PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY

INTEGRATED RESOURCE PLAN 2025

P.U.D.
CHELAN COUNTY

2025 Integrated Resource Plan

December 2025

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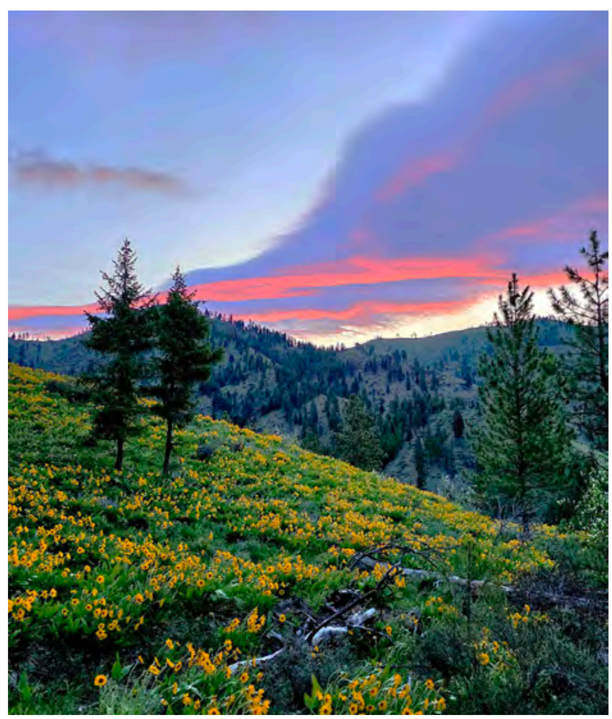

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2025 Integrated Resource Plan

Summary of Determinations

The District has completed its 2025 Integrated Resource Plan (IRP). This report is required by the Revised Code of Washington (RCW) 19.280: Electric Utility Resource Plans. It was passed by the legislature in 2006. According to the statute, "it is the intent of the legislature to encourage the development of new safe, clean and reliable energy resources to meet demand in Washington for affordable and reliable electricity. To achieve this end, the legislature finds it essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the short-term and the long-term. The legislature intends that information obtained from integrated resource planning under this chapter will be used to assist in identifying and developing: (1) New energy generation; (2) conservation and efficiency resources; (3) methods, commercially available technologies, and facilities for integrating renewable resources, including addressing any overgeneration event; and (4) related infrastructure to meet the state's electricity needs." The enacted legislation requires investor-owned and consumer-owned utilities with more than 25,000 retail customers to produce a progress report every two years and a fully updated 10-year plan every four years. Consumer-owned utilities shall encourage participation of their consumers in development of their IRPs and progress reports after providing public notice and hearing.

Based upon the analysis over the 2025-2034 planning period, the Board of Commissioners of Chelan County Public Utility District (Chelan PUD or District) has approved this 2025 IRP and determined that:

- The District retain its current mix of generating resources.

And additionally:

- The District continues to evaluate and implement conservation and demand response (DR) programs based on the foundational work performed in the 2025 Conservation Potential Assessment (CPA) and the 2025 Demand Response Potential Assessment (DRPA).
- The District will evaluate new sources of generation for diversification and/or overall portfolio objectives.
- The District will carry on the evaluation and implementation of strategies consistent with financial policies and the hedging strategy.

These determinations continue to provide the platform for the District to serve its customer/owners with reliable, low-cost energy, while meeting renewable energy targets for the foreseeable future.

Report Overview

To meet the requirements of RCW 19.280, the development of Chelan PUD's 2025 IRP includes, amongst other items, the following:

- An update of the long-term forecasts of native retail electric customer demand and new Large Loads
- Revised costs and operational information for Chelan PUD's existing generating resources
- Updated data pertaining to the District's existing operational and power sales contracts

- Amended conservation inputs to align with Chelan PUD's 2026 10-year conservation target submittal to the Washington State Department of Commerce (Commerce) as required
- Report on DR potential developed to meet Clean Energy Transformation Act (CETA) requirements
- An update on regional and Chelan PUD's resource adequacy (RA) development
- Analysis of the forecasted load/resource balance (using the District's existing portfolio of resources) with the aforementioned input changes, while evaluating service reliability and environmental impacts and communicating with customers and the public
- Restatement of the ten-year Clean Energy Action Plan (CEAP) for implementing portions of the CETA
- Board approval of the 2025 IRP
- Submittal of the final 2025 IRP to Commerce by September 1, 2026, as required

Planning & Regulatory Environment

Resource Planning Situation

Chelan PUD is forecasted to be surplus to its own native retail load needs throughout the current planning period (2025-2034). A framework for power sales to new Large Loads was recently developed at the District (see Hedging Strategy). District Strategic Directive-09, Integrated Resource Planning, passed by the Board on September 15, 2025, is a strategic value to ensure that Chelan PUD has sufficient resources to meet customer demand for essential utility services. Additionally, a comprehensive long-term look at the District took place through a 50-year visioning process discussed under Imagine 2075 below.

The District has longer-term power sales contracts and also enters into shorter-term contracts for a portion of its hydro output, providing the District flexibility. The shorter-term contracts, part of the District's hedging policy, are discussed more fully in the Portfolio Analysis section.

Resource adequacy (RA) is a topic of great concern to the region and individual utilities alike. Demand response (DR) has been identified as a resource to help meet capacity demands in the region. RA and DR are required to be identified and evaluated under CETA. Both topics are discussed more fully below.

Imagine 2075

Nearly 90 years ago, Chelan PUD was formed after a vote of the people. Seventy years ago, a series of courageous decisions were made that set the course and put into motion the evolution of the District into a premier provider of clean energy in the Pacific Northwest (PNW) and as a trusted supplier of other essential utility services. Assets and a strong financial position allow Chelan PUD to measurably improve and enhance the quality of life in Chelan County.

Legacy is broadly defined as anything handed down from the past. What is the District doing with the gifts it inherited and how is it being a good steward to those that come in the future? Chelan PUD's 50-year visioning process, Imagine 2075, helped the District answer those questions and best align Chelan PUD for a resilient and prosperous future. Imagine 2075 used a planning process called Strategic Foresight. The strategic foresight process uses data, trends, scenario planning, analysis and feedback to set a course for the future. The foresight process lends itself to situations that have a high degree of uncertainty, where change is rapid, and there are many possible paths to travel. The hope is that even in the face of disruption, good decisions can be made because alternatives have been thoughtfully considered, and clear directions have been established. The Imagine 2075 effort resulted in a 50-year vision that will be cascaded through business plans and other documents in 2025 and beyond.

Preliminary work on this initiative was started in late 2023 and completed in late 2024 with implementation beginning in 2025. During 2024, a project known as "the Big Sort" was participated in by a large of number of District employees and resulted in the following top trends:

1. *Increasing Demand for Electric Energy:* Due to technology demands and population growth, according to the Northwest Power & Conservation Council (NWPCC or Council), the Northwest's electricity demand is expected to increase anywhere from 1.8% to 3.1% annually from 2027 to 2046. Expected peak demand growth ranges from 1.9% to 3.0% per year over that timeframe.
2. *Increasing Electricity Load:* By 2034, Chelan PUD's total system retail load, including Large Loads, is expected to increase by 125%, driven largely by growth in data centers and to a lesser extent, electric vehicles (EVs). By 2050, electricity is expected to account for 40-50% of U.S. energy consumption, up from the current level of approximately 34%.
3. *Increasing Energy Storage Demand & Options:* Not all renewable energy sources generate power equally and consistently. Long duration energy storage is crucial for managing this variability by storing surplus energy for use during peak electricity demand.
4. *Elevated Cybersecurity Risk:* Cybersecurity threats will become increasingly sophisticated. New technology like quantum computing, artificial intelligence (AI), and distributed energy renewables present new cybersecurity risks and challenges to protect sensitive information and electric power grid reliability.
5. *Increasing Wildfire Frequency & Severity:* Chelan County is among the counties with the highest wildfire risk in Washington state. From 1984 to 2015, large fires in the western U.S. doubled. Very large fires could surge by 200-500% due to rising temperatures and emissions.
6. *Increasing Extreme Weather Events & Impacts:* Heat waves will intensify, with Chelan County expecting days over 90 degrees to increase by 50% to 100% by mid-century. This trend poses risks such as those to health, higher fire danger, reduced hydroelectric power supplies, higher water temperatures, and erosion vulnerability.
7. *Growing Use of Artificial Intelligence (AI):* AI adoption is expected to reshape the energy sector by changing the way work is conducted. By 2030, AI could automate roughly one-third of current working hours, impacting various support and service jobs.
8. *Increasing Recognition for Diversified Renewable Generation Portfolio:* A diversified renewable energy portfolio is required to meet state and national sustainability goals with varying targets between 2030 and 2050.
9. *Increasing Demand for Municipal Water:* In Chelan County's river basins, municipal water use is expected to rise 18% by 2040, with half of this increase occurring during the hottest months.
10. *Decreasing Snowpack in Columbia & Chelan Basins:* Some projections have statewide average spring snowpack decreasing 38-46% by mid-century and 56-70% by the 2080s. For Chelan PUD, the mountain snowpack is crucial, serving as winter water storage for hydropower.

11. *Changing Long-Term Marketing Strategy & Surplus Energy Sales:* Chelan PUD projects an average annual total system, including Large Loads, load growth of 8.87% over the next decade, which could reduce power available for wholesale energy markets.
12. *Increasing State Authority for Public Power:* State laws are increasingly restricting utility operations, raising concerns about state overreach in locally controlled PUDs. Trends could erode local decision-making and disadvantage certain customer segments.

As evidenced by this list, most of the trends and concerns tie directly to loads and resources and those issues that have a direct impact upon them. Following the Big Sort, a customer survey was taken. More than 1,700 customer-owners responded. The survey format paired the seven top priorities identified so far in the visioning process. Participants were asked to pick the most important priority in a head-to-head match-up in 21 combinations. Here's how customer-owners ranked the list of priorities that will help guide Chelan PUD's future for the next 50 years:

1. Invest in equipment, people, and technology to make Chelan PUD's services more resilient
2. Make sure energy and water are available for future generations, even if it costs more
3. Invest in clean energy resources to support future community needs
4. Keep the public informed and involved by sharing details and collaborating with them
5. Strengthen partnerships with governments, community organizations, and others to support a high quality of life
6. Be bolder in exploring opportunities (including some with higher risks) that could benefit Chelan County in the long run
7. Develop a more effective way for Chelan PUD to make decisions for the future

The survey also included open-ended questions, to which customer-owners provided about 700 comments. Some of the top concerns were rapid community development, resource use, environmental impact, and energy management and infrastructure.

Resource Adequacy

Resource adequacy refers to the ability of the electric power system to provide sufficient electricity to meet customer demand under various conditions. It is a critical aspect of grid reliability and is measured by the probability of outages due to insufficient capacity. In FY 2023, the Council adopted a new, more sophisticated way to test whether the region's power grid has adequate resources by using multiple metrics. The Council was among the first power planners in the U.S. to move to a multiple metric approach.

The Council's previous adequacy metric of Loss of Load Probability (LOLP) focused on identifying the probability of a year with one or more simulated shortfalls from modeling that tested a range of hydropower, load, and wind conditions. The LOLP metric was effective for a power system heavily reliant on hydropower, thermal plants, and energy efficiency, where generation uncertainty was minimal and revolved around the coincidence of high loads and low water.

The Council evaluates shortfalls as a signal for needing emergency measures, such as a utility buying amounts of power from wholesale markets that are above market-import caps to meet peak demand. A multi-metric adequacy framework provides insights into the frequency, duration, and magnitude of potential shortfall events. An adequate system means all metrics stay within their respective thresholds.

The previous LOLP approach didn't offer insights into how large the shortfall would be, how long it would last, or what month or season in which it would occur.

In August 2024, the NWPCC published the 2029 power assessment. Over the next five years across the PNW, significant load growth and changing system dynamics are creating risks for maintaining power system adequacy. The regional adequacy assessment for 2029 provides early warnings on system adequacy, with a specific focus on how the Council's Eighth Power Plan (finalized in 2022) resource strategy supports adequacy given the rapid changes the grid is experiencing, such as the announced coal-to-gas conversions and transmission expansion.

This adequacy assessment finds that implementing the resource strategy in the Eighth Power Plan, specifically achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029 and ensuring sufficient balancing resources and DR, will provide for an adequate system. However, areas of risk remain. Using the same strategy but only pursuing the low end of the Council's energy efficiency target, would not provide for an adequate system. Further, if data center load growth accelerates and more closely aligns with utility projections in the region by 2029, the resource strategy will also be insufficient to maintain adequacy. These risk areas, and other changing system dynamics, highlight the importance of the Council's upcoming power plan to provide new guidance to the region in support of an adequate, efficient, economical and reliable power supply.

The Council uses an adequacy model called GENESYS to simulate the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not indicate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above a normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in the September 2022 California heatwave).

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Rather, the Council evaluates shortfalls as a signal for emergency measure needs. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration and magnitude of potential shortfall events, and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk (VaR) sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk (VaR) sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk (VaR) sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

The adequacy assessment for 2029 explores how the Council's Eighth Power Plan resource strategy supports an adequate system. The assessment accounts for system changes that will be implemented by 2029, including load growth, in-region resource developments, and out-of-region market fundamentals. Electric load is expected to substantially increase by 2029, due to data centers and electric vehicles. However, announced changes to thermal plant retirements, such as Valmy 1 & 2 and Jim Bridger 1 & 2 conversions from coal to gas fueling, and anticipated transmission expansion throughout the Western Electricity Coordinating Council (WECC), including Boardman-to-Hemingway in the region, appear to alleviate some of the challenges associated with the increased loads when coupled with the Eighth Power Plan's resource strategy.

The Eighth Power Plan's resource strategy recommends between 750 and 1,000 average megawatts (aMWs) of cost-effective energy efficiency, at least 3,500 megawatts (MWs) of renewable resources, 720 MWs of low-cost and frequently deployable DR be acquired, as well as increasing balancing up reserve requirements to 6,000 MWs to respond to growing short-term uncertainty in variable energy resources (primarily wind and solar) by 2027. Because the resource strategy provides a range for both energy efficiency and renewable development, the Council created a "reference strategy" to test in this assessment. This reference represents the high-end of the Council's cost-effective energy efficiency target (roughly equivalent to 1,300 aMWs by 2029) and a renewable build consistent with many of the sensitivities analyzed in the plan that informed the strategy (roughly 6,600 MWs by 2029).

The 2029 adequacy assessment tested a range of potential future conditions, including (1) the reference resource strategy (2) higher data center load growth, and (3) alternative trajectory within the resource strategy, the low end of the energy efficiency target.

The reference scenario did not violate thresholds in any metric, frequency, duration and magnitude, and therefore is deemed adequate. The higher data center scenario used all the same assumptions from the reference case, except it added 1,600 aMWs of additional power demand from the tech sector by 2029. The reference case anticipates roughly 2,400 of incremental tech-related aMWs by 2029, and the high data center scenario assumes 4,000 aMWs. This scenario violated thresholds for all the metrics and therefore is deemed inadequate. The alternative trajectory, the low end of energy efficiency scenario, used the same assumptions as the reference case, but only met the low end of the efficiency target, 1,000 aMW instead of 1,300 aMW in 2029. This scenario satisfied some metrics (duration and energy), but it violated other metric thresholds (frequency and peak) and therefore is deemed inadequate.

The reference scenario indicates that the Eighth Power Plan's resource strategy mostly eliminates summer challenges and greatly mitigates winter challenges with only a minor set of system conditions posing adequacy concerns in January evening ramp that are within the acceptable adequacy limits. However, should only the low end of cost-effective energy efficiency target be achieved, the region may experience winter challenges throughout the majority hours of the day, with the greatest need in the morning and evening ramps, as well as additional challenges in spring and summer. The higher data center scenario further exacerbates the winter, spring and summer challenges as the resource strategy is insufficient to meet the potentially much higher electrification loads.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming power plan and the eventual resource strategy to address the evolving needs of the region.

In September 2025, the consulting firm, E3, completed a new analysis of RA in the PNW. It projects a stark resource shortfall beginning in 2026 and reaching nearly 9 GW by 2030, or about the size of Oregon's entire energy load. This updated analysis reflects permitting and interconnection delays, cost pressures and federal rollbacks of clean energy tax incentives. Also, regional load forecasts will continue to increase due to higher-than-expected air conditioning adoption, EVs, and data centers. In addition to identifying the capacity gap, the study also examined the effectiveness of different resource types at filling the gap. New resource additions in Oregon and Washington have been slow, and coal-fired power plant retirements add to the complexity by reducing firm capacity. Wind and solar make up most of the new capacity in the PNW, and while valuable, provide little dependable capacity. Today, natural gas is the only dispatchable resource that can be built in time, provide for firm fuel security, and keep the lights on during extended cold-weather reliability events. In the longer-term, nuclear, geothermal and other firm carbon-free resources will be essential.

The PNW's energy system is changing. Demand for electricity is growing, and electric utilities are feeling mounting pressure to add power resources to keep the grid reliable. At the same time, natural gas and electricity systems, both critical to regional reliability, are increasingly interdependent. As these changes accelerate, the region must take coordinated, realistic steps to ensure energy RA and system resilience. As revealed in the Council's 2029 power assessment, the region is dangerously close to experiencing significant energy supply disruptions, which could lead to blackouts during peak demand events. Energy emergencies during extreme weather events are increasing in frequency and threatening reliability. The multiday cold snap in January 2024 is the most recent in a string of examples. Meeting peak demand during the cold snap required execution of emergency operations and procedures, careful coordination between natural gas and electricity providers, customer response to energy conservation requests and significant electricity imports from the Desert Southwest and the Rockies. The system held, but with limited margin. This past 2024-25 winter, the region's electricity demand nearly reached an all-time peak. Multiday cold snaps and rising peak demand are a threat to reliability.

Electricity demand in the Northwest is projected to grow by over 30% in the next decade. The Pacific Northwest Utilities Conference Committee (PNUCC) estimates an increase of 7,800 aMW, equivalent to adding enough power to supply seven new cities the size of Seattle. Demand for power during the hottest and coldest times of the year is also rising. Utilities may need as much as 30 GW of new nameplate capacity over the next 10 years to meet peak demand and move toward a cleaner energy future. Across the broader Western Interconnection, more than 170 GW of new generation are planned. The pace and scale of resource deployment required is unprecedented. Execution risk is real. The WECC looks at risks to the power system throughout the Western Interconnection. WECC warns if demand grows as expected and industry experiences delays and cancellations in building added resources over the next decade, the West will face potentially severe RA challenges. According to WECC, only 53% of generation additions planned for 2023 were completed as scheduled. If the resource build-out over the next 10 years mimics the last five years, then by 2034, the West will have hundreds of hours each year when demand is at risk. Factors such as siting delays, interconnection queue congestion, supply chain issues and financing challenges contribute to significant uncertainty.

