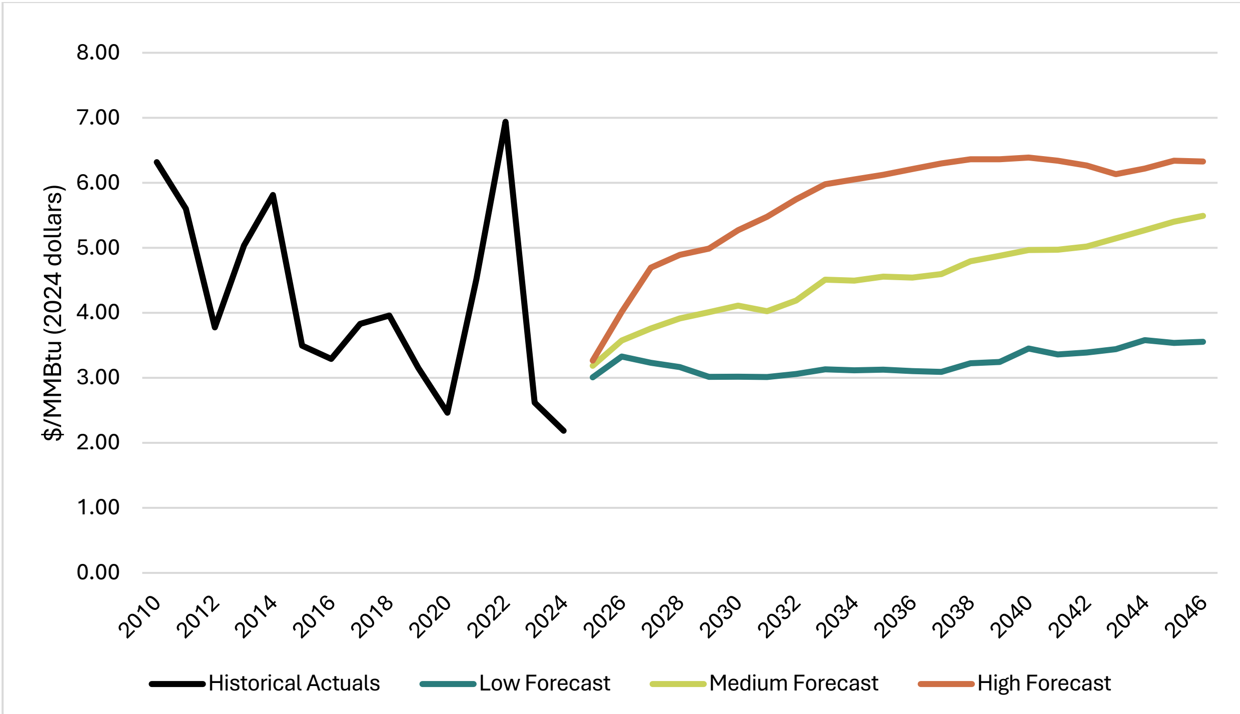
The Power Act requires the Council to develop an electricity demand forecast for at least 20 years.[63] Knowing the exact amount of electricity required tomorrow is impossible, let alone forecasting a need 20 years into the future. That's why the Council has always assumed a range of potential load forecasts in its power planning. For the Ninth Plan, the Council developed five different load growth trajectories reflecting the uncertainty around the pace of load growth, as well as the size and shape of that growth. The details of this approach are discussed later in this chapter.

Natural Gas Price Forecast

Natural gas prices are an important input for power planning. Not only do they inform the price of operating natural gas power plants, but since natural gas plants are often the resource on the margin, gas prices have a large impact on electricity prices.[64] Similar to load growth, trying to predict gas prices a year from now is a challenge, let alone modeling them 20 years into the future. The Council developed its price forecast for natural gas based on industry data and stakeholder feedback. The forecast includes a low, medium, and high forecast to reflect the uncertainty around future prices (see Figure 3 - 1).[65]

[62] The Council accounts for fuel availability of different resources. For hydropower, the fuel is water running down the river, which can vary year to year with different conditions. For wind power, the fuel is wind, which can vary throughout the day, month, or year. For solar, the fuel is the sunshine.
[63] Northwest Power Act, Section 4(e)(3)(D).
[64] A resource that is "on the margin" is the next resource to come online to meet load. The cost of that next resource then as a direct connection to the market price for electricity.
[65] More information on the development of the natural gas price forecast is captured in Technical Appendix E – Thermal Fuels Forecast.

Figure 3 - 1: Natural Gas Price Forecast Range for Henry Hub



As seen in Figure 3 - 1, the price of natural gas is not stable year by year. One-off events can cause spikes in natural gas prices. Examples of events from recent years include a pipeline rupture in Canada and a low gas-storage event that coincided with a western pipeline outage. Recognizing that it is not feasible to predict when a natural gas price spike might occur, the Council created ten futures informed by these past events that capture volatility and assigns it randomly to future years.[66] Additionally, there is a price adder built into the forecast to reflect western liquified natural gas export facilities coming online in the late 2020s. The three gas price trajectories combined with these ten volatility pathways result in 30 unique gas price futures used in the Ninth Plan.

Hydro, Wind, and Solar Fuel Availability

Because hydropower is the dominant resource in the region, the Council has always modeled a range of different streamflow conditions. For the Ninth Plan, the Council used data from three different climate models that forecast future weather and streamflow conditions.[67] From this, the Council

[66] Technical Appendix E – Thermal Fuels Forecast captures more detail on the approach to creating volatility futures.
[67] The climate models were developed as part of the Intergovernmental Panel on Climate Change's Figh Assessment Report. The Council selected three of these models that had been downscaled by the River Management Join Operating Committee to provide more granularity for the Pacific Northwest. For tracking, the Council has labeled these options A, C, and G, from the initial suite of 19 models. More information on the models themselves, the Council's selection of models, and the use of those in the Ninth Plan is detailed in Technical Appendix D – Climate Model Data and Assumptions.

developed 90 different sets of hydro conditions, capturing variability in the timing and amount of streamflow throughout the system.

To ensure consistency across assumptions, the Council also used temperature data from these models to develop a suite of different wind and solar profiles. A portion of fuel availability for both wind and solar is connected to temperature. Wind availability is generally lower when temperatures become more extreme. This is true for warmer and colder extremes. For solar, the efficiency of a solar panel decreases as temperatures become hotter.[68] The Council's profiles capture this relationship, resulting in a suite of 90 different wind and solar profiles that are paired with the 90 different hydro conditions described above.

Sampling Futures

Collectively, the different load forecast trajectories, natural gas price pathways, streamflows, and renewable resource profiles resulted in 13,500 different combinations of future conditions. Modeling all 13,500 combinations would be impractical. Therefore, the Council developed a methodology to evenly sample from the suite of combinations by creating ten different futures for each year modeled, which collectively capture the range of uncertainty.

The ten futures were first built by sampling the annual net load in different futures. Net load is the total annual energy load minus the total annual energy generated from existing hydroelectric, wind, solar, and other renewable resources. This is used as a proxy for economic risk, since years with higher net loads require more thermal generation or imports, and thus have more exposure to commodity prices. For the net load sampling, the futures were ranked by 10-percentile bins, and each of the ten futures has a net load from a different bin. A similar approach was used for sampling from hydro generation, ranking the generation for each of the 90 pathways, grouping them into 10-percentile bins, and selecting one from each bin. For loads, natural gas prices, gas price volatility, and the climate futures, the Council sampled evenly (or as evenly as possible) for each future.[69]

Table 3 - 1: Future Sampling Approach

Uncertainty	Pathways	Sampling Approach
Load forecasts	5	2 from each pathway
Natural gas prices	3	3 each from low and high, 4 from medium
Natural gas price volatility	10	1 from each pathway

[68] When temperatures are lower in the colder months, there is also less solar availability. This is due to location of the sun and other factors. The Council also accounts for seasonal differences, such as this, in the availability of all resources.
[69] Technical Appendix K – Modeling Framework provides more detail on the sampling approach to selecting futures for modeling years.

Uncertainty	Pathways	Sampling Approach
Climate models	3	3 from models C and G, 4 from model A[70]
Hydro generation	90	1 from each 10-percentile bin
Net load futures	450	1 from each 10-percentile bin

Scenarios and Related Sensitivities

Most of the Council's analysis assumes a static set of assumptions around the existing system and future resource cost and availability. The use of scenarios, and related sensitivities, allows the Council to ask one-off specific questions in the analysis that can shift these otherwise static assumptions to explore areas of uncertainty.

The Council represents the existing system as described in Chapter 2. This includes capturing the generation and transmission that is available today, existing policies, and the current hydro operations. For the Ninth Plan, the hydro operations included the operations to mitigate and protect fish and wildlife as defined in the Council's Draft 2026 Columbia River Basin Fish and Wildlife Program.[71] For new resources, the Council develops its best assumptions for future cost and availability, based on available data and expert insight. The Ninth Plan scenarios explore a range of uncertainty around these assumptions. Specifically, the scenarios assess how new resources are added to the system under a range of hydro operations for fish and wildlife, varying timelines and cost for new resource potential, and different transmission system buildouts.

New Resource and Transmission Risk

The Council's power plans have often included scenarios that explore how resource decisions change with fluctuations in the availability (or pace) of potential resource development. Historically, much of this analysis focused on the pace of demand-side resource development, particularly conservation. As the Council embarked on the preparation and development of the Ninth Power Plan, entities throughout the region expressed concern regarding the availability of a wide range of resources. The worldwide Covid-19 pandemic caused supply chain challenges for many goods, including materials needed for the development of new resources. This coincided with a period of increased demand for new resources across the globe, and the concern that these supply chain challenges would persist in the years to come. The Council is also aware of the concerns regarding new resource development, including permitting hurdles and interconnection queue timelines, which could make supply side

[70] Of the three models, Climate Model A shows more of a warming trend, as it was selected because of its representation of warmer winters and summers. Climate Model G shows less of a worming trend than either of the other models, also leading to relatively lower winter hydro generation (with more precipitation captured as snow) and relatively higher summer generation. Climate Model C shows higher winter hydro generation and lower summer hydro generation than the other models.

[71] Current operations are also defined by the biological opinions, current Water Management Plan, current Fish Operations Plan, Columbia River Treaty, and other documents that define how the projects in the Columbia River Basin are operated.

resource acquisition slower and more expensive. Lastly, as discussed in Chapter 2, the region recognized the need for new transmission development. After experiencing challenges developing transmission in the region, several entities expressed concern about the ability to build sufficient levels of transmission to help bring remote resources to serve load.

The Council scoped the New Resource and Transmission Risk scenario to explore these areas of uncertainty. The scenario includes nine different sensitivities that test different aspects of resource or transmission availability. See Table 3 - 2 for more information on the sensitivities included in this scenario.[72]

Table 3 - 2: New Resource and Transmission Risk Scenario Scope

Sensitivity	Description
Constrained Resources and Transmission	Constrains supply-side resources in the near-term (first 6 years), limits transmission to the existing system, and delays emerging technologies by 10 years. Sensitivity will inform how the region maintains adequacy when the whole system is constrained on the supply-side.
Changing Transmission Availability	Includes three sensitivities with different levels of transmission development: existing transmission, transmission consistent with the WestTEC 10-year study, and additional transmission. Sensitivities will inform how resource decisions change with more or less transmission availability.[73]
Changing Emerging Technology Costs	Includes two sensitivities with different cost assumptions for emerging technologies: 25% lower costs and 50% higher costs. Sensitivities will provide insight on at what costs different emerging technologies might provide value to the system.
Limited Short-Duration Storage Availability	Constrains the availability of short-duration (lithium ion) battery storage in the near-term (first 6 years). Sensitivity will provide insights on the potential value of short-duration storage to the region and how the region will maintain adequacy if that resource is not available.
Slower Demand-Side Availability	Slows down the pace of potential demand-side resource acquisition, including conservation, demand response, and rooftop solar. Sensitivity will provide insights on how the system maintains adequacy if less demand-side resources are available in the near-term.
Evolving Federal Policy Landscape	Assumes a change in federal policy in 2030, shifting to policies similar to Biden-era policies. Sensitivity provides insights on how resource decisions change in the region with changes in policies at the federal level.

[72] The specific details of the assumptions behind each of these sensitivities is described in Technical Appendix N – Scenario Modeling and Results.
[73] WestTEC is the Western Transmission Expansion Coalition, a west-wide voluntary effort to conduct long-term transmission planning for the west. The 10-year study is available at: https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition.

Changing Hydro Operations

In the early stages of developing the Ninth Plan, the Council anticipated the need to analyze the intersection between hydropower operations and new resource development. The Council's 2021 Power Plan identified a new tension with hydropower operations and the daily flexibility of the system. As discussed in Chapter 2, the Council's Columbia River Basin Fish and Wildlife Program has long included measures seeking to reduce the daily flow fluctuations of the system to benefit the migration of juvenile fish. At the same time, the Council's power planning analysis has shown value in ramping the system on a daily basis to support power system needs and the integration of new renewable resources in the region. The Council planned a scenario to explore the trade-offs in this flexibility.

Additionally, the Ninth Plan was developed at a time of high uncertainty around future hydropower operations, particularly those operations designed to protect and mitigate for the impacts on fish and wildlife. In June 2025, President Trump issued a Presidential Memorandum withdrawing from the 2023 Resilient Columbia Basin Agreement, which had established a set of operations for fish that was expected to continue for ten years.[74] Withdrawing from the agreement created uncertainty not just for long-term operations, but also for the near-term 2026 operations. At the same time, the Council was in the process of developing the 2026 Columbia River Basin Fish and Wildlife Program, which included recommendations for hydropower operations. The Council also received public comments on the recommended operations during its amendment process.

In August 2025, the Council scoped four sensitivities for this scenario. The purpose was to reflect the uncertainty around future operations, while also providing insights to inform the ongoing amendment process. These operations are distinct from those assumed in the New Resource and Transmission scenario, which assumes the operations of the Draft 2026 Columbia River Basin Fish and Wildlife Program.[75] The specific sensitivities are described in Table 3 - 3.[76]

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[74] In December 2023, the U.S. Government released a set of commitments in partnership with the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington. These commitments included a range of actions related to fish and wildlife and power planning, that ultimately resulted in a 10-year stay in the long-standing National Wildlife Federation et al v. National Marine Fisheries et al litigation.

[75] The Council conducted much of the early modeling for the Changing Hydro Operations scenario first, with a goal of informing both the Council's Fish and Wildlife Program and power planning processes. This timing also allowed the Council to update the GENESYS model to reflect the operations in the Draft 2026 Fish and Wildlife Program in advance of the necessarily modeling for the New Resource and Transmission Risk scenario. The intent was to ensure a suite of modeling results that provided for adequacy based on the draft operations.

[76] The specific details of these operations, including assumed spill levels, elevations, and other assumptions is captured in Technical Appendix N – Scenario Modeling and Results.

Table 3 - 3: Changing Hydro Operations Scenario Scope

Sensitivity	Description
2020 BiOp Flex Spill Operation	Assumes the operations based on the 2020 Columbia River System Operations Environmental Impact Statement. This sensitivity was intended to provide one end of the bounds for potential 2026 operations, based on the assumption that legally, until another agreement was in place, the system should revert to these operations.
2023 RCBA Operations	Assumes the operations as defined in the 2023 Resilient Columbia Basin Agreement. This sensitivity was intended to provide an alternative set of operations with a focus on steady spill throughout the spring, acting as a potential bookend to the range of uncertainty round 2026 operations.
Recommended Spill and MOP Targets	Analyzed specific minimum operating pool elevations and limits and spill operations, as recommended by some of the states and tribes in the Fish and Wildlife Program amendment process. This sensitivity was intended to provide insights on potential hydropower system impacts of those specific recommendations.
Limited Flex Operation	Analyzed limitations of the hydro system's ability to change daily elevations and outflows at the lower Columbia and lower Snake River projects. This was intended to inform about the hydropower system implications of limiting the daily flexibility of the system.

Electricity Demand Forecast

Electricity demand growth is a key driver of future resource needs. Under the Northwest Power Act, the Council is required to develop and include "a demand forecast of at least twenty years…".[77] The Council's forecast is both an early input into the planning process, as well as a final output. As an input, the Council creates a 20-year forecast of demand. This forecast explicitly excludes any new potential for demand-side resources, such as conservation, allowing the Council to identify the cost-effective amounts of those resources later in the analysis.[78]

The amount of electricity needed in the future is uncertain. The Ninth Plan demand forecast accounts for this uncertainty by developing forecast ranges across multiple sectors and then compiling those into a set of five distinct load growth pathways. For the first time, the Council forecasted this demand in 13 geographically distinct forecast zones.[79] Because load growth is not uniform across the region,

[77] Northwest Power Act, Section 4(e)(3)(F).
[78] The Council uses the term "frozen efficiency forecast" for this early demand forecast input. The idea is that conservation, demand response, and rooftop solar are frozen based on current levels (existing stock or current market levels, depending on the resource). Later in the planning process, the Council will net out of the demand forecast the cost-effective amount of these resources. This creates a final sales forecast, which is included in Chapter 4 of this Plan.
[79] These forecast zones are informed by the region's balancing authorities.

this approach allows the Council to account for those nuances and develop a conservation and resource strategy that meets the diverse needs of the region.

The final forecast is a compilation of several distinct forecasts, each with their own range of potential uncertainty. At the base is a residential, commercial, and industrial/agricultural forecast that focuses on economic conditions and changes over time. The Council also produced separate forecasts for data centers and high-tech loads, electric vehicles, and electrification of end-uses. This section provides an overview of the Council's approach to forecasting electricity demand for the Ninth Power Plan. More information is provided in Technical Appendix F – Electricity Demand Forecast.

Residential, Commercial and Industrial Forecast

The core of the Council's demand forecast is a forecast of demand for the residential, commercial, and industrial sectors. The agricultural sector is captured in this forecast as part of the industrial demand forecast. Key factors that inform the forecast for each of these sectors include recent demand trends, weather, and economics. The Council also uses sector specific information to provide more nuance when possible. The sections below describe key considerations for each of these sectors.

Residential

Multiple factors drive changes in electricity use in the residential sector. A core assumption is the number of households in the region, including a projection of how that might change over time as new housing is added or older homes are demolished. The Council relies on U.S. Census and other data to provide information on the existing housing stock and recent trends. This information, along with economic assumptions, guides forecasted growth over time.

Most homes in this region are in Washington (53%) and Oregon (30%). Idaho, however, has experienced the greatest growth in recent years (see Figure 3 - 2). The Council's forecast continues to assume greater growth in Idaho than in other states, but this growth dampens over the planning horizon (see Figure 3 - 3).

Figure 3 - 2: Housing Growth Rates from 2010-2025

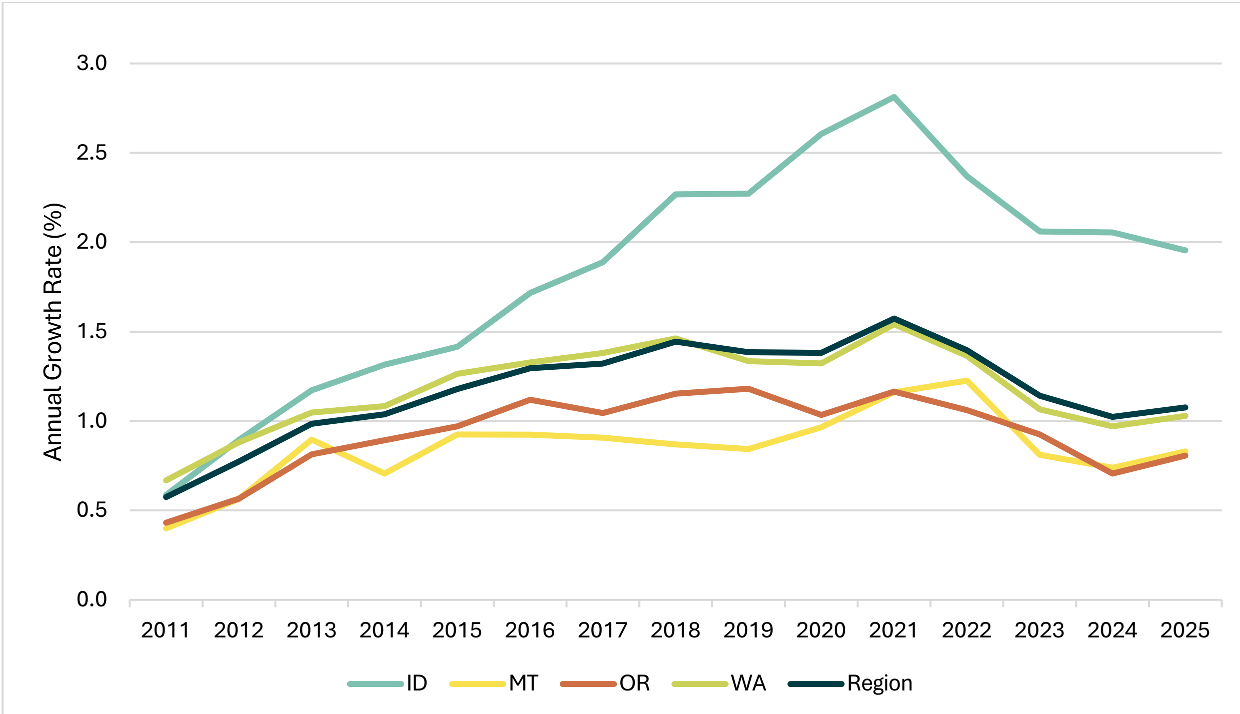
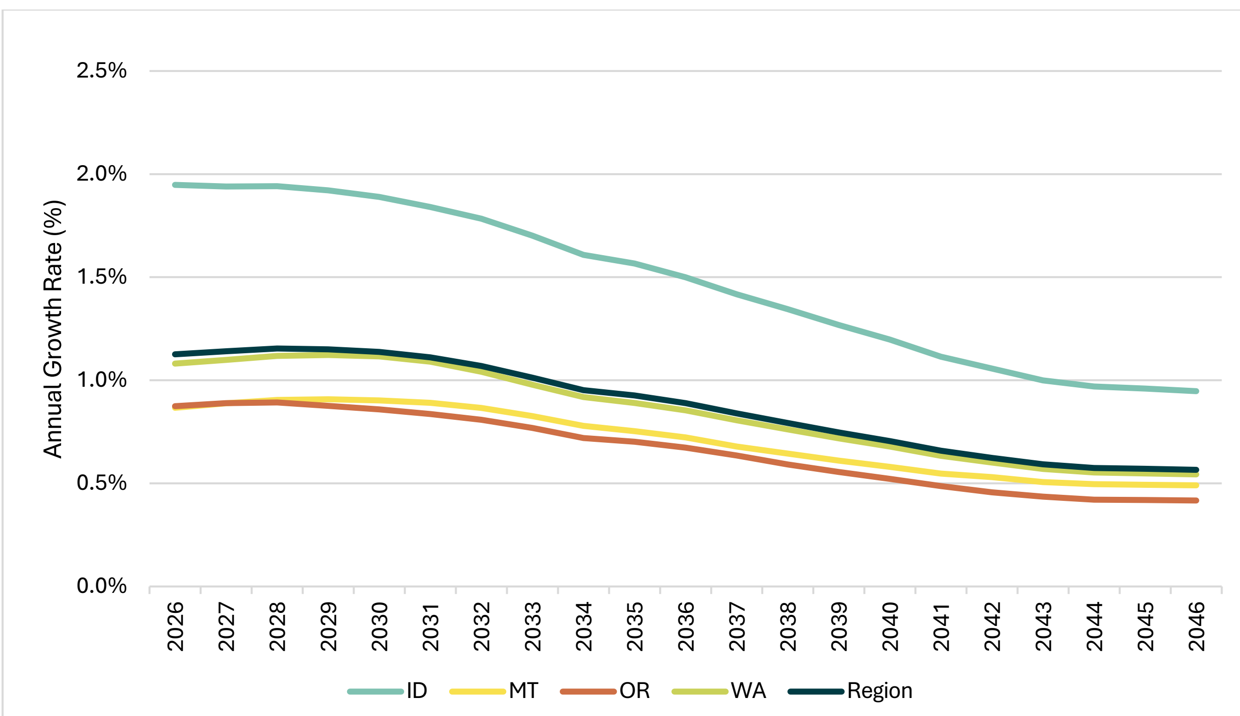


Figure 3 - 3: Forecasted Housing Growth Across in the Region



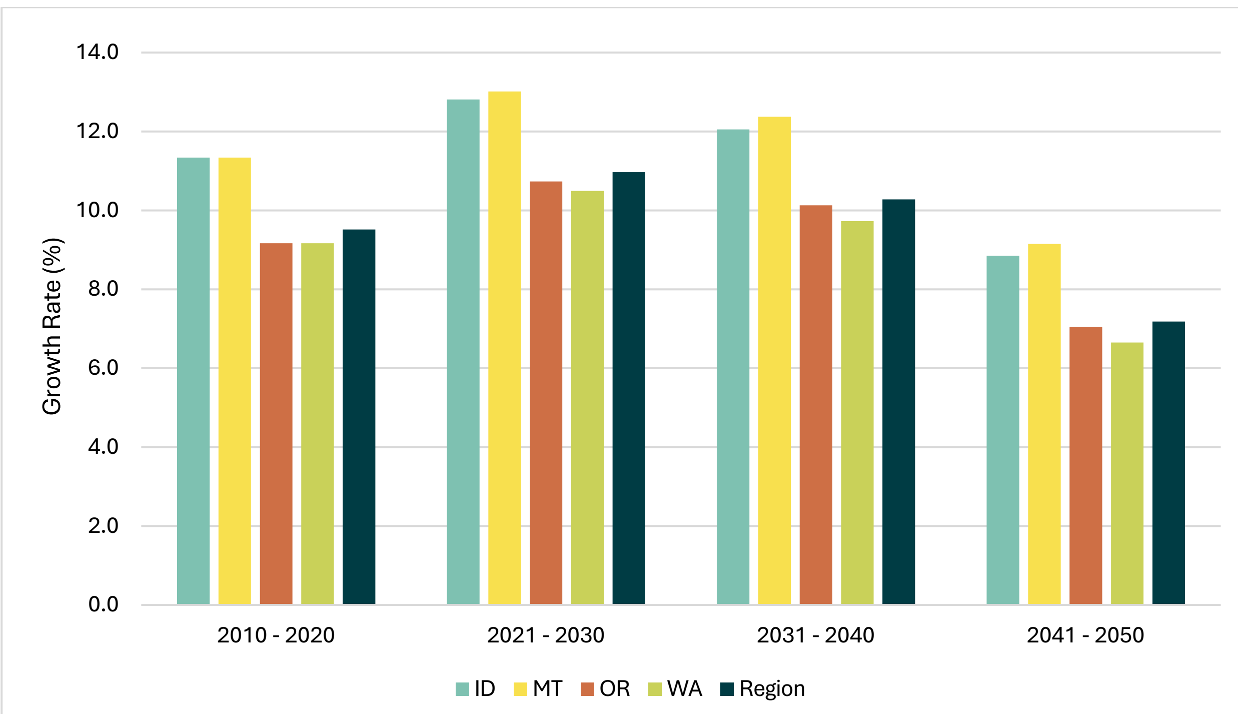
Another key factor is the type of equipment in each home and the efficiency of that equipment. This is particularly important for heating and cooling systems and water heating units. Whether a home is heated with natural gas or electricity has an impact on that home's overall electricity use. If the home is heated with electricity, then information on the specific type of equipment helps to understand the overall demand placed on the system. The same is true for water heating. While most homes continue to use natural gas for heating, the region is seeing an uptick in electric heat pumps, resulting in an overall increase in electric demand. The region is also experiencing growth in cooling loads. In 2020, approximately 60% of homes had some form of cooling. The Council estimates this to increase to almost 75% by 2030. The Ninth Plan forecast accounts for these and other trends to forecast residential electricity needs over time.

Commercial

Like the residential sector, commercial electricity demand is a function of the building stock. This includes an understanding of the types of buildings in the region, as well as the type of equipment and efficiency of that equipment in these buildings.

Similar to the residential sector, Washington has the highest total of commercial square footage (47%), followed by Oregon (37%). Over the past decade and a half, Montana and Idaho have experienced greater levels of growth in this sector, and the Council forecasts that the growth rate in those states will remain higher than in Oregon and Washington in the coming years (see Figure 3 - 4).

Figure 3 - 4: Forecasted Commercial Building Square Footage 10-Year Growth Rate



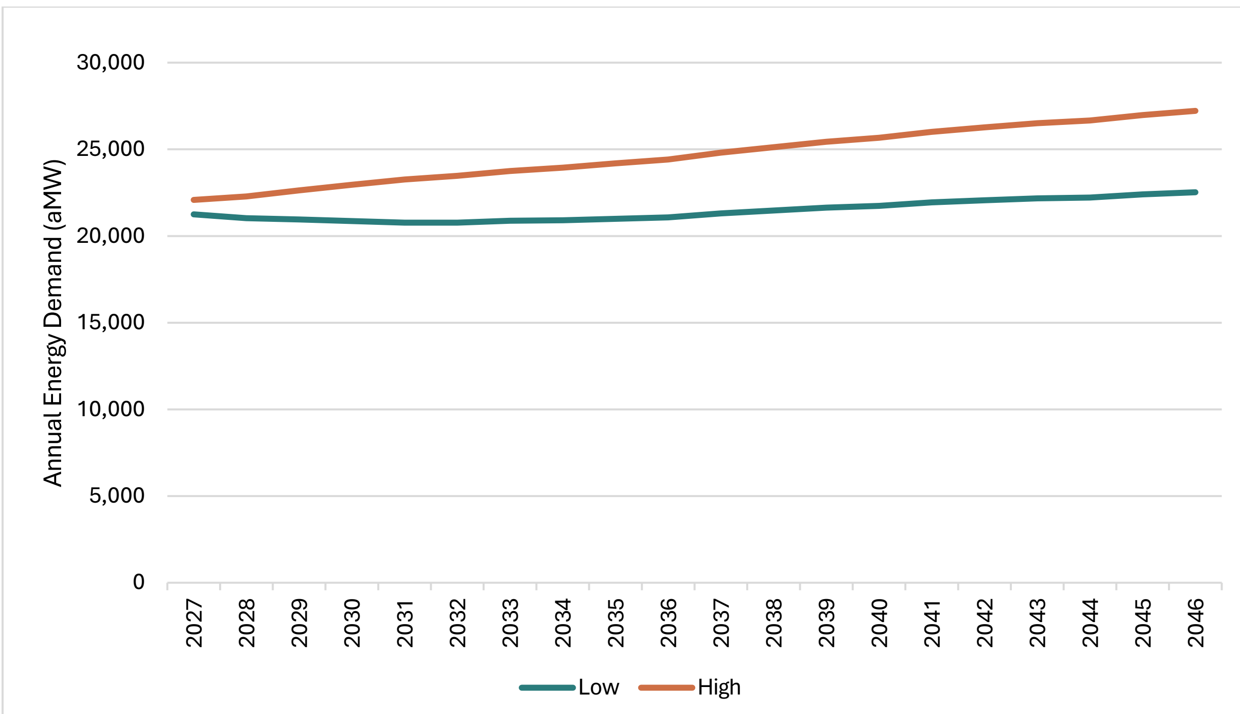
Industrial

Industrial demand is estimated for each industrial sector, including agricultural, wood, paper, aluminum, machinery, etc. The demand is a function of the energy intensity of that sector and economic factors affecting employment in the sector. The forecast for each of these sectors is combined with the others to produce an overall industrial demand forecast.