Natural gas will continue to play a critical role in this transition, as called out in the recent E3 analysis mentioned earlier. It remains the region's second largest source of electricity after hydropower and is essential for meeting winter peak demand. Both the gas and electricity systems are close to using the full capacity available. If either system fails during high demand, there could be energy shortages. These systems depend on each other more than ever and need to be planned more carefully together to reduce reliability risks. Given this outlook, enhanced coordination between gas and electric systems is essential. Siloed planning increases risk and hinders the region's ability to make informed, cost-effective investment decisions. Improving transparency, aligning planning horizons and identifying shared infrastructure constraints will be key steps toward more resilient outcomes. Policymakers, regulators, utilities and infrastructure developers must work together to address both near-term and long-term reliability needs. This includes supporting critical investments in gas and electricity infrastructure. The region needs clear, consistent signals and collaborative frameworks to manage this transition effectively and affordably. The path forward is complex but navigable.

Individual utilities within the Northwest are facing a wide range of future resource needs and are preparing for those needs in their IRPs and Integrated System Plans (ISPs). The District analyzed its own RA in the preparation of this 2025 IRP.

In addition to the region-wide RA assessments mentioned above, the Western Power Pool (WPP) is currently working to implement a robust capacity RA program, known as the Western Resource Adequacy Program (WRAP). In February 2023, the Federal Energy Regulatory Commission (FERC) approved the tariff for the WRAP, clearing the way for full implementation of the region's first West-wide reliability program. The WRAP is a voluntary program, but once an entity commits to joining the program, it must follow the FERC tariff and commit to a binding season by January 2026.

Phase 3A of the WRAP began October 2021 and went through the summer 2023 season. It included the beginning of implementation and the forward showing for the first four non-binding seasons. Phase 3B began in April 2023 and focuses on the transition to a binding RA program set to begin in the summer of 2027 (with a probationary period until summer 2028). Participants will face penalties for noncompliance. The WPP Board has approved several business practice manuals that detail the operational framework of the WRAP. This includes guidelines on how participants will collaborate and share resources to enhance reliability. The WRAP is actively developing metrics for assessing RA for upcoming summer 2026 and winter (2026-2027) seasons. This data will help in planning and ensuring that there is sufficient capacity to meet demand. The program emphasizes collaboration amongst participants to improve overall reliability while minimizing resource use. This approach aims to leverage operational efficiencies and resource sharing. Participant data submission is required so that the Program Operator, the Southwest Power Pool (SPP), can run models to deliver RA metrics (planning reserve margin, qualifying capacity contribution (QCC), effective load carrying capability, etc.) back to participants. As such, individual entities must have each of its resources qualified and quantified with a QCC value, while gaining an understanding of their individual RA positions in the process. Utilities must forecast demand seven months in advance and demonstrate they have secured sufficient supply and transmission capacity, including a planning reserve margin set by the Program Operator, to meet their demand. Utilities can request capacity from others in the region when facing unforeseen deficits, provided they meet the WRAP criteria. Below summarizes some key elements of the program:

- Forecast Horizon: Looks out 1–4 years to ensure adequate resource capability is available to meet customer demand.
- Coordination: Enables utilities across the WPP footprint — each with different local RA methods — to forecast and manage adequacy in a coordinated regional manner.
- Local Autonomy: Respects each utility's rights and operational characteristics, including those of transmission service providers and Balancing Authorities (BAs).
- Voluntary Commitment: Joining the WRAP is voluntary, however, once a utility opts in, it is contractually bound to meet requirements for the binding season between 2026 and 2028.
- Standardized Measures:
    - Common peak load standards and measurement methodologies.
    - Uniform metrics for resource contributions to adequacy.
- Regional Allocation & Diversity:
    - Defined approach for allocating the regional adequacy requirement.
    - Mechanisms to leverage regional diversity and unlock investment savings.

The District has formally committed to the WRAP and is actively participating in Phase 3B implementation, collaborating with other members to enhance reliability and operational efficiency through shared resources and standardized processes.

Demand Response

The Council's Demand Response Advisory Committee (DRAC) supported the Council in development of updated DR supply curves for the Eighth Power Plan.

In June 2017, the DRAC adopted a definition for DR:

"Demand response is a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties."

The Council recommends utilities examine two DR products: residential time-of-use (TOU) rates and demand voltage regulation (DVR) to offset the electric system needs during peaking and ramping periods and to reduce emissions. A given utility's time of need may differ from the regions, but these products are likely still part of a cost-effective strategy. The Council's assessment shows about 520 MWs of DVR and 200 MWs of TOU available by 2027. With unique assets at each utility and across the region, the most strategically valuable program offerings may vary, so there may be other similar products that are also frequently deployable, low cost, and with minimal customer impact that could provide similar benefits. Those should also be considered in utility planning. In addition to benefits on the power system side, DR could be used to relieve transmission constraints and defer transmission and distribution system upgrades. The Council will track regional DR implementation to assess progress, recognizing that the lack of a regionwide economic signal for capacity makes adopting DR challenging. Based on the scenario analysis, the Council recommends the Bonneville Power Administration (BPA) and regional utilities consider the value of adequacy, capacity, and emissions reduction when evaluating DR in IRPs and other analyses. As organizations and utilities develop DR capability, they should do so by leveraging existing energy efficiency infrastructure and considering them together as part of an integrated demand-side management approach to optimize delivery of both resources holistically and equitably. The Council recognizes, however, that their DR target recommendation depends, in part, on investments made by utilities to install advanced metering infrastructure (AMI) across their service territories. While many utilities have installed advanced meters and the back-office architecture necessary to implement TOU rate designs, those that have not may need financial support to accomplish it. Therefore, the Council encourages BPA, regulators, and utility leadership to support investment in AMI architecture as a tool to encourage the most efficient use of grid resources.

In addition to these resources, the Council recommends BPA and the regional utilities, along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools, such as capacity and reserves products, that contribute to system accessibility and efficiency. The Council would expect to see significant cost savings from greater regional collaboration to drive more efficiency into the system operations. A more aggressive examination would expand such a cost and benefit analysis to include the development of an organized or independently operated electricity market across the region (see Organized Markets section). While any market design should protect the region's investments in its existing generation and transmission system, there may be reliability and cost benefits from the central dispatch of resources across a broad footprint. The Council also recommend the region concurrently work toward more collaborative understanding of the impacts of changes in market liquidity outside the region and the implications, especially for peaking and ramping periods, and pursue additional collaborative approaches to mitigate identified risks.

The need for DR arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices change very little in the short-term. The result of this mismatch is that consumers do not have the information that might encourage them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage DR are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market. The Council evaluated DR products that impact residential, industrial, commercial, and agricultural sectors, as well as the utility distribution system. DR products evaluated include utility-controllable and price-responsive options across the sectors. Utility-controllable products give the utility the ability to change the operation of end-use equipment to reduce peak. Price-responsive products give the end-use customer the ability to choose how to modify loads based on a price signal from the utility. In general, price-responsive products are less expensive because equipment needs are lower, but the utility has less control over the resulting impact.

In the Eighth Power Plan, in total, 23 DR products were incorporated into DR supply curves. The Council estimates about 3,721 MWs of summer load reduction potential and 2,761 MWs of winter load reduction potential. This potential was focused on reducing load during times of system need, though it is recognized that DR could also be used to increase loads during low or negative prices to balance with supply. The potential is based on an estimated impact per participant and the potential number of participants based on eligibility (e.g., customers need to have air conditioning to participate in an air conditioning control program), assumptions of willingness to participate, and participation rates for any given DR event (a customer may opt out of any given event). Products range in cost from $5 per kilowatt-year up to $250 per kilowatt-year (2016 dollars). These costs include setup, operation and maintenance, equipment, marketing, and incentives. The Council also incorporates benefits (or negative costs), such as deferring buildout of the transmission and distribution system by reducing electricity use during times of the highest electricity need.

The Council is currently working on DR to be included in the Ninth Power Plan. In early 2025, they sought comments on residential and non-residential products and incorporated some changes to input assumptions into their work. The Council notes that numbers are intended to represent a proxy DR resource for the region to the best extent possible, with the understanding that certain actual cost and impact parameters may vary significantly from utility to utility. The Ninth Power Plan is expected to be finalized in late 2026.

CETA requires utilities to develop a DR potential assessment (DRPA). The District developed a DRPA in 2025 that is discussed fully in the Demand Response section.

Regulatory & State Statutory Requirements

In addition to the integrated resource planning requirements of RCW 19.280, the District is directly affected by other regulatory and legislative actions that relate to resource planning. Those of greatest focus for Chelan PUD and the region are discussed below. These requirements were specifically evaluated in the preparation and adoption of this IRP.

Renewable Portfolio Standard (RPS)

The Washington State Renewable Performance Standard (RPS), RCW 19.285, The Energy Independence Act, requires utilities with a retail load of more than 25,000 customers to use eligible renewable resources (excluding most existing hydroelectric power) or acquire equivalent renewable energy credits (REC), or a combination of both, to have met 3% of retail load by January 1, 2012, 9% by January 1, 2016 and 15% by January 1, 2020. Under the law, the District can count efficiency gains made after March 31, 1999 at its existing hydropower projects toward meeting the RPS. Additionally, the District's entire share of the Nine Canyon Wind Project qualifies as an eligible renewable resource for meeting the requirement of the RPS. The law also required that by January 1, 2010, utilities evaluate conservation resources, submit their initial 10-year conservation plans and begin pursuing all conservation that is cost-effective, reliable and feasible. This 2025 IRP includes updates to the evaluations and required reporting under both the renewable and conservation portions of the RPS which are discussed further below.

This legislation and other regional efforts have increased the amount of renewable energy in the wholesale power markets. The new Washington CETA adds additional utility requirements surrounding use of renewable and nonemitting resources. The effect of increased wind capacity and overgeneration events in the region is discussed in the Resources section.

Clean Energy Transformation Act (CETA)

In May 2019, The Washington Clean Energy Transformation Act (CETA) was signed into law, which added requirements that relate to resource planning.

Key sections of CETA that may impact a utility's resource portfolio include: 1) section 3—elimination of coal-fired resources from a utility's allocation of electricity by the end of 2025; 2) section 4— a greenhouse gas (GHG) neutral policy requiring a utility to use electricity from renewable and nonemitting resources in an amount equal to 100% of its retail electric load over multiyear compliance periods starting in 2030 (up to 20% may be met with alternative compliance options); and 3) section 5— a policy that electricity from renewable and nonemitting resources supply 100% of all sales of electricity to Washington retail customers by 2045. Unlike the Washington RPS, CETA considers all existing hydroelectric resources to be renewable. In 2025, HB 1329 amended the previous restriction that prevented utilities from using power from coal-fired power plants after 2025 to serve Washington customers, with a limited exception for short-term wholesale power transactions. HB 1329 changed that exception to allow contracts up to three months in length. A contract length of up to six months is allowed if the power will be used to meet WRAP requirements.

Among other requirements, CETA also requires utilities to include 10-year clean energy actions plans (CEAP) in their IRPs for implementing sections 3 through 5 of CETA and requires utilities to consider the social cost of GHG emissions when developing their IRPs and CEAPs (see 10-year Clean Energy Action Plan (CEAP) section).

During the development of the 2021 IRP, the District concurrently developed its first Clean Energy Implementation Plan (CEIP) as required under CETA. Both planning processes utilized the same resource mix and retail customer load assumptions. A CEIP is intended to identify a utility's plans over the following four years to meet CETA's 2030 GHG neutral standard and 2045 100% clean electricity standard. The CEIP included 1) an interim target for the percentage of retail load to be served using renewable and nonemitting resources during 2022-2025; 2) specific targets for energy efficiency, DR and renewable energy for 2022-2025; 3) specific actions Chelan PUD would take between 2022-2025 to reach those targets; 4) identification of highly impacted communities and vulnerable populations; 5) a report of the forecasted distribution of energy and nonenergy costs and benefits for the District's portfolio of specific actions; 6) a description of how Chelan PUD intended to reduce risks to highly impacted communities and vulnerable populations associated with the transition to clean energy. The District is concurrently developing its next CEIP. It includes the aforementioned sections focused on the 2026-2029 timeframe and discussion on energy and nonenergy benefits and the avoidance and reductions of burdens to vulnerable populations and highly impacted communities, including long-term and short-term public health and environmental benefits, costs, risks and energy security and risk. It will also be completed concurrent with this IRP.

The Climate Commitment Act (CCA)

Additional climate legislation became law in Washington state in May 2021. The Climate Commitment Act (CCA) (Senate Bill (SB) 5126) established a "cap and invest" program that sets a limit on the amount of GHG that can be emitted in and imported into Washington and then auctions off allowances for companies and facilities that emit GHG until that cap is reached. Over time, the cap will be reduced, allowing total emissions to fall to match the GHG emission limits set in state law. Those limits were set in 2020 by the Washington legislature and are as follows: 2020 — reduce to 1990 levels, 2030 — 45% below 1990 levels, 2040 — 70% below 1990 levels and 2050 — 95% below 1990 levels and achieve net zero emissions. Auction proceeds go toward investing in climate resiliency, reducing pollution in disproportionately affected communities and expanding clean transportation.

The program, launched in 2023, is designed to financially encourage companies to reduce emissions by making allowances increasingly expensive. Each allowance represents 1 metric ton of carbon dioxide (CO2). Each year, the state issues fewer allowances and raises the minimum bid price. Financial penalties for companies that don't cover their emissions with allowances also increase. Auctions are open to companies that must cover their emissions and other registered bidders, including traders hoping to sell allowances on the secondary market. Electric and natural gas utilities are given free allowances based on reported and forecast emissions. Utilities can bid if they need more than their no-cost allotment.

For each auction, entities submit bids specifying how many allowances they want to buy and the price they'll pay for each one. The state's Department of Ecology (DOE) arranges the bids by price from highest to lowest and tallies the number of allowances in each bid until all units are sold. The price of the last allowance sold sets the price for all winning bids. When the program's soft price cap is broken, the supplemental auctions of reserve allowances are open only to companies that must cover their emissions.

In 2024, Washington initiative 2117 sought to repeal the CCA and prevent future carbon tax or cap-and-invest programs. Voters rejected the initiative with 62% voting against it. The initiative sunk allowances prices during 2024 as many speculated that it would pass, and the program would be repealed.

Prices rebounded robustly in 2025 back to 2023 levels. The second auction of 2025 on June 4th resulted in 8.75 million allowances sold, generating an estimated $322 million, according to the Washington State DOE. As of mid-2025, year-to-date revenue had reached $550 million. Since its inception in early 2023, the cap-and-invest program has generated $3.2 billion in revenue.

The allowance price in the June 4th auction settled at $58.51. In combination with the price of future vintage allowances, which are those brought into this year's auction that are intended for use in future years, the average price came out to $51.22. CCA funds are going to a wide range of programs, including small grants for e-bikes and heat pumps as well as hundreds of millions in funding for charging infrastructure, electrifying ferries, conservation work and wildfire mitigation.

There has been upward pressure on power prices in the West since the inception of the CCA due to the cost of covering emissions for energy producers that rely on fossil fuels. Proponents of the CCA believe its long-term effects could stabilize or reduce prices as Washington invests in cleaner energy solutions.

The program is evolving. DOE is working to link its cap-and-invest program with the already linked markets of California and Quebec. Officials say linkage could further reduce emissions and improve long-term program sustainability. DOE is also working to address the treatment of certain industries, like manufacturing facilities, that could be more difficult to decarbonize. As of now, these emissions-intensive, trade-exposed industries are given most of their allowances at no cost until 2034. DOE implemented a stakeholder process and is developing recommendations for the legislature to ensure these industries reduce their emissions under the cap prescribed by the cap-and-invest program.

Chelan PUD received 227,378 allowances for 2024 and 218,829 allowances for 2025. The District does not own or operate emitting generation in Washington state, however, it does import a relatively small sum of energy from BPA that is deemed to have emissions. The District will first manage its allowances for compliance purposes and then for the benefit of rate payers (with priority going to low-income customers).

Zero Emissions Vehicle (ZEV) Standard

In 2020, SB 5811, the Zero Emissions Vehicle (ZEV) standard, was signed into law. The ZEV standard requires automakers to deliver a certain number of zero emission vehicles each year and earn credits based on the number of vehicles produced and delivered for sale. The ZEV standard is discussed in detail in the EV portion of the Load Forecast section.

Clean Fuel Standard

In May 2021, HB 1091, the Clean Fuel Standard, became law. It directed the DOE to develop a low carbon fuel standard for the state. The overall goal was to reduce the GHG emissions attributable to each unit of fuel to 20% below 2017 levels by 2038.

On November 28, 2022, the DOE adopted a new rule, Chapter 173-424 Washington Administrative Code (WAC), Clean Fuels Program Rule and updated Chapter 173-455 WAC, Air Quality Fee Rule. This new rule:

- Establishes carbon intensity standards for transportation fuels used in Washington.
- Assigns compliance obligations to fuels with carbon intensities that exceed the standard.
- Establishes compliance methods including assigning credits to fuels that have carbon intensities below the standard.

In 2025, HB 1409 became law, enhancing the state's Clean Fuel Standard. It tightens carbon intensity reduction requirements for transportation fuels, aiming for a 45% reduction by 2038. It includes provisions for increased investments in EV infrastructure, such as charging stations, and incentives for utilities to support the transitions to electric mobility. The legislation promotes the use of sustainable biofuels and other low-carbon fuel alternatives, aiming to create a cleaner transportation sector. The bill emphasizes centering equity in the clean energy transition, ensuring that frontline communities and small businesses are included in the benefits of the program.

Reduction of Hydrofluorocarbons (HFC)

In May 2025, HB 1462 was signed into law. The law aims to phase out the use of hydrofluorocarbons (HFC), which are potent GHGs commonly used in refrigeration and air conditioning systems. The legislation is part of Washington's broader efforts to combat climate change and reduce overall GHG emissions. The law is expected to contribute significantly to reducing climate pollution and promoting the reclamation and reuse of refrigerant gases. This legislation aligns with national and global efforts to phase down HFCs, as part of commitments under international agreements aimed at addressing climate change.

Reforming Building Codes

In April 2025, HB 1183 was signed into law. The law aims to streamline building codes to facilitate more efficient construction processes, address regulatory barriers that may hinder development, particularly in housing, and promote sustainable building practices and potentially enhance energy efficiency standards. The reform is expected to impact local governments, developers and builders by simplifying compliance with building regulations. It may also contribute to addressing housing shortages by making it easier to develop new residential projects.

Fusion Energy Development

In May 2025, primarily through HB 1018, Washington State passed significant legislation regarding fusion energy. The law enables fusion energy projects to apply for permits through the Energy Facility Site Evaluation Council (EFSEC), which simplifies the approval process and aligns it with existing renewable energy projects. The legislation is designed to advance Washington's clean energy objectives, reinforcing the state's commitment to reducing GHG emissions and promoting sustainable energy sources. The bill received unanimous support in the Senate, indicating a strong political consensus on the importance of developing fusion energy as a viable alternative to fossil fuels. The bill emphasizes the need for environmental safeguards and aims to ensure that the development of fusion energy facilities minimizes adverse effects on the environmental and local communities. By facilitating the development of fusion energy, the state aims to position itself as a leader in the clean energy sector, potentially attracting investments and creating jobs in the emerging fusion industry. There are provisions for public processes to ensure transparency and community involvement in the siting and operation of fusion energy facilities.

The legislation is particularly relevant as it coincides with plans by Helion One, LLC, a fusion energy company, to build a fusion power plant in Malaga, with expectations to generate 50 MWs of power by 2028. The Board of Chelan PUD has approved a ground lease with Helion for property near the Rock Island hydroelectric project on which to build their fusion energy plant. Helion obtained a conditional use permit to build their fusion generator building in October 2025.

Community Solar Expansion Program

Beginning in 2022 through mid-2033 (2SHB 1814), the Washington State University Extension Energy Program (WSU Energy Program) was authorized to administer and implement a new community solar incentive program that provides up to $20 million in payments for the purpose of providing direct benefits to low-income subscribers, low-income service provider subscribers, and tribal and public agency subscribers. A community solar project is a solar energy system that: (1) has a direct current nameplate capacity that is more than 12 kilowatts (kW) and no greater than 199 kW; (2) has at least two low-income subscribers or one low-income service provider; and (3) meets the eligibility requirements of the program. A community solar project may include a storage system. An administrator of an eligible community solar project may apply to the WSU Energy Program to receive a precertification for the project. An administrator may be a utility, nonprofit, tribal housing authority, or other local housing authority. If the WSU Energy Program approves the precertification, within two years the project must be completed, and the administrator must apply for certification. If the WSU Energy Program then certifies a project, the utility serving the site of a community solar project is authorized to remit a one-time low-income community solar incentive payment to the administrator. The administrator accepts the payment on behalf of, and for the purpose of providing direct benefits to, the project's qualifying subscribers. For tribal and public agencies, only that portion of their subscription to a community solar project that demonstrates benefits to low-income beneficiaries is considered qualified. A utility's participation in the program is voluntary.

National Climate and Energy Policy and Legislation

Federal GHG regulation of power plants under Clean Air Act Section 111 has been redefined over three Presidential administrations, with each redefining the "best system of emission reduction". In 2017, the Environmental Protection Agency (EPA) under the first Trump Administration, proposed to repeal of the Obama-era Clean Power Plan (CPP). The CPP was based on heat-rate improvements at coal plants, generation shifting from coal to existing natural gas units, and renewable energy and demand-side efficiency to displace fossil generation.

Repeal of the CPP was finalized in July 2019 and replaced with the Affordable Clean Energy (ACE) Rule. The ACE confined best system of emission reduction to on-site heat-rate improvements at existing coal units. The D.C. Circuit vacated ACE in January 2021, remanding it to EPA for failure to adequately justify CPP repeal and for narrowing the best system of reduction scope.

In June 2022, the U.S. Supreme Court's decision in West Virginia v. EPA limited EPA's authority to mandate generation shifting as the best system of reduction scope. Specifically, the U.S. Supreme Court held that EPA lacked authority to impose generation-shifting caps under 111(d) absent clear congressional authorization.

In May 2024, EPA under the Biden Administration finalized Carbon Pollution Standards to set GHG standards for new, modified, reconstructed, and existing fossil-fired generating units with compliance largely relying on carbon capture and storage for certain new gas units and long-running existing coal units, with deadlines starting 2032. The rule triggered immediate litigation from industry and more than 20 states.

In February 2025, the D.C. Circuit held the cases in abeyance at EPA's request as the agency undertook a review. On June 11, 2025, EPA proposed complete repeal of all GHG standards for fossil-fired generation units. The agency took public comment and is working toward finalizing the proposal.

In a related action, July 29, 2025, the EPA formally proposed repeal of the 2009 endangerment finding that is the legal underpinning of GHG emission limits on power plants, oil and natural gas facilities, and motor vehicles. The EPA has also proposed eliminating tailpipe GHG emissions limits for motor vehicles and engines. If finalized, the proposal is will face legal challenges.

After taking office in January 2021, President Joe Biden effectively halted construction of the Keystone XL Pipeline (Phase 4) by revoking a permit needed for a US stretch of the 1200-mile project. The project was proposed in 2008 to bring oil from Canada's western tar sands to US refiners. In June 2021, project owner, Canadian company TC Energy, cancelled the project. The pipeline was expected to carry 830,000 barrels per day of Alberta oil sands crude to Nebraska, but the project was delayed for the past 12 years due to opposition from U.S. landowners, Native American tribes, and environmentalists. Opposition has expressed concern about spills and fossil fuels contributing to climate change. TC Energy said it would continue to coordinate with regulators, stakeholders and Indigenous groups to meet its environmental and regulatory commitments and ensure a safe termination of and exit from the project. "We remain disappointed and frustrated with the circumstances surrounding the Keystone XL project, including the cancellation of the presidential permit for the pipeline's border crossing," the Alberta premier, Jason Kenney, said in a statement at the time.

In early 2025, President Trump indicated that reinstating the project is a priority on his agenda. He believes that bringing the pipeline back will reinforce his pro-oil stance. There is currently no committed company to take the project forward. New permits and approvals would be required and parts of the pipeline that were already constructed have been removed, complicating potential reconstruction efforts. There have been new proposals for alternative pipelines, such as the "Big Sky Pipeline System," which aim to transport Canadian oil to the U.S. However, these plans are still in the early stages and face their own set of challenges.

The Inflation Reduction Act (IRA) of 2022 was the largest legislative action in climate change mitigation in U.S. history. The Act set out provisions to invest in increasing renewable energy and electrifying areas of the U.S. economy. The bill, passing by a 51-50 vote in the Senate, created and expanded tax incentives, grants, fees and financing programs to support clean energy deployment. According to several independent analyses, the law was projected to reduce 2030 U.S. GHG emissions to 40% below 2005 levels compared to 24% without the bill. According to the Congressional Budget Office (CBO), it would invest $391 billion in provisions relating to energy security and climate change. This included $270 billion in tax incentives and $27 billion for a green bank created by amending the Clean Air Act. However, other forecasts differed from the CBO's report. A report by Credit Suisse projected that the total climate spending in the bill would be $800 billion, and Goldman Sachs predicted a total of $1.2 trillion. Of particular interest to consumer-owned utilities, the IRA made tax-exempt entities eligible for elective payments for the production and investment tax credits, among others. The bill also modified the existing ITC and PTC and established tech-neutral tax credits for projects placed in service after 2024.

The "One Big Beautiful Bill" (OBBB), signed into law on July 4, 2025, introduced significant changes to the IRA as well as broader tax policy (also see Integrating Renewable Resources and Overgeneration Events section). The OBBB accelerated the phase-out period for solar and wind tax credits, impacting the financial viability of projects that were previously planned under the IRA's original provisions. Hydropower's eligibility timeline for the credits was preserved in the OBBB. However, the bill imposes stricter compliance requirements for entities seeking tax credits, particularly relating to "foreign entities of concern" to ensure that tax benefits are not exploited by foreign interests. The OBBB also rescinds some of the funding allocated for clean energy initiatives under the IRA, which may limit the scope and scale of future projects.

The OBBB reinstates immediate expensing for domestic research and development expenses, allowing businesses to deduct those costs in the year they are incurred, which could benefit clean energy technology development. It also eliminates the phase-out of bonus depreciation for certain qualified property, allowing businesses to continue benefiting from the accelerated depreciation. Importantly for consumer-owned utilities, the OBBB preserves tax exemptions for municipal bonds. The changes introduced by the OBBB significantly alter the landscape for clean energy investments and initiatives originally outlined in the IRA. While the OBBB aims to stimulate economic growth and simplify tax structures, the reductions in funding and stricter compliance requirements may pose challenges for the clean energy sector. The long-term effects on energy transition efforts and environmental goals will depend on how these changes are implemented and their impact on project financing and development.

Since January 2025, the Trump Administration's actions related to energy efficiency have centered on deregulation. In response to Executive Order 14154 (Unleashing American Energy), the Department of Energy has postponed or reconsidered specific appliance and equipment actions across dozens of product categories (e.g., central AC/heat pump test procedures, walk-in coolers/freezers, gas instantaneous water heaters), framing them as consumer-choice and cost measures. EPA also moved to restructure the voluntary Energy Star program.

Primarily driven by EO 14154, all federal agencies have been directed to review their actions that potentially burden the development of domestic energy resources, with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources. For example, the Department of Interior published emergency permitting procedures on April 23, 2025, relying on National Environmental Policy Act (NEPA) "alternative arrangements", Endangered Species Act Section 7 emergency consultation, and National Historic Preservation Act emergency provisions. Further, the Council on Environmental Quality removed its prior NEPA regulations via an interim final rule and federal agencies are revising or establishing their own NEPA review procedures. Meanwhile, the U.S. Fish and Wildlife Service and National Marine Fisheries Service are considering reforms to their Endangered Species Act regulations, and EPA is revising its Section 401 Clean Water Act regulations.

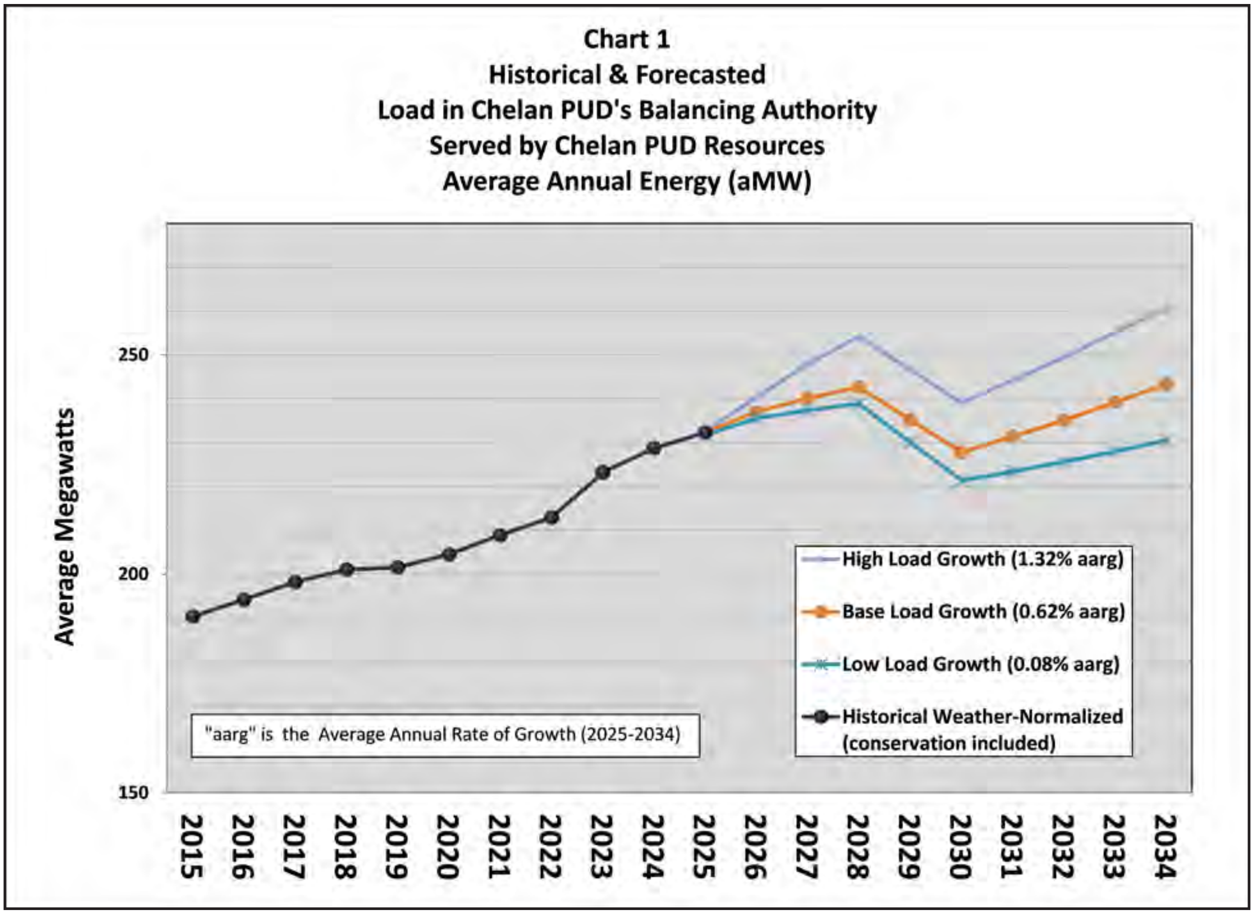
Finally, numerous energy and permitting reform bills have been introduced in the 119th Congress to align with the Trump Administration's regulatory reform agenda. Some of these address transmission, Endangered Species Act procedures and definitions, scope of the Clean Water Act, hydropower licensing, NEPA reviews and utility infrastructure for vegetation management.

Load Forecast

A new 10-year econometric retail load forecast was developed for this IRP's 2025-2034 planning period. These low, base and high forecasts are prior to planned conservation savings and DR. Future cost-effective conservation and DR are considered resources for integrated resource planning purposes, so they can be evaluated on the same basis as other resources.

Demographic trends and economic conditions remain the primary drivers used to arrive at the forecasted retail electricity sales by sector. The resulting forecasts are an integration of economic evaluations and inputs from the District's own customer service planning areas. Chelan PUD continues to actively work with the economic development community, businesses, building contractors and developers to gain insights into how economic development projects are moving forward in the near-term and future.

Total annual projected megawatt-hours through the planning period were forecasted on an annual incremental basis by sector, including system losses at 3.5% of load, using 2024 weather-normalized loads as the starting point. **The low, base, and high average annual composite retail energy sales forecast growth rates, including system losses, otherwise known as the forecasted annual energy load growth rates, are 0.08%, 0.62%, and 1.32%, respectively.** In the 2023 IRP progress report, all forecasted Large Loads (see Sector Energy Sales below) were included in the total District load forecast. Large Loads are now being forecasted separately from native District load to provide more historical context and because the District has implemented a new framework for serving Large Loads as discussed fully in the Hedging Policy section. The District is not obligated to serve Large Loads from its resources. The term native load is used to describe Chelan County retail loads served by Chelan PUD resources and the forecasted growth of these loads. The low, base and high native District load forecasts have decreased from the 2023 IRP progress report. The weather-normalized average annual rate of growth at the District (before the effects of cumulative conservation) was approximately 2.2% for the 10-year period from 2015-2024. The net of cumulative conservation growth percentage was approximately 2.0% for the same 10-year period. This historical net of cumulative conservation growth average has increased since 2023. This is primarily due to a Large Load that began being served by District resources in 2019 (with a 10-year contract). While this Large Load, residential loads, cryptocurrency processing loads, and electric vehicle (EV) loads have increased during the last 10 years, increased conservation achievements that began in earnest in 2010 continue to mitigate load growth. The three energy forecasts for load served by Chelan PUD resources for 2025-

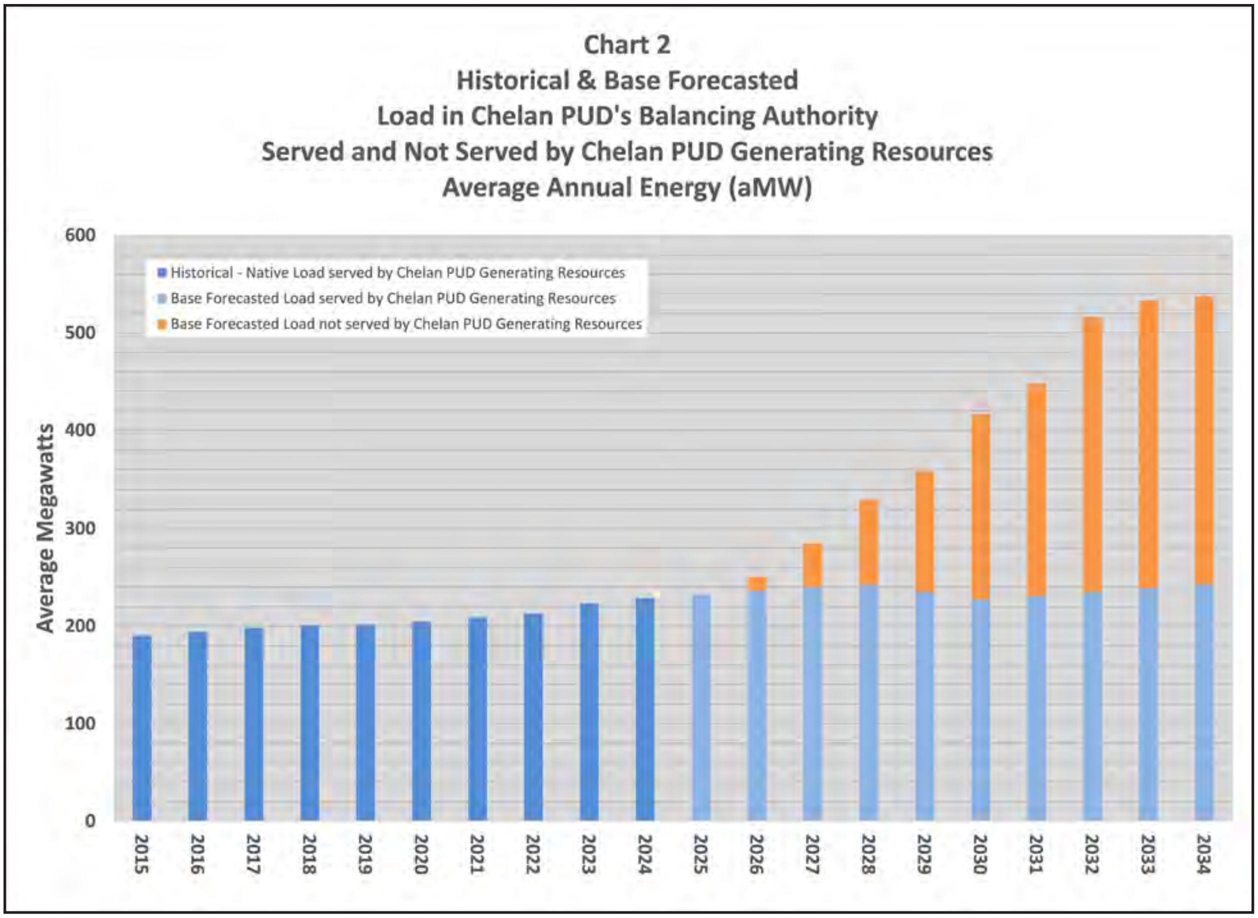


2034 as well as the actual weather-normalized energy load for 2014-2024 are presented in **Chart 1**. The base forecasts for load served and not served by Chelan PUD resources for 2025-2034 is presented in **Chart 2**. In preparation for the NWPCC's Ninth Power Plan, the Council released a load forecast in April 2025. The forecast predicts energy demand will increase anywhere from 1.8% to 3.1% annually from 2027 to 2046. Similarly, peak demand growth ranges from 1.9% to 3.0% per year over that timeframe. The growth is driven largely by data centers, tech fabrication and vehicle electrification. Like the District's forecasted annual energy load growth rates, these forecasts do not include any new conservation measures or DR programs beyond what is already in place.