Combined Forecast

Collectively, the residential, commercial, and industrial forecasts make up the base economic forecast. The Council developed two of these forecasts to reflect a range of potential economic growth. The higher case reflects data from S&P Global Market Intelligence Long-Term Annual Report. This provided a benchmark economic forecast to inform assumptions around population, household size, employment, gross state product, and more. The lower case reduces the growth rate for these factors on an annual basis. Together, these provide a range in potential growth driven by economic factors.

Figure 3 - 5: Forecast Range for Residential, Commercial, and Industrial Sectors

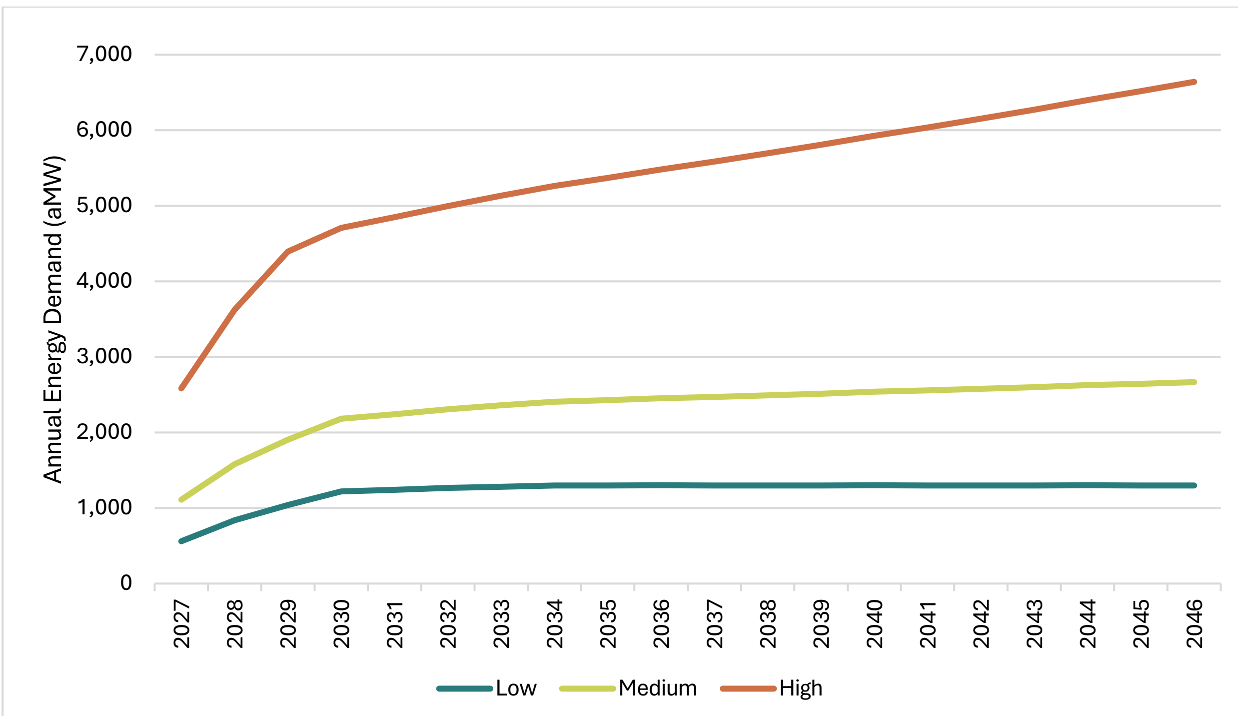


Data Centers and High-Tech

Data centers and chip fabricators have the potential to add significant amounts of demand to the power system. Both industries have existed in the Northwest for decades, but there has been an increase in development in recent years driven in part by advancements in artificial intelligence. These large loads present a unique challenge in forecasting future demand. Unlike most load sources, the constraint on technology sector growth may be due to infrastructure needs, construction timelines, permitting, and supporting power infrastructure and supply, among other factors.

Due to the significant uncertainty in technology load growth, the Council developed three different forecasts incremental to 2024 loads. Since technology loads are not located in all parts of the region, the Council concentrated future projections in areas with current technology loads or announced planned loads. The Council relied on information from utilities and data on historical loads from the U.S. Energy Information Administration. The low forecast represents the lower estimates from utility integrated resource plans when available, a slower pace of historical growth, or a 60% dampening of expected new load. The medium forecast assumes that technology load will continue to arrive at the same magnitude as in the past four years, or that 80% of the utility forecasted load will materialize (for jurisdictions without historical technology demand). The high forecast uses utility forecasts for demand with the assumption that all announced projects will arrive on schedule. All three trajectories suggest potential for rapid growth in the near-term, but declining growth after 2030 as uncertainty increases.

Figure 3 - 6: Forecast Range for Data Center and other High-Tech Demand



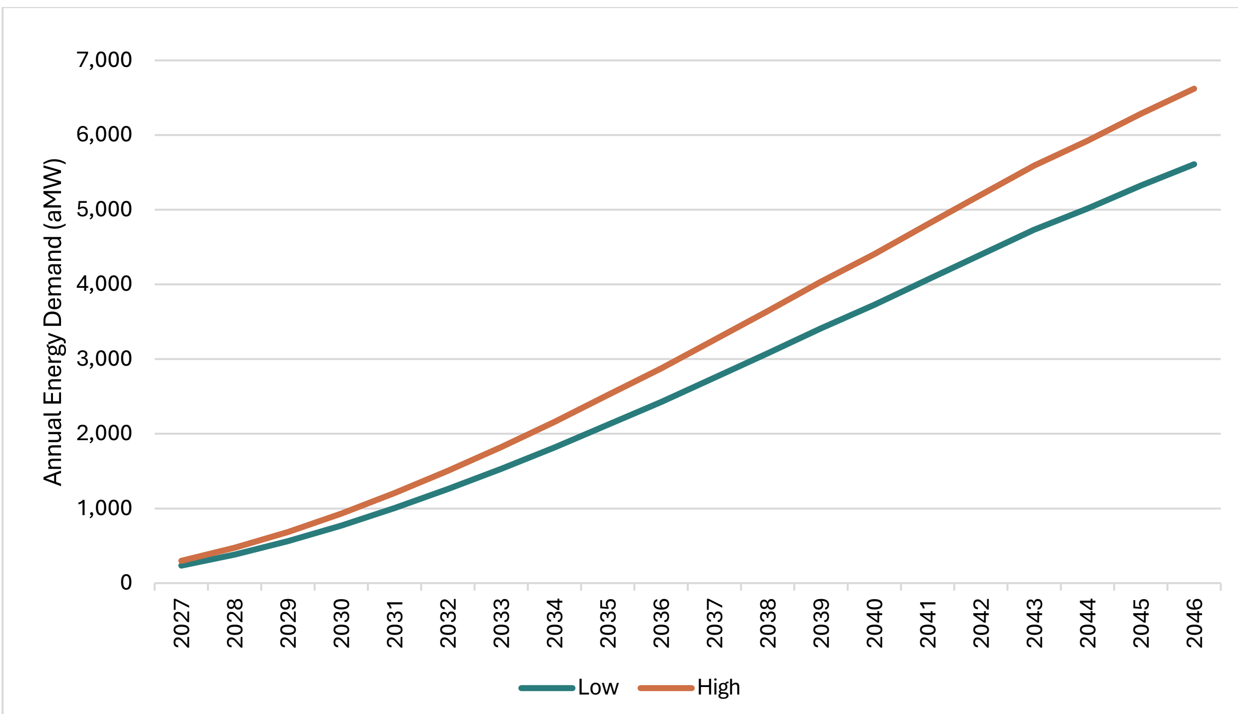
Electric Vehicles

Electric cars, vans, trucks, and buses are a relatively recent and rapidly growing electric end-use. The growth in this sector has the potential to impact power system needs in multiple ways. As more consumers purchase electric vehicles, overall energy demand will increase. The timing of charging also matters. Residents coming home from work and charging their cars at the same time can significantly increase the amount of electricity needed for that period. Furthermore, if those same vehicles are concentrated in a specific location on the grid, such as an urban center, there can be significant constraints placed on local infrastructure.

The number of electric vehicles in the states of Oregon and Washington have more than doubled in recent years, and Idaho and Montana have also seen significant growth in this time. Further, Oregon and Washington have adopted the California Clean Cars II rule, which requires 100% of new vehicle sales to be zero emission by 2035. The Council's forecast assumes significant growth to continue in this sector over the next 20 years.

The Council developed a low and a high forecast for future electric vehicle demand. Both forecasts assume Oregon and Washington meet their policy goals of 100% new sales being zero emission by 2035, but the low forecast assumes approximately 15% less demand for vehicles overall. Figure 3 - 7 shows the Council's Ninth Plan forecast for annual energy demand for electric vehicles. What is not well captured in this figure is the shape of that demand, driven by the timing of charging. Consistent with the Council's overall approach to developing an early load forecast input, the Council assumes that there is no managed charging for these vehicles. In other words, consumers charge their cars whenever they choose. The Council's forecast of demand response potential (discussed later in this chapter) includes products that manage the charging by shifting it to certain times. While these products will not change the overall annual energy demand for electric vehicles, they have the potential to reduce the overall peak impact on the system or reduce local system constraints.

Figure 3 - 7: Forecast Range for Electric Vehicle Demand



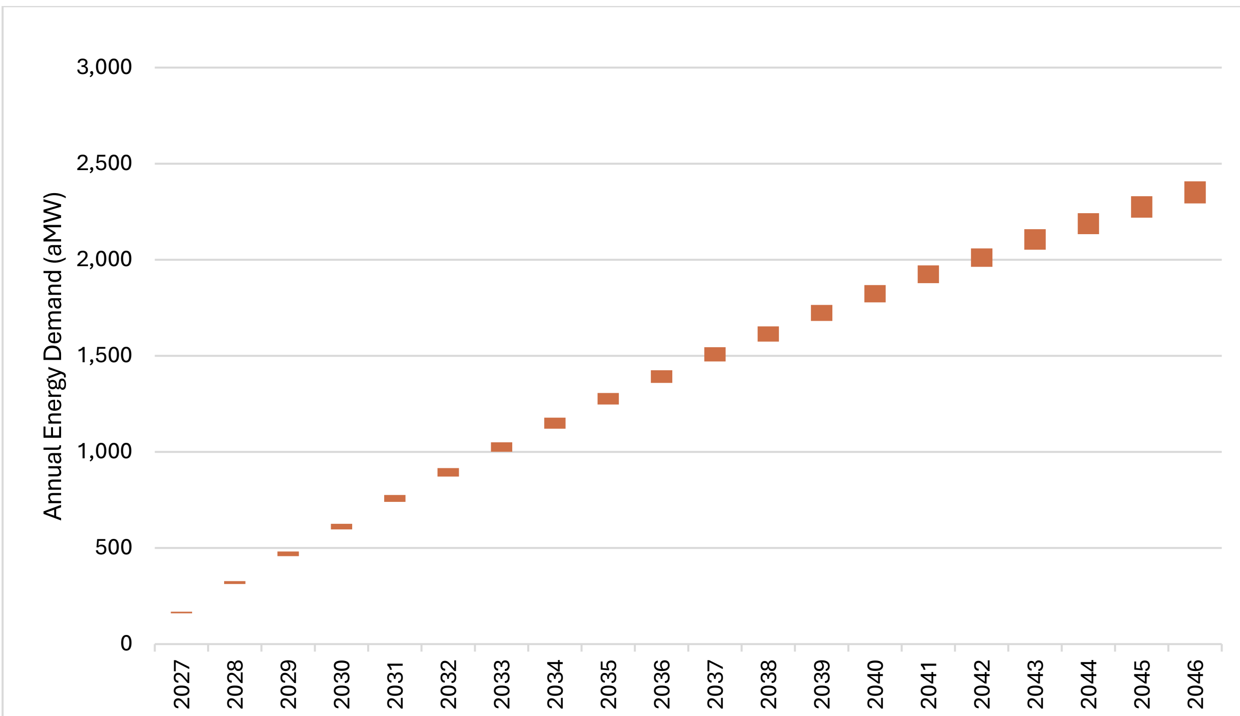
Other Electrification

Driven by policy and consumer preference, the region is seeing the electrification of other end uses. This includes the electrification of buildings through the transition to electric heating, water heating, and appliances that were previously served with natural gas. It also includes potential electrification of other fuels or industries, such as in the industrial sector. The Ninth Plan includes two additional forecasts to account for that electrification.

Building Electrification

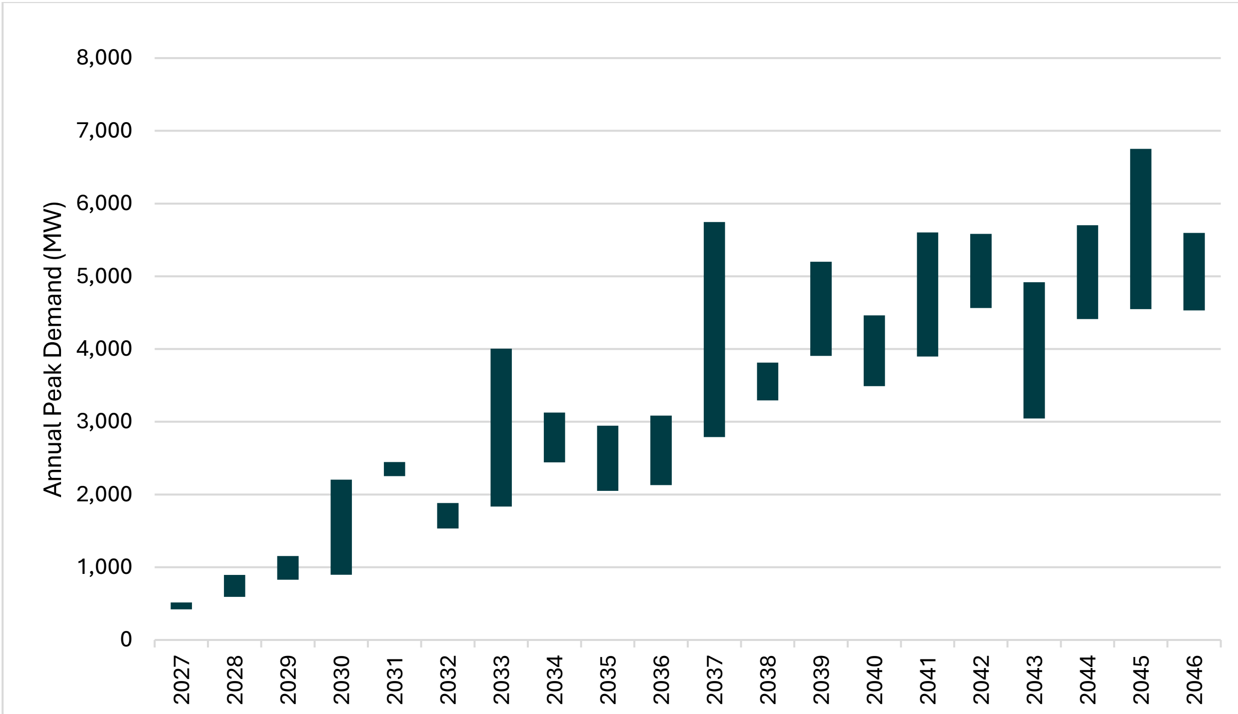
The base residential, commercial, and industrial forecast as described above includes some level of building electrification driven by recent trends in the region. Recognizing the potential for greater levels of electrification, the Council developed a high building electrification forecast. This forecast assumes increased saturations of electric heating, water heating, and cooking equipment. The projected growth in this sector is concentrated in Washington and Oregon, aligning with state policies that seek to reduce greenhouse gas emissions. Because the annual energy consumption of these end uses varies with temperature, the final forecast assumes a range of impact informed by the Council's three different climate models and associated temperatures. Figure 3 - 8 shows the Ninth Plan high building electrification forecast, including the temperature-dependent impacts on annual energy demand.

Figure 3 - 8: Forecast of High Building Electrification



Building electrification has the potential to add to the overall peak load of the system. The amount of additional peak demand varies year-to-year, driven by temperature and extreme weather events. Figure 3 - 9 shows the range of additional peak impact for the high building electrification forecast, with the variance driven by the differences in the climate model data. For example, in 2037, one of the climate models has a set of multiple extremely cold days in a row. In this specific case, the increase in electric heating has the potential to not only add significantly to the overall system peak, but to also shift the peak from evening to morning as more heating is required to warm homes in the morning.

Figure 3 - 9: Forecast of High Building Electrification Peak Impact

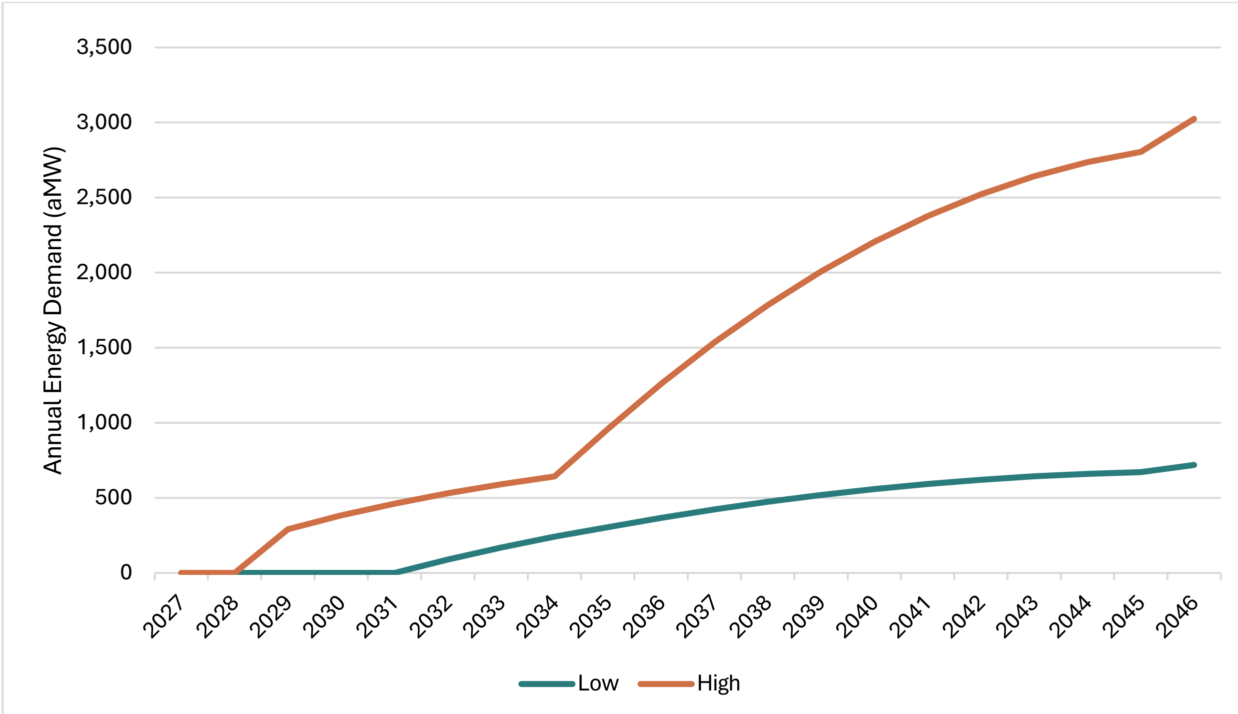


Industrial Electrification

The Council also developed a forecast for hydrogen generated by electricity for use in non-power applications. This includes hydrogen used for transportation, liquid fuels, and industrial applications such as refining or high-heat applications. Currently, most hydrogen is produced with natural gas. With policies seeking to reduce greenhouse gas emissions, there is an interest in developing clean hydrogen by using carbon-free resources, including hydropower, wind, and solar, as well as interest in lower-carbon hydrogen using natural gas with carbon capture and sequestration. Since clean hydrogen does not exist at scale today, the future demand forecast for this end use has high uncertainty. The Council developed a wide range for this forecast, based on data from the 2023 U.S. Department of Energy Clean Hydrogen Strategy and Roadmap and data from the Pacific Northwest Hydrogen Hub.[80] More details on this forecast is available in Technical Appendix F – Electricity Demand Forecast.

[80] The Pacific Northwest Hydrogen Hub is a project that is estimated to include eight potential project nodes and produce an estimated 300-400 tons of hydrogen per day.

Figure 3 - 10: Forecast Range for Industrial Electrification



The Pacific Northwest Hydrogen Hub was relying on up to $1 billion in federal funds. In October 2025, the Trump Administration canceled that funding, making its path forward less clear. Despite the uncertainty regarding the future of this technology, the hydrogen forecast is included in the Ninth Plan to represent a proxy for general industrial and medium/heavy transportation electrification. Both hydrogen production and industrial/heavy transport electrification represent potential increases in annual energy demand. Both loads also have the potential to be curtailed during times of significant system need and are modeled as curtailable loads in the Ninth Plan.

Projected Loads

The final Ninth Plan demand forecast trajectories combined different pathways for the forecasts described above. The Council sought a range that reflected variability in the overall size of projected load growth, the pace of that growth (i.e., whether it is concentrated to early years in the planning horizon or later years), and the overall shape of that growth. The Council ultimately developed five different pathways based on each of these factors, as described in Table 3 - 4.

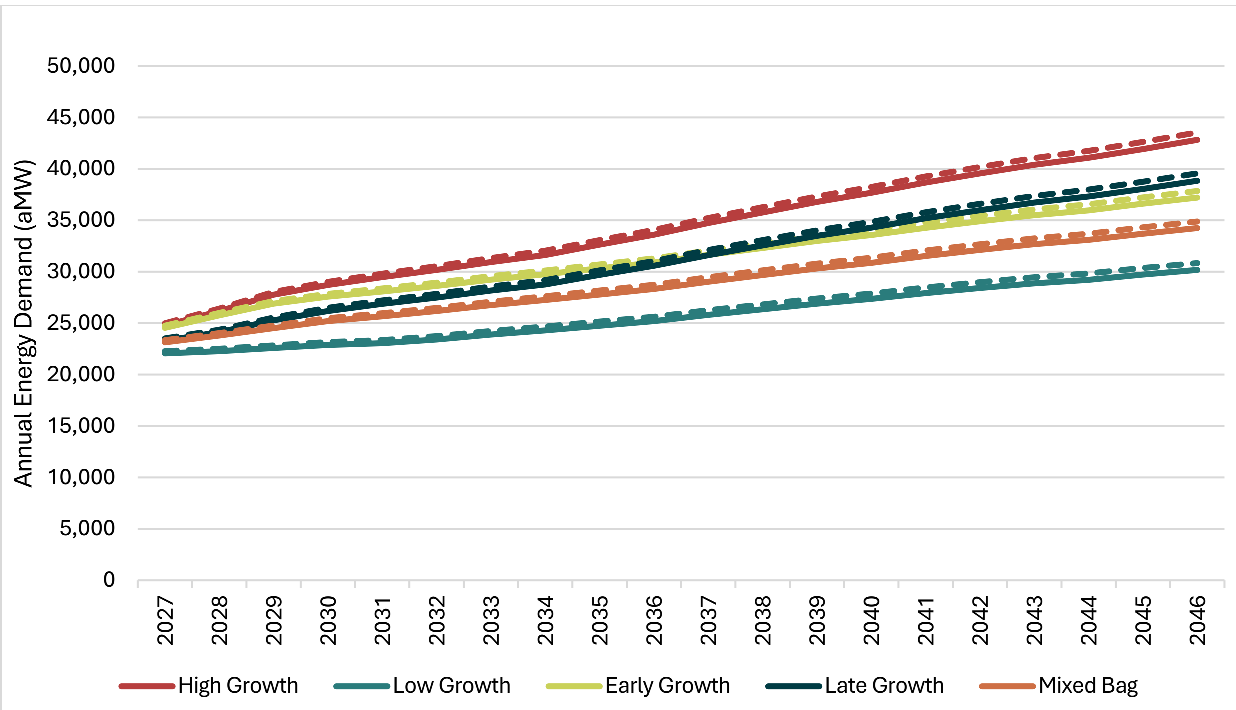
Table 3 - 4: Ninth Plan Demand Forecast Pathways

Description	Economic (Res/Com/Ind)	Data Center	Transportation	Building Electrification	Hydrogen Production
High Growth	Higher	High	Higher	Higher	Higher
Low Growth	Lower	Low	Lower	Lower	Lower
Early Growth	Higher	High	Lower	Lower	Lower

Description	Economic (Res/Com/Ind)	Data Center	Transportation	Building Electrification	Hydrogen Production
Late Growth	Higher	Medium	Higher	Higher	Higher
Mixed Bag	Higher	Medium	Higher	Lower	Lower

Figure 3 - 11 shows the energy forecast for each of these pathways. The solid line captures the minimum forecast for that pathway, and the dashed line captures the maximum. The variance between the minimum and maximum is driven by different temperatures across the climate models. While small in terms of annual energy, the different climate models cause significant differences in the overall peak demand forecasts.

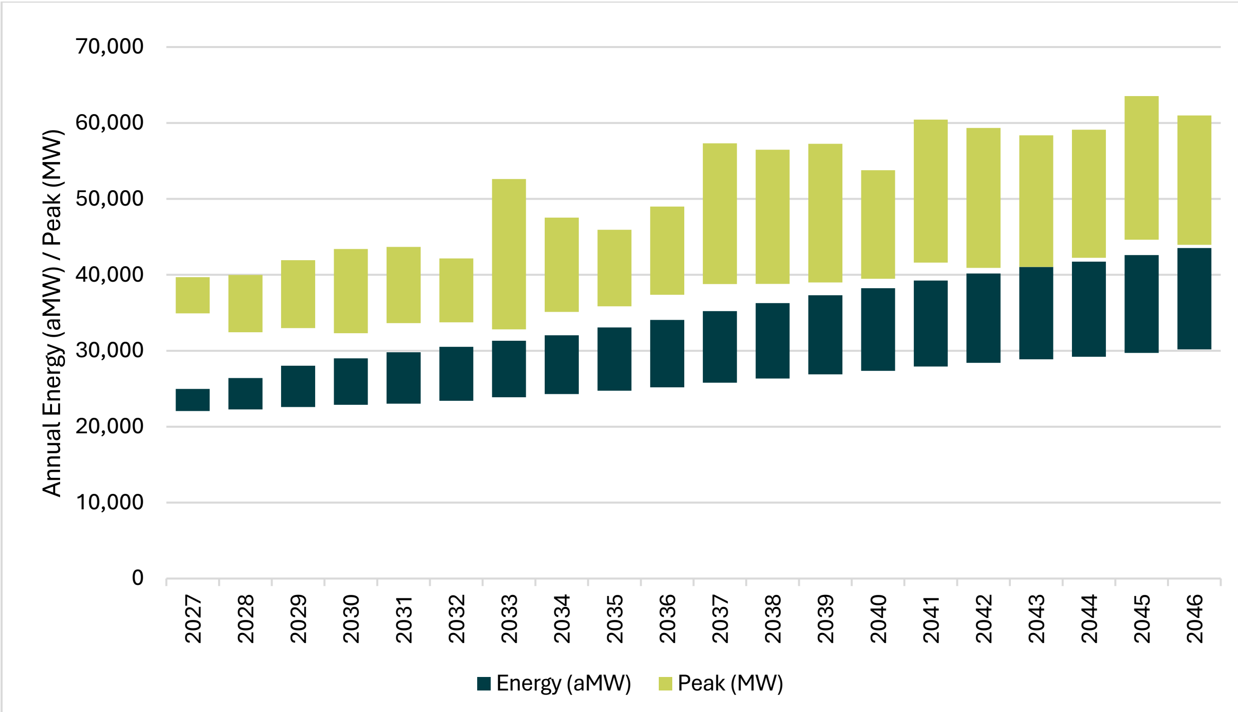
Figure 3 - 11: Ninth Plan Demand Forecast, by Pathway



The final Ninth Plan forecast shows significant uncertainty around future load growth. From the energy side, the Council forecasts the potential for loads to grow to over 40,000 average megawatts, as soon as the early 2040s in a high-growth trajectory. That would roughly double the size of today's demand. Even at the lower end, as represented by the low growth pathway, the Council still forecasts load to grow to around 30,000 average megawatts regionwide by the end of the 20 years.

The Council also anticipates significant growth in the system's peak requirements. Particularly pathways with high forecasted transportation loads, such as the high growth and late growth trajectories, are likely to drive future system peaks. These peaks are also weather sensitive. The variability seen year to year in the forecast stems from the variability in the underlying climate model data informing loads. Figure 3 - 12 shows the full range of both energy and peak forecasts for the Ninth Plan period.

Figure 3 - 12: Ninth Plan Demand Forecast, Annual Energy and Peaks



New Resource Needs

Based on an understanding of the capabilities of the existing system and the projected future electricity demand, the Council developed an assessment of need. This study provides context on the size and shape of the gap between where the system is today, and where the system needs to be in the future to support projected load growth. This information guides future stages of modeling, ensuring that the resources selected meet the Council's standards for adequacy. This section describes the Council's adequacy criteria and the needs assessment results for the Ninth Plan. More information on the needs assessment is included in Technical Appendix M – Needs Assessment Results.

Council's Adequacy Criteria

One of the key purposes of the Northwest Power Act is to assure the region an adequate, efficient, economical, and reliable power supply.[81] Over the years, the Council has developed and refined its approach to determining power system adequacy. Historically, the main risks to the system were

[81] Northwest Power Act, Section 2(2).

periods when there was low water, and therefore low hydropower production, happening at the same time as high electricity demand. With the addition of more variable energy resources into the system, along with the electrification of loads that often have specific timing impacts on the system, there are more potential risks for system adequacy today.

In 2023, the Council transitioned to a multiple-metric approach for assessing adequacy. This approach relies on the Council's GENESYS model, which evaluates the system across a range of conditions and identifies periods when the modeled resource generation cannot meet system demand, called shortfall events.[82] The Council then assesses these events across a suite of different metrics. For each metric, the Council has set a threshold limit connected to the specific risk the region wants to protect against. These limits were developed over multiple years working with experts across the region and beyond.

Core to assessing adequacy is the frequency of events. The Council has always had a metric to assess and protect against frequent use of emergency resources.[83] Under this new multi-metric approach to adequacy, the Council uses a frequency metric called loss of load event (or LOLEV). The Council assesses frequency for the summer and winter seasons, as well as looking at the system on an annual basis. The threshold is set to not exceed an average of one in ten years for each summer or winter, or not to exceed an average of one in five years annually. In addition to frequency, the Council's metrics are designed to protect against events that are too long or too large. For this, the Council established three different metrics that look at the tail-end risk from the range of simulation results. This is intended to ensure that for 39 out of 40 years, events are not too long (do not exceed 8 hours) or too big (do not exceed 1,200 megawatts or 9,600 megawatt-hours). Combined, these metrics ensure that there are enough resources to meet load. An adequate system means the model does not see shortfalls that are too frequent, and when they do occur, they are not too long or too large in magnitude.[84]

Power System Needs

For the Ninth Plan, the Council conducted needs assessments for every sensitivity that had different assumptions around the capabilities of the existing system. This resulted in a single needs assessment for the sensitivities included in the New Resource and Transmission Risk scenario, because all those sensitivities assume the same existing system conditions. The Council conducted four separate needs assessments for the Changing Hydro Operations scenario, since the varying

[82] The Council's uses its GENESYS model to capture information on resource adequacy and understand hydropower system operations. More information is available on the Council's webpage: https://www.nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/genesys--generation-evaluation-system-model.

[83] Emergency measures cover a range of potential actions the region could take to avoid blackouts. This includes things like curtailing loads, using back-up generators, purchasing high price market sales, official calls for conservation, and curtailing fish and wildlife hydro operations.

[84] More information on the Council's multiple metric approach to adequacy is available on the Council's website: https://www.nwcouncil.org/energy/energy-topics/resource-adequacy and in Technical Appendix M – Needs Assessment Results.

requirements for hydropower across those sensitivities impacts the potential output of the existing system.

The needs assessment focused on assessing the requirements in 2031. This 2031 date represents a time near the end of the Ninth Plan's five-year action plan period, where there is enough of a change in load growth to provide insight on future needs, but is not so far into the future that the cumulative uncertainty around future demand and existing system capabilities would be too large to provide useful guidance for near-term decisions. Rather than assessing the needs across the full range of potential load growth, the Council used the high growth pathway (described above) for this assessment. This ensured that the information about needs passed to the later stages of modeling was correctly capturing the risk of these potential futures.

The results of this analysis show a significant gap between where the system is today and where it needs to be in the future. This is driven by the forecasted growth in loads. This result is consistent across all sensitivities, regardless of the assumed differences in hydropower operations. There is a need to develop resources for capacity, with modeling showing large events with high peak needs across all months of the year. There is also a need to develop resources for energy, particularly to meet winter and summer energy demands. While the system is constrained throughout the years, the biggest challenges occur in winter. Based on the electricity forecasts described above, these results are unsurprising. The Council's recommendations for meeting these demands are detailed in the Ninth Plan Action Plan (Chapter 4).

While the need is informed by the adequacy metrics described above, it is not defined in terms of missing nameplate capacity. Rather, it is translated to a planning reserve margin for capacity (see Figure 3 - 13) and an adequacy reserve margin for energy (see Figure 3 - 14). These reserve margins act as a percentage above load that the region's resources should satisfy to account for adequacy in extreme load and temperature conditions. In other words, enough new resources must be added to the system to meet loads, as well as these planning reserve margins. More detail on the development of these reserve margins and the overall needs assessment approach is in Technical Appendix M – Needs Assessment Results.

Figure 3 - 13: Ninth Plan Planning Reserve Margins

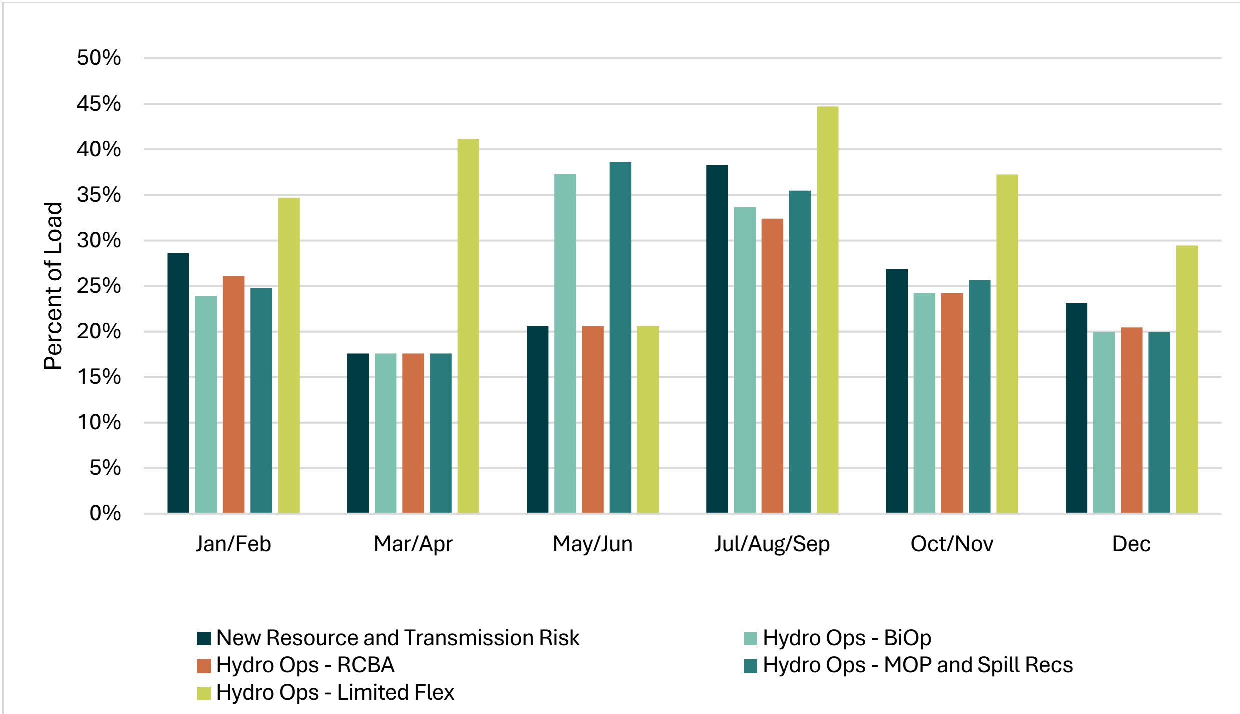
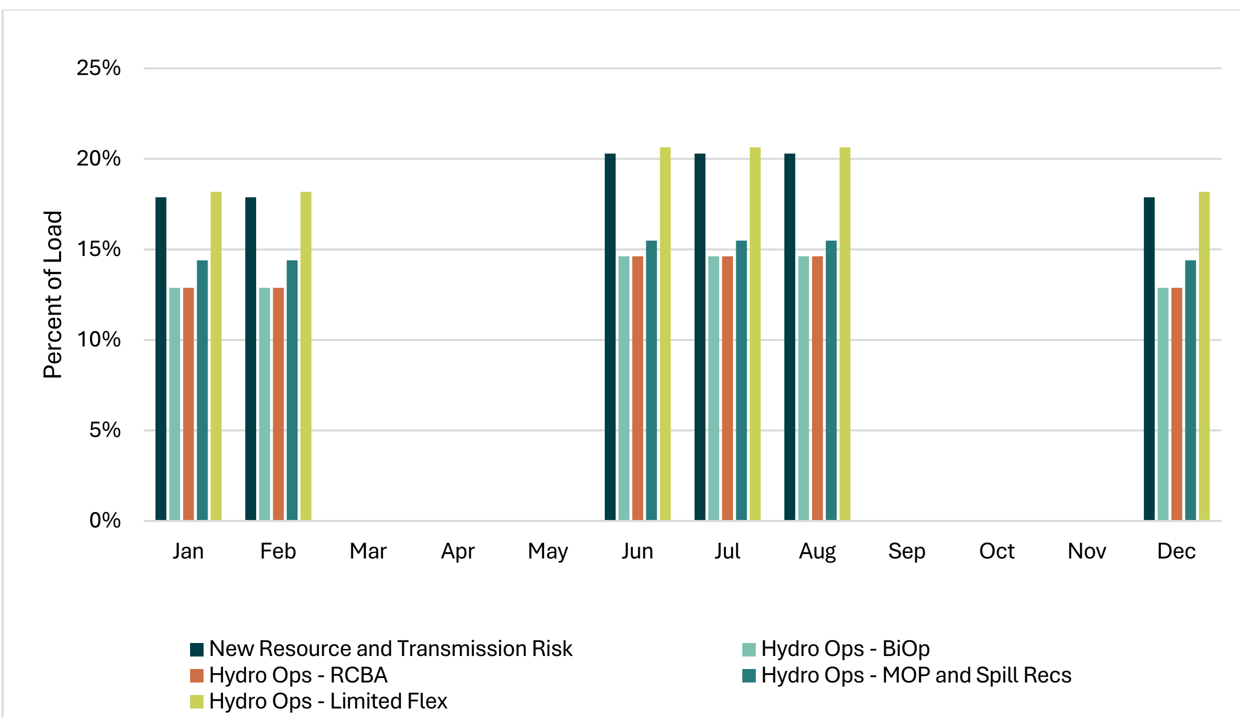


Figure 3 - 14: Ninth Plan Adequacy Reserve Margins



New Resource Potential

Many of the Northwest Power Act provisions regarding power planning focus on the Council's role for guiding new conservation and generating resource development. These resources must support a variety of system needs. This includes meeting or reducing Bonneville's obligations for power sales and assisting Bonneville in implementing the fish and wildlife program operations. It also requires ensuring the regional power system maintains adequacy, meeting both energy and peak needs throughout the years. The Council's strategy must also give "due consideration" for environmental quality, compatibility with the existing system, and the protection of fish and wildlife.[85] All of this requires an understanding of the capabilities of new resources, including how much power they deliver (or reduce), the availability of that delivery, and the pace at which that resource can be acquired.

The Power Act also places emphasis on the cost comparison between resources by requiring the prioritization of cost-effective resources.[86] This means that those resources that can reliably provide power at a lower cost than a similarly available and reliable resource must be prioritized. The Power Act outlines what costs to consider, focusing on the total direct costs of a resource over its effective lifetime, regardless of who pays the cost. The cost consideration must also include directly attributable environmental costs and benefits as outlined in a methodology to be included in the Council's power plan.[87]

This next section outlines the Council's approach to assessing and estimating new resource potential. This includes a high-level description of new resource options considered, and the Council's approach to capturing the important attributes around cost, availability, and power system contribution. It also includes the quantification of environmental costs and benefits included in those costs, and the qualitative treatment of environmental costs where needed.

Methodology for Quantifiable Environmental Costs and Benefits

Before discussing resource options, potential, and costs more comprehensively, the Power Act directs the Council to develop a methodology to determine and apply quantifiable environmental costs and benefits that are directly attributable to a resource. The Power Act does not define the terms environmental, quantifiable, or directly attributable. The Council defines these terms when developing this methodology. The Council's methodology considers four different categories for whether and how to apply potential environmental costs and benefits.[88] This includes:

[85] Northwest Power Act, Section 4(e)(2).
[86] Ibid., Section 4(e)(1).
[87] Ibid., Section 3(4).
[88] The full methodology is detailed in Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits.

1. Cost of compliance with existing environmental regulations,
2. Cost of compliance with proposed environmental regulations,
3. Quantification of environmental effects beyond regulatory control, including residual damages that are regulated but not entirely eliminated and unregulated damages, and
4. Quantification of environmental benefits.

The primary mechanism for quantifying environmental impacts is through the first category, compliance with existing environmental regulations. The Council's power planning assumes that all new resources will meet existing environmental regulations. The estimated cost of compliance with those regulations is included in the total cost assumed for the new resource. This includes the cost of compliance for addressing emissions regulated by the Clean Air Act, water discharges regulated by the Clean Water Act, solid waste such as chemicals in decommissioned solar panels, and costs of environmental compliance in the siting and construction of new resources. The Council considers additional costs for proposed environmental regulations on a case-by-case basis. For the Ninth Power Plan, there were no relevant proposed regulations to consider.

Environmental effects beyond those under regulatory control include residual effects (such as emissions beyond the regulatory limit) and unregulated effects not covered by explicit regulation. Emissions are the key environmental effect that fall into this category. As discussed in Chapter 2, there is a patchwork of policy around emission regulation, with significant shifts occurring recently at the federal level. In the Ninth Plan, the Council does not explicitly include any costs to new resources for these unregulated effects. Rather, the Council considers these effects through the implementation of existing state policies, including those aimed at emission reduction. For example, the models are guided by the clean policy requirements in Washington and Oregon, as well as voluntary utility and municipality goals in other states. The Council also applies the social cost of carbon to emissions in Washington, consistent with their Clean Energy Transformation Act that requires utilities to use the social cost of carbon in their resource planning.

The final category, environmental benefits, are challenging to quantify. There is a lack of data to support symmetric treatment across all resources. Additionally, an environmental benefit often displaces an environmental cost that would have already been accounted for in the previously described process. For example, the air quality improvement of building a wind farm over a coal plant has been accounted for by avoiding the compliance cost of the coal plant. Adding a monetary benefit to the wind farm on top of that avoided cost would result in double-counting. For the Ninth Plan, the one environmental benefit accounted for is water savings from conservation measures. This is a distinct benefit that can be quantified and does not run the risk of double counting.

As noted above, the Power Act also requires that the Council give "due consideration" to environmental quality and fish and wildlife concerns. These are broader than those considerations that fit within the methodology defined above, in part because the considerations often cannot be quantified. One example is the inclusion of the Council's Fish and Wildlife Program and the operations they entail. By planning under the assumption that these operations come into effect, the Council is ensuring that there are sufficient resources to meet power needs, while operating the system to benefit fish. Another example is compliance with the protected areas described in Chapter 2, which means not recommending new hydro resources in those river reaches. The Council also models all existing energy regulations and voluntary goals, ensuring that new resource additions are meeting those policies. While the Council does not necessarily put a direct dollar value on these costs, they are still considered in assessment of new resources and the ultimate resource strategy included in the Council's recommendations in Chapter 4 of this plan.[89]

New Demand Side Resources

Rather than generating power to be delivered to load, demand side resources directly reduce or shift the electricity demand of the consumer. This, in turn, has the potential to reduce the overall amount of energy required to serve the region's needs. The three demand side resources included in the Ninth Plan analysis are conservation, demand response, and rooftop solar. The following section provides an overview of the potential for new demand side resources and the associated costs.

Conservation Resources

The Northwest Power Act defines conservation as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution."[90] The Act requires that the Council consider conservation as a resource to meet future load growth alongside other resources. Technical Appendix H – Conservation Methodology and Potential provides more detail on the Council's approach to assessing conservation potential for the Ninth Plan.

For conservation, the Council develops supply curves to characterize the resource potential. The conservation supply curve is made up of thousands of individual conservation measures bundled together. On the residential side, this includes efficient appliances and electronics, upgrades to heating and cooling, water heating equipment, and options for vehicles. The commercial sector includes similar measures, as well as food preparation and refrigeration opportunities, efficient lighting, motors and drives, compressed air, and whole building energy management. The industrial sector potential includes advancements with fans, blowers and motors, pumps, refrigeration, and process improvements that conserve energy. Finally, the agricultural sector focuses on efficient irrigation, along with a handful of other measures. The Council also includes potential for distribution efficiency, such as voltage regulation, which can be operated as an "always on" conservation measure or deployed on an as needed basis like demand response. To avoid double-counting, this resource was assessed as part of the demand response potential discussed below.

These supply curves include information on measure savings, timing of savings, lifetime costs, and overall availability of the resource. For savings, the Council relies heavily on its Regional Technical Forum, as well as other data sources from existing conservation programs, the U.S. Department of

[89] Technical Appendix B – Existing System Parameters and Policies details out the environmental effects of all supply side resources, including both existing resources and new potential resource options.
[90] Northwest Power Act, Section 3(3).

Energy, and other experts.[91] The Council starts with a savings estimate for each individual measure. It then develops out a total technical achievable potential that accounts for the total number of potential applications in the region, the pace (or ramp rate) of being able to deliver that conservation, and a maximum achievability limit recognizing that not every household or business will adopt the conservation opportunity.

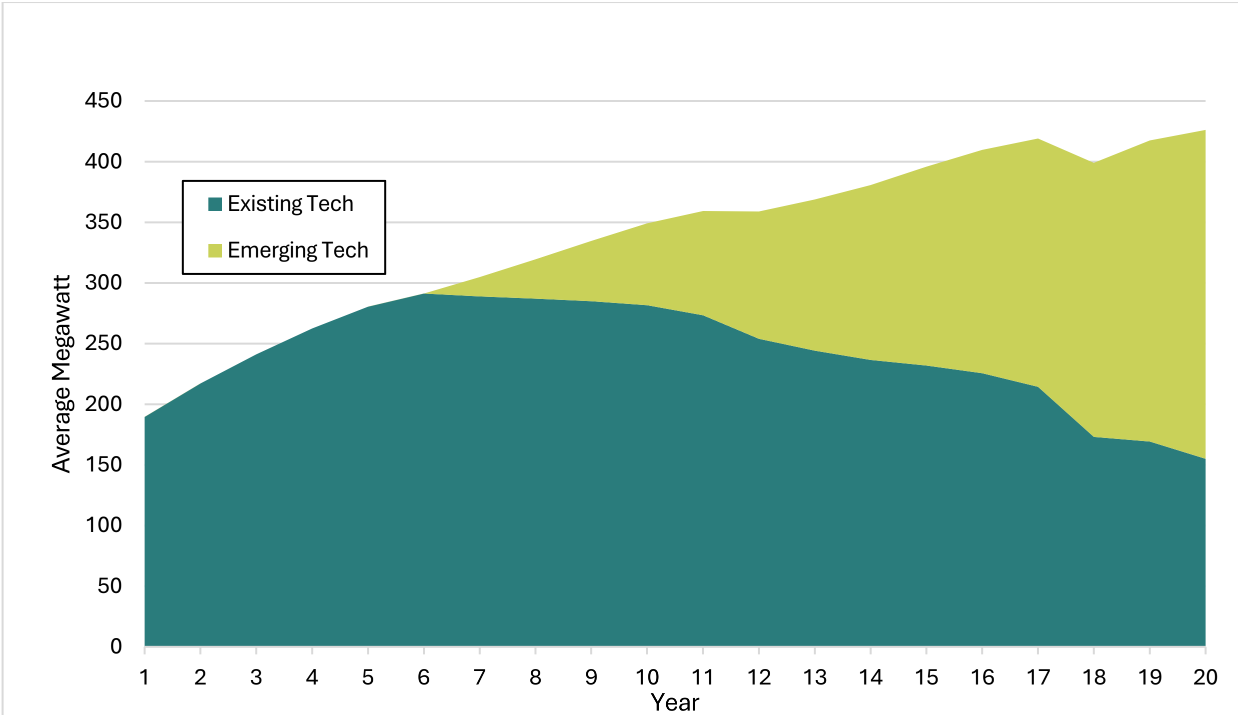
On the cost side, the Council considers direct costs of the measure over its effective lifetime, regardless of who pays the cost. This includes the upfront capital cost of the measure, operations and maintenance costs, and costs (or savings) from reducing other fuels including wood, propane, or natural gas. The Council also accounts for the benefit of deferring some transmission and distribution costs and water saving benefits (where applicable). Finally, the Northwest Power Act directs the Council to give conservation a 10% cost advantage over other resources, which is then factored into the costs.[92]

Like other resources, the conservation potential and value can vary in different parts of the region. For example, agricultural conservation is limited to those areas with significant agricultural loads. To address and explore these variances, the Council allocated the total regional potential to the 17 different zones used for modeling.

The Ninth Plan is the first of the Council's power plans to include emerging technologies in the conservation supply curve for consideration across the bulk of the analysis. This reflects the fact that there is continual investment in new technologies that have the potential to further reduce energy consumption at various end uses. While not considered available and reliable in the near term, this analysis provides insight into the long-term potential for conservation. The Council developed proxy resources to represent the potential in the various sectors. These emerging opportunities include whole building performance options for commercial and residential buildings, advancements in industrial motors, advancements in distribution system efficiencies, and the potential for efficiency in the electric vehicle sector. Given the uncertainty of these technologies, the Council assumes they are not available until starting in year six (2032) of the power plan analysis. This ensures the early strategies do not overly rely on resources that may not yet be available and reliable. Figure 3 - 15 shows the annual amount of conservation available in the Ninth Plan, split out between the existing technologies and the emerging potential.

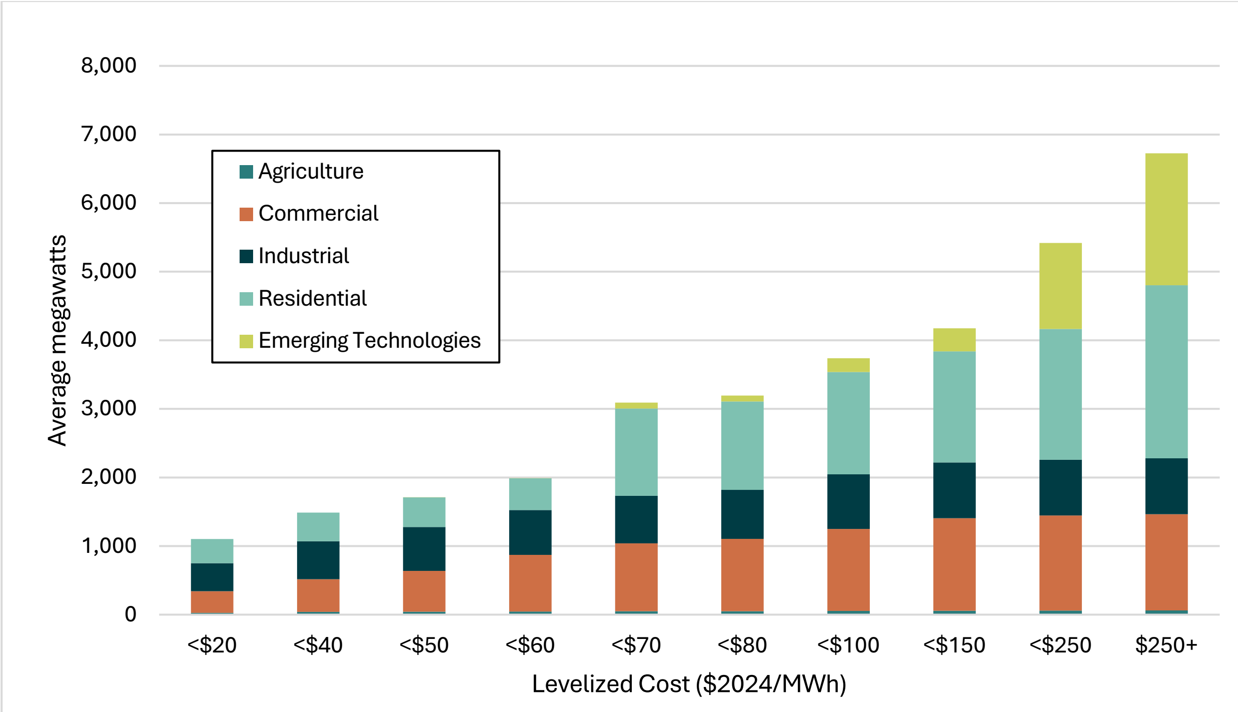
[91] The Council's Regional Technical Forum is an advisory committee to the Council chartered to develop consistent and reliable energy savings estimates for conservation measures.
[92] Northwest Power Act, Section 3(4)(D).

Figure 3 - 15: Ninth Plan Annual Incremental Conservation



In total, the Ninth Plan identifies over 6,700 average megawatts of potential new conservation over the 20-year planning horizon. This includes approximately 2,500 average megawatts in the residential sector, 1,400 average megawatts in the commercial sector, 800 average megawatts in the industrial sector, and 60 average megawatts in the agricultural sector. This also includes the estimated 1,900 average megawatts of emerging technologies. As shown in Figure 3 - 16, roughly 2,000 average megawatts of potential are available at a cost less than $60 per megawatt-hour in 2024 dollars. Most of the emerging technology potential is estimated to cost more than $150 per megawatt-hour in 2024 dollars.

Figure 3 - 16: Ninth Plan Conservation Potential



Demand Response

Demand response allows utilities to adjust the electricity demand of consumers at specific times to help reduce the power demand on the system. This is either done through direct adjustments or through the price signals that encourage consumer behavior. The Ninth Plan includes a range of products covering a variety of end uses across sectors, including space heating and cooling, water heating, electric vehicle charging, agricultural irrigation, and other loads. Technical Appendix I – Demand Response Methodology and Potential provides more information on the specific products considered and the Council's assumptions for each product.

Like conservation, the Council developed a supply curve to estimate the potential for demand response products. The Council uses a bottom-up and a top-down methodology to get to the technical potential for each product. The bottom-up approach considers the expected per-unit peak impact and an estimate of the number of eligible customers with the required equipment. The top-down approach begins with an understanding of the electricity use for a specific end use, then estimates a demand reduction for that load for a specific event based on its coincidence with peak hours. These estimates are then modified to account for the achievable potential, considering the time required to develop a program, the willingness of consumers to adopt the technology or program, and the level of participation expected in each event. On the cost side, the Council considers all direct costs for the demand response product, including those related to initial program set-up, equipment costs, ongoing operations and maintenance, and program marketing. Because these products shift and reduce load, the Council also accounts for the value of lost service which is based on the incentives provided to encourage the adoption of demand response.

The frequency of deploying (or dispatching) demand response varies by the type of product. Some products have relatively minimal impact on the consumer, allowing them to be dispatched frequently. This provides the benefit of allowing regular price mitigation and system flexibility. Examples of these products include electric vehicle charging programs and time-of-use rates. Other products more directly impact the consumer, and utilities limit their deployment to a designated number of events per year. Examples of these limited dispatch products are space heating and cooling controls and irrigation controls. Each product is also assigned a shape to represent the temporal characteristics of its deployment. This includes assumptions about event duration based on the enabling technology's capabilities and the characteristics of existing programs, as well as timing of deployment targeting hours of peak energy usage.

The Ninth Plan estimates close to 6,800 megawatts of demand response potential. Of this, 5,400 megawatts are considered frequently dispatchable. The bulk of that represents potential from shifting the time of electric vehicle charging from periods of high system peak to off-peak times. Of the remaining potential, roughly 1,400 megawatts represent from limited dispatch demand response. The primary product in this category is heating and cooling controls, working with consumers to adjust their temperature set points for a few hours during times of high peak needs on the system.