Sector Energy Sales

Demographic and economic data used for the load forecast was updated. The Washington State Office of Financial Management (OFM) released its latest Chelan County population projections out through 2050 in 2022. The growth rates were applied to the OFM actual population estimate for Chelan County for 2024 to arrive at updated population estimates through the planning period. Actual Chelan County population data from the OFM (through 2024), along with actual per capita income data from the U.S. Bureau of Economic Analysis and actual sales revenue data from the Washington State Department of Revenue were used to update the various sector regression analyses.

After various regression studies, residential load was projected based upon population only based on statistical significance. The



results were adjusted upward some based upon known and expected changes coming to the sector. The three average annual growth rates for the residential sector are forecasted at 0.54%, 1.20%, and 1.57%. The low is up slightly while the base and high are down slightly since 2023. The District has been seeing some moderate residential growth in the last few years. There are still several large new residential developments underway throughout the Chelan county and others in the application process. It is likely not all of these will come to fruition, and it is likely full build out of these developments will take 10 years. It is important to note that Chelan PUD is infrastructure limited to serve power to the full build out of these developments. The District has already identified the need for new substation capacity along the Wenatchee foothills for new development and expects it will need to add a new substation, add capacity at existing substations or a combination of both. Additionally, the District continues to be on the lookout for changing end uses including changing federal standards (i.e., more efficient appliances, lighting, etc.). It is expected that these changing end uses will continue to be ongoing and take place outside of the District's organized conservation programs. It also appears as though the District is experiencing higher occupancy of second homes and vacation rentals throughout more of the year than historically experienced for several years now. Remote work options and/or a desire to spend more time in Chelan County seems to have increased for non-full-time residents.

For this load forecast, the commercial sales forecast is also a function of population only based on statistical significance. The results were adjusted up just slightly in all cases due to known and expected changes coming to the sector. The final average annual growth rates for the commercial sector are forecasted at 0.89%, 1.09%, and 1.58%. Since 2023, all cases have decreased with some continued recovery expected in the sector after a few years of decreases. As with residential load, the District expects ongoing efficiency improvements, particularly in commercial lighting, HVAC, and water heating, to continue reducing per customer energy intensity over time. In addition, the District is leveraging 15-minute load profile data from its AMI system to analyze commercial load patterns, reduce unnecessary consumption during unoccupied periods, and inform future demand-side management and resource planning efforts.

Industrial loads can be very large and can come and go very quickly depending upon the industry, the local economy and much broader regional, national and global economic conditions. Industrial loads have been historically quite stable with low growth rates in Chelan County. These loads fluctuate year to year, depending upon industry specific needs, with agricultural crop variations creating the greatest swings. Industrial sales were again manually estimated based upon ranges of use per customer amounts and ranges of customer counts with no known, but some potential smaller industrial load additions in the high class. The average annual growth rates for the industrial sector are forecasted at 1.21%, 1.21% and 1.70%. These have all increased slightly since 2023, based on a lower base due to the reasons previously discussed.

Other load categories include High Density Loads (HDL) (Rate Schedule 35), Data Centers & Similar Loads (Rate Schedule 36) and Large Loads (> 5 aMW) (Rate Schedule 4). HDLs are those loads with intense energy use — 250 kWh per square foot or more per year with average electrical loads up to 3 MWs at a single point of delivery, excluding Data Center & Similar Loads with specific characteristics. The District does not have any current customers under the HDL rate schedule. Data Center & Similar Loads applies to data centers and similar computing or data processing loads, regardless of the number of servers/processors, including those related to rack space rental, hosting services, cryptocurrency mining, blockchain, data processing, or other loads. In the last few years, most cryptocurrency operations of less than one aMW have curtailed energy use or shut down completely. The District's existing Large Load sector began ramping up in 2019 and is forecasted for further increase in the high load forecast through 2029 (contract expiration). Within this larger load grouping, the high load forecast includes the possibility of some smaller data processing load growth. The average annual growth rates for the Data Center & Similar Loads and existing Large Load combined are forecasted at -10.32%, -10.32% and -7.11% for the planning period due to the expiration of the Large Load power contract currently served by Chelan PUD resources. The low, base, and high cases were estimated considering existing approved applications, infrastructure timing limitations and general interest and economic conditions.

The aggregate of "other" energy sales (streetlights, interdepartmental use, frost protection and irrigation) growth projections remain at 0% for all three load cases. This sector was again manually projected based on ranges of use per customer and ranges of customer counts after looking at the subcomponents of this sector.

Based on a high-level assessment, the District forecasts the potential effects of distributed solar photovoltaic generation or other distributed energy resources on retail load in its service area to be negligible during the current planning period.

Peak Load Forecast

The peak load forecast was also updated to ensure the District has enough resources to meet peak demand, or the maximum one-hour average system peak load. The District's peak retail load occurs in the winter. The all-time high retail load peak occurred on Saturday, January 13, 2024. The peak of 580 MW was established when the temperature was approximately -12 degrees Fahrenheit. This occurred on a weekend morning when peak demands are typically less given lower business, school, and other commercial needs. At the time of this peak, distribution system staff estimated a 10 MW load loss in the Manson area, so the peak load would have been higher. Chelan PUD experienced its highest historical summer peak of 284 MW at approximately 111 degrees Fahrenheit on Tuesday, July 9, 2024.

The District's peak forecast is broken down by sector, and the expected load factor for each sector is applied to the annual energy forecast for that sector. The load factors are adjusted, as appropriate, to forecast the peak at varying temperatures. District staff believe this methodology provides more forecast accuracy, particularly if the total retail load shifts over time between the sectors. Most HDL, Data Center and many industrial and Large Loads are not very weather-sensitive, and therefore, do not add much additional peak load beyond their normal energy load. The new peak forecasts at average, or expected peak temperatures, resulted in average annual peak load growth rates in winter of between 0.4% and 1.5% (net of conservation) for the three energy growth forecasts. The weather-normalized winter peak growth rate over the last 10 years was approximately 2.20% (net of conservation).

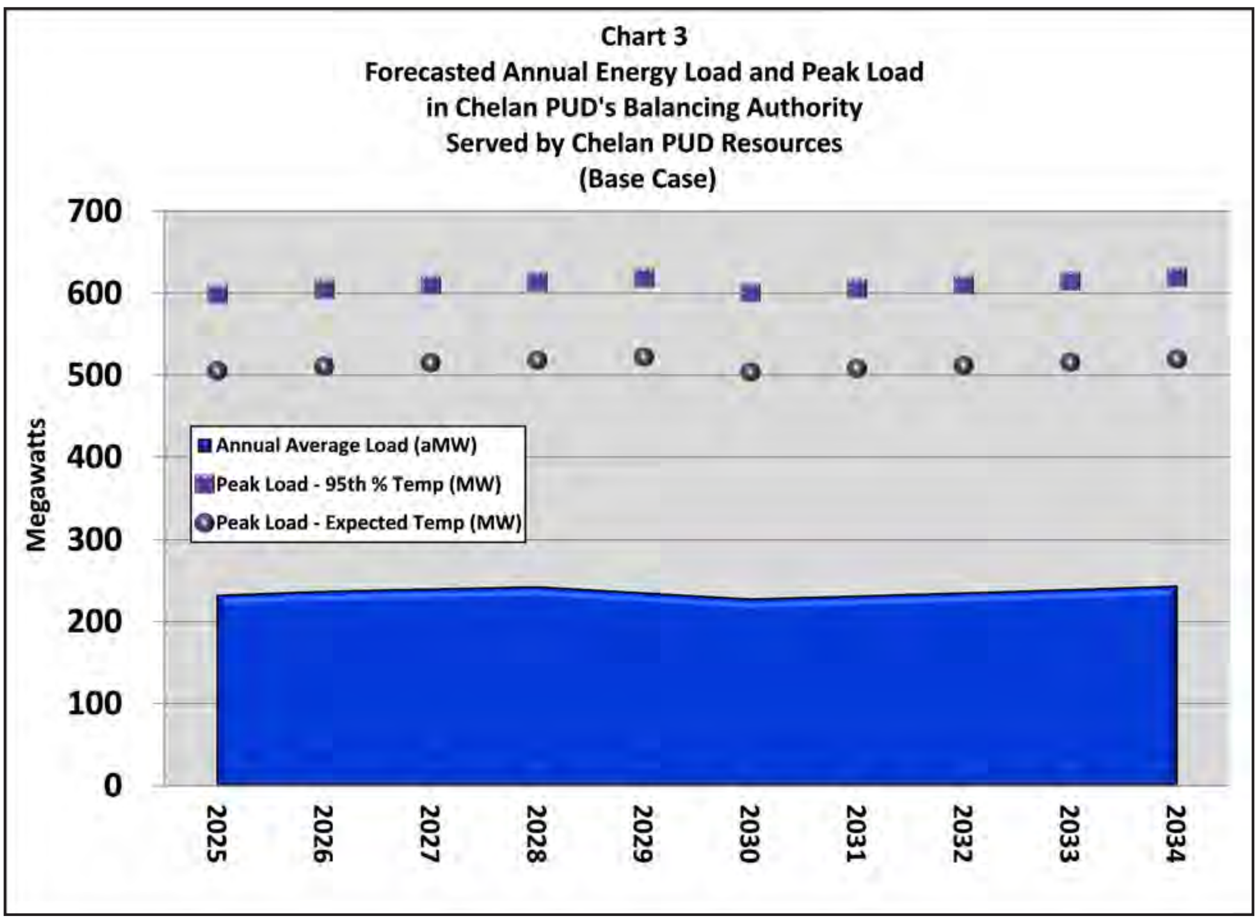


Chart 3 illustrates both the base case energy forecast for load served by Chelan PUD resources with the respective peak load forecast at both an average, or expected, peak temperature and at a 95th percentile extreme peak temperature for 2025-2034.

Electric Vehicles (EVs)

As mentioned in the Regulatory and State Statutory Requirements section, in December 2022, the Washington State DOE adopted two rules. The DOE is directed by the Motor Vehicle Emission Standards law (RCW 70A.30.010) to adopt California vehicle emission standards, including the zero-emission vehicle (ZEV) program, and maintain consistency with California's standards and Section 177 of the federal Clean Air Act (CCA).

Under the federal CCA, California held a unique position that allowed it to request waivers from the U.S. EPA to enforce stricter vehicle emissions standards and influence national markets. As of mid-2025, multiple challenges are ongoing regarding California's waivers, including U.S. Supreme Court cases and Congressional Review Act (CRA) resolutions, creating uncertainty in the regulatory environment for manufacturers and fleet operators.

Chapter 173-423 WAC, Clean Vehicles Program:

- Adopts California's rules:
    - Heavy-Duty Engine and Vehicle Omnibus rules and associated amendments — Starting in model year 2026, these rules require that new internal combustion engines for heavy-duty vehicles emit much lower quantities of nitrogen oxides, particulate matter, and GHG.
    - Advanced Clean Cars II — This rule will increase the percentage of passenger cars, light-duty trucks and medium-duty vehicles sold in Washington that are ZEVs. The sales mandate would take effect in model year 2026 and begin by requiring 35% of new passenger vehicles sales to be ZEVs. That percentage will increase 6-9% per year until ZEVs make up 100% of new sales starting in model year 2035. It will also require light and medium-duty vehicles to meet stronger emission standards.

On June 12, 2025, President Trump signed three CRA resolutions disapproving EPA's waivers that had allowed California to enforce its Advanced Clean Trucks, Advanced Clean Cars II, and Omnibus Low-Nox programs. The President framed the action as preserving consumer choice in vehicle purchases. The ACC II waiver had authorized California (and other states that choose to follow) to require a ramp to 100% zero-emission new-vehicle sales by 2035.

California's Governor Newsom quickly responded to Trump's action by announcing a lawsuit against the resolutions as well as a June 12 executive order doubling down on the state's efforts to transition away from fossil fuels. California's Attorney General Bonta and 10 other state attorneys general filed suit in federal court, seeking to have the resolutions invalidated. Other states filing suit are Colorado, Delaware, Massachusetts, New Jersey, New Mexico, New York, Oregon, Rhode Island, Vermont, and Washington.

Newsom's executive order builds on the lawsuit. It directs the California Air Resources Board (CARB) to create an Advanced Clean Cars III regulation that reduces GHG, criteria air pollutants and toxic emissions from passenger cars and light-duty trucks as well as medium and heavy-duty vehicles. The order also directs CARB to make publicly available lists of light-duty vehicle manufacturers that are continuing to certify to and follow the requirements of the Advanced Clean Cars II regulation, medium and heavy-duty vehicle manufacturers that are continuing to certify to and follow the requirements of the Advanced Clean Trucks regulation and the heavy-duty low NOx omnibus regulation or requirements agreed to as part of any agreements between such manufacturers and CARB and fleets that continue to follow the Zero Emission Airport Shuttle Bus regulation and that take early action in alignment with the Advanced Clean Fleets regulation. CARB, the California Energy Commission, the Governor's Office of Business and Economic Development, the California State Transportation Agency and the state's Department of Consumer Affairs were also directed to immediately assess additional actions to advance progress on light, medium and heavy-duty ZEV adoption in California, and within 60 calendar days to submit to the governor's office recommendations on development of the additional actions.

The District began taking a close look at potential future EV retail load in 2010. For these purposes, EVs include both plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV). As of the beginning of 2025, there were over 235,000 EV light vehicles registered in the state of Washington, approximately 1350 of which are in Chelan County. That was a greater than 90% increase from the spring of 2023. Several variables continue to have significant impact on the timing of EV adoption. These variables include gas and battery prices, regulations, battery range, charger speed and availability, supply of new EV models and general economic conditions amongst others.

Every year the world runs more and more on batteries. EVs passed 20% of total global vehicle sales in 2024, albeit slowing in the last quarter. This amounted to more than 17 million vehicles in 2024, up by approximately 25% over 2023, according to the International Energy Agency. Over 11 million of these EVs were sold in China due to price competitiveness and government incentives. Growth in EV sales stagnated in Europe (3.2 million vehicles) as subsidies were phased out or reduced in several major markets. EV sales in the U.S. reached 1.6 million units, an increase over the 1.4 million in 2023. Sales to the rest of the world totaled 1.3 million vehicles. While the Tesla Model Y and Model 3 have been the two best-selling models in the U.S. since 2020, the 110 new models that have entered the market since then have driven the market share of Tesla down from 60% in 2020 to 38% in 2024. Furthermore, 2024 was the first year in which Tesla saw a drop in sales in the U.S., while other manufacturers saw sales increase by 20% on aggregate.

In the U.S., Presidential Executive Order 14154, signed January 20, 2025, directed the government to reconsider market interventions that favor EVs. Legislation has since been proposed that would end the Clean Vehicle Tax Credit for both cars and light commercial vehicles. This proposal may result in consumers that have been considering buying an EV rushing to do so before the tax credit is removed. A dampening effect on EV sales in the U.S. is expected only once the tax credit is repealed on September 30, 2025. In addition, tariffs for conventional and electric cars have also been announced, which may result in lower car sales.

Nearly 300,000 new EVs were sold in the U.S. in the first quarter of 2025, according to Kelley Blue Book, up 11% compared to Q1 2024. Approximately 7.5% of total new vehicle sales in Q1 2025 were EVs, up from 7% the year before.

Some major automakers have shifted away from investing in EVs in the face of more modest than previously forecast sales and federal regulatory uncertainty, including the threat of tariffs, previously mentioned. General Motors, on May 27, 2025, announced an $888 million investment into an upstate New York production plant to manufacture its sixth-generation V-8 engines, scrapping previously announced plans to invest $300 million for EV production at the facility. Meanwhile, Honda is reducing EV investments through 2030 by nearly $21 billion due to changes in environmental regulations and foreign trade policies.

Washington, Oregon, and California are among several states involved in a class-action lawsuit against the Trump administration over the suspension of National Electric Vehicle Infrastructure (NEVI) Formula Program funds awarded for a nationwide EV charging network. In Washington, the state legislature appropriated $101.5 million for the Washington Electric Vehicle Charging Program for the 2025-2027 biennium, including $23 million in new funding. However, the state's EV Instant Rebate Program went unfunded by the Legislature after launching with $45 million in 2024.

Battery technology continues to be a primary issue of the EV transition. Most EVs today are powered by lithium-ion batteries, a decades-old technology that is also used in laptops and cell phones. All those years of development have helped push prices down and improve performance, so today's EVs are approaching the price of gas-powered cars and can go for hundreds of miles between charges. Lithium-ion batteries are also finding new applications, including electricity storage on the grid that can help balance out intermittent renewable power sources like wind and solar, but there is still lots of room for improvement.

Advanced battery technologies under development include solid-state, sodium-ion, lithium-sulphur, iron-air, and redox-flow batteries, among others. Some of them, like iron-air and redox-flow batteries, target different applications to established lithium-ion technologies, such as longer-duration storage for grid applications. Others, like sodium-ion batteries, aim to reduce dependence on lithium. Lastly, technologies like solid-state and lithium-sulphur batteries could also accelerate electrification in sectors that require or would benefit from higher energy densities, such as long-haul electric trucks or short-haul boats and planes. However, their deployment in these sectors will depend on meeting stringent safety requirements and on their total cost of ownership.

Sodium-ion batteries gained significant attention in 2022 as lithium prices surged, leading to the first EVs using the technology. Despite enthusiasm waxing and waning because of material supply chain challenges and falling lithium prices in 2023 and 2024, CATL, the world's largest battery producer, announced its second generation of sodium-ion batteries in 2025, alongside the launch of a dedicated sodium-ion battery brand. Meanwhile, BYD is also investing in sodium-ion battery production for EVs and battery storage. In March 2025, HiNa launched its new sodium-ion battery, which offers improved energy density and faster charging compared to the previous generation. However, recent analyses indicate that sodium-ion batteries will require either increased energy density or more favorable operating conditions, particularly higher lithium prices, to compete with lithium-ion phosphate (LFP) batteries on a price per kWh basis. Nevertheless, sodium-ion technologies could play a significant role during times of elevated lithium prices and may offer a cheaper option for batteries in cold climates, where LFP batteries typically don't perform as well.

In 2024, solid-state batteries moved closer to commercial reality with new large prototypes and manufacturing investments from Samsung SDI, Toyota, NIO, Honda, Quantum Scape, BASQUEVOLT, and Factorial, among others, and the creation of a government-led Chinese battery alliance, including large producers such as CATL, BYD, SAIC and Geely, to accelerate solid-state battery development. Despite this, their potential advantages, including enabling higher ranges and safety, still need to be demonstrated for battery packs manufactured at scale and tested under controlled, realistic and standardized conditions. The technology readiness level (TRL) of solid-state batteries therefore remains at large pilot stage (TRL 6), although this could change rapidly with companies like Toyota and BYD planning first mass production by 2027-2028. However, volumes will be limited initially, and it will take several years following roll-out for solid-state batteries to eventually become competitive with lithium-ion batteries. Additionally, "solid-state batteries" is often used as a generic term covering a range of options between fully solid-state and incumbent lithium-ion batteries, which creates some confusion. The first "solid-state batteries" to be commercialized might be semi or quasi-solid-state batteries, for example using gel-like electrolyte or incorporating small volumes of liquid electrolytes, as they could help address some scale-up challenges and reduce production costs.

Lithium-sulphur (Li-S) batteries, promising higher specific energy (Wh/kg) and lower reliance on critical minerals, have also gained momentum. The U.S. start-up, Lyten, announced the world's first Li-S gigafactory, while Stellantis partnered with Zeta to commercialize this technology by 2030. However, several challenges remain, including improving volumetric energy density (Wh/L), enhancing durability and addressing safety concerns related to the use of lithium metal anodes. Overcoming these hurdles will be key to enabling real-world applications.

Innovation extends far beyond battery chemistries, and the already broad landscape of battery innovation is getting even broader. In 2023 and 2024, there was a remarkable surge in improvements for incumbent lithium-ion batteries, from superfast charging and "no-degradation" batteries to ultra-energy-dense batteries and new charging platforms, manufacturing processes, cell formats, and pack designs, among others. Advances in manufacturing are also notable, for example, AI for image analysis can enable the early detection of battery defects and their root causes, thereby improving production yields and reducing scrap rates. This capability is critical for scaling up production given the pace of modern gigafactories. A 50 GWh facility can produce up to 10 million (cylindrical) or hundreds of thousands of (prismatic) EV battery cells per day. The nature and pace of innovations in legacy technologies are already making a big impact on the market, posing a formidable challenge for emerging technologies to compete.

The District continues to use the Council's basic EV load forecasting methodology for passenger vehicles, with updated District estimates for overall vehicle sales and EV market share. Additionally, District staff worked to better estimate existing EV load as most of it is included in residential meter reads ("behind the meter") while some commercial chargers now exist and are metered separately in their own load sector. At the beginning of 2025, approximately 1350 EVs were registered in Chelan County. Based on EV market share, or penetration rates, experienced in the District's service area to date, the District updated Chelan County's EV low, base, and high load forecasts with all decreasing from the 2023 IRP progress report. By the end of the planning period, the market share rates vary from 21% to 93% in the three cases. This translates into approximately 5,800 to 20,700 cumulative EVs in Chelan County (after EV retirements) in 2034. The three cases now result in forecasts of between 2.70 aMW and 9.52 aMW by 2034 for passenger vehicles.

In 2025, District staff added a separate fleet EV load forecast to the passenger EV load forecast to arrive at the total EV load forecast. In 2023, Chelan PUD contracted with TRC Companies of Seattle to perform a Fleet EV Impact Study. Based on data from a fleet survey of local agencies performed by TRC as well as battery and usage information and future fleet estimates, District staff developed a Chelan County fleet EV load forecasting model. Fleet vehicle types include sedans/SUVs, light-duty trucks, medium-duty trucks, heavy-duty trucks, vans, shuttle buses, school buses, motorcycles and forklifts. Large numbers of electric forklifts have existed for many years in Chelan County. All the other categories are just beginning to accumulate in numbers. The three cases now result in forecasts of between 1.52 aMW and 2.90 aMW by 2034 for fleet vehicles.

The low, base, and high EV forecasts (passenger and fleet) total between 4.22 aMW and 12.42 aMW in 2034. The average annual growth rates for total EV load are forecasted at 8.57%, 15.62% and 21.32% for that same planning period.

Because most city Link buses in Chelan County are already electrified, District staff did not specifically add additional Link bus load and feels comfortable that the total EV forecasted ranges of results take into account all EV loads.

Total EV peak load estimates now range from 5.56 MW to 19.81 MW in 2034. Future assumptions about charging behavior have a substantial effect on the peak forecast. The District's peak forecast for total EV load occurs in the evening after most cars are assumed to be plugged in at home at the end of the day. Although assumptions about where, how and when EV charging occurs can vary greatly, the District does not expect the peak to be in the morning when Chelan PUD experiences its highest peaks in the winter.

The District will continue to monitor the development of the EV industry and its potential impact on future retail electric load in Chelan County.

Resources

Existing District Portfolio

Chelan PUD's resource mix currently remains unchanged. The District owns and operates three hydroelectric projects, all located in Chelan County, and is a participant in the Nine Canyon Wind Project, located in Benton County, Washington. The three hydroelectric projects, Rocky Reach, Rock Island and Lake Chelan, together, have capacity to generate nearly 2,000 MW of power. The District continues to invest in modernization and relicensing at the projects to ensure reliable, locally controlled operation of resources for future generations.

Long-term power sales contracts are currently in place with Douglas County PUD, Alcoa Power Generating Inc./Alcoa Inc., Puget Sound Energy and Avista Corporation. The Alcoa contract expires in 2028 during this planning period (2025-2034). District power contracts and the hedging strategy are more fully discussed in the Portfolio Analysis section.

Hydropower has many characteristics that make it highly desirable. It is free of the emissions associated with fossil fuel-fired generating resources. Operational flexibility allows hydropower to quickly follow load changes and provide reserves to the electric grid in a timely manner, which contributes to overall system reliability. In addition, hydropower provides backup for intermittent resources such as wind and solar.

The amount of hydropower the District is able to generate depends on water availability, which is variable and hinges on a number of factors, primarily snow pack in the mountains upstream of its hydroelectric facilities, precipitation in its watershed, the operations of upstream storage reservoirs, certain operating agreements (see Columbia River Treaty section), and the operation of the downstream reservoir from Rock Island belonging to the Wanapum project.

During the Rock Island B2 generator stator replacement work, fatigue cracks were observed on the blades of the turbine. From October 2015 through January 2016, District staff made repeated attempts to grind out the cracks and repair the resulting excavations with various welding procedures. After each repair procedure, inspections resulted in the observation of new fatigue cracks. Engineering analysis indicated the B2 turbine was experiencing a phenomenon known as corrosion fatigue. The turbines of B1, B3, and B4 are of similar design and vintage as B2. These three units were taken out of service and inspected to determine if similar cracking existed in their turbine runner blades. These turbines also had significant cracking due to corrosion fatigue. All four turbines will remain out of service until the District can install replacement turbine runners. The District completed the development of specifications for the procurement of turbine runners for B1 through B4 and awarded a construction contract in late 2016. Repairs and replacement on unit B4 were completed in August 2021. Repairs and replacement on B3 were completed in December 2024. The remaining two units are scheduled to return to service between 2027 and 2029.

The District modernized units B5, B6, B7, B9, and B10 between 2009 and 2024. B8 is currently undergoing rehabilitation.

The second Rock Island powerhouse was constructed in 1979 and consists of eight horizontal bulb generating units. In the late 1980's, stator frames and stator windings were either replaced or repaired due to deficiencies in design. Since then, no other significant repairs or replacements of turbines or generators has occurred. A modernization contract was initiated in 2018 for the replacement of the generator stators and rotors, governor systems, and to convert the turbines to "oil-free" hubs. The modernization work on U5 is currently in progress.

The risk management plans Chelan PUD has in place are working effectively. The long-term wholesale sales contracts and hedging program (discussed in the Portfolio Analysis section), Large Load policies, insurance program and strong financial policies continue to reduce the impact to the District from the lost generation revenue, repair costs and associated risk mitigation efforts for the aforementioned operational challenges.

District Transmission

Chelan PUD's relatively small service territory has a robust transmission system and is able to use its own hydropower generation, which is located in Chelan County, to serve the District's native retail load and potentially some Large Load(s). In 2025, the District connected a Large Load to the transmission system with relatively small improvements to the transmission system. Chelan PUD assessed 20-year transmission in a WPP 20-year study and is currently participating in the Western Transmission Expansion Coalition, or WestTEC, effort to evaluate 10-year and 20-year transmission solutions and system improvements in the WECC. The District also completes annual assessments under its TPL-001 Transmission Planning Studies to assess reliable load service in the 5-year and 10-year horizons. Chelan PUD has not identified any further transmission needs to meet its energy or reliability needs that would require expansion or upgrade.

The District is a member of the NorthernGrid Regional Transmission Planning Group and participates in NorthernGrid's two-year Regional Transmission Plan. The 2024-2025 Draft NorthernGrid Regional Transmission Plan identified projects in southern Idaho and Wyoming that "facilitate renewable generation from Wyoming to serve the larger load pockets in Seattle/Portland and allows for deliveries into the Wyoming and Utah areas when generation is rich in the Pacific Northwest." No projects in the mid-Columbia service territory have been identified. Chelan PUD also participated in the WPP 20-Year Study, the WPP 2030 Extreme Weather Event study, WPP annual TPL-001 regional case builds which coordinate critical regional assumptions and contingency lists, and the WECC WestTEC effort to evaluate 10-year and 20-year expansion needs and opportunities. WECC is also in the process of defining a new 20-year study case process, which the District will participate in as part of the WECC Base Case build process.

Regional Infrastructure & Load

In the region, nearly all wind and solar sites are east of the Cascade Mountain Range while most of the load is in Seattle and Portland. In addition, current high voltage cross-Cascades transmission lines are fully loaded. Devising methods to provide new transmission to PNW load centers or even upgrade existing 230-kV transmission to 500 kV across this environmentally sensitive barrier, is a major challenge. The degree of difficulty associated with overcoming this challenge, since it affects nearly all PNW renewables development, probably exceeds such geographic/environmental challenges in any other region.

Compounding this, the changes are taking place during a period of unprecedented load growth across the West, with infrastructure development lagging behind. The WECC, PNUCC, and the NWPCC all recently released forecasts showing electricity demand increasing anywhere from 30% to 50% over the next decade. Many believe it could be higher. Apparent roadblocks in the Northwest, such as utilities contending with wildfire liability issues and slowed procurement, could impact those forecasts if large load users take their business elsewhere.

One of the proposed solutions advocated by the Northwest & Intermountain Power Producers Coalition (NIPPC) and Renewable Northwest is the creation of a state-level transmission authority. Legislation in Washington creating an authority nearly reached the finish line during the 2025 legislative session. The District recently submitted a Minority Report to the Washington State Governor's Data Center Workgroup in response to some of the group's adopted recommendations. See the Hedging Strategy section for more detail.

Additionally, BPA's interconnection and transmission queues are significantly bigger than BPA's entire load. They have put in place a reform, but they must work through the existing queue to get to the reforms. As previously mentioned, energy developers are contending with supply chain bottlenecks that have lingered since the COVID-19 pandemic, as well as the uncertainty created by federal tariffs. Resource challenges in the Northwest may be mitigated or improved by the development of the day-ahead markets, permitting reform, and the resurgence of energy conservation technologies and programs. Peak shaving through load shifting and battery storage should ultimately be good for ratepayers.

Columbia River Treaty

The 1964 Columbia River Treaty (Treaty) between Canada and the U.S. was based on the development and operation of dams in the upper Columbia River basin for power and flood control benefits in both countries. The Treaty provides for the sharing with Canada of one-half of the downstream U.S. power and flood benefits and allows the operation of Treaty storage for other benefits. The Treaty has no expiration date, but operational elements of a basic feature of the Treaty, flood control, expired in 2024. Either party had to provide 10 years notice for Treaty termination, so 2014 was a pivotal decision year.

In 2013, the Northwest and a variety of stakeholders endorsed the U.S. Army Corps of Engineers and BPA's (collectively the U.S. Entity) final recommendation on the Treaty.

The recommendation noted that “the region’s goal is for the U.S. and Canada to develop a modernized framework for the Treaty that ensures a more resilient and healthy ecosystem-based function throughout the Columbia River basin while maintaining an acceptable level of flood risk and assuring reliable and economic hydropower benefits.” A consortium of U.S. utilities laid down negotiation markers that called for notification of termination if its principles were not met. A primary U.S. concern was the Canadian Entitlement, half of the originally calculated increase in U.S. downstream power benefits that is delivered to Canada. The utilities argued that the payment should be adjusted for diminished downstream benefits and the expense of subsequent U.S. environmental legislation imposed on the hydro system.

In March 2014, British Columbia, on behalf of Canada, released a 14-point position for updating the Treaty. Their principles included that the Treaty should primarily maximize benefits to both countries, the Canadian Entitlement did not account for all U.S. benefits or impacts to B.C., post-2024 flood control should include effective use of U.S. reservoirs and a coordinated flood risk management approach, ecosystems are an important consideration, and adaption to climate change should be incorporated.

The process is a federal, interagency review under the general direction of the National Security Council on behalf of the President. The Department of State has been designated as the agency to coordinate and oversee this process on behalf of the National Security Council. The U.S. Entity is committed to supporting this effort. In May 2018, Treaty negotiations began between the U.S. and Canada. Negotiations have taken place in private. U.S. tribes were not originally involved, but tribal representatives became involved in late 2019. After many, many rounds of negotiations, an Agreement in Principle (AIP) was reached in July 2024.

The AIP enables B.C. to continue receiving a share of Canadian Entitlement, albeit reduced from the original Treaty, of the additional hydroelectric power potential in the U.S. as a result of how B.C. operates its Treaty dams and includes newly negotiated access to U.S. transmission infrastructure. Canadian Entitlement delivery from the U.S. to Canada will immediately be reduced 37%, with a reduction of 50% by 2033.

The AIP also provides annual indexed compensation from the U.S. for a reduced volume of reservoir space for flood control and for other benefits the U.S. receives, including benefits to irrigation, navigation, recreation and fish population enhancement in the U.S. portion of the Columbia Basin. According to the AIP, Canada will store several million-acre-feet of water that can be used in 2025 and for the next 20 years to help prevent floods in the Columbia River Basin downstream in the U.S., according to federal dam operators speaking in December 2024 on the AIP’s flood control protections. That’s about half of the pre-planned flood control storage provided in the last 61 years when the flood control portion of the original Treaty was in effect.

Beginning this year, Canadians will hold back some 3.6 MAF of preplanned space each year at the Hugh Keenleyside Dam (Arrow Dam) in British Columbia to aid flood control in the U.S. at Grand Coulee Dam and lower downstream in the Columbia River, mostly during spring runoff when water levels in the river rise. That’s a drop from the as much as 7.1 MAF of preplanned storage from Canada for flood control management that was included in the original Treaty agreement. In the original Treaty, about 5.1 MAF was dedicated for flood control with an additional 2 MAF of accessible storage when needed in real time. The new arrangement places more of the responsibility on the U.S. to manage its own flood risk and that will require a change to flood control protocols at Grand Coulee Dam and John Day Dam. Nearly 40% of floodwater originates in Canada. In certain spring runoff conditions when flooding is threatened, the difference in storage between the old 7.1 MAF and the new preplanned 3.6 MAF will have to be made up by drawing down Lake Roosevelt, behind Grand Coulee and the John Day reservoir, effectively providing more of the storage needed to deter flooding in the U.S.

A new final modernized Treaty was not completed or signed before the Biden administration left the U.S. office of the presidency in January 2025. As of early 2025, Treaty negotiations are currently paused as the Trump administration reviews it international engagements.

In 2023, the Mid-C PUDs (Mid-Cs), Chelan PUD, Grant PUD, Douglas PUD, submitted a Petition for Rulemaking to BPA asking BPA to adopt a binding rule requiring entitlement allocations to be transparent, subject to public process under the Administrative Procedure Act and bound by the Federal Power Act fairness standards, including the equitable allocation of system benefits and burdens. In June 2024, the Mid-Cs filed a lawsuit in District Court for the Eastern District of Washington regarding the Treaty. The Mid-Cs are suing the U.S. Entity. At issue is the share of the Canadian Entitlement that the Mid-Cs will be responsible for in the new Treaty. In 2017, the Mid-Cs began asking BPA "for a fair and transparent process to determine an appropriate factual and legal basis" for the Canadian Entitlement allocations. When the Canadian Entitlement Allocation Extension Agreements for each PUD expired in September 2024, the Mid-Cs stopped providing their share of the Canadian Entitlement. They immediately received a letter from BPA stating they do not have the authority to use improved streamflows under the Treaty for power generation. The Mid-Cs have asked what the improved streamflows are, to which BPA has been unable or unwilling to provide such information. They further state that BPA has not been coordinating the use of downstream power benefits, as obligated. They noted that because of the lack of coordination, the perceived downstream benefits do not necessarily transfer to the Mid-Cs. The Mid-Cs also noted that they will be carrying greater risks due to potential changes in flood control in 30% to 40% of water years. The Mid-Cs are asking the court to find that the U.S. Entity has unreasonably delayed action on their petition and that it has no authority to impose conditions on the Mid-Cs use of streamflows after September 2024.

Climate Impacts to Loads and Resources

Chelan PUD has been following regional efforts to assess the future impacts of climate change on the power industry, including changes to hydroelectric generation and electricity demand. The prediction for the Northwest is for less snow and more rain during winter months, resulting in a smaller spring snowpack and lower summer flows. Winter electricity demands would decrease with warmer temperatures, easing generating requirements. In the summer, demands driven by air conditioning and irrigation loads would rise.

Other potential climate change impacts include increased flooding concerns in fall and winter, reduced salmon migration survival due to lower summer river flows combined with higher water temperatures and increased summer electricity prices.

The River Management Joint Operating Committee (RMJOC) (BPA, the Corps of Engineers and the Bureau of Reclamation) leads this regional effort. Most recently, in 2018, the RMJOC along with researchers in the University of Washington Hydro/Computational Hydrology research group (UW), in conjunction with the Oregon Climate Change Research Institute at Oregon State University, completed an updated study known as RMJOC-II. They have a web-based database that includes temperature, precipitation, snowpack and streamflow forecast projections for the entire Columbia River system.

The key research objective of the project was to determine, if possible, to what degree each methodological choice made in the hydroclimate modeling chain introduces additional spread into future projections. For the Columbia Basin as a whole, future climate scenarios depicted by global climate models as forecasted by the representative concentration pathways (RCPs) and downscaled by different methods, are the largest source of variability in future streamflows. The RCPs describe different 21st century pathways of GHG emissions and atmospheric concentrations, air pollutant emissions and land use. However, the choice of hydrologic model itself, the hydrologic model's particular calibration parameters, the choice of bias correction technique, and the historical data set used for model calibration, are all important drivers for increasing the spread of the hydrologic projections.