Figure 3 - 17: Ninth Plan Supply Curve of Frequent Dispatch Demand Response

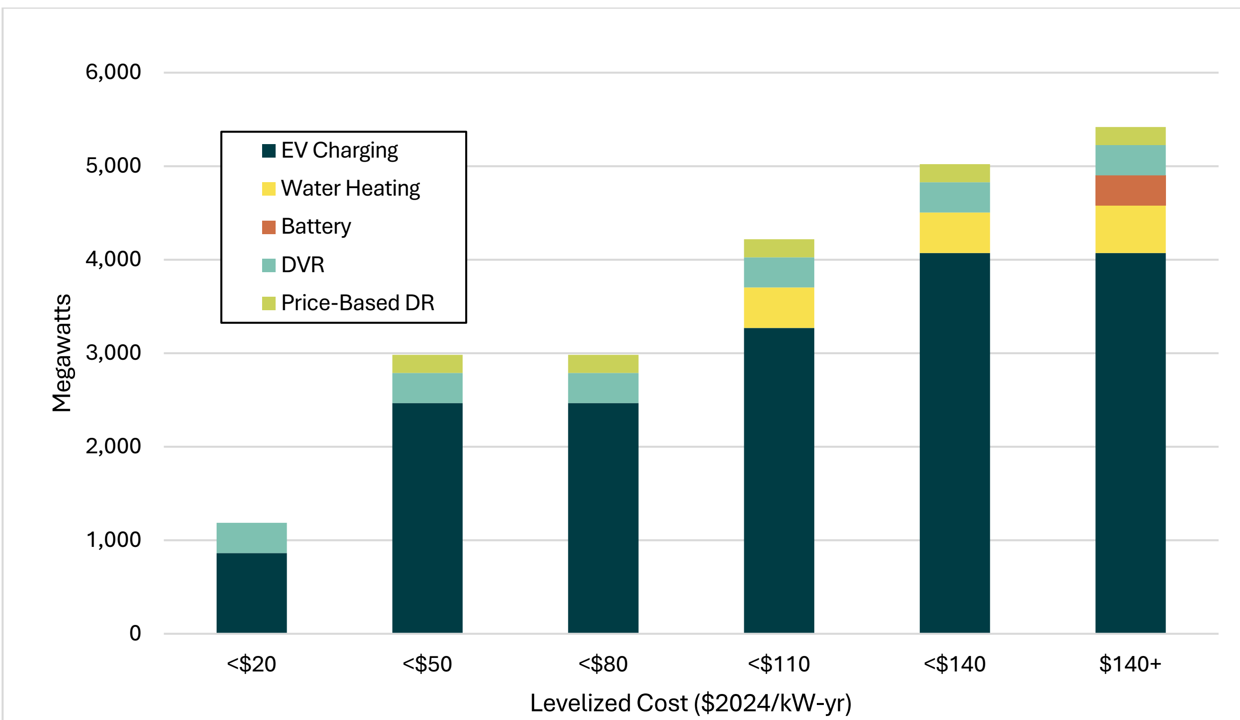
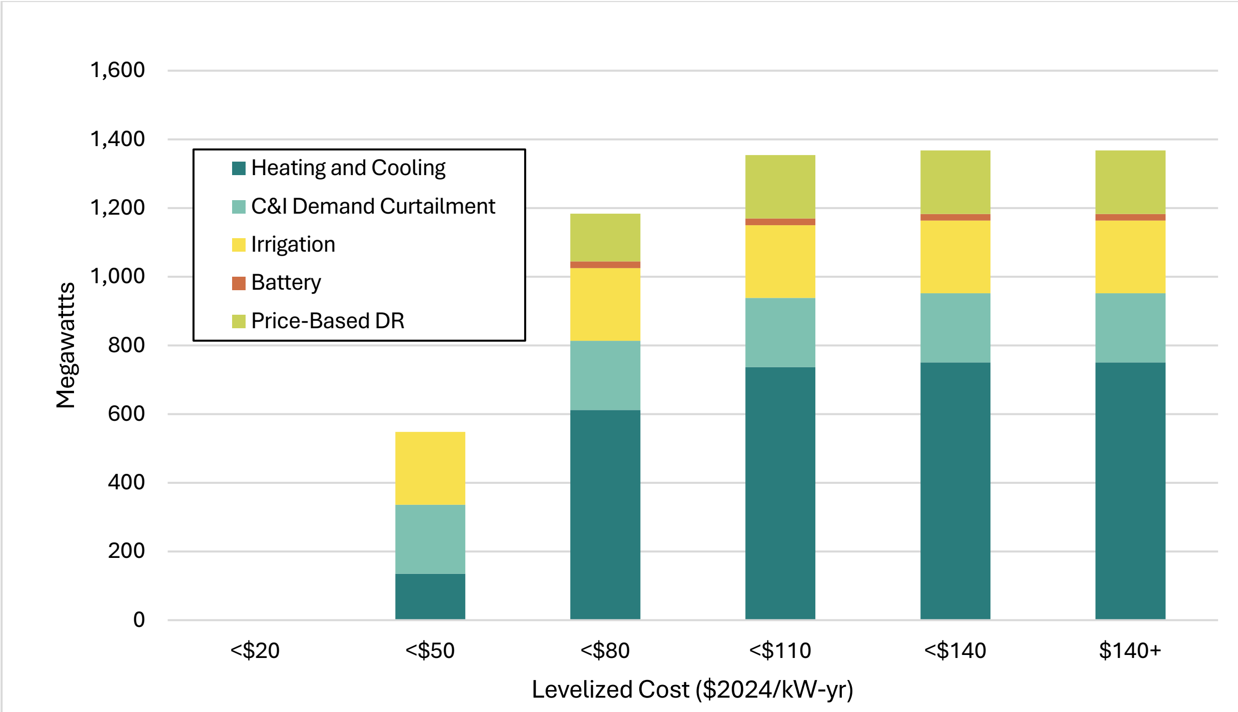


Figure 3 - 18: Ninth Plan Potential of Limited Dispatch Demand Response

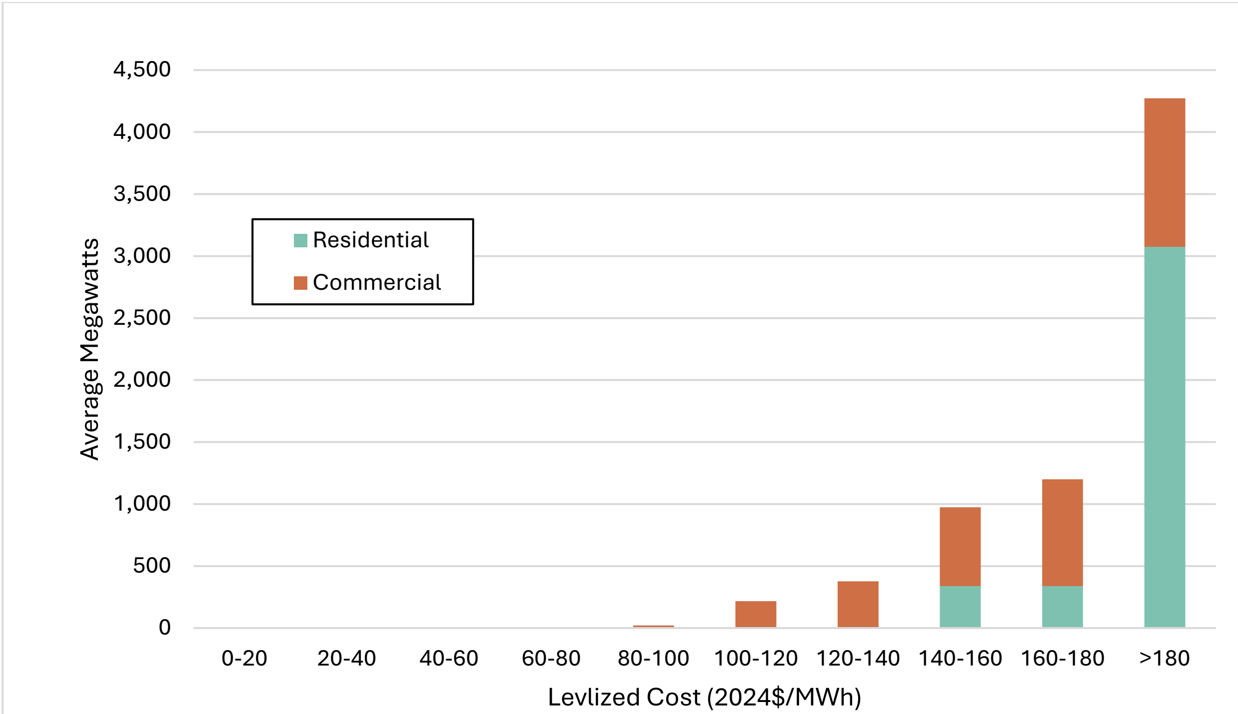


Rooftop Solar

The Ninth Power Plan is the first to explore the role of rooftop solar as a potential new resource to meet power system needs. As discussed in Chapter 2, while it is currently a smaller resource for the region, there has been growth in rooftop solar installations in recent years. To assess whether, and in what amounts, rooftop solar might support future system needs, the Council developed a supply curve of potential new rooftop solar. Technical Appendix J – Rooftop Solar Methodology and Potential provides more detail on the development of the Ninth Plan supply curve.

To estimate the total potential for rooftop solar additions in the region, the Council estimated the amount of rooftop available to solar, as well as factors around the assumed panel orientation, capacity, and efficiency. The Council assumed the same solar shapes as used for the utility scale solar potential, discussed later in this chapter. For costs, the Council assumed an average of $3.50 per watt. In total, the Ninth Plan assumes over 4,000 average megawatts of potential, around half of which is between $60-160 per megawatt-hour, with the rest costing greater than $160 per megawatt-hour in 2024 dollars.

Figure 3 - 19: Ninth Plan Rooftop Solar Potential



New Generating Resources Options

The bulk of power system needs are served through a suite of generating resources. These are often referred to as "supply side" resources. To characterize the capabilities of generating resource options, the Council develops reference plants. These reference plants do not represent specific planned projects in the region, but reflect the general capabilities of a generating resource and its theoretical application in the region. They include estimates of typical costs, logistics, and operating specifications. These reference plants represent new resource options for the model to consider, along with demand-side resources. For the Ninth Plan, the Council assessed a wide range of potential resources. This section describes the resources considered and gives an overview of their regional potential. Technical Appendix G – New Generating Resources provides a full description of each resource, including the specific reference plant assumptions.

Reference Plant Characteristics

Each reference plant includes sufficient information to understand the generating resource technology, the costs, and its operating characteristics. These components can be characterized by the following categories:

- **Resource Attributes:** These define how a generating technology serves the grid. This includes the technology type, configuration, nameplate capacity, operating life, and any assumptions around transmission access. The reference plant also includes information on timing, including construction timelines and availability date.

- **Financials:** These components detail the costs of the resources over the operating life of the plant. This includes the upfront capital costs, fuel costs, and operations and maintenance costs (both fixed costs from routine maintenance and variable costs like consumables that are a function of power production). It also includes any costs for connecting the resource to the grid via transmission, and the quantifiable environmental costs described above. For many resources, the Council incorporates forward cost curves that reflect improvements in technology (in terms of performance and price) over the power plan period. These curves vary from resource to resource based on the maturity of that resource. For the Ninth Plan, the Council used conservative forward cost curves to reflect the current uncertainty around resource availability and costs in the near term.
- **Operating Characteristics:** These define how the generating technology works. This includes information on the heat rate, capacity factor, and generation shape.
- **Developmental Potential:** These components identify how the generating resource fits into the grid, including the location and the requirements for transmission and/or gas pipeline access. The Council also specifies the maximum buildout assumptions, which for most resources is limited to the physical constraints of the system.

For each of these components, the Council uses a wide variety of publicly available data sources to inform assumptions. This includes manufacturer data, information from power purchase agreements or project-specific specifications, technical handbooks, reports from the U.S. Energy Information Association, the U.S. Department of Energy, national labs, and regional utility integrated resource plans. Where required, the Council varies assumptions to account for regional differences, like adjusting the capacity factors for renewable resources based on location.

Primary Resources

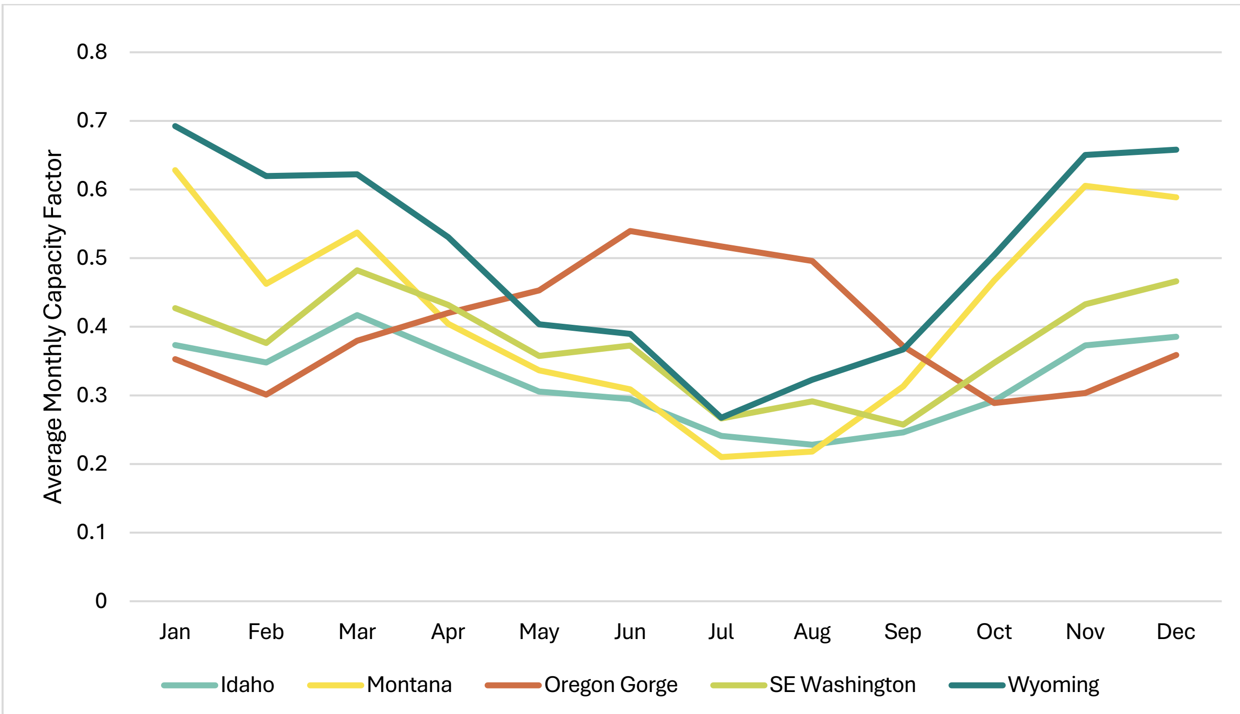
For assessing new generating resource options, the Council groups resources into one of three buckets. The first is primary resources, or generating resources that are deemed proven, commercially available, and deployable on a large scale in the region at the start of the power plan. The primary resources considered in the Ninth Plan are onshore wind, solar, battery storage, hybrid renewable and storage plants, and natural gas (including combined cycle and simple cycle technologies). The Council developed reference plants for each of the primary resources.

Onshore Wind

Wind power is a naturally occurring, renewable form of energy. Power plants are made up of individual turbines that harness and transform energy into electricity. As the wind blows, the turbine blades rotate. These blades are connected to a rotor, which is then connected to low- and high- speed shafts, that are then connected to a generator that produces electricity. The region currently has over 13,000 megawatts of installed nameplate wind.

One of the main considerations for wind development is location. Like other resources, wind can face challenges with siting constraints, land availability, potential community push back, and supply chain challenges. More unique to wind, however, is the difference in generation potential across the region due to variability of the wind resource. To address this, the Council developed five different reference plants with different generation shapes to account for locational differences between potential wind resources. These wind zones are consistent with where the region has developed wind to date: Columbia River Gorge, Southwest Washington, Southern Idaho, Montana, and Wyoming.

Figure 3 - 20: Onshore Wind Average Monthly Capacity Factors by Location



The capital cost of onshore wind has declined by more than 50% since its peak in 2008.[93] These trends have flattened in recent years, because the technology has matured and supply chain issues have slowed development. The Council assumes a capital cost of around $1,700 per kilowatt in 2024 dollars, with an assumed decrease to below $1,500 per kilowatt in 2024 dollars by the end of the 20-year power plan horizon. The Council varies these costs slightly between the locations defined above to account for differences in costs across the region.[94]

Solar

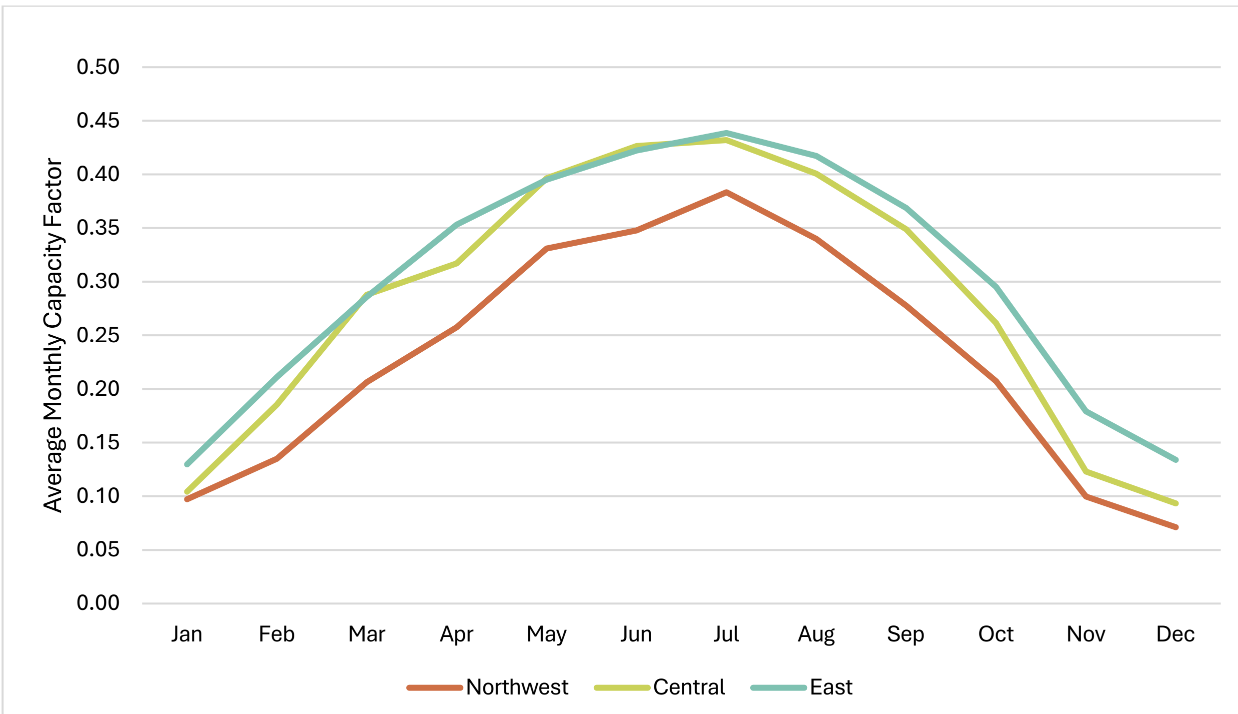
Solar power is a naturally occurring, renewable resource that converts energy from the sun into electricity. Solar photovoltaic (or solar PV) consists of photovoltaic cells assembled into models that are ground mounted on panels. These panels can either be fixed or can track in either one (single axis)

[93] Lawrence Berkely National Lab, 2024. Land-Based Wind Market Report, Executive Summary. https://eta-publications.lbl.gov/sites/default/files/land-based_wind_market_report_2024_edition_executive_summary.pdf.
[94] The Council uses locational cost adjustment factors from the 2025 Energy Information Administration Energy Outlook. More detail is provided in Technical Appendix G – New Generating Resources.

or two (dual axis) directions. The region currently has around 2,400 nameplate megawatts of solar, with most of these utility scale systems being single axis tracking systems.

Like wind, the location of solar is an important factor for this resource. Solar generation requires land. While the specific amount can vary based on project design and other considerations, a basic rule of thumb is that one megawatt capacity of solar requires around five to seven acres. Also, like wind, generation varies across the region. To address this variance, the Council developed three primary zones to reflect differences in the solar resource: Northwest (representing the areas west of the Cascade Mountains), Central (representing areas east of the Cascades in Oregon and Washington), and East (representing Idaho and Montana).

Figure 3 - 21: Solar Capacity Factors by Location



The Council further split these three locations to account for the operational risk of wildfires. The Ninth Power Plan is the first Council power plan to directly consider the impacts of wildfire on the power system. The specific focus for the Ninth Plan is the impact on solar generation from nearby smoke. To address this, the Council developed smoke-modified solar capacity factors. This approach essentially introduced “wildfire smoke days” that reduces the capacity factors for a specific location by around 10% for that period. The Council developed these days based on historical wildfire data from around the region. Recognizing that wildfire smoke within a zone would not necessarily impact the solar generation across that entire zone, the Council split each initial zone into two, creating six final solar zones.[95]

The capital costs of solar have declined by around 75% since 2010, driven by improvements in the technology.[96] For the Ninth Plan, the Council assumes a capital cost of around $1,500 per kilowatt in 2024 dollars. These costs are anticipated to decline to around $900 per kilowatt in 2024 dollars by the end of the power plan period. Similar to the approach with wind, the Council has varied these cost assumptions for the different locations to account for differences across the region.

In addition to the utility scale solar reference plant described above, the Ninth Plan included a reference plant for small-scale solar. Community solar, where multiple community subscribers share a local solar facility, is an example of small-scale solar developed in the region. These projects are usually less than five megawatts. While these smaller projects are more expensive on a per-kilowatt basis compared to the larger utility scale solar, with initial costs closer to $2,000 per kilowatt in 2024 dollars, the smaller size allows projects to be built faster and in more locations.

Battery Storage

Battery storage allows for the capture and storage of energy for use at a future time. Lithium-ion technology is the most common form of battery storage on the power system. This is the same technology as used in consumer electronics and electric vehicles. Utility scale lithium-ion batteries are typically a collection of tens of thousands of small batteries connected and packaged together to form a larger resource. These batteries are commonly referred to as short-duration storage, meaning the period over which the battery can discharge is relatively short. The Ninth Plan reference plant assumes a 4-hour lithium-ion battery.

A key consideration for storage resources is the unit's round-trip efficiency. This refers to the ratio of useful energy output to useful energy input. Lithium-ion batteries have round-trip efficiencies of between 85 and 90%. The Ninth Plan assumes an 88% round-trip efficiency for battery storage.

The cost of lithium-ion batteries has declined significantly in the last 10 years, with some estimates showing declines of around 70%.[97] The Ninth Plan assumes capital costs of around $1,800 per kilowatt in 2024 dollars, declining to below $1,400 per kilowatt in 2024 by the end of the power plan horizon.

[95] Technical Appendix G – New Generating Resources provides more detail on this approach.
[96] Lawrence Berkely National Lab, 2024. Land-Based Wind Market Report, Executive Summary. https://eta-publications.lbl.gov/sites/default/files/land-based_wind_market_report_2024_edition_executive_summary.pdf.
[97] BloombergNEF Press Release from December 2025. https://about.bnef.com/insights/clean-transport/lithium-ion-battery-pack-prices-fall-to-108-per-kilowatt-hour-despite-rising-metal-prices-bloombergnef

Hybrid: Renewables and Storage

Co-locating renewables with storage helps avoid curtailment of energy, reduce integration costs, provide grid services, and reduce transmission costs. With costs declining for solar, wind, and batteries, opportunities to pair these resources are gaining traction. While these technologies can be paired in multiple configurations, hybrid plants that include wind generation are not yet common practice. Wind generation is less consistent than solar on a day-to-day basis, so the pairing of wind and storage provides for a relatively less reliable short duration storage resource. Therefore, the Council focused on the development of a solar plus storage hybrid reference plant.

The Council developed the costs for this reference plant based on a combination of the solar and battery storage costs discussed above. The Council accounted for costs savings of shared equipment, such as the inverter costs. The capital costs are assumed to be $2,500 per kilowatt in 2024 dollars. This represents roughly 25% in cost savings compared to developing each resource individually. These costs decrease to around $1,600 per kilowatt in 2024 dollars by the end of the 20 years.

Natural Gas

Natural gas turbine technologies are a proven and mature source of electricity generation. The Council assessed two types of natural gas resources: combined cycle combustion turbines and simple cycle gas turbines.

Combined cycle combustion turbines are an efficient thermal resource that provides baseload power, with on-call fuel providing some flexibility. These plants consist of one or more gas turbine generators that exhaust to a heat recovery steam generator, which produces steam that ultimately produces additional electricity. This use of the exhaust energy increases the efficiency and the output of combined cycles combustion turbines compared to their simple cycle counterparts.

Simple cycle gas turbines are more flexible than combined cycle combustion turbines. They can ramp up and down quickly to address changes in demand. Newer units are more flexible and efficient, allowing them to follow the variable output of wind and solar. Generally, these plants produce electricity at lower capacity factors, running only when needed. There are three primary simple cycle gas turbine technologies available today: frame turbines, reciprocating engine generating units, and aeroderivative turbines. The Council developed two simple cycle reference plants reflecting the frame and reciprocating engine technologies. Frame turbines are generally less expensive, more reliable, and less efficient than other units. Reciprocating engine units are generally more flexible and more efficient than other simple cycle technologies.

The Ninth Plan assumes some limitations to the availability of new natural gas plants. Clean policies regulating emitting resources impact the potential for natural gas. Oregon law bans new gas plants in the state. While Washington laws do not explicitly ban natural gas, their carbon tax and 100% clean targets increase the cost of emitting resources and are considered in the Council's modeling assumptions. Pipeline access is an additional limiting factor. The existing gas pipeline system faces significant constraints, with no more firm capacity available for new plants. The Ninth Plan accounts for these constraints in two ways. First, the Council assumes an added cost associated with ensuring firm supply. Second, the Council assumes a 3,000-megawatt limit for new gas plants through 2032, increasing that limit to 10,000 megawatts by the end of the plan period based on the assumption that the region would expand the pipeline if additional gas were needed over the long-term.

Since natural gas is a more mature technology, the capital cost declines have been less significant in recent years than those experienced by wind, solar, and batteries. For combined cycle combustion turbines, the Ninth Plan assumes a capital cost of $1,500 per kilowatt in 2024 dollars. To address pipeline constraints, the Council assumed an added $30 per kilowatt-year in fixed operations and maintenance costs to account for the cost of firming up the fuel supply. The Ninth Plan assumes cost declines of about 15% for this technology over the planning horizon.

The capital cost for frame turbines is around $1000 per kilowatt, with the more expensive reciprocating engine turbines at $1800 per kilowatt, both in 2024 dollars. The Council assumed an upfront cost of $78 per kilowatt and ongoing fixed operations and maintenance costs of $5 per kilowatt-year to account for added onsite storage and fuel to ensure firm capacity for new simple cycle plants. The Ninth Plan assumes that both simple cycle technologies' costs will decline by around 20% over the 20-year plan horizon.

Limited Availability Resources

The Council considers limited availability resources to be those that are commercially available but have limited development potential in the region. Due to these physical constraints, the Council assigns harder availability limits to these resources. The Council considered a suite of potential resources in this category: conventional geothermal, offshore wind, pumped storage, biomass, hydropower upgrades and small hydropower turbines, and combined heat and power. Ultimately, the Council only developed reference plants for conventional geothermal, offshore wind, and pumped storage, which are discussed more below.

The Council opted not to develop a reference plant for the other three technologies due to their more limited application in the region. While biomass is used for electricity production in the region, it is not a common fuel choice. Small hydropower turbines refer to projects that capture energy from irrigation infrastructure, low-head stream flows, water treatment plant outfalls, and other areas with both a small footprint and environmental impact. Both these small projects and hydropower upgrades are very site-specific and there is minimum development in the region. Combined heat and power plants are most often used in industrial applications, where the process heat produces electricity to support further needs of the operation. Many of the industries that deployed this resource have left the region, making it a less viable option going forward. While the Council has opted to not develop a reference plant for these technologies, the Council continues to consider the potential role these resources might play in meeting overall system needs.

Conventional Geothermal

Conventional geothermal is a renewable resource with zero or low carbon emissions.[98] Conventional geothermal requires the natural occurrence of heat, water, and permeability beneath the earth's surface. The units leverage the heat to produce electricity. The region has a significant geothermal resource, especially in southern Oregon and Idaho, but development to date has been limited.

Based on data from the U.S. Geological Survey, the Council estimates that the region has around 460 megawatts of conventional geothermal potential.[99] This equates to around 22 plants for the region. Because of the need for a naturally occurring resource, the reference plants are limited to areas of southern Oregon east of the Cascade Mountains and Idaho. Due to the timelines required to identify the appropriate location, the Council assumes construction timelines of seven years. The Council assumed capital costs of around $5,000 per kilowatt in 2024 dollars, with some cost decline to a final cost of around $4,600 per kilowatt in 2024 dollars.

Offshore Wind

Offshore wind turbines are like their onshore counterparts, but they tend to be larger in size and energy output. Offshore wind has an average capacity factor of around 50%. While offshore wind is an established resource in some parts of the world, it is still very much emerging in the Pacific Northwest. Due to the depths of the coast, offshore wind in this part of the world requires a floating turbine. This technology is less well established than the fixed-bottom technology deployed elsewhere in the world.

Development of offshore wind in this region is limited to federally designated leasing areas. There are two such areas identified in the region off the Oregon coast, one near Coos Bay and the other further south near Brookings. In total, these sites are estimated to have around 3,000 megawatts of capacity. The timing of offshore wind availability is highly uncertain. Early in the Ninth Plan development, the Bureau of Ocean Management estimated the earliest online date would be 2032. Recognizing the uncertainty and changing federal landscape, the Council assumed a more conservative assumption of 2043. Since the start of analysis, the Trump Administration has temporarily halted offshore wind leasing.

The Council assumed a capital cost of $7,000 per kilowatt in 2024 dollars, which is based on data from the National Lab of the Rockies. Costs are estimated to decline as the technology develops, with final estimates of around $4,000 per kilowatt in 2024 dollars.

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[98] The emissions depend on the technology. Flash steam technology emits minimal excess steam. Dry steam and binary cycle technologies have zero emissions.
[99] U.S. Geological Survey, 2008. Assessment of Moderate- and High-Temperature Geothermal Resources of the United States.

Pumped Storage

Pumped storage hydropower is an established and commercially mature energy storage resource. A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower reservoir to the upper reservoir and then generated by releasing that stored water through turbines back to the lower reservoir. The estimated round-trip efficiency of these projects is around 80%.

These projects require suitable topography and geologic conditions. Based on those limitations, the Ninth Plan assumes 10 reference plants totaling 4,000 megawatts of potential. This estimate was informed by the projects currently identified for development in the region and what is realistically achievable over the next two decades. The Ninth Plan cost for these reference plants is around $4,000 per kilowatt. Because pumped storage is considered a fully mature technology, the Council does not assume any decline in cost over the power planning period.

Emerging Technologies

The Council also includes an assessment of potential new resources that are not yet considered available and reliable but might provide value for the system in the long term. The Council groups these into the emerging technologies category.

The Ninth Plan approach to assessing emerging technologies is to create proxy reference plants. These reference plants are not intended to represent any single emerging technology, but rather to provide characteristics to the model reflecting a range of potential technologies. The Ninth Plan includes three proxy emerging technology reference plants: clean long duration storage, clean baseload, and clean peaker/medium duration storage.

Given these are proxy plants representing a range of potential technologies, the Council developed some shared assumptions to use across all reference plants. One common assumption is on costs, particularly the potential for technological advancement and declining costs over the power plan period. The Council used a single assumption for all reference plants. This is based on National Laboratory of the Rockies' assumptions for small modular reactors. Because these costs are so uncertain, the Council developed two sensitivities that vary the cost assumptions for emerging technology. These sensitivities will provide additional insight into the potential future role of these emerging technologies for the region.

Clean Long Duration Storage

The clean long duration storage proxy includes resources that support integration of variable energy resources, provide operational flexibility, and offer demand shifting between days or seasons. The Council considered multiple emerging technologies that provide long duration storage. This includes different types of electrochemical energy storage (e.g. lead-acid or flow batteries), mechanical energy storage (e.g. compressed air or gravity storage), and thermal energy storage.

The Ninth Plan clean long duration storage proxy is based on data for iron air batteries, which are a kind of electrochemical energy storage. These batteries employ a reverse rusting mechanism, rusting and de-rusting, to create a form of electrical current. While this cycle is durable and repeatable, it is not particularly efficient. The assumed round-trip efficiency for this resource is around 40%. Despite this low efficiency, they have the potential to add value to the system by shifting more stored excess energy over longer periods of time.

The iron air battery is close to commercial readiness. There are factories in production and successful test projects have been completed. Therefore, the clean long duration storage reference plant is the first of the emerging technologies available to the model with a first potential online date of 2032. The Ninth Plan assumes only 1,000 megawatts could be developed by 2040, with the potential to expand production by an additional 2,000 megawatts by 2046. The assumed cost is around $2,500 per kilowatt in 2024 dollars.

Clean Baseload

The clean baseload proxy includes resources that offer reliability and firm supply to the grid. There are several emerging resources in development that could provide these characteristics including enhanced geothermal, wave energy, and small modular reactors. The Ninth Plan clean baseload reference plant is based on information for the small modular nuclear reactor. The level of regional interest in this technology has provided a relative wealth of data from which the Council could construct the necessary reference plant characteristics.

As indicated by its name, the small modular reactor has a smaller size and more modular construction than a conventional full-sized nuclear unit. This has the potential to shorten construction lead time, permit greater flexibility in resource siting, allow for some load following capability, and provide potential for cogeneration. Despite the investment in development of this (and other clean baseload) resources to date, the Council anticipates a longer timeline before commercial readiness. The Ninth Plan assumes a first online date of 2040, with the potential for up to 3,000 megawatts in the plan horizon. The assumed cost for this reference plant is around $9,000 per kilowatt in 2024 dollars.

Clean Peaker and Medium Duration Storage

The clean peaker and medium duration storage proxy includes resources that mitigate high peak demands, while extending the system's operational flexibility. These resources also provide storage for a period between that of the shorter duration lithium-ion battery and the clean long duration storage proxy. This makes the resource adept at providing support for daily or hourly demand shifting.