It was noted that this study did not make a determination on which climate model, downscaling method, or hydrologic models will perform "better" or "worse" in the future. Because considerable scientific rigor was applied to each step in the process, the diversity of the methods used should be respected and maintained for possible downscaled selection for subsequent scenario-based studies. One important finding is that uncertainties introduced in each step of the modeling chain must be included if planners seek to represent a fuller range of potential hydroclimate change impacts.

The District is focusing on the following areas:

1. Columbia River mainstem modeling — power generation impacts, aquatic resources impacts and water quality impacts
2. Lake Chelan Basin modeling — Lake management impacts (power generation, Chelan River operations impacts and water quality impacts)
3. Wenatchee and Methow rivers modeling — Habitat Conservation Plan (HCP) hatchery program impacts
4. Distribution system load forecasting

Previously, Chelan PUD reviewed the effects on Rocky Reach generation under various climate change scenarios using RMJOC-I regulated hydro data. As anticipated, the result was more generation during winter and spring months (December through June) and less generation during summer months (July through September) with little change during October and November with changes becoming larger over time. The "2020s" (a 30-year period spanning 2010 to 2039) and the "2040s" (a 30-year period spanning 2030 to 2059) were studied. RMJOC II data for Rocky Reach and Rock Island was later received by the District. Updated analysis using the RMJOC II data confirmed the previous study as the data showed more flow and generation in the winter/spring and less in the summer. In addition to the changing shape of annual inflow, the data also showed an increase in total annual volume of water received over time.

The District worked with the UW to determine which data sets to use to complete its own modeling of future climate change scenarios on Lake Chelan operations and reservoir management. In 2020, Chelan PUD conducted internal modeling of the 2050 timeframe and determined the current operating structure and modeling approach for Lake Chelan is sufficient. Climate change modeling for Lake Chelan will be updated to reflect changing conditions and updated data sets when it is available.

UW researchers provided data sets (1980-2010), enabling District staff to perform basic calculations to predict changes to monthly

District peak loads (based on 2007-2016 average peak loads and 1980-2010 average temperatures at Saddlerock substation). That data showed increasing average temperatures for every month, increasing over time and did not account for load growth. The results were as expected, reduced winter demands and increased summer demands. It should be noted, however, that Chelan County set new record winter load peaks in December 2022 and again in January 2024 that were beyond 95th percentile forecasts due to extreme cold temperatures.

Chelan PUD will remain attentive to any forthcoming regional work on this issue as science and experience help shed light on the best methods for predicting load changes and water and snowpack inventories and reshaping flood curves. Changes in the Columbia River Treaty, as previously discussed, will have more profound effects on flood control in the Columbia River Basin than those from these climate impact studies.

Integrating Renewable Resources and Overgeneration Events

In 2013, by legislative action, a new requirement was added to Washington State IRPs: an assessment of methods, technologies or facilities for integrating renewable resources and addressing overgeneration events, if applicable to the utility's resource portfolio. In 2019, that requirement was clarified to include battery storage and pumped storage among the methods, technologies or facilities to be assessed. The assessment must also include a description of how overgeneration events are mitigated at the lowest reasonable cost and risk to the utility and its ratepayers. An overgeneration event is defined as an event within an operating period of a BA when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility's energy delivery obligations and when there is a negatively priced regional market.

Negatively priced regional market occurs, at times, when hydro and wind, which are very low variable cost resources (i.e., free fuel), are forced to the margin during periods of low load and high hydro and/or wind and solar production. This results in very low or negative spot market prices. Negative spot market prices mean that a utility or other market participant must pay another entity to take unwanted power (i.e., power for which no load exists). The negative pricing occurs for two primary reasons. Sometimes hydro generators and other generators are must-run due to operational constraints, thus adding additional energy to an over-supplied market.

Additionally, many wind generators receive federal incentive credits and/or payments based upon their wind production. They can also sell the RECs from this generation. The value of these items combined is more than $30/MWh. These generators can afford to withstand some degree of negative pricing and still make a profit due to these other payments.

The 2022 Inflation Reduction Act (IRA) extended existing tax credits for renewable and energy storage projects while creating new clean energy credits. Most provisions of the IRA became effective January 1, 2023.

Starting January 1, 2025, the IRA replaced the traditional Production Tax Credit (PTC) with the Clean Energy Production Tax Credit (CEPTC) and the traditional Investment Tax Credit (ITC) with the Clean Electricity Investment Tax Credit (CEITC). These tax credits are functionally similar to the PTC and ITC but are not technology specific. They apply to all generation facilities and energy storage systems that have an anticipated GHG emissions rate of zero.

Beginning in 2025, the CEPTC is available to taxpayers with a qualified facility and energy storage technology placed in service after December 31, 2024. With the passage of the OBBB, the CEPTC termination date is December 31, 2027. Projects must begin construction by July 4, 2026, to retain eligibility for full credit. Additionally, the OBBB introduces restrictions on projects that receive "material assistance" from Prohibited Foreign Entities. The credit starts at a base rate of $.03 per kWh of electricity produced. A higher rate ($1.50) applies to small facilities, with a maximum output of less than 1 MW, that meet certain prevailing wage and registered apprenticeship requirements. The rate will be adjusted for inflation. There is a 10% increase for facilities meeting certain domestic content requirements for steel, iron, and manufactured products and a 10% increase if located in an energy community. The traditional PTC remained available for projects that began construction before January 1, 2025. It now terminates at the end of 2027. The traditional PTC provides a tax credit to a facility for 10 years. In 2025, the rate is $.03 per kWh of production (assuming prevailing wage and apprenticeship requirements are met). Traditional PTC eligible technologies include wind (multiple technologies), solar (multiple technologies), geothermal, tidal, biomass, landfill gas, hydroelectric, marine and hydrokinetic, and municipal solid waste (the value is reduced by one-half for facilities using municipal solid waste, open-loop biomass, landfill gas, trash, qualified hydropower and marine, and hydrokinetic facilities).

Beginning in 2025, the CEITC is also available to taxpayers with a qualified facility and energy storage technology placed in service after December 31, 2024. The OBBB terminates the CEITC for projects placed in service after December 31, 2027. Projects must be started by July 4, 2026, for full credit. The base amount for the CEITC is 6% of the qualified investment. Credit is increased by up to five times or up to 30% for facilities meeting prevailing wage and registered apprenticeship requirements, 10% for facilities meeting certain domestic content requirements for steel, iron, and manufactured products and a 10% increase if located in an energy community. The traditional ITC remained available for projects that began construction before January 1, 2025. The traditional ITC value of 30% terminates at the end of 2027 (compliance with prevailing wage and qualified apprenticeship requirements is necessary for full value). Technologies available for the traditional ITC include, energy storage, fuel cell, geothermal, combined heat and power, microturbines, interconnection property, microgrid controllers, solar (multiple technologies), municipal solid waste, wind (multiple technologies), geothermal, and tidal.

Chelan PUD's share of Nine Canyon wind is a relatively small portion of its overall resource portfolio (less than 1%). In most cases, the District can integrate this wind operationally without issue due to its hydro resource reserves. The District may have to sell at negative prices when it has already reduced its hydro generation as much as possible under certain operating circumstances.

State and regional policies, California markets, and solar/renewable energy expansion continue to create oversupply conditions throughout the Western Interconnect. For comparison, in the spring runoff period (April-July), 2024 was a lower-than-average water year and had zero day-ahead days with negative local prices (2023 had 4 days, 2022 had 9 days, 2021 had zero days, 2020 had 25 days, 2019 had 2 days and 2018 had 35 days). In the hourly balancing or real-time market, 2024 experienced 22 hours with negative local prices (2023 had 74 hours, 2022 had 115 hours, 2021 had 9 hours, 2019 had 17 hours and 2018 had 129 hours). Snowpack and timing of spring runoff affects the number of days and hours with oversupply and negative prices.

As wind's intermittent nature can push a region into oversupply, behind-the-meter or unmetered solar (residential) and metered (utility-sized) solar continue to increase. Full solar output can just as easily push a region into oversupply as wind alone once did. The opposite is true when the sun sets and there is an increased need for electricity generators to quickly ramp up energy production as solar falls. Starting in 2023 and again in the spring of 2024, the California ISO regularly experiences low load, high renewable generation in which 100% of the California ISO's demand was met with renewables.

In the Northwest, BPA has business practices that push the burden of oversupply back to the market and away from themselves. These practices include not selling at negative prices until spilled water reaches dissolved gas limits, holding renewable generators to a fixed schedule, not accepting unplanned surplus and canceling transmission loss returns. The cancelling of transmission loss return scheduled MWs from utilities to BPA can add hundreds of MWs to an already oversupplied period and drive prices even more negative for the loss-returning entity.

The extension of California's Energy Imbalance Market (EIM) (see Organized Markets section) into the Northwest and Canada allows California utilities to expand their market boundary when wind and solar push California into oversupply or create shortages as the sun sets. By optimizing renewables throughout a larger footprint, participants now see similar price signals and react to grid needs in a similar way. In the EIM market, when excess energy floods the market, Northwest hydro utilities must sell their surplus at very low or even negative prices to compete while managing water quality requirements. Conversely, when solar production drops off each day, California can meet peak loads by accessing flexible Northwest generation thus increasing local competition for power and therefore, increasing power prices during hours the District is also in the market to buy power for load.

The new carbon rules (see Regulatory & State Statutory Requirement — Climate Commitment Act (CCA) section) have changed the fundamentals of bi-lateral trading in Washington State. There has almost been an order of magnitude increase in the price of day-ahead energy and the forward curve. The widely recognized Mid-C Hub still trades, however new products are being requested that include or exclude Mid-C energy products. Energy that comes from outside of Washington State under the rules would need to be carbon mitigated and is heavily discounted or explicitly not wanted.

For example:

- Non-Washington Sink (NWS) identifies products that would normally hub through or could have been sunk at the Mid-C and are now not brought into the Mid-C and instead delivered to points outside of Washington. NWS daily energy is usually discounted by $1 to $5 per MWh when traded at the Mid-C.
- Non-California Independent System Operator (CAISO) source indicates that a party does not want energy from California as it would incur a carbon obligation or cost and is also heavily discounted.
- British Columbia (BC) Hydro energy — Exports from BC into Washington have been reduced as they would also incur a Washington carbon obligation. Much of the BC energy goes directly to California during the highest price periods or stays in BC due to their own carbon requirements.

The result has been additional pressure on the remaining Washington State fossil fuel generators to run longer making up some of the previously available supply, and their pricing has increased to reflect the cost of additional gas and the cost to mitigate carbon. The price also reflects a "keep it in Washington" premium as normally North to South intertie flow has changed to much lower flow and there are times of South to North flow not normally utilized by the Northwest except in extreme weather conditions.

The timing of peak solar in California and hydro freshet in the PNW has introduced periods of price volatility in the spring when solar serves demand during the daylight and then later that same day other resources are serving load as the sun sets. Mid-C power prices vary sharply through the historically level on-peak price periods.

Organized Markets

An Energy Imbalance Market (EIM) is a balancing energy market that optimizes generator dispatch within and between participating Balancing Authority Areas (BAAs) every 15 and five minutes. An EIM dispatches generators in a way that attempts to minimize the total cost to serve load (and exports) while honoring all system constraints.

WEIM

The California ISOs (CAISO) Western Energy Imbalance Market (WEIM) is a real-time energy market. By allowing BAs to pool load and generation resources, the WEIM has the potential to lower total flexibility reserve requirements and minimize curtailment of intermittent or variable energy resources for the region as a whole.

In the fall of 2014, PacifiCorp joined the CAISO in its WEIM. The WEIM uses advanced technologies to automatically find and deliver the lowest cost energy to consumers. By optimizing resources from a larger and more diverse pool, the WEIM better facilitates the integration of renewable energy that may otherwise be curtailed at certain times of the day, providing an added environmental benefit.

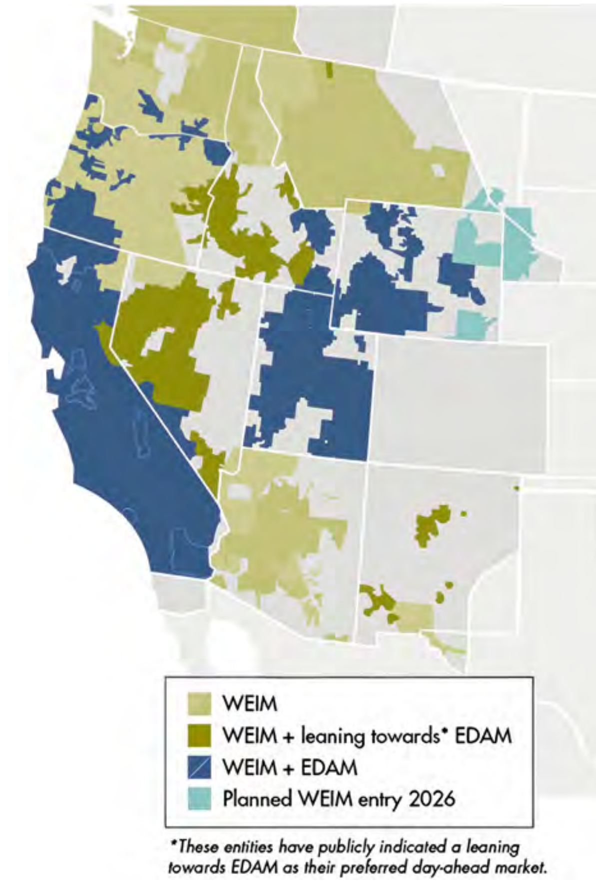
Since 2014, WEIM has expanded to include 21 BAs outside of the ISO across 11 western states.

- Imperial Irrigation District — planned entry 2028
- Black Hills — planned entry 2026
- PowerWatch (formerly BHE Montana) — planned entry 2026
- Avangrid — entered 2023
- El Paso Electric — entered 2023
- WAPA Desert Southwest Region — entered 2023
- Bonneville Power Administration — entered 2022
- Tucson Electric Power — entered 2022
- Avista Corp — entered 2022
- Tacoma Power — entered 2022
- NorthWestern Energy — entered 2021
- Los Angeles Department of Power & Water — entered 2021
- Public Service Company of New Mexico — entered 2021
- Turlock Irrigation District — entered 2021
- Salt River Project — entered 2020
- Seattle City Light — entered 2020
- Balancing Authority of Northern California — entered 2019
- Idaho Power Company — entered 2018
- Powerex Corp. — entered 2018
- Portland General Electric — entered 2017
- Puget Sound Energy — entered 2016
- Arizona Public Service — entered 2016
- NV Energy — entered 2015
- PacifiCorp — entered 2014
- CAISO — entered 2014

Set to launch in 2026, the CAISO's Extended Day-Ahead Market (EDAM) is a voluntary day-ahead electricity market that will optimize the use of existing transmission and resources in the much larger day-ahead timeframe across an expanded western footprint. EDAM is available to entities participating in the WEIM and will assist BAs in pre-positioning supply to meet forecasted electric demand for the following day. It is designed to increase regional coordination, encourage the development of renewable energy resources, and lower costs for consumers.

Under current law, CAISO's Governor-appointed Board retains authority over CAISO, including WEIM/EDAM operations. This governance structure has been a concern for many prospective EDAM participants. In 2025, the California Legislature enacted AB 825 (signed Sept. 19, 2025), which authorizes CAISO and participating utilities to use markets governed by a new independent regional organization envisioned by the West-Wide Governance Pathways Initiative, while preserving CAISO's system operations and requiring a formal CPUC determination that statutory conditions are met before California utilities participate.

Figure 1: CAISO WEIM/EDAM Market Footprint (as of May 2025) (*Extended Day-Ahead Market - Western Energy Imbalance Market*)



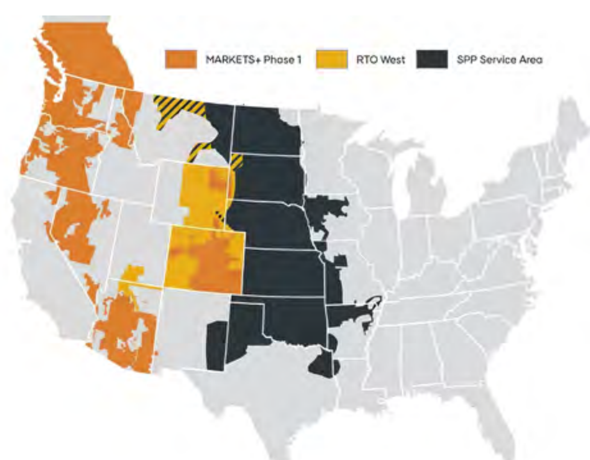
SPP

In addition to the WEIM expansion, the SPP launched its real-time Western Energy Imbalance Service (WEIS) market to interested utilities beginning February 1, 2021. SPP is also working to implement a day-ahead market, Markets+, expected to go-live in 2027. SPP collaborated with hundreds of western stakeholders, including Chelan PUD, to develop the detailed Markets+ proposal. Markets+ is more than just a day-ahead market offering. It's a stakeholder-driven bundle of services coordinated by SPP to provide benefits and savings, greater access to renewable energy sources and increased reliability to participants in the west. Lower production costs, increased market competition and fair and equitable tariffs will return economic benefits to Markets+ participants. It will greatly expand access to a diverse portfolio of sustainable energy sources, including wind, hydro, and solar. SPP's current footprint features the largest share of renewable energy among the 7 RTOs operating in the U.S. Markets+ will increase grid capacity during weather events that threaten local power supply. By utilizing the new WPP WRAP (discussed in the Resource Adequacy section above) to evaluate and address needs, Markets+ participants have taken an important step toward greater reliability. Markets+ has had a fully independent governance from day one, including oversight from SPP's independent board of directors and the Markets+ Independent Panel (MIP).

Markets+ phase one participants included the following organizations.

- Advanced Power Alliance
- American Clean Power Association
- Arizona Public Service Company
- Basin Electric Power Cooperative
- Black Hills Colorado Electric
- Black Hills Power, Inc.
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- Cheyenne Light, Fuel & Power Co.
- Clean Energy Buyers Association
- Colorado Independent Energy Assoc.
- Interwest Energy Alliance
- Liberty Utilities (Calpeco Electric)
- Municipal Energy Agency of Nebraska
- Natural Resources Defense Council
- Northwest & Intermountain Power Producers Coalition (NIPPC)
- NW Energy Coalition
- Powerex Corp.
- Public Generating Pool
- Public Power Council
- Public Service Company of Colorado
- PUD No. 2 of Grant County
- Puget Sound Energy
- Renewable Northwest
- Salt River Project
- Sierra Club
- Snohomish Public Utility
- Tacoma Power
- The Energy Authority
- Tri-State
- Tucson Electric Power Company
- Western Energy Freedom Action
- Western Power Trading Forum
- Western Resource Advocates

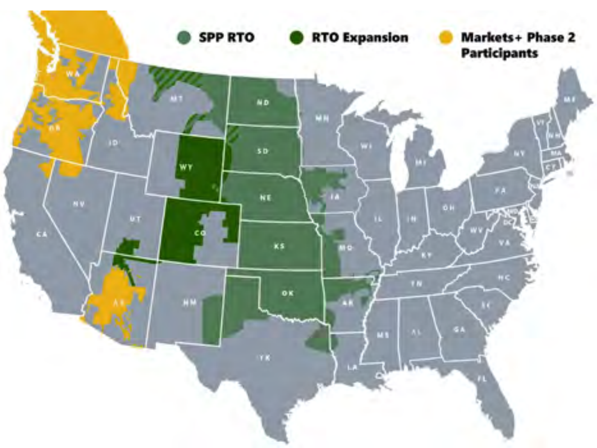
Figure 2: Markets+ — Phase One Participants



Markets+ phase two participants include the following organizations.

- Arizona Public Service
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- PUD No. 2 of Grant County
- Powerex Corp.
- Puget Sound Energy
- Salt River Project
- Tacoma Power
- Tucson Electric Power
- Xcel/Public Service Co. of Colorado

Figure 3: Markets+ — Phase Two Participants



Entities in the region moving towards organized markets and the expansion of these markets are a key development in the industry. The commitment of BPA and Puget Sound Energy in May 2025 to join Markets+ day-ahead market was pivotal to the future expectations of the Markets+ day-ahead implementation. The BPA announced in September 2025 that it is targeting October 2028 to begin participating in the market. That date coincides with the start of new 20-year regional power contracts. In October 2025, Chelan PUD formally announced its participation in Markets+ beginning in 2028.

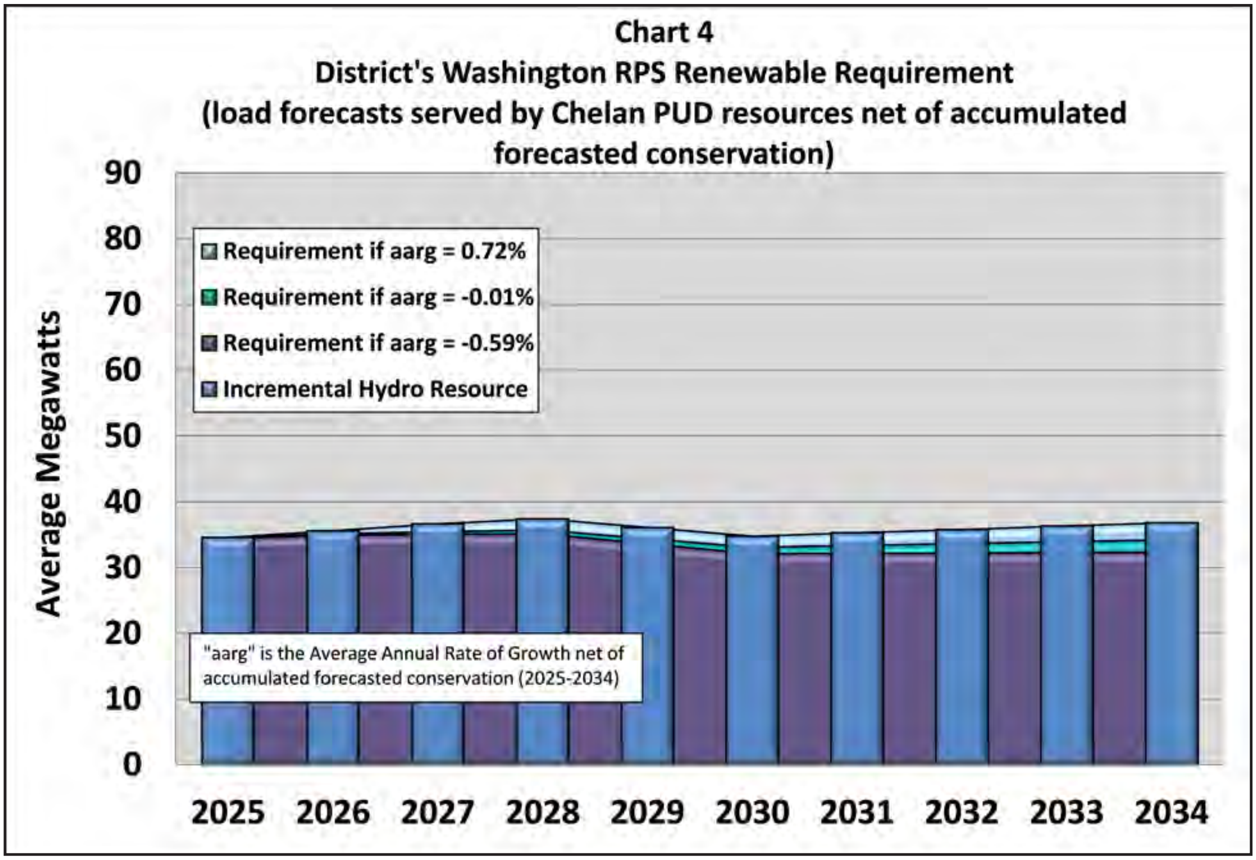
Renewables

The District has been complying with Washington State RPS renewable requirements since it became mandatory in 2012. The renewable energy section of the initiative now requires utilities to serve 15% of retail load with eligible renewable energy, RECS or a combination of both. Most hydropower is not an eligible renewable resource under the Washington RPS statute, though certain efficiency gains resulting in incremental hydropower are eligible.

Chelan PUD's existing mix of generating resources complies with the renewable requirement of the RPS throughout the planning period. The District meets its renewable requirements with incremental hydropower. Incremental hydropower is derived from efficiency gains at the District's existing hydropower projects resulting from equipment and operational upgrades, or increased power generation with the same amount of water. The District has made significant investments in equipment upgrades such as generator and turbine rehabilitations, new transformers and trash rack installations. In addition, the District has installed systems designed to optimize generation which have resulted in operational efficiency gains. Only those equipment and operational improvements placed in-service after March 31, 1999, qualify under Washington State RPS rules. The District uses a Hydro Optimization Model to calculate its qualified incremental hydropower under average water conditions.

Based upon the current base native load forecast, net of accumulated forecasted conservation, the amount of renewable resources required will be approximately 35-39 aMW in 2025-2034. **Chart 4** shows the potential target requirements based on the District's three load forecasts.

The District continues to evaluate options to meet its renewable compliance requirements. For the purpose of evaluating



the financial impact of the RPS, the District analyzes the cost of renewables as compared to its existing hydro resources.

Because Chelan PUD is long resources relative to its native retail load, the District's existing hydro resources are considered its "substitute resource" as defined by the WAC rules that pertain to the RPS.

In 2012, an advisory opinion process for eligible renewable resources was authorized to provide additional clarity and certainty. The District uses this process to confirm incremental hydropower from both Rocky Reach and Rock Island as qualified under the Washington State RPS and registered the incremental hydro in the Western Renewable Energy Generation Information System (WREGIS).

The western renewable and clean energy markets continue to evolve as compliance rules change and higher renewable targets and new clean energy standards have become a reality for utilities. California passed SB 100 in 2018 requiring zero-carbon resources supply 100% of electric retail sales to end-use customers by 2045. Since 2016, Oregon's RPS has required that 50% of the electricity used by retail customers come from renewable resources by 2040. As previously mentioned, Washington State passed the CETA requiring all electric utilities to use renewable and non-emitting resources in an amount equal to 100% of their retail electric loads starting in 2030. For 2030-2044, utilities can use alternative compliance to offset the use of emitting electricity for up to 20% of their CETA requirement. CETA considers all existing hydropower to be renewable, so due to its hydro resources, Chelan PUD is expected to be able to meet its CETA requirements through this planning period (2025-2034). Chelan PUD continues to monitor the potential impacts of CETA , the CCA, and other state policies.

Conservation

Since 2010, Washington's RPS has required that "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." Under the RPS, conservation is defined as any reduction in electric power consumption resulting from increased efficiency in energy use, production or distribution.

There are two primary conservation-related components of the RPS:

1. Establishing conservation targets (i.e., setting the goals), and
2. Documenting the conservation savings (i.e., demonstrating progress toward those goals).

To develop its 10-year plan and two-year conservation target for the 2026-27 biennium, Chelan PUD conducted a utility-specific Conservation Potential Assessment (CPA) in 2025. This CPA, prepared by Lighthouse Energy Consulting, established the conservation targets used in this 2025 IRP. The CPA incorporated Chelan County-specific data on demographics and building characteristics to more accurately estimate local conservation potential and was developed in alignment with the NWPCC's methodology. The resulting conservation supply curves inform the analysis presented in this IRP.

Conservation Potential Results

Chelan PUD has actively pursued conservation and energy efficiency resources since the early 1980s. Historically, the utility has offered a variety of programs for both residential and non-residential customers. While industrial projects have historically contributed to the majority of savings, since 2014 there has been a growing emphasis on residential and commercial sectors.

The 2025 CPA estimates of energy and peak demand savings by sector for the 2026-2045 period. The methodology complies with RCW 19.285.040 and WAC 194-37-070, Section 6 (a)(i)-(xv), and is consistent with the Council's approach in recent Power Plans.

The key baseline changes in the 2025 CPA include:

- Avoided cost: The 20-year levelized value in the current 2025 CPA is approximately $45 per megawatt-hour (2016$), using a discount rate of 4.39%. This price is approximately 70% of the levelized price from Chelan PUD's 2023 CPA, which was $65 per megawatt-hour (2016$).
- Code Changes — Recent updates to energy codes, such as lighting standards, have reduced remaining conservation potential.
- Updated Measure Data: The CPA incorporates revised data from the Regional Technical Forum (RTF).

Table 1 summarizes the economically achievable conservation potential by sector over two, four, 10, and 20-year periods. The 10-year potential is approximately 15.55 aMW, and the total 20-year potential is 32.78 aMW.

Table 1
2025 Conservation Potential Assessment Cost-Effective & Achievable Savings aMW

Sector	2 Year	4 Year	10 Year	20 Year
Residential	0.35	0.95	4.16	9.07
Commercial	1.10	2.09	5.43	10.09
Industrial	0.22	0.74	4.33	8.94
Distribution	0.03	0.14	1.49	4.39
Agriculture	0.01	0.02	0.15	0.29
TOTAL	**1.71**	**3.94**	**15.56**	**32.78**

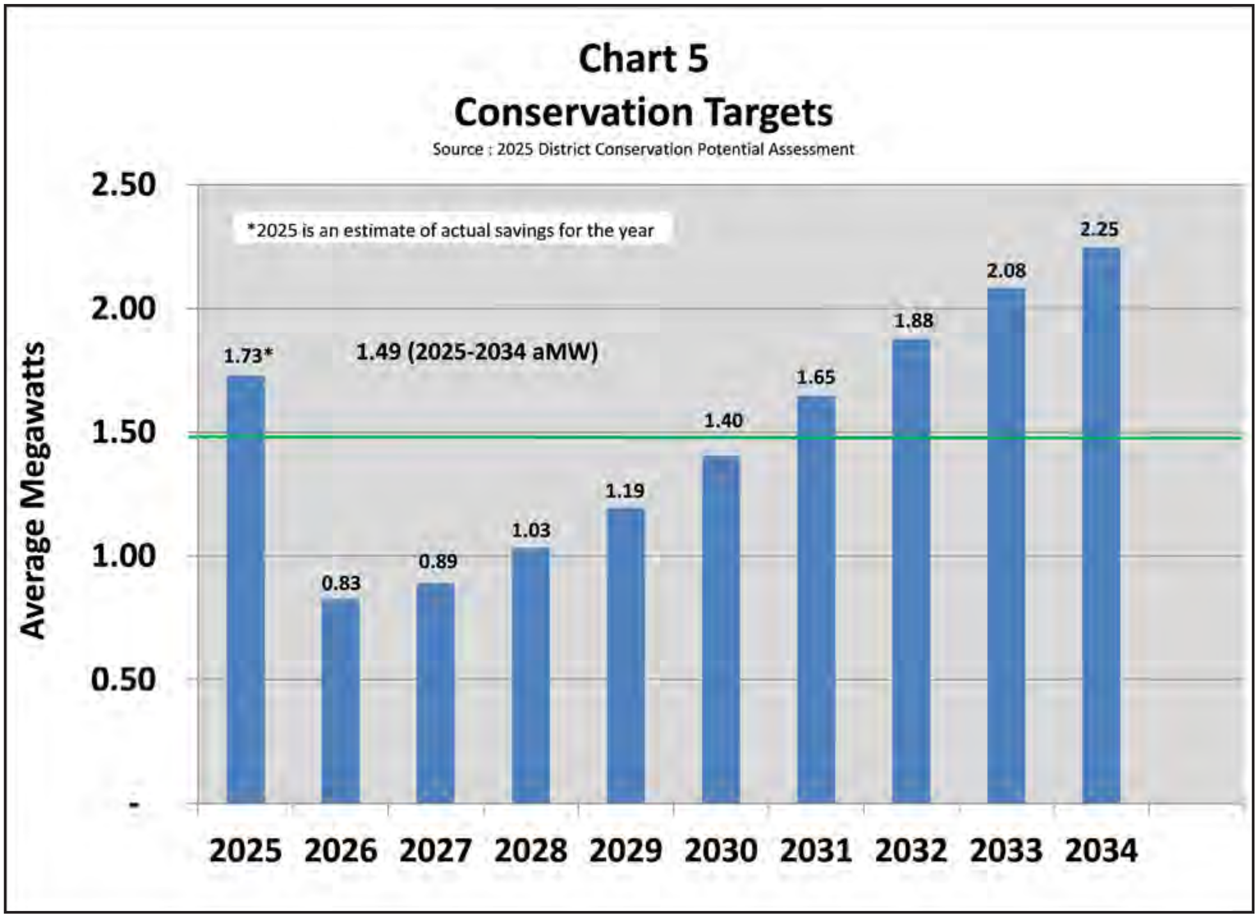


Chart 5 illustrates the conservation potential targets through the planning period. These estimates include savings from regional market transformation efforts and new codes and standards. Chelan PUD participates in the Northwest Energy Efficiency Alliance (NEEA), which supports regional market transformation. As a member, Chelan PUD applies a pro-rata share of NEEA's projected savings toward its biennial targets. NEEA defines market transformation as "the strategic process of intervening in a market to create lasting change in market behavior by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency as a matter of standard practice."

Social Cost of Carbon

In alignment with RCW 19.280, which mandates that utilities in Washington State incorporate the social cost of GHG emissions into their integrated resource planning, Chelan PUD evaluates the carbon implications of its energy efficiency programs and resource portfolio. This statute emphasizes the importance of considering environmental costs in utility planning to support the state's transition to a cleaner energy future.

Chelan PUD's energy efficiency programs not only reduce retail load but also result in additional carbon-free energy being made available on the wholesale market. Approximately 80% of the energy savings achieved through these programs translate into increased availability of carbon-free hydroelectric power, which contributes to regional decarbonization efforts. This carbon-free surplus is recognized as a "carbon-free premium" in the utility's resource valuation.

To quantify this benefit, Chelan PUD applies a carbon-free premium value beginning at $15/MWh in 2026, escalating to $25/MWh by 2035, and then declining to $16/MWh by 2044 (all in 2025 dollars). These values reflect the market and policy-driven value of carbon-free electricity and are consistent with estimates provided by the Council.

However, since 20% of Chelan PUD's energy mix is sourced from unspecified resources, this portion is valued using the social cost of carbon (SCC) as prescribed by the CETA. The SCC values are converted to a dollar-per-MWh basis using the Council's latest estimates of regional marginal emissions rates, ensuring consistency with state and regional planning methodologies.

This approach ensures that Chelan PUD's resource planning is consistent with RCW 19.280's directive to internalize the environmental costs of carbon emissions and supports the broader goals of Washington State's clean energy transition.

Residential

2-Year Potential (2026-2027): 0.35 aMW

10-Year Potential (2026-2035): 4.16 aMW

Commercial

2-Year Potential: 1.10 aMW

10-Year Potential: 5.43 aMW year

Industrial

Industrial potential was estimated using the Council's top-down methodology, which allocates annual electricity consumption by industrial segment and disaggregates it by process shares to create end-use profiles. Estimated measure savings were then applied to each segment.

2-Year Potential: 0.22 aMW

10-Year Potential: 4.33 aMW

Agriculture

2-Year Potential: 0.01 aMW

10-Year Potential: 0.15 aMW

Cost

Energy efficiency reduces the need to purchase power on the wholesale market and allows Chelan PUD to sell surplus power, both of which help keep local electric rates low.

The 2025 CPA identified 1.71 aMW of cost-effective and achievable conservation for the 2026-2027 biennium.

To evaluate cost-effectiveness, Chelan PUD used forward market projections of wholesale power prices and carbon pricing as avoided costs. The levelized cost of all conservation measures identified in the 2025 CPA was:

- $41/MWh over the 2026–2035 period
- $41/MWh over the 2026–2045 period (in 2016 real dollars)

Current Demand-Side Offerings

Chelan PUD's conservation programs are designed to offer a diverse portfolio of cost-effective measures that maximize value for District ratepayers while supporting compliance with RPS conservation targets. These programs are evaluated biennially to align with the CPA, with the next evaluation scheduled for the 2027.

Chelan PUD currently offers a range of programs, including residential rebates, commercial and industrial funding assistance, and targeted low-income initiatives. All programs contribute to meeting RPS targets, and the two low-income offerings also support compliance with the CETA.

Residential Offerings

Chelan PUD generally adheres to the program implementation guidelines and deemed savings values established by BPA, which serve as the basis for determining rebate amounts. Residential energy efficiency programs are available for homes with electric heating systems.

Insulation Rebates

Rebates range from $0.90 to $2.50 per square foot for wall, floor, and attic insulation. Rebate amounts are based on existing insulation levels and the type of upgrade performed.

Exterior Entry Doors, Window and Patio Doors

Incentives are available for replacing inefficient windows, patio doors, and exterior entry doors. Rebates range from $6 to $20 per square foot, depending on housing type (single-family, multi-family, or manufactured homes) and existing window conditions. A $100 rebate is available for upgrading non-ENERGY STAR® entry doors to ENERGY STAR®-certified models.

Whole House Heat Pumps

Customers converting from electric resistance heating to a qualified heat pump may receive rebates ranging from $3,500 to $4,000, depending on system efficiency. Installations must meet Chelan PUD's commissioning requirements.

Ductless Heat Pumps

Rebates are available for customers replacing zonal electric, radiant, or electric furnace systems with ductless heat pumps:

- $1,500 for multi-family homes
- $2,000 for single-family homes
- $2,500 for manufactured homes

Heat Pump Water Heaters

Single-family homes replacing electric resistance water heaters are eligible for a $1,000 rebate, regardless of tank size.

Thermostats

- Line Voltage Thermostats (LVT): $40 rebate per unit
- Line Voltage Communicating Thermostats (LVCT): $75 rebate per unit
- Smart Thermostats: $150 rebate for qualifying thermostats in homes with electric, centrally ducted resistance furnaces or heat pumps.