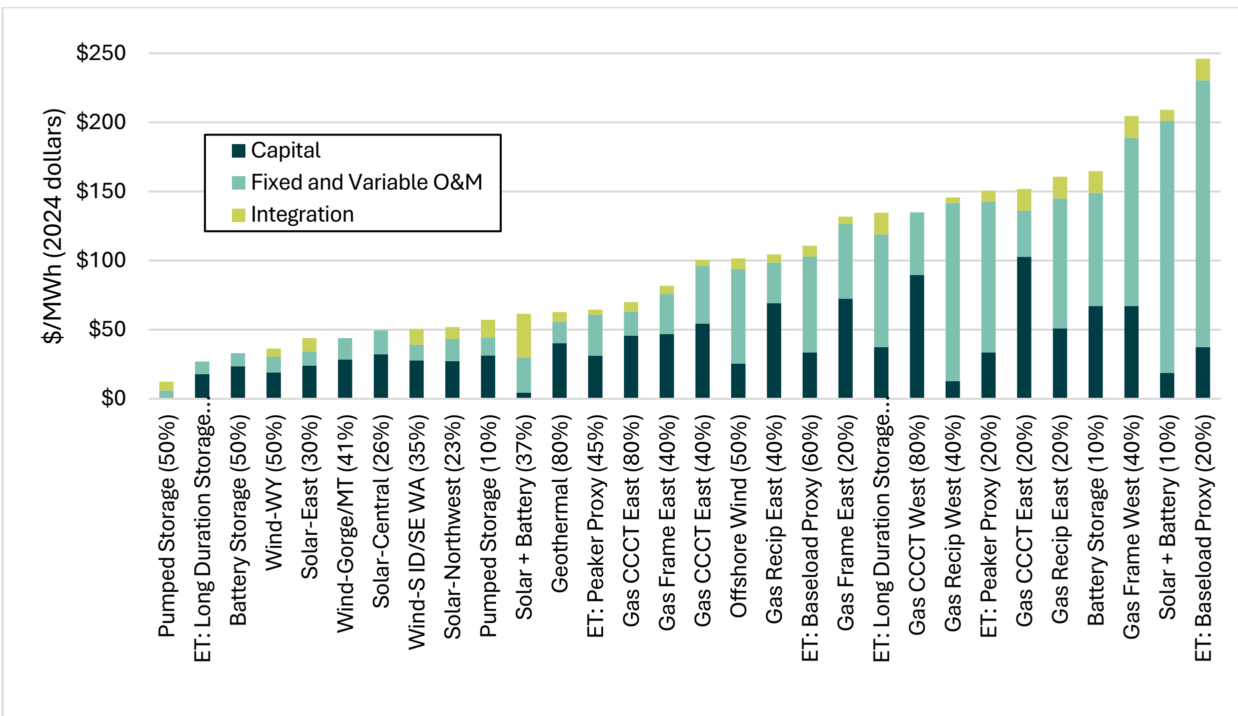
The Council considered multiple emerging resources under this category, including flywheel energy storage and alternative hydrogen fuel sources like ammonia and pyrolysis. The Council selected hydrogen with onsite electrolysis as the basis of this proxy reference plant, due to the broad interest in this technology and potential to convert existing peaker plants to green hydrogen to meet clean goals. Because there is no existing infrastructure for hydrogen, the Council chose to model this as a resource that produces its hydrogen fuel onsite via electrolysis. In doing so, the reference plant also reflects the same attributes as a medium duration storage resource, where excess electricity at times of low load is used to create hydrogen and then dispatched by burning that hydrogen when there is a need. The Council assumed a relatively low round-trip efficiency of 40%.

Like the clean baseload proxy, the Council assumed a first online date of 2040 for the clean peaker/medium duration storage proxy. The total available to the model is 3,000 megawatts. The assumed cost for this resource is around $3,500 per kilowatt in 2024 dollars.

Summary

In total, the Council developed 14 different reference plants, several with multiple iterations, to account for variability across the region. Each of these reference plants includes information on cost and availability, as well as other attributes the resource provides the system. Figure 3 - 22 compares the reference plants on a levelized cost of energy basis. For readability, not all iterations of each reference plant are included in the chart. Because of this, and other flattening of assumptions to create these estimates, it is not a perfect way to represent the exact value each resource might provide to the system. But it provides some information to assess and compare resources.

Figure 3 - 22: Levelized Cost Comparison for Select Reference Plant Iterations



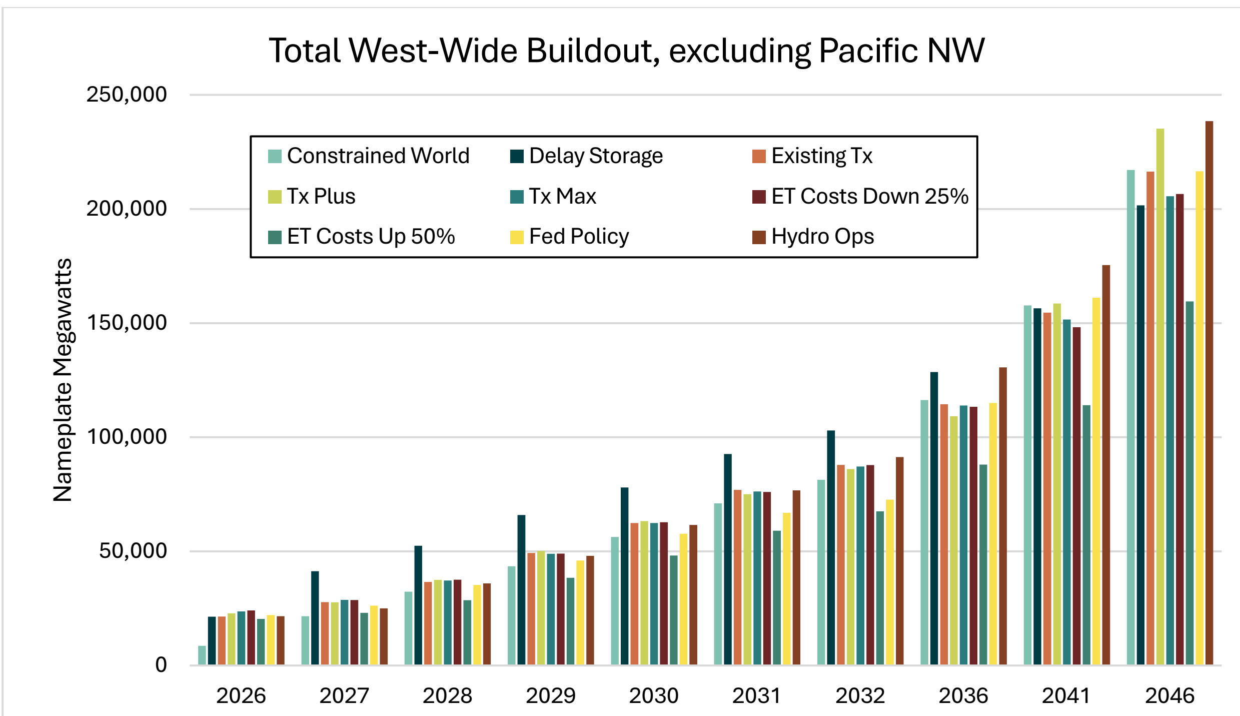
Market Availability

Purchasing energy and capacity from the market is an important part of maintaining system reliability. When more generation is produced than required for load in an area, that additional generation is available as a market resource for others to acquire to support meeting loads. To understand the depth of the market (how much energy and capacity might be available at any point in time), the Council conducts market availability studies. Each of these studies provides information on how and when many resources are being built across the broader Western Interconnection. This in turn provides information about the availability and cost of market resources.

Just as resource decisions change in the Northwest due to changing loads, policies, resource options, and costs, the same is true for the broader West. For example, tax incentives impacting the cost of certain resources will make those resources more or less attractive for all potential developers. Additionally, if new emerging resources do not come online at the pace expected, this will have implications for all entities trying to ensure the lights stay on for their customers. Therefore, the Council conducts a separate market availability study for each sensitivity with varied assumptions on resource availability, costs, or transmission buildouts. For the Ninth Plan, the Council ran nine market availability studies. This included one study for the Changing Hydro Operations scenario and eight for the sensitivities included in the New Resource and Transmission Risk scenario.[100]

Figure 3 - 23 shows the total buildout for each of the nine market availability studies. In general, the West-wide buildouts are similar across the sensitivities. In the near-term, the biggest impact was the availability of battery storage. More resources in total nameplate megawatts were required when battery storage is limited in the near-term. In the long-term, the biggest impact is the availability of transmission. As more transmission comes online, the overall buildout shrinks.

Figure 3 - 23: Ninth Plan Market Study Results



[100] The one sensitivity in the New Resource and Transmission Risk scenario that did not require a separate market availability study is the Slower Demand Side Availability sensitivity. The Council does not explicitly model demand-side resources in this analysis, but rather assumes they are accounted for in the load forecasts. Therefore, changes in assumptions around in-region demand-side options do not change the assumptions for these out-of-region studies.

Digging deeper into the results, the Council found that most of the resources built across the sensitivities were a balance of renewables, storage, and natural gas. The specific mix varies by sensitivity. Emissions pricing in Canada, California, and Washington (which accounts for around 60% of the West-wide load) drives much of the early variable energy resource decisions. These resources are also being used both for renewable portfolio standards and clean policies. The amount of storage impacts the type of resources. Delays in short-duration storage drive increases in both variable energy resources and natural gas builds. Transmission also impacts builds, as more transmission allows for more variable energy resources, while more limited transmission results in increased natural gas builds.

The Council uses the market availability results to inform the next step of regional resource optimization, which is conducted in the Council's OptGen/SDDP model framework. Specifically, the Council takes the West-wide buildout of resources for each study and puts those resources directly into the model. As OptGen is solving for what new resources are required to meet load, it has direct insight into what resources (including type of resources) are available on the market from outside the region. This provides insight into market depth and market prices. This market availability becomes in essence another resource for the model to consider, alongside the new resource potential discussed above. In the Ninth Plan, the Council was careful to ensure that enough resources are built in the region to avoid overreliance on the market.

Transmission

As discussed in Chapter 2, the Council recognizes the need for new transmission development to support the addition of resources and meeting projected load growth. There have been several efforts to improve and expand transmission planning, most notably the Western Transmission Expansion Coalition, also known as WestTEC. This is a West-wide voluntary effort to conduct long-term transmission planning. For the Ninth Plan, rather than developing an independent look at potential transmission needs, the Council leveraged the work of WestTEC and others to inform a suite of transmission buildout sensitivities. This analysis is intended to provide insight into how resource decisions change as transmission development occurs. They are also designed to inform what resources, if any, might provide a role in ensuring system reliability if planned transmission development is stalled.

The Ninth Plan assumes three different transmission buildouts. The first is the existing system. This includes all the existing transmission in the ground, as well as projects that are under construction. Most notably for the region, this assumes that the Boardman-to-Hemingway transmission line comes online. Beyond the existing system, the Council assumed two additional transmission buildouts: transmission plus and transmission max (see Table 3 - 5). The additional projects assumed in transmission plus are planned projects estimated to come online during the Ninth Plan action plan period (2027-2032) with some additional transmission on the east side of the region. Those projects in the transmission max sensitivities include additional planned projects anticipated after 2033.

Table 3 - 5: Additional Transmission Assumed in Sensitivities

Project	Description	Date	Sensitivity	
			Plus	Max
Cross Cascades North	650 MW across the Cascades in Washington	2031	X	X
Cross Cascades South	1,500 MW across the Cascades in Oregon	2031	X	X
Path 8 Upgrade 1	600 MW upgrade between Montana and Oregon	2035	X	X
Gateway West Segment D3	1,000 MW between Wyoming and Idaho	2035		X
Gateway West Segment E	2,000 MW across Idaho	2036		X
Path 8 Upgrade 2	Added 200 MW west to East and 1,500 MW east to west on Path 8	2036		X
Path 14 Upgrade 2	650 MW west to east and 1,000 MW east to west between Idaho and Oregon	2036		X
North Plains Connector	1000 MW interconnection into the Dakotas	2033		X

Developing new transmission is not the only way to help bring more remote resources to load. There are several technological options to expand the existing transmission capacity. One such option, reconductoring, involves upgrading existing transmission lines by replacing the conductors. This mitigates the need to build entirely new infrastructure. Traditional steel reinforced cores using aluminum conductors can be placed with conductors using fully annealed aluminum. This allows the conductor to operate at higher temperatures, which in turns allows more current to run through it. There are also opportunities for more advanced reconductoring that replaces the steel with lighter composite cores. This can increase transmission capacity up to two times, while also reducing the line sag at high temperatures. These options can be deployed more quickly and more cheaply than building new transmission lines, often at less than half the cost.[101] Reconductoring is most suitable for shorter, thermally limited lines. The Idaho National Lab estimates approximately 20% of transmission lines nationally could be viable candidates for reconductoring.[102]

Other grid enhancing technologies exist that can be deployed within the existing transmission system to help increase the capacity, flexibility, and efficiency of the grid. Dynamic line rating can dynamically adjust the carrying capacity of transmission lines based on real-time measurement of ambient conditions like temperature and wind speed. Other options like topology optimization and advanced power flow controls optimize the flow of electricity through transmission lines to avoid congestion and capacity constraints. The Council did not explicitly model these in the Ninth Plan analysis; however, they were modeled in the WestTEC analysis. Therefore, it is reasonable to assume that

[101] GridLab, 2024. 2035 and Beyond: Reconductoring with Advanced Conductors Can Accelerate the Rapid Transmission Expansion Required for a Clean Grid.
[102] Idaho National Lab, 2023. Advanced Conductor Scan Report.

some of the additional transmission capacity reflected in the Ninth Plan scenario modeling is a result of enhancements to the existing system.

Transmission is an essential part of ensuring system adequacy. From the resource planning perspective, the types and amounts of new resources required to meet demand varies based on the amount of future transmission capacity (see Chapter 4 for a discussion of scenario modeling results). At the same time, there are resources that can be used to mitigate against the need for future transmission development or mitigate against the risk of delays in that development. And there are solutions to enhance the existing transmission system without adding new lines. All these options, new transmission, new resources, or enhancing the existing system come with costs and risks. The Ninth Plan resource strategy considers all of these, providing a cost-effective solution to meet needs, mindful of this important interplay with the transmission system. The action plan also includes recommendations for Bonneville and the region on these issues. See Chapter 4 for more information.

Chapter 4: Action Plan – Resource Strategy and Other Recommendations for Bonneville and the Region

This chapter contains the Council's recommendations for new conservation and generating resources that Bonneville and the region are to acquire to meet regional needs. It also includes additional recommendations to support Bonneville and the region in implementing the resource strategy. Combined, these recommendations make up the Ninth Power Plan's Action Plan for the next six years (2027-2032).

The Northwest Power Act requires that the Council's power plan "set forth a general scheme for implementing conservation measures and developing resources."[103] This describes the regional resource strategy that the Council puts forth in each power plan. The strategy includes recommendations for resources, and amounts of those resources, required to meet regional needs. This includes specific recommendations to Bonneville about its role in supporting the implementation of the resource strategy. In addition, the Action Plan includes recommendations on data center integration and investments in the transmission and distribution systems, as both are critical for successful implementation of the strategy. The final piece of the Action Plan is a suite of recommendations for research and development, consistent with the requirements of the Northwest Power Act.

Regional Resource Strategy

As described in Chapter 3, the Council analyzed a range of uncertainty through a set of sensitivities that explored the impacts of new resource availability, resource costs, transmission capacity, and hydro conditions. In each sensitivity, the Council's regional capital expansion model, OptGen, developed a least cost, optimized portfolio of new resources to provide adequacy across a range of potential futures. These futures reflect uncertainty around potential load growth, hydro and variable energy resource conditions, and natural gas price forecasts. The Council used the analysis from the 13 sensitivities, as well as insight from the Council's advisory committees and other regional experts, to develop the Ninth Plan resource strategy. The results of this analysis and process show that the region needs a broad range of resources by 2032, including: 1,060 average megawatts of

[103] Northwest Power Act, Section 4(e)(2).

conservation, 590 megawatts of demand response, 220 megawatts of voltage regulation, 9,000 megawatts of renewables, 5,200 megawatts of storage, and 2,100 megawatts of natural gas. This strategy provides a robust approach for meeting regional needs and ensuring adequacy.[104] The following sections outline the analytical results and the resulting Council recommendations for a regional resource strategy.

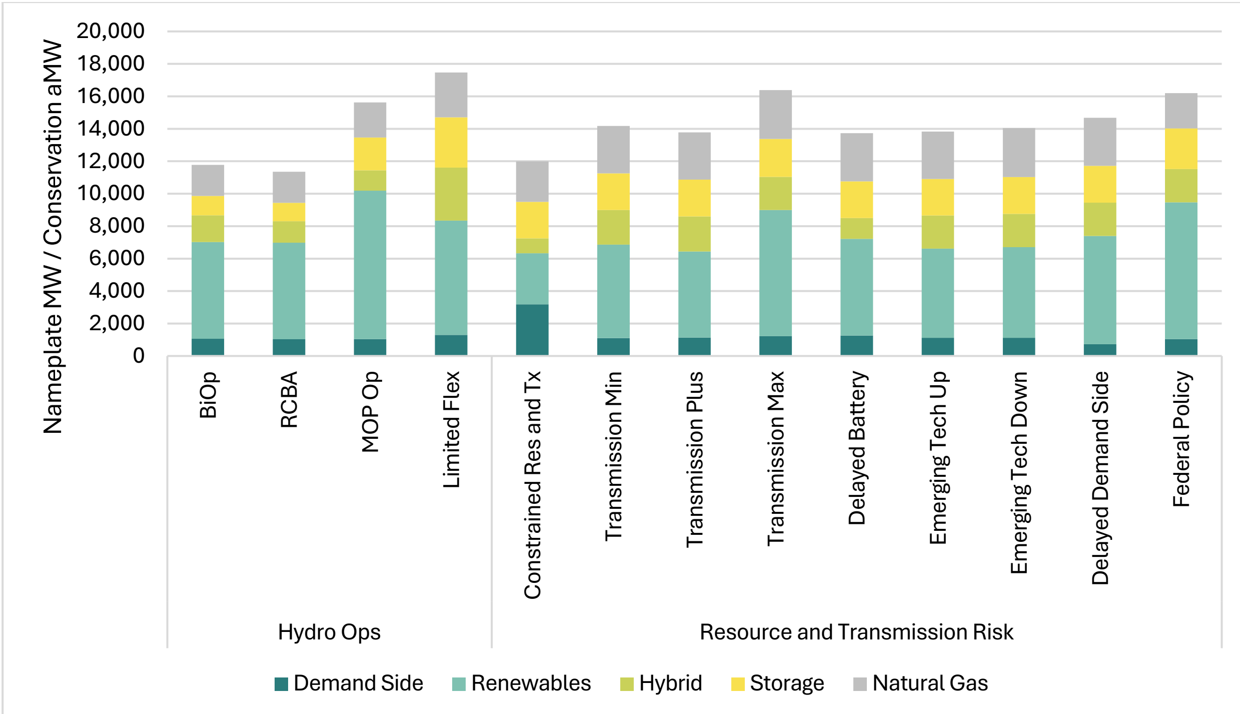
Discussion of Analytical Results

The modeling showed that a suite of resources was selected across every sensitivity, including conservation, demand response, voltage regulation, renewables, storage, and natural gas.[105] This suggests that a mix of these resources is robust across the range of potential uncertainty explored in the modeling. Figure 4 - 1 shows the resource buildout across the sensitivities for 2032. By using information from across all the sensitivities that explore a range of risks, the final recommended regional resource strategy provides a risk-informed approach to meeting future system needs (see Action Item RES-1). This portfolio approach will help ensure the Northwest power system remains adequate, efficient, economical, and reliable for all consumers.

[104] The Council tested this strategy against the Council's multi-metric criteria for adequacy using two different sets of hydro operations for fish. The first was the operations as defined in the 2026 Columbia River Basin Fish and Wildlife Program. As the program does not include a measure for summer spill, the Council assumed an August 31 end date to performance spill, as this provides a more conservative approach for testing adequacy. The second set of operations include different spill operations implemented by the federal agencies in 2026 to comply with a preliminary injunction issued by the federal district court of Oregon [pending review in that court of a challenge to the federal government's decision on system operations under the Endangered Species Act and the National Environmental Policy Act]. Details of these studies are available in Technical Appendix N – Scenario Modeling Results.

[105] The sections below provide high level results from the Council's Ninth Plan scenario modeling. More details around the modeling are available in Technical Appendix N – Scenario Modeling Results.

Figure 4 - 1: 2032 Resource Build Across Sensitivities



Conservation

Conservation was acquired in every sensitivity to provide energy to the system, reduce loads and thereby lower the planning reserve margin requirements, and meet clean policies and goals. The amount of conservation acquired in each sensitivity varied based on the assumed costs and constraints of other resources. To maintain adequacy, the model selected more conservation when supply side resources were limited and costs for those resources were higher. Less conservation was selected in sensitivities with lower prices for supply side resources, particularly renewables, as those resources start to become a more cost-effective way to provide energy to the system.

In addition to upfront costs, conservation may be less cost-competitive compared to other resources depending on the market price. Conservation is an “always on” resource. Once a homeowner or business installs a more efficient technology, that technology provides energy savings regardless of the outside market conditions. Other resources can dispatch down, if needed, for economics. The futures (described in Chapter 3) capture a range of these market prices. The amount of conservation selected by the model is part of the lowest cost portfolio to meet system needs, even with uncertainty around future market prices.

The scenario analysis demonstrated that more conservation, including higher cost conservation, is needed over time to support long-term resource adequacy. The specific amount of conservation to be acquired varies by sensitivity, by zone, and by year.[106] Figure 4 - 2 captures the range of maximum levelized cost bin for each snapshot year across the sensitivities. This figure excludes snapshot year 2028, and the Constrained Resource and Transmission sensitivity, both of which show significantly more investment in conservation as a way to mitigate the risk of supply side resource availability.[107] Essentially, for each snapshot year of a sensitivity, the model provides the highest cost bin acquired for a specific zone. The top end of each range represents the sensitivity with the highest maximum levelized cost bin acquired in that zone for that year. The bottom end of the range represents the sensitivity with the lowest maximum levelized cost bin acquired in that zone for that year. The diamond shows the average maximum levelized cost bin acquired across the 12 sensitivities included in this figure. This figure shows that the range and average costs generally trend upward for each zone over the snapshot years. This demonstrates that the model wants higher cost conservation over time as a way of meeting long-term load growth.

[106] As described in Chapter 3 and Technical Appendices K, the Ninth Plan scenario modeling used seven different snapshot years to model the 20-year planning horizon for each sensitivity. The model represented the region with 17 zones, including specific assumptions around future forecasted load growth, conservation potential, transmission connectivity between zones, and other assumptions.

[107] In both the Constrained Resources and Transmission sensitivity and the 2028 snapshot year, supply side resources are constrained. As described earlier, more conservation is acquired when there are constraints on the supply side. In the Constrained Resources and Transmission sensitivity and many of the 2028 snapshot years, the model acquires all available conservation. While this specific signal is an important finding from the modeling, incorporating those results into this specific figure would mask the other modeling findings.

Figure 4 - 2: Average Levelized Cost Per Zone, Across Sensitivities, Over Time

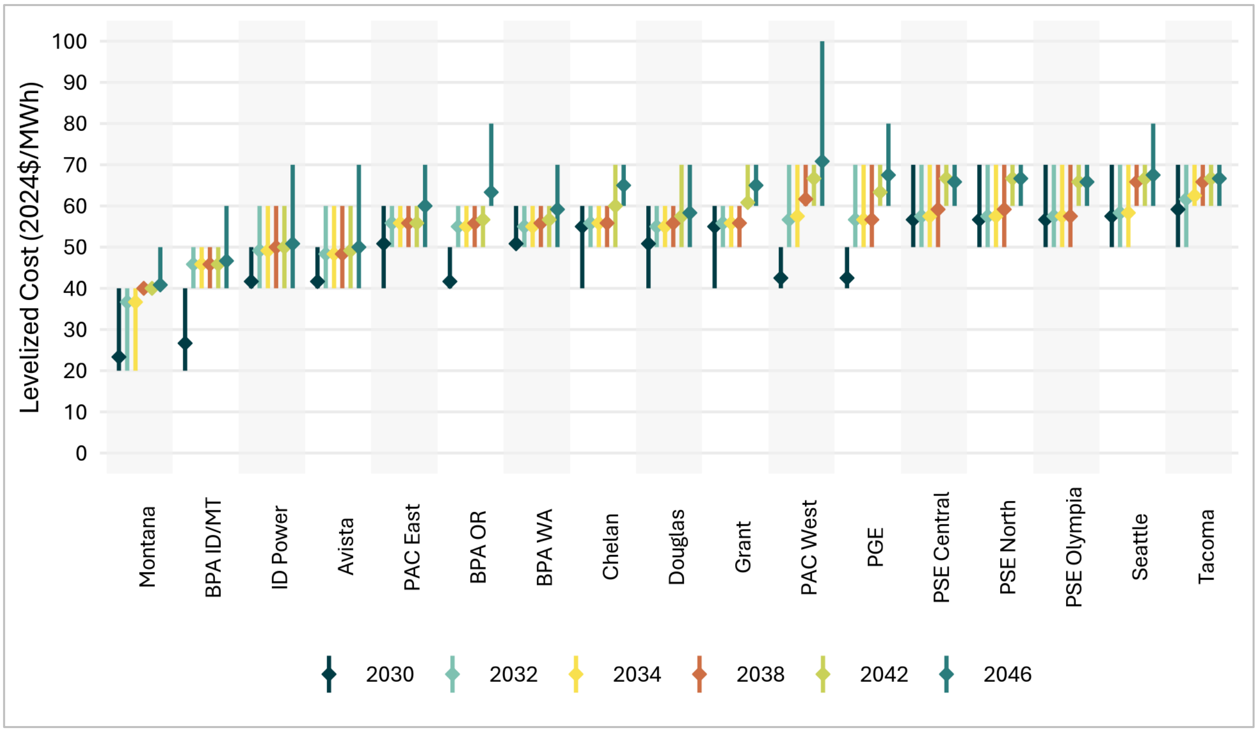


Figure 4 - 2 also shows another important finding from the Ninth Plan modeling, which is the differing locational value of conservation across the region. The zones in this figure are organized from roughly east to west. The model consistently acquires higher cost conservation on the west side of the region relative to the east. The differences vary by sensitivity, but the general trend shows the lowest value for conservation in Montana and the highest value in the Puget Sound area.

These modeling results are consistent with the realities on the ground. While the entire region is experiencing load growth, the resource options available to meet that growth vary across the region. Policies in Oregon and Washington limit the future role of natural gas, both in terms of availability and economics. Additionally, there is limited potential for new renewable energy development near the urban centers west of the Cascades and existing transmission constraints that limit the near-term potential to bring remote renewable resources to load. These factors increase the value of conservation for ensuring resource adequacy. Across the region, in Idaho and Montana, the realities on the ground are different, and there is generally a more diverse set of resource options to meet future needs. For example, natural gas is both more available and more economical than on the west side of the region. There is also greater renewable energy potential, as well as greater transmission connectivity to the broader west. These factors result in conservation being cost competitive only up to the comparable price of competing natural gas and renewable resources. The Council incorporated this locational signal into its recommended regional resource strategy (see Action Item RES-1).

Demand Response

Demand response allows utilities to adjust the electricity demand of consumers at specific times to help reduce the power demand on the system. As such, it can provide flexibility to the system, lowering planning reserve requirements at times by reducing load, and support meeting policies. The amount of demand response acquired in each sensitivity varied based on the constraints assumed around supply side resource availability, costs, and overall system flexibility. The model acquired more demand response to support resource adequacy when fewer supply side resources were available, particularly those that also provide flexibility to the system. It also acquired more demand response in sensitivities where the system flexibility was constrained, particularly in sensitivities with assumed constraints on the daily flexibility of the existing hydropower system.

Generally, however, the model did not select significant amounts of demand response. In most sensitivities, the model selected only the lowest cost bin of the frequently deployable demand response product. One factor influencing this result is that the model shows a preference for resources that provide both energy and flexibility, such as hybrid renewable and storage resources and new natural gas. By selecting these resources for energy, the model is also filling a large portion of its flexibility need, leaving relatively little remaining flexibility for demand response to serve directly.

The Council recognizes some modeling limitations around demand response for the Ninth Plan, and that these limitations may have contributed to dampening the signal for this resource. As discussed more in Action Items R&D-5, R&D-6, and R&D-18, the Council recommends the region continue to work on advancing its understanding of demand response potential and system benefits and to improve modeling capabilities around this resource to capture those benefits. Despite this muted signal, the Council recognizes the regional need for new resources, including those that provide flexibility in the system, and has accounted for that in the regional resource strategy described in Action Item RES-1.

Voltage Regulation

Voltage regulation is a demand side resource that regulates the voltage on the distribution system to provide energy savings. This can be operated in a couple of different ways. One approach is to lower the voltage once and keep it at that lower level. This approach is akin to conservation and is typically called conservation voltage reduction. The second approach is to lower the voltage at times when it provides value to the system but keeps the voltage higher at other times for economics. This approach is called demand voltage regulation.

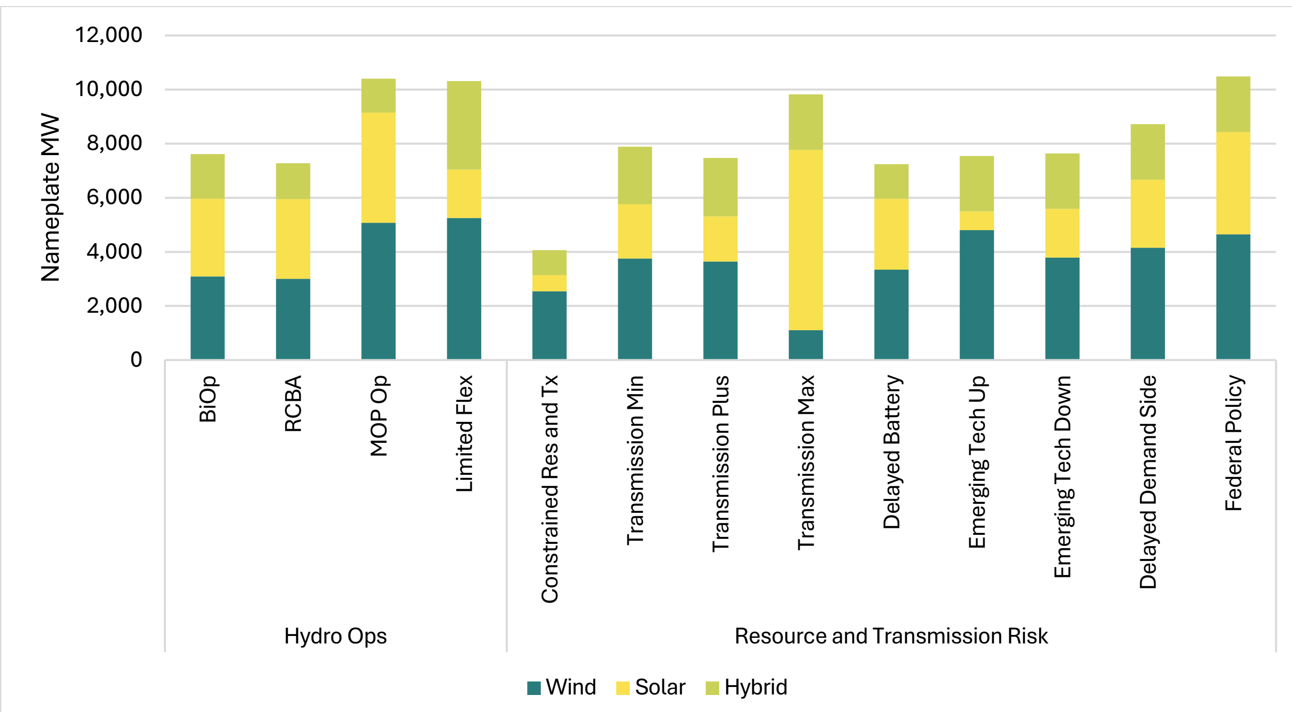
For the Ninth Plan, the Council modeled this resource separately from both conservation and demand response, allowing the model to determine whether there was value in this resource, and if so, what strategy would best meet regional needs. The modeling selected all the available potential for this resource in every sensitivity. Generally, the model operated this more as a conservation resource in the early years of the power plan period and more as a demand response product in the later years. The model also showed locational differences, with more flexibility (and therefore more of a demand response product) on the east side of the region.

Renewables and Storage

The Council modeled a variety of renewable and storage resources. This included onshore wind, solar, hybrid solar and storage, standalone battery storage, pumped storage, offshore wind, and two emerging technology reference plants for long-duration and medium-duration storage. The model selected all these resources (except for pumped storage and offshore wind) in all sensitivities for which the resource was allowed.[108] These resources support energy (renewables and hybrid), flexibility and ensuring the region meets its planning reserve margins (hybrid and storage), and policy.

In the Action Plan period, the model selected wind, solar, hybrids, and battery storage in all 13 sensitivities. The model showed a signal for diversity between renewable resources, with an approximately equal allocation between wind and solar, including hybrid solar plus storage projects (see Figure 4 - 3). In some sensitivities, the model selected more of a specific type of renewable to provide diversity to the overall market buildout. For example, as shown in Figure 4 - 3, the Transmission Max sensitivity has a significantly higher build of solar compared to the other sensitivities. This regional solar buildout provides diversity to the large buildout of wind across the west from the market study for the sensitivity while meeting load and policy needs.[109] This interaction with the broader market is one of the largest drivers for diversity in regional renewable builds across sensitivities.

Figure 4 - 3: 2032 Renewable Build Across Sensitivities



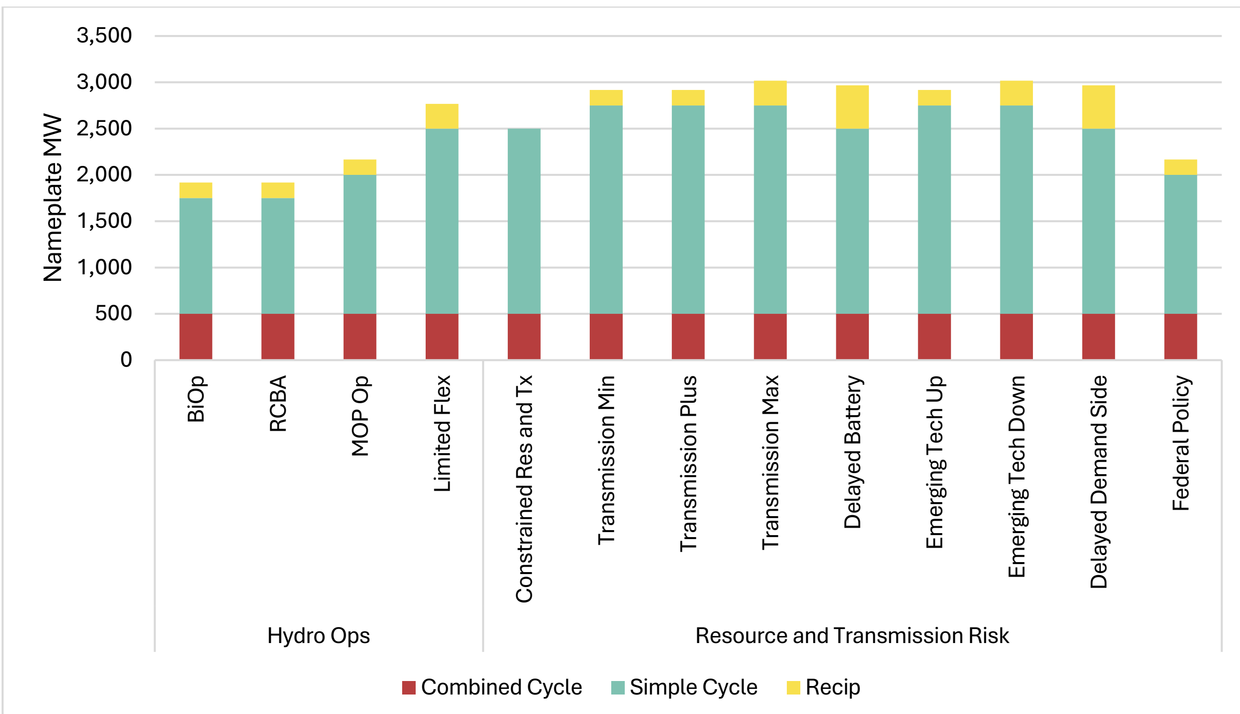
[108] One of the assumptions in the Constrained Resource and Transmission sensitivity was that the timelines for emerging technologies were 10-years out from that otherwise assumed in the modeling. This pushed the emerging tech long-duration proxy plant out to 2042 and the emerging tech medium-duration storage plant out of the study entirely.
[109] See Technical Appendix L – Wholesale Market Availability Results.

Storage is also selected in all sensitivities. The model prefers hybrid solar plus storage resources to standalone battery storage. In addition to providing flexibility, the hybrid resources also provide energy to meet the system needs in the long-term.

Natural Gas

New natural gas is also selected in every sensitivity as a means of providing both flexibility and energy to the system. As discussed in Chapter 3, the Council developed three different natural gas reference plants: two peaking plants (a frame turbine and a reciprocating engine) and a combined cycle combustion turbine. While the model selected all three reference plants, it showed a preference for peakers, particularly in the near term (see Figure 4 - 4). These peaking plants provide flexibility to the system and a hedge against futures with low hydro conditions.

Figure 4 - 4: 2032 Natural Gas Build Across Sensitivities



The existing gas pipeline system faces significant constraints, with no more firm capacity available for new plants. To account for this, the Ninth Plan assumed both an added cost associated with ensuring a firm supply of gas and placed a 3,000-megawatt limit for new gas through 2032. These assumptions were developed with guidance from the Council's advisory committees on Fuels and Generating Resources. The intent of these limitations was to reflect the physical capability of the system to add new natural gas, a constraint that is otherwise not captured in the Council's current model setup. As is shown in Figure 4 - 4, the model built up to the 3,000-megawatt limit in several sensitivities. The sensitivities with the lowest amount of natural gas developed assumed federal policies consistent with Biden Administration-era policies encouraging the development of non-emitting resources.

Additional Analysis on High-Tech Load Impacts

The Council conducted additional analysis exploring the implications of data center and high-tech loads on the overall resource builds. For this, the Council ran two different tests. The first test recalculated the planning reserve margin for the study using a lower load growth trajectory. This approach essentially asked what the region would build if some of the data center and high-tech loads were responsible for supplying their own adequacy. The second test removed the load trajectories with the highest data center growth from the modeling in order to determine what resources would be developed if those loads did not materialize. In both studies, the Council's OptGen model acquired a similar amount of conservation, demand response, voltage regulation, and natural gas as in the Transmission Plus sensitivity (which was otherwise comparable across all other assumptions). The main difference was in the acquisition of storage. In both tests, the model selected significantly less storage, both in terms of standalone storage and hybrid solar plus storage resources. The first test selected roughly half the storage as otherwise seen in the Transmission Plus sensitivity. In the second test, which removed the highest loads entirely, the model selected essentially no new storage resources. In this case, the model selected additional renewables, which provided energy to offset the loss of the hybrid resources. These results also inform the Council's regional resource recommendations below.

Regional Resource Recommendations

The Council developed its regional resource recommendations informed by the scenario modeling results, additional analyses, and feedback from advisory committee participants and others. The regional resource strategy and supporting recommendations seek to provide direction for a cost-effective approach for adding new conservation and generating resources to the system as a means of ensuring an adequate, efficient, economical, and reliable power supply.

RES-1 **Develop new demand and supply side resources consistent with the portfolio approach outlined in this recommendation.** The Council recommends the region, including Bonneville, its customers, investor-owned utilities, and others, acquire a portfolio of resources as described in the table below:

Resource	Amount by 2032
Conservation	1,060 aMW total 860 aMW OR/WA (up to $150/MWh) 200 aMW ID/MT (up to $70/MWh)
Demand response	590 MW
Voltage regulation	220 MW
Renewables	9,000 MW
Storage	5,200 MW
Natural Gas	2,100 MW

The Council recommends the region achieve 1,060 average megawatts of conservation regionally. This includes 860 average megawatts coming from the states of Oregon and Washington, or conservation up to $150 per megawatt-hour (in 2024$), representing an average cost of around $45 per megawatt-hour net levelized. This also includes 200 average megawatts coming from the states of Idaho and Montana, or conservation up to $70 per megawatt-hour (in 2024$), representing an average cost of around $32 per megawatt-hour.[110] The Council developed this dual target approach to represent the cost-effective differences between the west and east sides of the region.[111] Accounting for these differences ensures regional resource adequacy with a lower cost portfolio than otherwise required through the historical single target approach.[112]

The Council recommends the region acquire 590 megawatts of demand response. This represents the potential from time-of-use rates for electric vehicles. The Council recognizes that each utility is positioned uniquely and may therefore need different products to support peak needs, manage system ramping, mitigate price exposure, and address distribution challenges. The Council recommends that utilities acquire demand response that is most strategically valuable for them, focusing on those products that are frequently deployable to support system flexibility. The Council's modeling showed a strong preference for frequently deployable demand response, as the lowest cost bin of limited deployment demand response was selected only in the Constrained Resource and Transmission sensitivity.

The Council recommends the region pursue voltage regulation to provide energy and flexibility to the system. All available potential for this resource was selected in every sensitivity. While the model generally showed a preference for conservation voltage reduction in the Action Plan period, the Council recognizes that utilities may have their own unique needs, and therefore recommends utilities pursue this resource in whatever form provides the most value for their system.

The Council recommends the region acquire 9,000 megawatts of renewables, with a balanced approach between wind and solar. This diversity in renewables provides balance to the strategy to support resource adequacy. The Council also recommends the region acquire 5,200 megawatts of storage. This includes acquiring the already planned roughly

[110] These costs reflect the net levelized cost for the conservation potential as an input to the Ninth Power Plan. The resultant avoided costs are available in Technical Appendix O – Cost-Effective Conservation Methodology and Results.
[111] See Technical Appendix O – Cost-Effective Conservation Methodology and Results, which details the cost-effectiveness methodology and locational assumptions behind this dual target approach.
[112] The Council received significant input during the development of the draft plan on the proposed dual target approach for conservation. To provide more context around the Council's analysis that informed this proposed dual target and some power system analysis around transitioning to a single target, the Council developed Technical Appendix Q – Analysis of Dual Versus Single Target for Conservation. Throughout the public comment period on this draft Plan, the Council is committed to continuing the conversation about these two approaches. The Council is seeking public comment that provides specific recommendations for how to improve upon the proposed regional resource strategy while still ensuring the region has an adequate, efficient, economical, and reliable power supply.

2,000 megawatts of standalone storage. The modeling shows that adding new storage to the system is one element of a cost-effective approach for providing reserves. The model shows a preference for hybrid renewable and storage resources, and the Council recommends that a portion of the renewable and storage recommendations be met with these hybrid resources. While the Ninth Plan only modeled a solar plus storage hybrid resource, the Council recommends the region continue to explore other combinations of co-locating renewable energy resources with storage.

The Council conducted some additional modeling exploring how a resource strategy might change if either some data centers supply their own resources that could support adequacy or not all forecasted data center load materialized. The model selected less storage in these tests, both standalone storage and hybrid renewables and storage. This suggests that a portion of these storage resources may be the responsibility of the new large data center loads to provide system flexibility and reserves. This concept is discussed in more detail in Action Item DC-1 below.

Finally, the Council recommends that the region acquire 2,100 megawatts of new natural gas resources, with a focus on plants that provide benefits as a seasonal energy hedge against poor hydro conditions and for year-round flexibility. The modeling showed a preference for natural gas peaking plants to provide energy and flexibility. These new units are also part of the cost-effective approach for providing reserves to the region. These peaking plants can serve as a seasonal reserve, protecting against low hydropower conditions.

The total amount of new resources called for in this regional resource strategy is significant. The Council recognizes both the individual and cumulative impacts of siting new resources, particularly renewable resources that require significant land. The Council recommends that siting authorities, policy makers, utilities, developers, tribes, and others continue to bring creativity and practicality to the process, working to ensure that new resource development is carried out in a manner that protects fish and wildlife and cultural resources of the Pacific Northwest. Examples include, but are not limited to, developing smaller scale solar projects that can be sited in urban areas closer to loads and agrivoltaics that pair renewable generation with agriculture. The emphasis should be to incorporate “least impact, less conflict” siting principles to push development away from high value lands and ensure deliberate and strategic engagement in the process.

The Council will continue to monitor changes on the ground, as well as progress towards implementing this regional resource strategy, and use the mid-term assessment of the Ninth Plan to refine its direction to the region and Bonneville as needed.

RES-2 **Implement the conservation program, including the model conservation standards.** The Power Act requires that the Council include in the power plan a conservation program to be implemented by Bonneville and the region. The Ninth Plan conservation program described in Chapter 5 includes acquiring the cost-effective conservation in the regional resource strategy (RES-1), as well as additional actions focused on reducing costs, pursuing weatherization in leaky homes, improving performance of heat pumps, and exploring opportunities for deeper savings in commercial buildings. The conservation program also highlights the importance of evaluating delivery of conservation to ensure reliability of energy savings and improve program design for more effective delivery of the resource in the long-term. Bonneville, utilities, the Energy Trust of Oregon, and Northwest Energy Efficiency Alliance (NEEA) should implement the Ninth Plan's conservation program.

RES-3 **Increase the pace of resource development through streamlining permitting and interconnection.** The implementation of the Ninth Plan's regional resource strategy will require the region to develop resources at a faster pace than it has in recent history. This requires addressing resource permitting, transmission interconnection, and utility planning timelines.

State and federal agencies should endeavor to streamline the administrative burden of siting facilities. This could be accomplished through various mechanisms, including a "one-stop shop" approach that places all siting requirements for a facility under one regulatory umbrella. As an interconnected power system, the Council also sees benefit from increased coordination between individual state agencies, including identifying opportunities for increasing consistency in the siting and permitting processes across states.

Transmission providers, including Bonneville, should continue to focus on interconnection queue reform, building upon the success of the Federal Energy Regulatory Commission (FERC) Order 2023. This order implemented a cluster study "first ready, first served" approach, increasing financial readiness and site control requirements for facilities and enforcing deadlines and penalties on transmission providers that fail to complete interconnection studies on time. The order also deployed reforms that would better incorporate technological advancements in the interconnection process. This includes increasing flexibility, allowing hybrid resources to have a single request in the queue, and encouraging providers to consider alternative transmission solutions, such as grid enhancing technologies. The Council has specific recommendations for Bonneville around transmission development and interconnection, as described in Action Item BPA-7.

Bonneville and utilities, especially those utilities that provide transmission services, should plan farther into the future for generation needs than they have historically. Recognizing the cumulative amount of new resources required to meet growing need, even the most effective siting and interconnection processes will require longer lead times than they have in the past. Preemptive planning for new generation will help to ensure that resources are available and online in the time required to serve load.

The Council notes that this focus on accelerated development should not be at the expense of environmental quality or public engagement. As stated in Action Item RES-1, the Council recommends that siting authorities continue to ensure that new resource development is carried out in a manner that protects fish and wildlife and cultural resources of the Pacific Northwest.

RES-4 **Explore opportunities to leverage the flexibility of the existing hydropower system to support the integration of new resources and resource adequacy.** The Council's resource strategy assumes that the region uses the available flexibility of the existing system, including flexibility of the regional hydropower system during the fall and winter. The Council's GENESYS model shows more daily flexibility in the existing hydropower system (even within the existing constraints) than is used today. This flexibility is best understood from a systemwide level, as the Council recognizes that actual flexibility is more limited at specific projects. The region, including the hydropower operating agencies, should explore where flexibility exists, and seek to maximize that flexibility to better support the integration of new resources recommended by the Council in the regional resource strategy. For example, regional entities have historically had coordination agreements that allowed for more efficient use of the regional hydro system. Improving coordination of the river system is one approach for increasing flexibility overall.

At the same time, the Ninth Plan's regional resource strategy assumes implementation of the Council's 2026 Fish and Wildlife Program. In measures H18 and H19 of this Program, the Council explicitly calls on operators to operate the system to minimize ramp rates (the rate of change) and daily flow fluctuations (minimum and maximum daily flows) in the Columbia and lower Snake rivers during the spring and summer migration periods to keep water flowing and juvenile fish moving downstream. This requires that the region implement the regional strategy in a way that minimizes this flexibility during those periods to benefit fish survival.

RES-5 **Improve understanding of the Northwest gas supply and gas-electric interdependence.** During the January 2024 Northwest cold weather event, the natural gas system (existing pipelines and storage facilities) was heavily utilized for heating and power generation. There were some gas system challenges during that event, including a storage facility going offline briefly, that highlighted the reliance of the electric system on the gas system. Today, as the Northwest power system plans to add more gas generation via coal-to-gas conversions and new builds, it is of growing importance to better understand gas-electric interdependence, and fuel availability limits on the gas system. The Council accounted for existing constraints in the natural gas system in its analysis and ultimate regional resource strategy recommendations. The Council recognizes, however, that additional insight into these gas system limits, options and costs for alleviating these limits, and the timelines associated with those options will be beneficial for the region. The Pacific Northwest Utilities Conference Committee (PNUCC) and the Northwest Gas Association are actively discussing the issue of gas-electric interdependence. The Council is supportive of that work and encourages them to further investigate these questions as part of that effort.

RES-6 **Minimize seams between the two day-ahead markets emerging in the region.** Unlike other parts of the country, the Northwest power system generally operates within a bilateral (decentralized) market where electricity buyers and sellers directly negotiate contracts for power. In recent years, the region has been developing two potential day-ahead markets: the Extended Day-Ahead Market operated by the California Independent System Operator (CAISO) which went live in May 2026 and the Markets+ offering from the Southwest Power Pool that is expected to go live in 2027. These two markets can provide better optimization for resources in the day-ahead across a larger footprint than is currently possible under the bilateral market of today. Two markets fulfilling similar needs creates the potential for new market seams that ultimately decrease economic efficiencies and add costs for the region. The Council recommends that the CAISO, Southwest Power Pool, and market participants work together to minimize the seam costs between these two markets. This will be critical for reducing overall system costs and related impacts on ratepayers.

Recognizing the region is currently moving towards two day-ahead markets, the Council also recognizes that the Northwest system can operate more efficiently and costs for consumers can be reduced to the extent that the region can participate fully in a larger, organized, equitable, seamless market. Benefits from organized markets and regional transmission organizations include greater grid utilization, expanded resource diversity, accelerated investment in necessary grid upgrades, and better valuation of demand-side and distributed resources. The Northwest can reap these benefits by moving toward a fully organized market that delivers the reliability benefits and cost savings of west-wide resource breadth and diversity.

RES-7 **Participate in a resource adequacy program.** In addition to day-ahead markets, there are adequacy programs forming across the West. These programs seek to address resource adequacy needs by setting common standards for planning of resources and allowing for participants to pool and share resources during tight power system operations. The two programs are currently developing roughly along the lines of the two day-ahead markets. The first is the Western Resource Adequacy Program operated by the Western Power Pool. This program is a requirement for participation in the Markets+ day-ahead market. The second program is actively being developed by utilities participating in the CAISO day-ahead market. Regardless of the program, the Council recommends that utilities participate in one of these two resource adequacy programs. Participating in a resource adequacy program ultimately decreases the costs required to maintain resource adequacy.

RES-8 **Continue to explore conventional geothermal.** In addition to the resources identified in the RES-1, the Council recommends the region continue to explore the potential for conventional geothermal. The Council's modeling results show conventional geothermal being selected in every single sensitivity. Due to the long timelines required to identify and develop at an appropriate location, this resource was not available to the model until after the Action Plan period, and the Council is not including this in the resource recommendations for the Action Plan period. The Council does, however, encourage utilities seeking clean energy resources to continue to explore the potential for this resource, as it might be part of the cost-effective resource solution in the longer term.

As discussed in Chapter 3, the Council is required to develop and include "a demand forecast of at least twenty years…." This forecast is both an early input into the planning process, as well as a final output. The final output forecast, the "sales forecast," represents the forecasted future loads after accounting for the cost-effective amount of demand side resources as described in Action Item RES-1. Conservation and voltage regulation reduce the loads on an hourly basis. Demand response shifts the energy to a different time, such as shifting from evening to early morning hours. Combined, these demand side resources reduce overall loads and shift the hourly use patterns. By 2032, the average reduction in annual load across all forecast trajectories is 4.2% (see Figure 4 - 5). This impact is higher for peak hours, with peak loads reduced by 4.8% in that period (see Figure 4 - 6). As is seen in both figures, assuming a similar level of investment in these resources over the longer term, these annual energy and peak load reductions increase further. The generating resources recommended in the regional resource strategy provide a cost-effective solution for meeting the remaining forecasted load growth in the near term.

Figure 4 - 5: Ninth Plan Energy Demand Forecast, Accounting for Resource Strategy

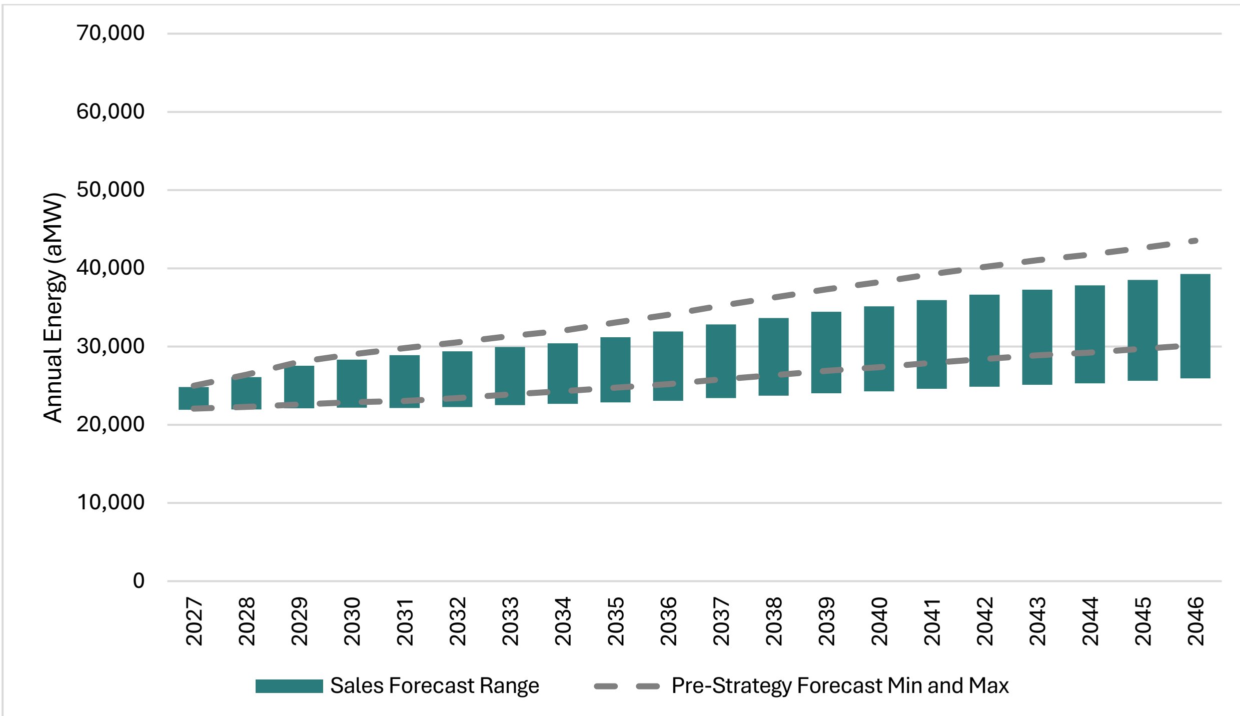
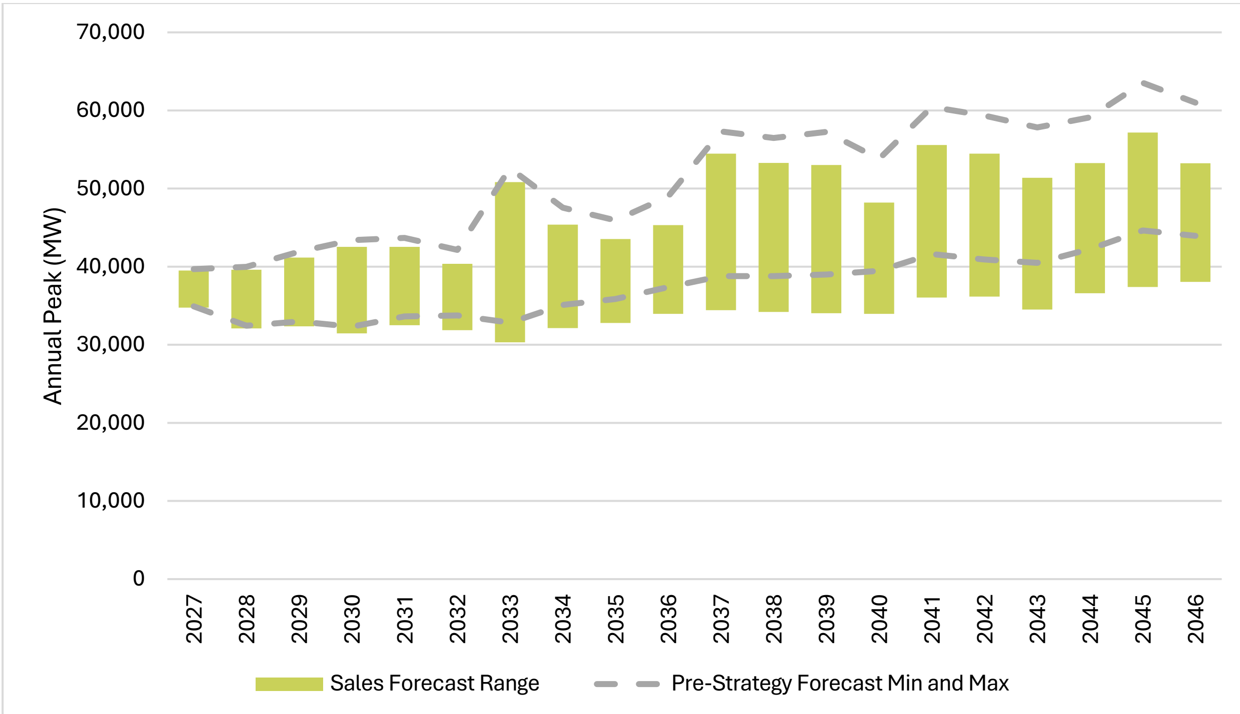


Figure 4 - 6: Ninth Plan Peak Demand Forecast, Accounting for Resource Strategy



Recommendations to Bonneville

In addition to providing important guidance to the region, the Council's power plan has a direct connection to Bonneville and its decisions around acquiring new resources to meet its obligations. In addition to providing a resource strategy for the region, the Council is to provide recommendations to Bonneville for new conservation measures and generating resources to reduce or meet the Administrator's obligation. This includes Bonneville's obligations for both power sales and implementation of the Council's fish and wildlife program. The following section includes the Council's recommendations to Bonneville for new resource acquisition.

BPA-1 **Achieve Bonneville's share of the regional targets for cost-effective conservation resource acquisition.** To support regional resource adequacy needs, the Council recommends that Bonneville acquire its share of the regional conservation target:

Resource	Amount by 2032
Conservation	435 aMW total 390 aMW OR/WA (up to $150/MWh) 45 aMW ID/MT (up to $70/MWh)

This amount of conservation represents the cost-effective portion within the service areas of Bonneville customers. Bonneville should use the Council's methodology and associated parameters for cost-effectiveness to identify efficiency opportunities at levels that are cost-effective for consumers. This includes managing its portfolio to the two different cost-effectiveness thresholds identified in that methodology.

Of the cost-effective conservation, the Council recommends that Bonneville plan to acquire at least 90% of it from cost-effective conservation programmatic savings. This includes savings currently funded through Bonneville's program (whether via the Energy Efficiency Incentive or self-funded utility contributions), as well as savings apportioned to Bonneville by NEEA.

If evaluation of the conservation 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, NEEA, and the regional utility community to ensure that the Regional Conservation Progress report, which the Council was directed by Congress to produce annually, accurately reflects the regional conservation achievement.

BPA-2 **Identify opportunities to modernize the conservation program.** The Council recognizes that there are challenges to acquiring cost-effective conservation across Bonneville's customer utilities. The amount and type of conservation available varies across the region and across the customer utility base. For utilities within urban centers, efficiency may be more readily accomplished, given the 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.

The Council also recognizes that while the dual target set forth in the Ninth Plan provides valuable signals regarding the locational value of conservation, it also creates an added layer of complexity. The Council encourages Bonneville to incorporate flexibility that minimizes complexity in its program, while ensuring cost-effective conservation is acquired to meet the region's needs. This includes incorporating elements that provide variability to better meet each customer utility with a suite of measures that is relevant and cost-effective for them and their consumers, as well as considering changes to funding necessary to support this approach (i.e. avoid cross-subsidization).

Recognizing that Bonneville has set rates for fiscal years 2027 and 2028 – and that the existing Energy Conservation Agreements are in place for that same time period – the Council is not requiring full implementation of the dual target immediately. Bonneville should use the first two years of the Action Plan to work with the Council and customer utilities to identify and develop necessary changes to support implementation of this dual target under the new Energy Conservation Agreements starting fiscal year 2029. During that time, Bonneville should continue to acquire savings consistent with the overall target of 435 average megawatts, leveraging existing flexibility in the program to start moving towards dual target implementation where feasible.

BPA-3 Enable and encourage customer utilities to pursue the recommended demand response. The regional resource strategy identifies 590 megawatts of cost-effective demand response, with a particular focus on frequently deployable products as providing the most benefit to the system. Bonneville should enable and encourage its customer utilities to pursue demand response. This includes providing expertise to support program design, particularly for those customer utilities without sufficient bandwidth to develop complex programs.

Under Bonneville's current contracts, many customer utilities do not have sufficient price signals to see value in pursuing demand response and are limited in their ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. Bonneville's new Public Rate Design Methodology provides important new tools, including the new capacity credit, that could be leveraged to send appropriate signals in support of demand response. Bonneville should use the tools in this methodology to provide sufficient cost signals in support of demand response.

BPA-4 Continue to develop and identify opportunities for supporting customer utilities in implementing voltage regulation. Whether pursued as conservation or demand response, voltage regulation is a critical piece of the Council's regional resource strategy. Bonneville has been exploring pilots to support customer utilities in developing this resource. The Council recommends Bonneville continue to develop those opportunities and seek to expand voltage optimization across the customer utility base. Any acquisition of this resource should be made in addition to the recommended conservation and demand response acquisition in Action Items BPA-1 and BPA-3.

BPA-5 Acquire renewables as needed to meet identified energy needs. Bonneville's needs under its new contracts are unknown at this time.[113] Under these contracts, Bonneville may need to acquire new resources, beyond conservation, to meet its obligations. The Council recommends that Bonneville acquire renewables to meet energy needs. Renewables are a cost-effective, reliable way of providing energy to the system.

Traditionally, Bonneville's needs assessments have shown that energy is the driver of needs, not capacity. The Council's regional resource strategy puts together a portfolio of resources that is cost-effective for the system, and renewables are included as a cost-effective way to provide energy. Between its hydropower base and transmission position, Bonneville is well positioned to support the integration of renewables. Bonneville's acquisition of renewables also supports the region in achieving the overall balance of supply side resources recommended in the portfolio approach outlined in Action Item RES-1.

[113] Bonneville will provide up to 7,250 average megawatts at a Tier 1 rate. Customer utilities have until late July 2026 to sign up for a Tier 2 product. Investor-owned utilities and utilities with new large single loads also can request service from Bonneville, which it would provide at a New Resource rate. The timing of these decisions is after the draft of the Power Plan. Therefore, the Council is unable to determine the full power sales obligation.

BPA-6 **Assess whether storage (including hybrid renewable and storage) or natural gas are a more cost-effective approach to supporting a capacity need.** While Bonneville has traditionally not been capacity constrained, the Council recognizes that its needs may shift. Should Bonneville identify a need for capacity through its needs assessment or other determination of need, Bonneville should assess whether storage or natural gas provides a more cost-effective approach to meeting that need. Both storage and natural gas are cost-effective ways to provide capacity in the Council's strategy. For storage resources, the Council recommends Bonneville also assess the potential for hybrid renewable plus storage resources in this analysis. Finally, the Council recommends Bonneville consider the overall resource acquisition in the region relative to the Council's regional resource strategy (Action Item RES-1) as part of this assessment.

BPA-7 **Develop already identified transmission projects and engage with the region on identifying and developing additional transmission capacity expansion.** Bonneville currently owns around 70% of the regional transmission, and it has a critical role in the region's transmission future. Bonneville has identified a set of projects that it is advancing through its Grid Expansion and Reinforcement Portfolios. The regional resource strategy assumes this transmission will be developed. These projects must be completed in a timely fashion.

Bonneville is also working on a process for evaluating, expanding, and improving access to the transmission system through the Grid Access Transformation Project. This work is critical to ensure that Bonneville is well positioned to support the transmission capacity expansion and interconnection needed for resource adequacy.

The Council recommends that Bonneville continue to engage with regional entities on transmission planning and development (see Action Item T&D-1). Bonneville should be the regional leader in identifying and developing cost-effective transmission capacity expansion.

BPA-8 **Prepare for rapid resource acquisition.** Bonneville has not acquired the output of a large supply side resource in decades. As noted above, it may need to do so under the new Provider of Choice contracts. Given the long planning horizons for bringing on new resources and the competitiveness of the resource acquisition landscape, Bonneville will have to be well positioned to act quickly when a need is identified. The Council recommends that Bonneville, working with the Council and regional entities, put into place a clear and ready-to-deploy resource acquisition process in advance of when the need arises. This includes establishing clear guidelines around when and how to trigger a 6(c) process under the Northwest Power Act if necessary.[114]

[114] As outlined in Section 6(c) of the Northwest Power Act, Bonneville must undergo a specific public process in advance of acquiring a major resource, defined as 50 average megawatts or greater or longer than 5 years. This is commonly referred to as the 6(c) process.

Data Centers and High-Tech Sector

As highlighted in Chapter 2 of this Plan, the recent and forecasted load growth in the data center and high-tech sectors is one of the biggest challenges facing the region's power system. The services provided by data centers are a core part of everyday life. The power needed to serve these loads will require the development of new resources, driving the pace of resource development beyond recent trends. Recognizing the importance of power to their bottom line, several of the large data center companies have committed to supporting the development of the power system through investment in emerging technology innovation and transmission expansion. The Ninth Plan's Action Plan provides two specific recommendations for working with data centers, focused on identifying opportunities to support system flexibility and reduce overall load impacts through efficient design.

As part of its annual studies and mid-term assessment of the Ninth Power Plan, the Councill will monitor changes in load and resource development. Specifically, the Council is interested in tracking actual growth of high-tech loads. The Council may refine its direction to the region and Bonneville to support successful implementation, as needed.

DC-1 **Work with data centers and other high-tech loads on approaches to provide flexibility to the system.** The loads from these sectors are large and relatively flat. The Ninth Plan analysis shows significant value in the flexibility of the power system. Regional utilities should work with these loads to identify opportunities to provide flexibility to support resource adequacy and system reliability. The most effective approach is likely site specific, depending on the nature of that facility and the requirements of the utility. Approaches being pursued to date include working with large loads to leverage the site's backup generation to provide flexibility (thereby reducing the overall reserve requirement for a utility), shifting non-time-critical data center workloads away from peak demand periods, and reallocating workloads to different data center locations where the grid is less strained.

Due to the pace of these growing loads, the Council sees urgency in working with these entities on approaches to a flexible supply in the near term. The Council recommends utilities work with these large loads to pursue those options that can be quickly and efficiently deployed, while continuing to encourage long-term research into a broader suite of tools to address this challenge. Additionally, as discussed in Action Item RES-1, some of the storage recommended in the regional strategy might be required for these large loads. Utilities should work with data centers and other high-tech companies seeking to acquire these resources to identify potential solutions for how they can be leveraged, if needed, to support broader system adequacy.

DC-2 **Implement the model conservation standard for new data center development.** Given the size of these loads, it is imperative that new data centers are designed as efficiently as possible to reduce the overall power burden on the system. The Ninth Plan's Conservation Program (Chapter 5) includes model conservation standards for new data center loads. These standards provide a cost-effective way to address power usage (including peak power usage) and water use in facilities, specifically focusing on the efficiency of the cooling systems. Incorporating these standards into the design of new data centers provides a cost-effective approach for reducing the overall power system impact of these loads. States, cities, and utilities should work with developers to ensure that new data centers are constructed to this standard.

Transmission and Distribution

The region is running into transmission constraints and needs to identify solutions to address those constraints to ensure system adequacy. The Council's regional resource strategy (Action Item RES-1) assumes additional transmission capacity is available, both through the effective use of the existing system and the expansion of new capacity. While not specifically modeled, the forecasted loads also create potential impacts to the distribution system that need to be addressed to ensure system reliability. The Council has developed a suite of recommendations seeking to increase the urgency and investment in the transmission and distribution system.

T&D-1 **Invest in expansion of transmission capacity.** More transmission capacity will be needed across the West to meet forecasted load growth with the most efficient use of resources. Recognizing the need for new transmission, Bonneville, utilities, and others have come together through the Western Transmission Expansion Coalition (also known as WestTEC) to conduct long-term interregional transmission planning for the West. This effort resulted in an already released 10-year study. The Council's regional resource strategy (Action Item RES-1) assumes the region invests in these identified transmission solutions. The Council recommends and encourages the region to develop the transmission projects identified by the study.

Action Item BPA-7 provides specific recommendations to Bonneville highlighting the urgency of ensuring the needed transmission capacity is developed. The Council extends this recommendation to all transmission providers, recommending that the region continue to prioritize transmission investment. The Council recommends that state agencies identify opportunities to streamline permitting processes to enable faster development of transmission, while also ensuring that this transmission expansion is not done at the expense of environmental quality or public engagement. Borrowing the example of WestTEC, the Council also recommends that transmission providers actively encourage and solicit public engagement throughout the transmission planning process. This has the potential to increase buy-in and expedite the pace of transmission development. Finally, the Council recognizes that cost allocation of new transmission provides a hurdle to new transmission development. The Council recommends the region continue to work on addressing cost allocation challenges, leveraging existing processes such as the Western Interstate Energy Board State Exploration of Western Transmission Cost Allocation Frameworks.

T&D-2 **Accelerate the evaluation and deployment of reconductoring and grid enhancing technologies.** Reconductoring and grid enhancing technologies are strategies to increase the capacity, flexibility, and reliability of the existing transmission system. The regional resource strategy assumes some of the needed transmission capacity might come from these types of improvements to the existing transmission system. Reconductoring, particularly using advanced conductors, can nearly double a transmission line's capacity within existing rights-of-way and can be deployed in 16 to 32 months. Grid enhancing technologies—such as dynamic line rating, advanced power flow controls, and topology optimization—can unlock additional transfer capability and improve grid reliability. These technologies are effective options to get more of the existing grid in the near term and help address interconnection queue issues without the costs and timeline of major new transmission builds. The region's utilities and transmission providers should consider these technology options in their transmission planning process.

Additionally, there is a role for state agencies to support the expansion of reconductoring and grid enhancing technologies. For example, Montana's HB 729 allowed the state Public Service Commission to establish cost-effectiveness criteria for reconductoring with advanced conductors and consider additional benefits offered by the technology, incentivizing deployment in the state. Oregon's HB 3336 requires electric companies to review cost-effectiveness of grid enhancing technologies when filing a resource or gird investment plan impacting the transmission system. It also requires that electric companies submit strategic plans with the Oregon Public Utilities Commission to implement cost-effective grid enhancing technologies. Policies like these send signals to transmission providers that create more parity for assessing reconductoring and grid enhancing technology options alongside new transmission development. Other policies, such as expediting or reducing permitting requirements for these technologies, would allow for faster deployment to support near-term needs. The Council recommends that state agencies develop policy solutions that create parity in the assessment of these solutions with other transmission options and minimize development hurdles to support faster deployment.

T&D-3 **Explore opportunities to modernize contracting, reserving, and scheduling transmission access.** As described in Action Item T&D-1, the Council sees a need to invest in new transmission capacity. At the same time, the Council recognizes that there may be opportunities to improve the utilization of the existing (and future) transmission system. It is common for a given transmission path to be fully contractually encumbered on a long-term firm basis, while still having available physical capacity for portions of the year. There is value in identifying pathways for unlocking this capacity, both as a means of minimizing the overall needed investment in new transmission capacity and as a potential solution to minimize the interconnect queue challenges discussed in Action Item RES-3. The Council recommends 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 and research potential solutions to increase utilization of the existing system, while balancing the existing long-term contracts and compensation to transmission providers.

T&D-4 **Manage peak loads from electrification to support distribution system reliability.** Electrification of vehicles and buildings can have significant impact on peak loads, creating demand spikes. These demand spikes can create challenges for the existing distribution system equipment, particularly when electrification is concentrated in localized areas, that may result in service reliability issues or require costly upgrades. The region's utilities, particularly in those jurisdictions pursuing electrification, should develop regional and local strategies based on new and existing research to mitigate unnecessary peaks and negative impacts on the distribution system. This includes exploring accelerating the deployment of infrastructure that can support demand response and allow the easy integration and coordination of different demand response programs in their systems. Early and thoughtful investment in these systems and programs will reduce costs of this resource and, in turn, will help to mitigate and defer some of the long-term investment needed in the distribution system. This investment also supports deferment of some transmission system development and the need for additional generation to ensure system reliability.

Research and Development Recommendations

The Northwest Power Act directs the Council to include with the power plan a "recommendation for research and development."[115] The Council has typically included a suite of recommendations seeking to expand research and development in key areas that, in the long-term, will help the region provide for an adequate, efficient, economical, and reliable power supply. The Ninth Plan includes a suite of these recommendations focused on advancing emerging technologies, improving the region's understanding of demand response as a power system resource, and advancing data sets and tools that improve the assessment of power systems loads, resource needs, and resource potential.

Emerging Technologies

In the Ninth Plan, the Council assessed emerging technologies for both supply side and demand side resources. On the supply side, the Council developed three emerging technology reference plants, including a clean baseload proxy, clean medium-duration storage/peaker proxy, and a clean long-duration storage proxy.[116] This approach allowed the Council to assess whether there were particular resource attributes that might be most valuable to the future power system. On the demand side, the Council incorporated estimates of potential emerging technology conservation measures that provide deeper savings in the residential, commercial, and industrial sectors into the conservation supply curve.

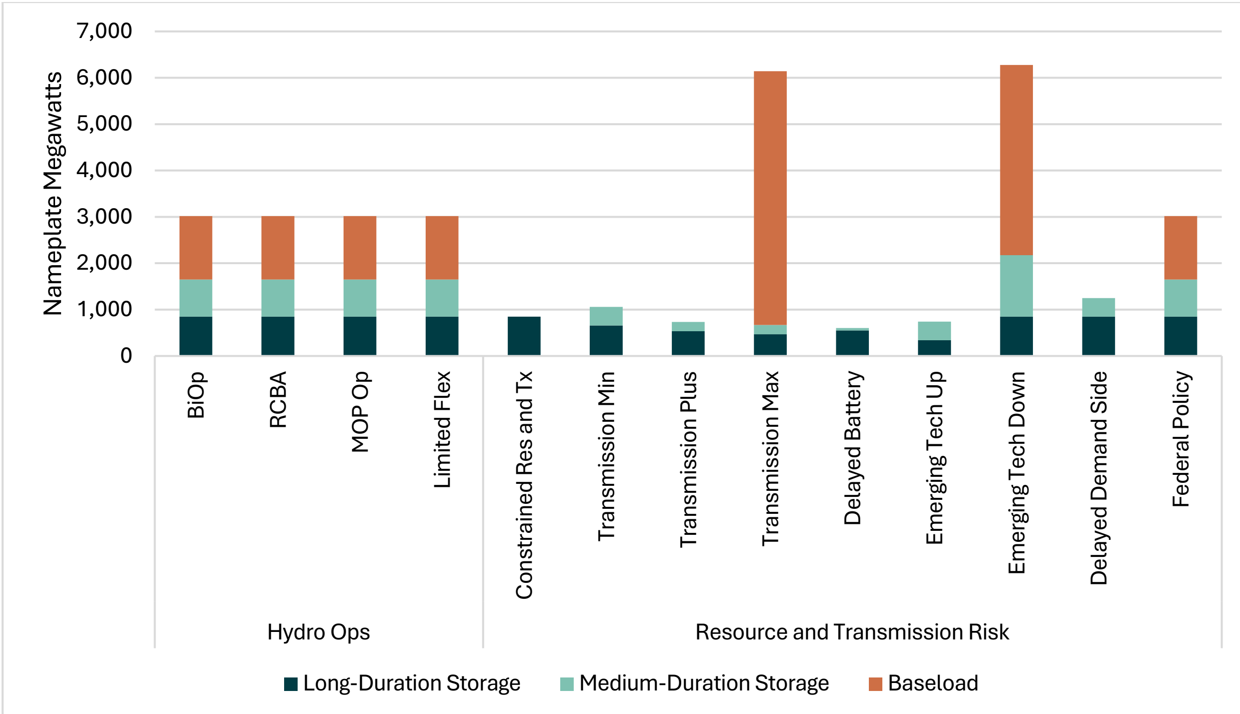
The Ninth Plan modeling showed a robust signal for the value of emerging technology resources. The long-duration and medium-duration storage proxies were selected in all sensitivities for which they were an option.[117] The model also selected the clean baseload proxy in seven of the sensitivities in the final year of the study.

[115] Northwest Power Act, Section 4(e)(3)(B).

[116] See Technical Appendix G – New Generating Resources for more information on these proxy plants.

[117] One of the assumptions in the Constrained Resource and Transmission sensitivity was a 10-year delay on emerging technologies. This pushed the clean medium-duration storage/peaker proxy and the clean baseload proxy outside the study horizon. Therefore, these were not a feasible resource for selection in that specific sensitivity.

Figure 4 - 7: 2046 Build of Clean Emerging Technology Proxy Resources



On the demand side, the bulk of the emerging technology potential estimated was in the highest cost bin of greater than $200 per megawatt hour in 2024 dollars. Some of the forecasted potential is estimated at a price that would be within the cost-effective limits, if the technologies were otherwise considered reliable and available. These are mostly technologies focused on improving the efficiency of the distribution system, including projects such as transformer right-sizing, phase balancing, and adding capacitors and regulators.

R&D-1 **Invest in emerging technology development.** As states and utilities progress towards achieving clean policy goals, emerging supply side technologies are a part of the solution. The Council's modeling demonstrated value in all three emerging technology proxy plants, with particular emphasis on those proxy plants that provided storage and flexibility to the system. The Council recommends that national labs, research institutions, and utilities continue to work with developers and manufacturers to research, explore, and bring to market these clean emerging technologies. The Council also recognizes that there is active private investment in the development of these resources. The Council encourages the region to identify opportunities for partnership, with a focus on advancing those resources that will best prepare the Northwest for its needs in the long term.

As discussed above, the bulk of the conservation emerging technologies exist in the higher cost bins. If more conservation were available at a lower cost, that would enable the region to better meet long-term energy and capacity needs through reducing loads at lower costs than today. The Council recommends that conservation programs through NEEA, regional universities, national labs, and others should continue to invest in emerging technology resources.

R&D-2 Investigate accelerating the work to replace hydroelectric dam turbines with designs that increase the generation of electricity while also allowing for increased survival of migrating fish. The Council's 2026 Fish and Wildlife Program includes a fish passage provision calling on the Corps of Engineers and others to continue the development of improved turbine designs that reduce mortality of migrating fish, including designs that might generate more electricity at lower amounts of hydraulic head than existing turbine head. For decades, the focus has been on developing turbines that reduce mortality on juvenile salmon and steelhead that pass through them. As more fish pass in-river via spill and avoid the turbines, a focus on researching, designing, and installing turbines that reduce passage mortality may be waning. On the other hand, new technologies may be emerging that could both increase fish survival and allow for increased generation per amount of water or head available. The Council recommends further investigation into the usefulness and cost-effectiveness of replacing existing turbines with turbines that may offer these dual advantages, thereby increasing generation from the existing hydro system.

R&D-3 Investigate potential value of pairing storage with existing hydro resources. The region has been pursuing hybrid renewable and storage resources as a cost-effective way to provide energy and capacity to the system. Less exploration has been done around the potential value of pairing storage resources with the existing hydro system. While the Council's GENESYS model continues to show more flexibility in the existing hydro system than currently utilized today (see Action Item RES-4), the Council also recognizes that there are limitations to this flexibility, particularly at some projects, including those limits included in the Council's 2026 Fish and Wildlife program for spring and summer operations. As recommended in Action Item RES-4, the regional resource strategy should be implemented in a way to minimize this flexibility in these periods to benefit fish survival. Storage, paired with hydro, might provide an effective way to increase the flexibility of the system, as well as offer additional benefits. The Council recommends the region's hydropower operators investigate this potential through a pilot project that would gather information about performance and inform whether, and under what conditions, such a resource pairing would provide value for the broader system. Such an investigation should not only focus on the power system benefits but also connect to work exploring the most biologically significant limits on flow fluctuations during migration and determining whether and how this pairing might support those limits.

R&D-4 Invest in research exploring data center flexibility and grid integration. Data centers loads are large, generally relatively flat loads. As highlighted in Action Item DC-1, there is a need to work with these loads to identify opportunities for flexibility to support the integration of these loads. The Council also believes there is value in a broader research effort that explores how these loads both contribute to and impact the efficiency of the power system, and then to apply those learnings to identify approaches to improve integration of these loads over the long term. The Council recommends that data centers, utilities, national labs, the Electric Power Research Institute, and others invest in research exploring approaches for effectively and efficiently integrating these loads into the power system over the long-term.

Demand Response

The Northwest power system has traditionally been capacity-rich, resulting in less need for resources that target peak power needs. This includes demand response. Historically, deployment of demand response has been concentrated in the agricultural and industrial sectors, and growth of demand response in the region has been relatively stagnant until 10 years ago. In recent years, however, there has been a shift in the region to explore more opportunities in other sectors, starting with the residential sector, and grow the resource portfolio. The Council's Ninth Plan scenario modeling identified a need for flexibility in the system to support the integration of new resources and manage the forecasted peak loads. Demand response is a resource that may provide more benefit to the system than is currently captured in the Council's modeling. The following Action Items seek to improve regional understanding around the potential for this resource.

R&D-5 **Develop a cost framework for demand response.** In developing the demand response potential for the Ninth Plan, the Council recognized that there is not a consistent framework for valuing demand response across the region. While elements like equipment costs can be well known, there are different approaches and assumptions around setup costs, incentives, value of lost service, and other values. Additionally, there are potential benefits from demand response, including frequency response and voltage management, that require additional quantification. The Council, Regional Technical Forum, NEEA, and other regional entities should collaborate in the development of a consistent and comprehensive cost framework for demand response. The framework should seek to account for the full lifecycle costs and values related to demand response programs. Improving cost assumptions is critical for resource planning and for the appropriate comparison of demand response to other resources.

R&D-6 **Develop a database of demand response deployment program profiles.** Ensuring continued accuracy of demand response deployment profiles is critical to understanding the potential role for this resource and support future power planning. Demand response impacts will vary based on differences in the building stock, as well as different program designs and dispatch strategies. Understanding how these differences impact demand response potential is critical to ensuring a reliable resource and system adequacy. In collaboration with the Regional Technical Forum, Bonneville and utilities should work to develop a database of deployment profiles that capture consistent data around profile size, duration, and timing of load reduction and shifting. These profiles should be informed by program design and baselines, and should include information on program design, event participation rates, and other information. A key to developing this database may include evaluation of demand response programs by utilities, using best practices for evaluation. Evaluations are key to ensuring planning estimates are accurate and the expected impacts are achieved.

R&D-7 **Holistically consider conservation and demand response interactions when assessing the technical potential of these two resources.** The Regional Technical Forum has been improving its analysis around the interaction between conservation and demand response resources. This includes understanding when and how conservation measures avoid or address peak loads, enable load flexibility through a demand response program, and unlock deeper or new demand response potential. The Regional Technical Forum should continue to build on this analysis, understanding the full suite of power system costs and benefits around deploying these two resources.

R&D-8 **Explore long-duration demand response products.** The needs assessment for the Ninth Plan shows a need for resources that can mitigate long-duration events, particularly in the winter. The Council did not include in its modeling of demand response potential products that address this specific power system challenge. There is recognition that getting customers to commit to long-duration programs may be challenging, however, some utilities in the region have started to develop programs that address these events. The Council encourages Bonneville and utilities to continue to investigate these offerings, initially through pilots, to understand where potential exists, limitations to achieving that potential, and possible solutions to addressing barriers.

R&D-9 **Work with national organizations and manufacturers on consistent control and communication protocols for demand response products.** There is currently a generally agreed upon control and communications protocol to support demand response with water heating. Having a single communication protocol that is independent from the specific manufacturer's equipment has the potential to broaden program deployment and, ultimately, reduce the cost of this resource. Bonneville and regional utilities, working through NEEA, should engage with national organizations and manufacturers on developing more consistent control and communication protocols for other key demand response end-use technologies and equipment. In these efforts, the region should work towards encouraging manufacturers to integrate these protocols directly into their equipment, which will remove the need for additional third-party proprietary hardware that can add costs and create added implementation barriers.

Conservation

R&D-10 **Investigate the tradeoffs and feasibility of using debt to acquire conservation and allowing a rate-of return on that conservation resource acquisition.** Utilities typically use debt to acquire supply side resources, which has the advantage of reducing the near-term impact on utility rates by smoothing the acquisition cost over time. Additionally, investor-owned utilities can use supply side resource acquisitions to increase the value of the utility's assets needed to provide service to customers (also known as their rate base). They then can earn a regulated rate of return on that rate base, thereby increasing earnings which is beneficial to shareholders.

Conservation is typically acquired with capital, which can lead to short-term rate impacts. It is also typically excluded from the rate base calculations for investor-owned utilities, reducing the incentive investors might see in this resource. Both of these differences create disparity between conservation acquisition and supply side resources. The Council recommends the region, including utilities and commissions, explore the tradeoffs, regulatory hurdles, and potential benefits of aligning the treatment of conservation resource acquisition with that of supply side resources.

Data Sets and Tool Development

Through the development of a power plan, the Council identifies areas of data and tool development required to improve our understanding of loads and resources and our ability to forecast and assess power system needs. The Council has developed the following recommendations for the region to address priority areas in advance of the Council's next power plan.

R&D-11 Continue to fund regional stock assessments. Through NEEA, the region has conducted regular stock assessments to provide snapshots of the existing building stock. This includes information on the number of buildings, size, use, types of equipment installed, availability of products with controls, and more. In recent years, these assessments have focused on the residential and commercial sectors, with more recent investment in a stock assessment for motor systems. These assessments provide critical information to inform load forecasting and the potential for demand side resources. They also can provide insights to guide demand side program investment.

The Council recommends that the region's utilities, through NEEA, continue to invest in regular residential, commercial, and motor systems stock assessments. The Council also recommends that these efforts be enhanced to include more data collection for multifamily buildings, including both tenant spaces and central building systems. Multifamily buildings, particularly the central systems, are a gap area in the region's understanding of existing loads and potential.

The Council also recommends the region consider a stock assessment for the data center sector. Key data elements would be location, energy consumption (including a breakdown of consumption by equipment), and other site-specific information that could inform future load forecasting and other power system analysis.

R&D-12 Develop benchmark end-use datasets. End-use data is critical to inform load forecasting and provide information around demand side resource potential. The region, through NEEA, has recently collected valuable end-use data in the residential and commercial sectors. This, combined with the regional stock assessments, provides a rich set of data that can be used to support load forecasting and demand side resource analysis. There are other datasets from outside the region, such as the U.S. Energy Information Administration, that can be used to supplement and enhance the regional data. The Council recommends that NEEA and the Council work together on creating a consistent and high-quality process and dataset for characterizing both current and expected future electric end-use data to support future power planning efforts at the Council and elsewhere in the region.

R&D-13 Characterize electrification potential. The Ninth Plan's load forecast shows significant growth potential from the electrification of loads, including transportation, buildings, and potential industrial loads. There is still significant uncertainty around the overall potential for these electrification loads. The Council recommends that the region, including NEEA, regional utilities, national labs, and industries, collaborate on the development of electrification potential datasets. This would provide value to the Council and regional utilities' load forecasting efforts and help inform estimates of demand side resource potential.

R&D-14 Update climate model informed temperature, precipitation, and stream flow forecasts. For the Ninth Plan, the Council used climate model informed data provided by the River Management Joint Operating Committee. These data inform load forecasts, hydro conditions, and solar and wind availability. When developing the Ninth Plan load forecasts and resource potential, the Council's Climate and Weather Advisory Committee recommended the Council use a newer vintage of climate model data in its analysis. These data do not include all the necessary information to support the Council's modeling, including accounting for irrigation and evaporation effects. Using these data would also require updated rule curves at various projects to enable simulation of hydro operations. Due to the time required for these efforts, it was not realistic for the Council to incorporate updated climate model data in this power planning cycle. The Council recommends the region, including climate scientists, national labs, universities, Bonneville, and utilities, collectively work to update the climate model and related hydro data in advance of the next Council plan.

R&D-15 Develop an approach to better forecast carbon prices for modeling. Washington, California, and Canada all have carbon pricing. The carbon market in Washington is still relatively new, and there is currently no consensus across regional forecasting entities on how to incorporate carbon price forecasts into power system modeling. The Council recommends using its System Analysis Advisory Committee to improve understanding of these markets and work to develop a consensus approach for incorporating carbon pricing into future power system modeling.

R&D-16 Develop an updated irrigation demand dataset. The modified stream flows used in the Council's models account for irrigation depletions, return flows, and evaporation effects. The Council relies on data from Bonneville to inform these assumptions. Based on the historical frequency of updating this data, the Council anticipates the next round of data will be available around 2030. The Council would like to work with Bonneville during this next update to increase the granularity of data to better support the Council's enhanced suite of modeling tools.

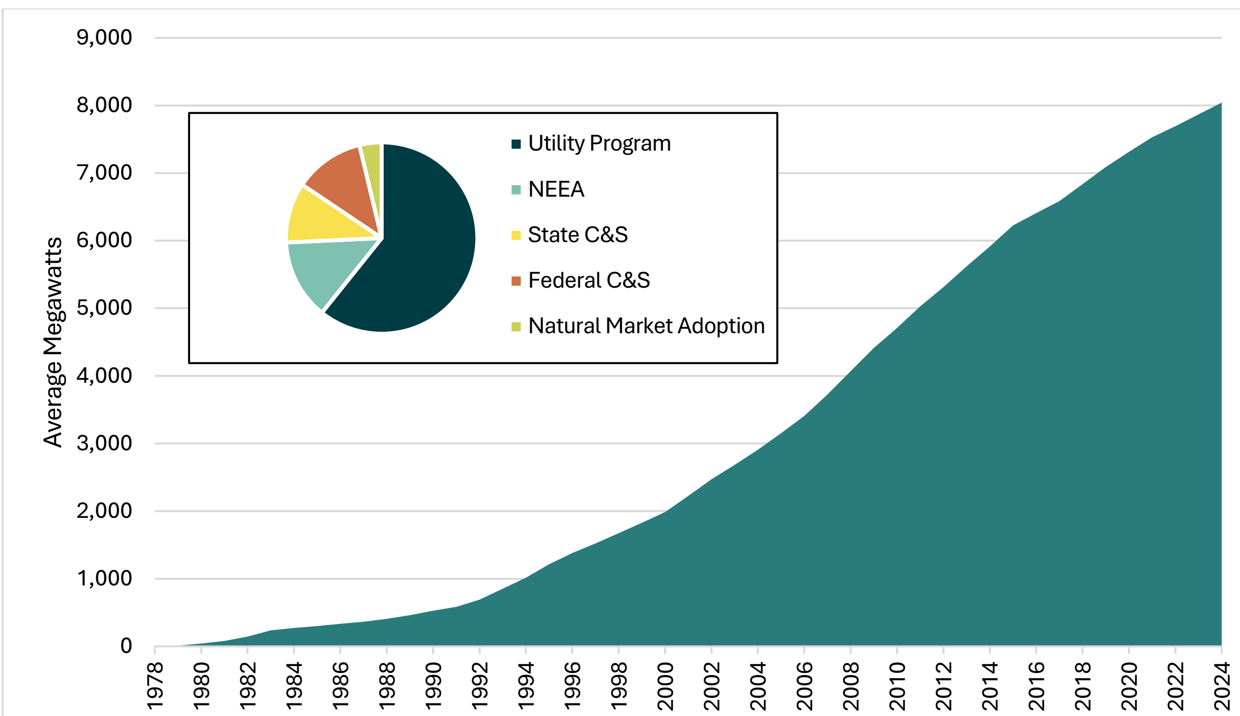
R&D-17 Revisit the Council's assumed market reliance limit. The Council assumes a 2,500-megawatt winter and 1,250-megawatt summer market reliance limit as a hedge against relying too heavily on the market. This limit, which is lower than the actual total transfer capacity, was established through the Council's Resource Adequacy Advisory Committee (RAAC) and directly connects to the Council's multi-metric approach for assessing resource adequacy. The RAAC periodically revisits these limits, and it agreed to keep these assumed limits in place for the Ninth Plan analysis. The Council has observed in recent market events, such as the MLK weekend storm in 2024, the market exceeded the limit in order to serve needed loads in the Northwest. The planned transmission capacity expansion will add additional transfer capacity, which might also impact how the region considers this market reliance limit. The Council recommends using the RAAC to conduct a dedicated reevaluation of the market reliance limit. Should this reevaluation result in a recommendation for an updated limit, the RAAC should also consider how that updated limit would influence the Council's multi-metric adequacy criteria and provide recommendations on any required updates to those thresholds. This work should take place to inform the Council's mid-term assessment of the Ninth Power Plan.

R&D-18 **Review the Council's tools and analytical methods.** As is customary between power plans, the Council will undertake a comprehensive review of the analytic methods and models that are used to support the Council's decisions in the power plan. The goal of this review is to improve the Council's ability to analyze major changes in regional power system and in Bonneville's portion of this system, which will help make recommendations to ensure a low-cost, low-risk power system for the region. This review will focus on methods for modeling or representing regional power system concerns including, but not limited to, hydropower operations, capacity and flexibility constraints for all generation types, market fundamentals associated with all generator fuel sources, existing system conversions, emerging technologies and demand response attributes, and transmission availability and costs, to better address these issues in future power plans.

Chapter 5: Conservation Program

The Northwest Power Act identifies conservation as a priority resource to meet power system needs. Conservation is acquired throughout the region via a mixture of utility-run programs, market transformation efforts, broader market adoption, as well as codes and standards. Over the last decade, the region has invested between $400-$600 million annually in acquiring this resource. Since the 1980s, Bonneville Power Administration, the region's utilities, the Energy Trust of Oregon, NEEA, and others have collectively acquired over 8,000 average megawatts of conservation (see Figure 5 - 1). For context, this is enough energy to provide continuous power to seven cities the size of Seattle. In terms of annual energy, conservation is the second largest resource in the Pacific Northwest, behind hydropower. In 2024, this level of conservation reduced Northwest consumer energy bills by around $7.3 billion.

Figure 5 - 1: Cumulative Regional Savings Since 1980



Conservation provides energy to the region by lowering loads and the requirement to otherwise meet those loads with generating resources. Conservation can also support states and utility clean policy requirements and goals in the region. While much of the low-cost conservation from products like residential appliances and lighting has been acquired, there continues to be significant potential for new conservation to reduce loads and meet regional power system needs. The Ninth Power Plan's regional resource strategy identifies conservation as a key element of the portfolio approach to meet the region's future needs. This chapter covers the Council's comprehensive approach for conservation acquisition under the Ninth Power Plan.

Recommended Cost-Effective Conservation

The Council conducted scenario modeling analyzing a range of uncertainty around forecasted loads, resource availability, natural gas prices, transmission availability, and hydro conditions. The Council's regional resource strategy (detailed in Action Item RES-1) draws on the suite of scenario modeling results, as well as feedback from the Council's advisory committees. Specific to conservation, the Council considered both the near- and long-term results, as well as locational information from the modeling, to develop a cost-effective target for conservation.

Conservation was acquired in every sensitivity to provide energy to the system, reduce loads (and thereby lower planning reserve margin requirements), and meet clean policies and goals. The amount of conservation acquired in each sensitivity varied based on the assumed costs and constraints of other resources. To maintain adequacy, the model selected more conservation when supply side resources were limited and when the costs for those resources were higher. Less conservation was selected in sensitivities with lower prices for supply side resources, particularly renewables, as those resources start to become a more cost-effective way to provide energy to the system.

The modeling showed that more conservation, including higher cost conservation, was required over time to support long-term resource adequacy. The model also showed strong locational differences in the value of conservation, with the model consistently going higher up the cost curve for conservation on the west side of the region relative to the east. The Council used the information from across the sensitivities to define a total amount of cost-effective conservation. The regional strategy seeks to invest sufficiently in conservation in the near term to both prepare for long-term needs, while also hedging against the risk from near-term supply side development constraints. The Council created a dual target for conservation to represent the cost-effective differences between the west and east side of the region.

The Council's recommendations for conservation, alongside the broader set of portfolio recommendations, provide for an adequate, efficient, economical, and reliable power supply. The following section expands on the specific recommendations for cost-effective conservation resource acquisition with additional detail around actions required to ensure an adequate supply.

CON-1 Acquire conservation consistent with the regional resource strategy and the related cost-effectiveness methodology and associated amounts. The Council recommends the region achieve 1,060 average megawatts of conservation regionally, with 860 average megawatts coming from the states of Oregon and Washington and 200 average megawatts coming from the states of Idaho and Montana, by 2032.

Of this, the Council recommends Bonneville acquire 435 average megawatts of conservation, with 390 average megawatts coming from Oregon and Washington and 45 average megawatts from the states of Idaho and Montana.

The Council developed this dual target approach to reflect the diverse value of conservation across the region while also seeking to minimize the potential complexity of implementing programs with differing avoided costs across a single programmatic footprint.[118] This level of investment would achieve 3,950 average megawatts regionally by 2046, the end of the Ninth Plan period. The recommended cost-effective conservation assumes acquiring conservation up to $150 per megawatt hour, in 2024 dollars, in Oregon and Washington and up to $70 per megawatt hour, in 2024 dollars, in Idaho and Montana. These are considered "input" levelized costs, as they reflect the costs and benefits for the measures in the development of the conservation supply curve.

After determining the cost-effective amount of conservation, the Council developed a cost-effectiveness methodology, which provides a way for the Council, Bonneville, regional utilities, NEEA, and state programs to assess the cost-effectiveness of new and updated conservation measures relative to the Ninth Plan resource strategy.[119] Bonneville, NEEA, the region's utilities, and state programs should use the Council's methodology and parameters to guide cost-effective implementation of the Ninth Plan.

The table below provides annual milestones towards the conservation target, both for Bonneville and the region:

	2027	2028	2029	2030	2031	2032
Regional	**177**	**353**	**530**	**707**	**883**	**1,060**
Oregon and Washington	*143*	*287*	*430*	*573*	*717*	*860*
Idaho and Montana	*33*	*67*	*100*	*133*	*167*	*200*
Bonneville	**73**	**145**	**218**	**290**	**363**	**435**
Oregon and Washington	*65*	*130*	*195*	*260*	*325*	*390*
Idaho and Montana	*8*	*15*	*23*	*30*	*38*	*45*

These annual milestones are not hard targets but provide a basis from which to track the region's progress towards the Council's conservation target. Recognizing that conservation spending is relatively consistent year-over-year, the Council assumed a linear ramp for creating these milestones.

[118] The Council received significant input during the development of the draft plan on the proposed dual target approach for conservation. To provide more context around the Council's analysis that informed this proposed dual target and some power system analysis around transitioning to a single target, the Council developed Technical Appendix Q – Analysis of Dual Versus Single Target for Conservation. Throughout the public comment period on this draft Plan, the Council is committed to continuing the conversation about these two approaches. The Council is seeking public comment that provides specific recommendations for how to improve upon the proposed regional resource strategy while still ensuring the region has an adequate, efficient, economical, and reliable power supply.

[119] The full methodology, including parameters, is detailed in Technical Appendix O – Cost-Effective Conservation Methodology and Results.

The Council, through its annual Regional Conservation Progress report, will track regional progress towards the Ninth Plan cost-effectiveness target. As part of that effort, the Council will seek to understand how the region is applying the dual target approach for acquiring the recommended cost-effective conservation. This will provide valuable information for providing adaptive guidance throughout the implementation of the Ninth Plan.

The Council will also work to ensure that all reported savings in this process reflect the long-term resource savings. Emphasis will be placed on tracking savings for conservation measures that have estimated lifetimes shorter than the Action Plan period (2027-2032). This is to ensure that savings reported from continued program investment in these measures do not over-represent the actual conservation resource acquired.[120] This will be critical as part of the Council's tracking of regional progress towards the Ninth Plan recommendations and annual assessment of resource adequacy.

CON-2 **Conduct rigorous evaluations of conservation programs.** Evaluation is a critical element of delivering conservation as a resource. Evaluations provide information to ensure that the planned savings are realized. This is a requirement of ensuring resource adequacy. Evaluation can provide information to allow utilities, the Regional Technical Forum, and others to update their estimates of assumed savings and improve future planning efforts. It can also provide important insights that improve program effectiveness, which ultimately helps to ensure savings are delivered at the lowest possible cost.

The region already has robust evaluation efforts, although more emphasis is needed in this area. For example, currently only about 18% of the measures that the Regional Technical Forum assess are classified as "Proven." This designation can only be attained by having adequate evaluation data. Achieving this designation reduces the overall evaluation burden over the long term, thereby reducing program delivery costs for the region. The Council recommends the region continue and expand its investment in evaluation. These efforts should be done in accordance with the Regional Technical Forum's guidelines, which support consistent and reliable determination of conservation across all measures.

In addition, as more energy savings shift from traditional equipment-based resources to behavior-based resources, the Council recommends the region pay particular focus on better understanding and estimating these behavior-based resources, including the key actions driving behavior-based savings, the magnitude of savings from these actions, and their persistence.

[120] For measures with lifetimes shorter than the Action Plan period, there is the potential to over count conservation savings. For example, to ensure long-term savings of a conservation measure with a one-year measure life, a utility program may make an annual investment into that measure. This annual investment is captured in the resource potential costs and benefits, and therefore accurately accounted for in the determination of potential cost-effective conservation. It can lead to, however, programs providing claimed savings in multiple years for the same measure. If this is not recognized and accounted for, it has the potential to overrepresent actual conservation savings. This in turn has the potential to result in underinvestment in new resources, including conservation resources, needed for resource adequacy.

CON-3 **Continue to invest in effective market transformation efforts.** Market transformation is a long-term effort to fill the pipeline with conservation measures. Effective market transformation helps to advance the pace of bringing new technologies to the market, reduces barriers to implementation, and brings down costs through the creation of sufficient market demand. The Council recommends that Bonneville, utilities, and the Energy Trust of Oregon continue to invest in market transformation efforts.

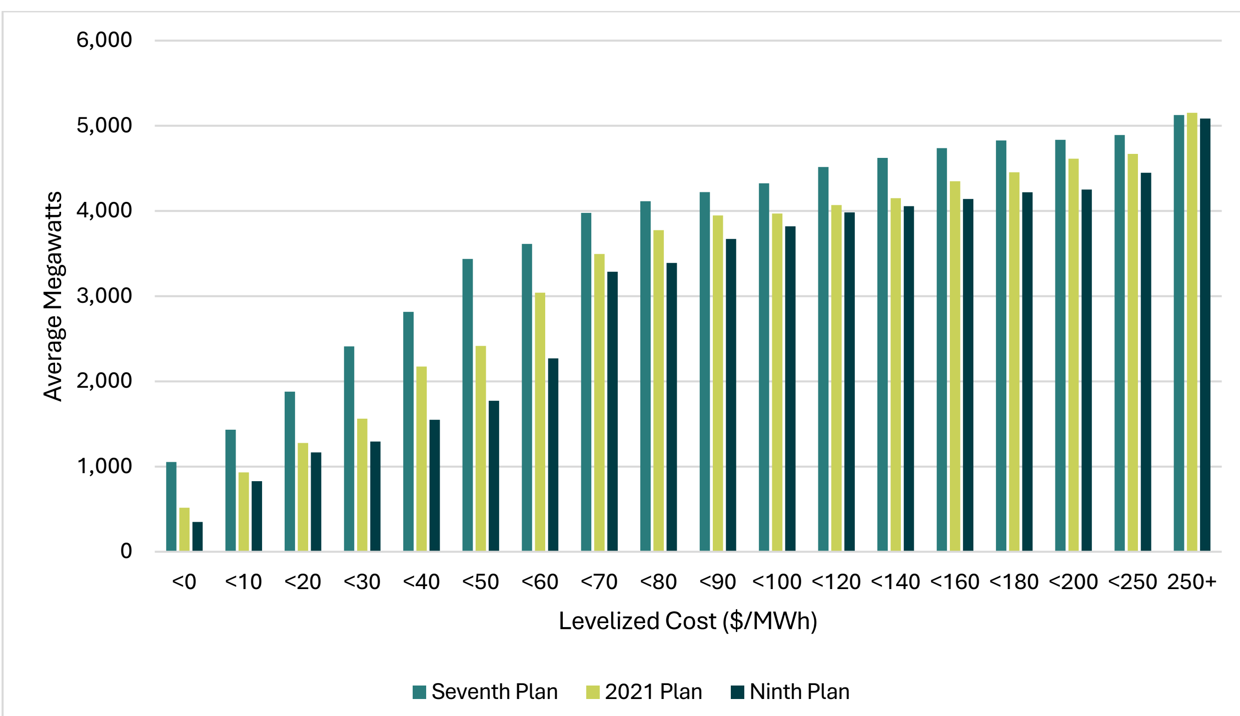
Supporting Recommendations

Throughout the development of the Ninth Plan, the Council, working with its Conservation Resources Advisory Committee and the Regional Technical Forum, have identified some specific elements related to conservation resource acquisition that warrant particular attention. These supporting recommendations seek to expand the amount of cost-effective conservation, ultimately providing more opportunity to address load growth, reduce consumer bills, and broaden consumer participation in conservation programs.

Addressing Measure Costs

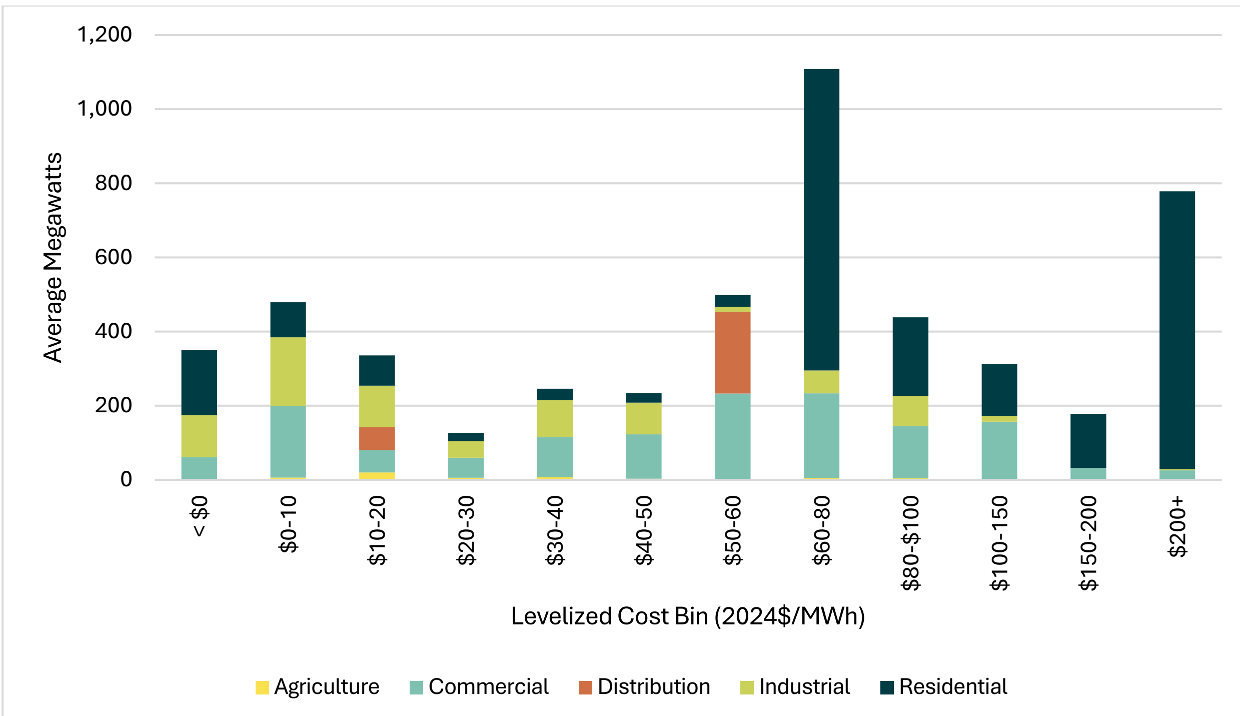
The Council's 2021 Power Plan first noted that other resources were starting to be more cost-competitive with conservation. This was driven by a mix of factors, including the success of conservation programs in acquiring the existing low-cost conservation, challenges with bringing costs down for remaining conservation technologies, and declining costs on the supply side, particularly renewables. The Ninth Plan continues to show this trend (see Figure 5 - 2).

Figure 5 - 2: Comparison of Seventh Plan, 2021 Plan, and Ninth Plan 20-Yr Supply Curves



Costs are a particular challenge in the residential sector. Much of the region's conservation acquired to date has been in residences, including energy efficient appliances, advancements in lighting, weatherization of homes, and efficient space and water heating. Significant potential remains for residential conservation; however, of the remaining residential potential, much of it is higher cost. Figure 5 - 3 shows the incremental amount of conservation in each cost bin (excluding emerging technologies). Roughly 30% of the residential potential is in the $60-$80 per megawatt hour cost bin, in 2024 dollars. The bulk of this bin is represented by heat pump water heaters. Close to 50% (or around 1,250 average megawatts) is at costs above $80 per megawatt hour, of which 30% of all residential conservation potential is in the most expensive cost bin at over $200 per megawatt hour.

Figure 5 - 3: Incremental 20-Yr Conservation Potential, by Levelized Cost and Sector



This cost challenge is driven by a combination of factors, including the rising costs of equipment and installation and declining forecasted energy savings due to poor installation and performance (Action Items CON-6 through CON-8 seek to address the latter). Improving both the savings and costs will be critical for providing cost-effective options to all Northwest consumers in the long term.

CON-4 **Prioritize efforts to understand barriers to declining costs and identify solutions to address those barriers.** Key to addressing cost-effectiveness challenges is addressing the rising costs for maturing technologies, such as heat pumps. The Council recommends NEEA, Bonneville, the Energy Trust of Oregon, regional utilities, and national labs conduct research to 1) understand the cost makeup of these technologies (e.g., equipment costs versus labor, markup, etc.), 2) understand the key drivers of incremental cost differences among varying levels of product efficiency, and 3) determine pathways for reducing equipment and other costs, including component analyses to identify savings opportunities. NEEA, as part of its market transformation efforts, should work to lower costs both through increases in sales volume and working with manufacturers to produce lower-cost versions of equipment. Regional conservation programs should also provide more options to consumers to help address high capital costs for cost-effective measures. For example, if a conservation resource is cost-effective, a conservation program can pay the full incremental cost of that resource and it is, by definition, a lower cost investment of ratepayer dollars than the next available resource.

As part of the research activities described above, the Council recommends that researchers also work to understand pressure points where products are not installed as efficiently as possible, due to installers seeing this as a barrier to cost competition. As discussed more below, the region has struggled with proper installation of heat pumps. For example, performing building load calculations is critical for optimal heat pump sizing and efficiency. But this can be seen by contractors as a barrier to cost competitiveness. Research should explore how to alleviate these kinds of pressure points that ultimately impact the ability of the region to deliver sufficient savings from conservation.

Addressing Residential Buildings

As noted above, the region has achieved significant conservation in the residential building sector. Close to 45% of all savings achieved since 1980 has come from improvements in residences. There continues to be significant potential in this sector. Roughly 50% of the Ninth Plan's 20-yr estimated potential (excluding emerging technologies) is in the residential sector. This includes home weatherization, efficient water heating technologies, and opportunities to improve space heating. Accessing this potential is challenging, in part, due to the high costs of opportunities. A second challenge comes from program implementation. This includes the need to identify and address remaining gaps, as well as ensuring proper installation of equipment to ensure reliable, long-term energy savings. The following recommendations seek to help address these issues and challenges.

CON-5 **Weatherize homes with little to no insulation.** The region's conservation programs have successfully weatherized many residences throughout the Northwest, although gaps still remain. Hundreds of thousands of homes in this region continue to have little to no insulation. In addition to providing energy savings, weatherization greatly improves occupant comfort and home resilience. Recognizing this, the Council recommended in the 2021 Power Plan that the region continue to invest in weatherization programs. Specific focus was to be given to homes with zero to minimal insulation. While some progress has been made in the past four years, significant potential remains. The Council recommends that the region continue to prioritize weatherization in homes with little to no insulation and/or high rates of air leakage. This means focusing on homes that are currently uninsulated, have single-pane metal-framed windows, and/or air leakage rates exceeding 10 ACH50.[121]

[121] ACH50 is a measure of the building's air leakage. It means air changes per hour at 50 pascals.

The Council recognizes that the cost of weatherization may not be affordable for all consumers and the incentives might not align for all consumers. This can be particularly true when the home is renter-occupied, as the homeowner who is often paying for the upgrade does not get the direct benefit in energy bills and home comfort. This split incentive is an ongoing challenge in conservation programs. The Council encourages programs to work to address these affordability and split incentive challenges. As noted above, for cost-effective measures, the conservation program can pay up to the full cost of the measure and it is, by definition, still cost-effective relative to an alternative resource. Where the measure is not cost-effective, conservation programs may want to seek out pathways of coordinating with other agencies (such as community action agencies, state agencies, or nonprofits) to explore co-funding options to serve these homes.

While not all these measures are strictly cost-effective under the Ninth Plan's cost-effectiveness methodology, the Council recognizes that weatherization has been a long-standing cost-effective way of providing energy savings. Filling the remaining gaps in this resource is critical to not leave households behind. This also means that programs may need to invest at levels higher than those simply required to acquire the cost-effective conservation recommended in Action Item CON-1, as well as work to identify additional funding sources where practical. The Council will track progress towards this goal through its annual Regional Conservation Progress survey.

CON-6 **Promote the concept of making homes "heat pump ready" before installing a heat pump.** One of the challenges to heat pump performance is that, at times, this equipment is installed in a home that is not sufficiently weatherized. In addition to the benefits described in CON-5 above, weatherization, air sealing, and duct improvements can greatly improve the efficiency of heat pumps. It can also allow for the installation of a significantly smaller heat pump, which provides cost savings. The Council recommends that Bonneville, the Energy Trust of Oregon, regional utilities, and NEEA promote the concept of a "heat pump ready" home. Technical Appendix P – Model Conservation Standards and Conservation Program Details includes general guidance on minimum and preferred weatherization levels for installing a heat pump into an existing home. The Council believes this guidance provides a useful starting place for conservation programs pursuing this concept. The Council also recommends conservation programs consider the benefits of whole home approaches that combine weatherization, duct improvements, and heat pump installations in a wholistic package of measures.

CON-7 **Prioritize proper installation of heat pumps to maximize savings.** Another challenge to heat pump performance is improper installation, which leads to the increased use of back-up heating sources that are inefficient. This can lead to large spikes in energy use at certain times of day. Properly installing a heat pump requires performing heat load calculations on every installation to size the heat pump to recommended standards; setting critical heat pump controls, such as compressors and auxiliary lockout settings, to maximize use of the compressor; and educating home occupants on how to operate systems. Following these best practices can maximize heating with the heat pump and significantly minimize, or even fully offset, the need for inefficient backup heat. The Council recommends that Bonneville, the Energy Trust of Oregon, and regional utility programs prioritize installation and commissioning of new heat pumps to maximize efficiency.

CON-8 Invest in heat pump retro-commissioning programs. Regional data sources suggest that many existing heat pumps in the Northwest were not properly sized or commissioned during installation. As noted in CON-7 above, improper heat pump sizing, commissioning, and/or control settings can lead to significant reductions in overall system efficiency. Consistent with MCS-2 described below, the Council recommends that regional utility programs invest in retroactive commissioning, or "retro-commissioning" of existing heat pumps to update control settings and educate households in order to maximize the efficiency of the existing heat pump base.

Addressing Commercial Buildings

The Ninth Plan supply curves estimate around 1,400 average megawatts of commercial potential, mostly representing individual measures. There is significant potential remaining in commercial buildings beyond these individual measures. The Council estimated another 766 average megawatts of potential from commercial deep energy retrofit programs, which was captured in the emerging technology portion of the conservation supply curves. The Council developed the following recommendations, recognizing that work remains to better understand and ultimately address this whole building potential through cost-effective programs.

CON-9 Develop a robust energy use intensity data set for commercial buildings in the Northwest. Energy use intensity, or EUI, is a measure of a building's total annual energy consumption relative to its size. Building EUI data can provide useful insights for load forecasting. More importantly, it can also help identify buildings that have consumption levels significantly higher than comparable buildings. The Council recommends that Bonneville and the region's conservation programs, through NEEA, coordinate with cities, states, and building owners to develop a robust EUI data set. This dataset should include both total energy EUI and electric EUI data. The Council recommends consistency with the ENERGY STAR® Portfolio Manager, a tool for benchmarking building energy use, as well as strong data quality control.

CON-10 Develop performance-based programs for commercial buildings. As the region collects more and better quality EUI data, the region will be better positioned to develop performance-based benchmarking programs seeking to support commercial buildings in obtaining lower EUIs. The Council recommends that Bonneville, the Energy Trust of Oregon, and utilities utilize this benchmarking data to develop performance-based programs for commercial buildings. NEEA has developed a whole building program to conduct research and support streamlined approaches to whole building programs. Regional conservation programs and Bonneville should work with NEEA and support this effort.

As currently estimated, these deep retrofit programs are in some of the highest cost bins. The Council recommends that NEEA and conservation programs conduct research to understand cost barriers and drivers, how to reduce the cost for whole building measures, develop costs for different whole building pathways, and develop streamlined program approaches for attaining low EUIs.

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.[122] These model conservation standards are applicable to new and existing structures; utility, customer, and governmental conservation programs; and other consumer actions for achieving conservation.[123] 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 model conservation standards 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.

The Power Act provides for broad application of the model conservation standards. In earlier power plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Since the Council adopted its first model conservation standards, all four states within the Northwest have adopted strong energy codes that largely incorporate those standards. More recently, the Council has focused model conservation standards on addressing program gap areas and providing consistency.

For the Ninth Plan, the Council recommends two model conservation standards, the first targeted at new data centers and the second on heat pump retro-commissioning. Both represent critical areas that must be addressed. Data centers represent a significant new load for the region and minimizing that impact through efficient construction will provide benefits for the entire Northwest. Similarly, while at a much smaller scale, heat pumps are a significant load in the residential sector and are expected to increase with electrification policies in some jurisdictions. It is important to maximize the efficiency of the existing stock of heat pumps to reduce peak issues. These practices will likely have a trickle-down effect on the installation of new units.

MCS-1 Data centers: New data center facilities over 300 kilowatts should be developed efficiently. The most common metric for measuring data center electric efficiency is Power Usage Effectiveness, or PUE. This represents the total data center electricity use divided by the total server equipment electricity use. A PUE of 1.0 means that all the energy use is from the server equipment. Anything higher comes from other uses, such as air conditioning. The model conservation standard for new data centers is a PUE of 1.20 or less. This requirement is 3% better than the 1.24 PUE voluntary ASHRAE 90.4 performance standard and can be

[122] Northwest Power Act, Section 4(e)(3)(A).
[123] Ibid., Section 4(f)(1).

met by reducing equipment mechanical losses. This is an achievable outcome for larger facilities, and many modern data centers already have PUEs of 1.20 or below.

In addition to PUE, Peak Power Usage Effectiveness (PPUE) and Water Usage Effectiveness (WUE) metrics provide additional information on data center impacts. All three metrics vary based on the equipment required for cooling the facility. This model conservation standard requires data centers to report energy and water consumption to inform each of these metrics.

The Council has provided additional information in Technical Appendix P for local jurisdictions considering stretch goals or targets for new data centers.

MCS-2 **Residential heat pump retro-commissioning: Installed heat pumps in the region that could benefit should be properly retro-commissioned.** Effective heat pump installation requires proper design, installation, air distribution, and owner education. Recent studies of heat pumps in the Northwest demonstrate that not all heat pumps are installed using best practices, often resulting in systems that do not operate as efficiently as they could. The Ninth Plan's analysis found that retro-commissioning of these existing heat pumps would be broadly cost-effective across the region. Conservation programs should offer programs that retroactively commission existing residential heat pumps. These programs could be offered for all customers or done through a targeted approach, such as identifying candidates through high monthly energy use or hourly demand or via existing home audit programs. Programs should focus on control settings that can minimize the need for back-up heat, including the compressor lockout, auxiliary lockout, emergency heat, thermostat droop, and thermostat night setbacks. Optimizing these settings requires an understanding of home heating load and duct system characteristics.

Technical Appendix P – Model Conservation Standards and Conservation Program Details includes the detailed specifications and guidance for each of these model conservation standards. Entities should reference those specifications when implementing these model conservation standards.

Surcharge Recommendation and Methodology

The Power Act authorizes the Council to recommend a surcharge that the Bonneville Administrator may impose on customers that have not implemented conservation measures that achieve energy savings comparable to those that would be obtained under the model conservation standards in the plan.[124] If the Council recommends a surcharge, the methodology for calculating that surcharge must be included in the power plan.[125]

The purpose of the surcharge is two-fold. First, it is to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent conservation

[124] Ibid., Section 4(f)(2).
[125] Ibid., Section 4(e)(3)(G).

savings. It is also intended 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 Power Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth. Per the Power Act, the surcharge must be no less than 10% percent and no more than 50% of the Administrator's applicable rates for a customer's load or portion of load.[126] 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 that the Administrator invoke the surcharge provisions of the Act at this time. The Council intends to continue to track regional progress toward the model conservation standards and will review its decision on the surcharge recommendation if accomplishment of these goals appears 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 those utilities' rates to recover those costs.

While the Council does not currently recommend a surcharge, the Council has developed a methodology for the calculation of that surcharge should the Council decide to recommend one later. The methodology is detailed in Technical Appendix P – Model Conservation Standards and Conservation Program Details.

[126] Ibid., Section 4(f)(2).