Residential Audits

Since 2019, Chelan PUD has offered in-person home energy audits using a web-based tool that provides personalized recommendations and rebate eligibility based on current program offerings. Audits are currently offered in person.

Income Qualified Programs

Low-Income Weatherization

Chelan PUD partners with the Chelan-Douglas Community Action Council (CDCAC) to provide weatherization services for income-qualified, electrically heated homes. Eligibility is based on 80% of Area Median Income (AMI) or 200% of federal poverty guidelines, whichever is lower.

- Chelan PUD provides an annual grant of $100,000, matched by the Washington State Energy Matchmaker program.
- CDCAC crews perform the work, which is inspected by both Commerce and Chelan PUD.
- Ductless heat pumps may also be installed in eligible homes.

ComfortPlus Low Income Energy Efficiency Program

ComfortPlus targets customers with high energy burdens (those spending more than 6% of annual income on energy bills). The program focuses on neighborhoods with a high concentration of income-qualified households.

- Includes an energy audit to identify HVAC, weatherization, and water heating upgrades.
- Work is competitively bid through a local trade ally network.
- Measures may include appliance replacements, heat pump installations, insulation upgrades, air sealing, and heat pump water heaters.
- Chelan PUD served approximately 25 homes in 2025 and plans to expand in 2026 and 2027.

Commercial/Industrial Energy Efficiency Programs

Chelan PUD's Commercial and Industrial (C&I) Energy Efficiency programs offer customers a combination of financial incentives, technical expertise, and strategic guidance to implement cost-effective energy-saving projects. These programs are a foundational element of Chelan PUD's demand-side resource portfolio, playing a critical role in reducing future load growth and lowering customer operating costs. The portfolio prioritizes long-term, cost-effective savings through a range of solutions, including custom retrofits, prescriptive measures, controls optimization, and operational improvements.

Lighting Rebates

Lighting project savings are calculated using a standardized lighting calculator that estimates annual kWh reductions based on fixture quantity, wattage, and operating hours. Incentives are offered at $0.30 per kWh saved, with an enhanced rate of $0.40 per kWh available to local government agencies. Incentives are paid on a per-kWh-saved basis, ensuring that larger energy savings result in higher incentive payments. Eligible measures include both interior and exterior retrofits using high-efficiency LED technologies.

When networked lighting controls — such as scheduling, occupancy sensors, or daylight harvesting — are included, the calculator captures the additional energy savings, which increases the total incentive amount. This consistent and transparent methodology not only ensures accurate savings estimates but also encourages customers to pursue deeper, more comprehensive efficiency upgrades.

Weatherization Rebates

Chelan PUD supports building envelope improvements in commercial and industrial facilities through the following incentives:

- Windows:
    - $32/sq. ft. for spaces primarily heated with electric resistance
    - $25/sq. ft. for spaces primarily heated with heat pumps
- Wall Insulation: $4/sq. ft.
- Attic/Roof Insulation: $4/sq. ft.

HVAC Rebates

Heating, ventilation, and air conditioning (HVAC) measures continue to be a significant source of commercial and industrial energy savings for Chelan PUD. Chelan PUD offers rebates for equipment upgrades and system conversions, using deemed savings values based on regional technical methodologies. All HVAC equipment must meet program efficiency standards.

These offerings help reduce energy consumption, lower customer operating costs, and remain among Chelan PUD's most cost-effective.

Available HVAC Rebates:

- Air-Source Heat Pump (ASHP) Retrofits — Customers replacing an existing electric-resistance heating system with a qualifying ASHP receive $3,000 per ton.

- Air-Source Heat Pump (ASHP) Upgrades — Customers upgrading an existing heat pump to more efficient model above code standards receive $400 per ton.
- Ductless Heat Pump (DHP) Retrofits — Customers replacing an existing electric-resistance heating system with a qualifying DHP system receive $3,000 per ton.
- Ductless Heat Pump (DHP) Upgrades — Customers upgrading an existing ductless heat pump to a more efficient model receive $1,000 per ton.
- Packaged Terminal Heat Pumps (PTHPs) —
    - $850 per unit for lodging facilities (e.g., hotels, motels, dormitories) replacing PTAC or zonal electric-resistance systems
    - $1,200 per unit for residential care facilities (e.g., nursing homes, assisted living)
- Thermostats — Customers replacing a non-web-enabled thermostat with qualifying connected models (retrofit only) receive $350 per unit.

Water Heating Rebates

Chelan PUD offers incentives for replacing existing electric-resistance water heaters in commercial applications with qualifying heat pump water heaters (HPWHs). These systems use ambient heat to raise water temperature rather than relying solely on electric resistance, resulting in significant energy savings.

- Incentives range from $1,750 to $2,850 per unit, depending on equipment tier and configuration (unitary or split-system).

Custom Projects

For commercial and industrial customers with energy efficiency opportunities that fall outside of prescriptive measures, Chelan PUD offers a custom project pathway. These projects are evaluated individually, with:

- Savings determined through engineering analysis
- Incentives based on calculated kWh reductions

This approach supports deeper retrofits and tailored solutions, including:

- Industrial refrigeration and cold storage upgrades
- Process efficiency improvements
- Advanced control systems and automation

Strategic Energy Management (SEM)

Chelan PUD's SEM program equips customers with tools, training, and technical support to embed energy efficiency into daily operations. The program emphasizes:

- Operational and behavioral changes that drive sustained savings
- Identification of capital improvements and customer project opportunities
- Long-term engagement to build internal energy management capacity
- SEM is proactive approach that helps customers reduce energy use, improve performance, and can deliver long-term efficiency gains.

Advanced Energy Managers

Chelan PUD is leveraging its advanced metering infrastructure, installed in 2023 and 2024, to help commercial customers significantly reduce energy use during unoccupied hours. As part of this effort, high school students are being trained and paid to analyze 15-minute load profile data. During off-hour "treasure hunts," they identify and quantify energy-saving opportunities. This innovative program not only conserves energy but also supports commercial buildings over

20,000 square feet in meeting Washington State's Clean Building Performance Standard. In addition to earning high school credit, the students are learning and applying their skills to help local businesses.

Demand Response

In compliance with WAC 194-40-330, Chelan PUD conducted a Demand Response Potential Assessment (DRPA) to inform resource planning for the performance period January 1, 2026, through December 31, 2029. The 2025 DRPA estimates cost-effective DR potential through 2045, using methodologies consistent with the NWPCC's Eighth Power Plan.

While the District has the ability to curtail loads during emergencies, the DRPA evaluated a variety of DR strategies across the residential, commercial, and industrial sectors, targeting both summer and winter peak periods. These strategies include direct load control, customer-initiated demand curtailment, and time-varying pricing mechanisms, all aimed at reducing peak demand and enhancing system flexibility. These strategies were assessed for their ability to reduce peak demand and provide system flexibility.

The assessment identified 21.2 MW of achievable winter DR capacity and 21.9 MW of achievable summer DR capacity by 2045. The residential sector represents the largest share of this potential. Among the most cost-effective and high-potential DR products were data center curtailment and residential smart thermostats, both of which offer value across seasons. In the summer, irrigation load control was also identified as a cost-effective opportunity.

It is important to note that the value of avoided distribution capacity can vary significantly by location within Chelan PUD's service territory. Additionally, implementation costs for DR programs are often highly utility-specific and may affect overall cost-effectiveness. The 2025 DRPA did not account for operational or resource constraints that may limit Chelan PUD's ability to deploy multiple DR programs simultaneously. Therefore, Chelan PUD has determined based on the results of the DRPA and its own assessment about what is realistic and achievable that the District will focus on data center DR programs as they are expected to be the most efficient to implement. In the CEIP, Chelan PUD will establish goals of 4.3 MW of summer DR and 3.3 MW of winter DR by 2030 and 14.6 MW of summer DR and 12.5 MW of winter DR by 2034. These data center opportunities have recently been identified, and an analysis of feasibility and actual cost-gathering to implement these programs locally is still ongoing.

Chelan PUD recognizes the increasing importance of demand-side flexibility in a decarbonizing and dynamic energy system. As part of its long-term planning, the District will continue to evaluate DR response opportunities that align with customer needs, system reliability, and evolving state energy policy.

Portfolio Analysis

The District is expected to be able to serve its native retail load throughout the planning period (2025-2034) with the power supply for new Large Loads being separately evaluated. The District is expected to meet Washington State RPS renewable requirements and CETA requirements through this period. Additionally, Chelan PUD's resource portfolio is comprised primarily of carbon-free, base load, reliable, low-cost hydro resources. For all these reasons, as in prior analyses, no new generating resources were added to the portfolio of resources. However, given the evolution of the marketplace and to mitigate risk under different load paradigms, the District is evaluating the feasibility of diverse new generating resources.

Portfolio Costs

The hydroelectric facilities' costs shown in **Table 2** and **Chart 6** represent all costs incurred, including debt service, operations and maintenance (O&M), taxes, reserve fund requirements and contractual fees. The Nine Canyon cost is the District's power purchase contract payments to Energy Northwest.

The 2024 cost for the District's existing portfolio is shown in **Table 2**. These costs were calculated in two ways. The second column, reading left to right, are the actual cost per megawatt-hour based on actual costs and actual generation in 2024. Columbia River runoff conditions were 73% of average and Lake Chelan runoff conditions were 64% of average in 2024. Wind generation conditions at Nine Canyon were below average at 94%. The column on the right was calculated using actual 2024 costs and average hydro and wind generation for any given year. This column illustrates what current costs were without the effects of runoff (including timing), wind variability and other factors, including unit outages and spill. As seen in the table, cost per megawatt-hour of generation can vary significantly depending upon actual generation including the aforementioned variables. This is because almost all costs are fixed, that is, they don't vary with the amount of generation (e.g., debt service, taxes).

Table 2
District's Existing Portfolio Cost
2024

Project	$/MWh w/actual generation	$/MWh w/ average generation
Rocky Reach	$23.31	$17.22
Rock Island	$71.69	$53.90
Lake Chelan	$28.60	$24.56
Nine Canyon	$49.45	$44.66

Chart 6 describes the projected base District portfolio costs by resource and relative size of each resource. To address the uncertainty in the District's hydro portfolio costs, two additional scenarios were developed along with the base costs' projection. The high scenario represents a 20% overall increase in hydro costs and the low scenario represents a 5% overall decrease in hydro costs. The weighted average cost of all resources under these scenarios are shown as dotted lines.

Hydro

The District forecasts the future costs of the hydro projects by compiling long-term operating plans and capital replacement programs, which are then incorporated into the forecasted debt service requirements of each facility. This cost-based activity is then adjusted to include other long-term power contract requirements to determine the overall cost of production.

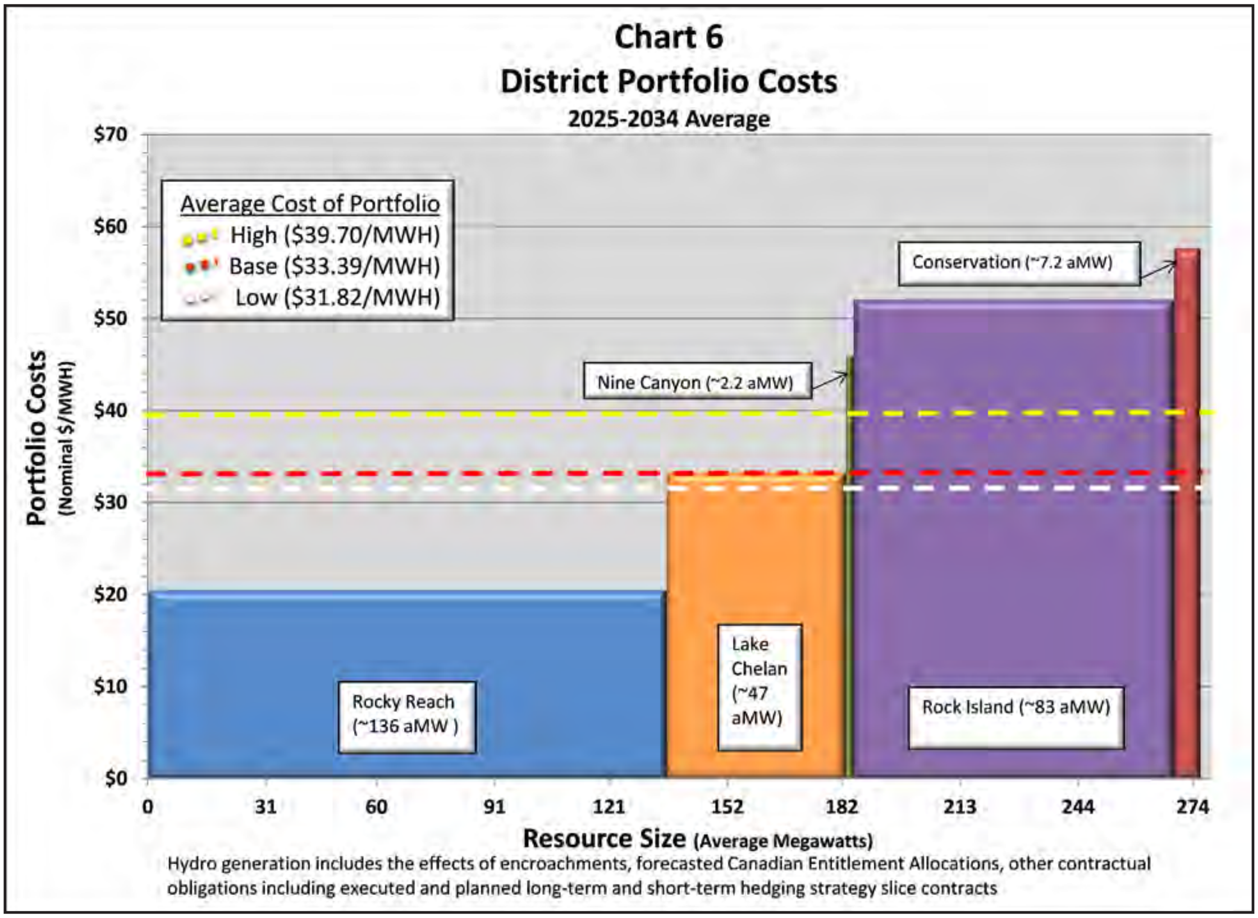
Examples of long-term power contract requirements include, but are not limited to:

- Capital Recovery Charge (base scenario-50% of average annual capital expenditures)
- Debt Reduction Charge (base scenario-3% of outstanding project debt)

Examples of significant capital and/or operational requirements include, but are not limited to:

- Costs associated with license and HCP implementation
  - Fish survival, hatchery programs, etc.
  - Plant rehabilitation, improvements and repairs

The forecasted hydro O&M costs for the base case scenario in this IRP consist of general cost growth rates for standard programs, while project-specific O&M such as unit



overhauls, licensing, fish, hatchery and major park maintenance are accounted for with specific forecasts for each project. The average project O&M growth rates are:

- Rocky Reach — ~3.5%
- Rock Island — 2.5%
- Lake Chelan — 3.0%

Debt service is driven by existing debt schedules and forecasted financing needs that are driven by specific project capital requirements. In addition, the anticipated use of other long-term power contract requirements such as the debt reduction charge account and capital recovery charge account are included as offsets to future debt service needs.

Nine Canyon Wind

The projected future costs of production at the Nine Canyon Wind Project are taken from an annually updated budget that includes the next year and projected future years. The budget is developed by Energy Northwest in conjunction with project participants.

Since increasing approximately 70% in 2008 due to higher-than-expected maintenance and repair costs and the cessation of anticipated federal Renewable Energy Production Incentive payments, the cost of production rates had remained fairly constant until the late 2010s. In mid-2022, the Phase I and II debt was paid in full. Rates declined by about 20% which was a combination of increasing O&M, increased decommissioning funding and decreased (to zero) debt. Rates have since declined another nearly 30% due to decommissioning funding being deeply cut. Rates are again planned to hold fairly steady through the remaining life of the purchase contract which expires in 2030. Currently, Energy Northwest is beginning to lead the Nine Canyon purchasers through an evaluation to determine the time and costs required to rehabilitate the project to extend its life.

Hedging Strategy

Chelan PUD has a comprehensive forward hedging strategy. The District pursues the sale of market-based products such as slice contracts (i.e., a percentage share of project capacity and energy), block sales (i.e., a predetermined quantity of energy) and/or other products approved by the District's internal Power Risk Management Committee and outlined in its Power Risk Management Policy to help manage wholesale revenue risk and stabilize such revenue at least five years into the future. Typically, the District uses a stair-stepped approach to hedging with more hedged in the near-term years and less hedged in future years.

Chelan PUD began supplying Microsoft's new data center campus in Malaga with up to 18 MW of surplus hydroelectric power at market-based rates when the new complex opened in August 2025. The new data center falls under the District's Large Loads category, or those loads > 5 aMW, as discussed in the Load Forecast section. The power is delivered to the newly constructed $86.5 million Jumpoff Ridge substation, which was paid for by Microsoft.

In 2024, Chelan PUD established a framework to serve Large Load customers with three options for power supply. For short-term supply, Chelan PUD procures wholesale energy from the market and resells it to the Large Load customer. The second option, customer choice, allows Large Load customers to identify and procure wholesale energy, which Chelan PUD purchases and resells to them. The last option involves a negotiated contract where, at the District's Board of Commissioners' discretion, the District negotiates a contract that could include surplus hydropower consistent with its wholesale energy marketing strategy. The District utilizes this structure to protect the interest of customer-owners and protect the assets of Chelan PUD, while finding solutions to meet the region's growing energy needs. Additionally, Large Loads are contractually responsible for meeting the renewable requirements of CETA (see Regulatory & State Statutory Requirements — CETA) with their power sources.

The District used the framework to negotiate a contract with Microsoft for a five-month term using Chelan PUD's surplus hydropower at market-based pricing. The power supply for the data center from 2026 to 2040 has not yet been determined. The District is not obligated to provide electricity from its hydropower resources. Microsoft can choose to source power from the wholesale energy market or negotiate another contract with Chelan PUD.

Central Washington, including Chelan, Douglas, and Grant counties, has grown to be a data center hub, largely due to the Washington state sales and use tax exemption for data centers in rural counties. In November 2025, Chelan PUD submitted a Minority Report to the Washington State Governor's Data Center Workgroup in response to some of the group's adopted recommendations. The District stated its strong belief that policy should enable, not impede, utility-led action by aligning timelines, streamlining permitting, and removing barriers that slow the development of new, clean energy resources. The District did so by stating that ensuring a resilient clean energy future will depend on giving utilities the flexibility and certainty to do what they do best: plan, build, and operate the systems that keep Washington powered. The District urged the state to resist expanding its role or administrative footprint through the creation of new offices and agencies and instead focus on removing policy and process barriers, including streamlining siting and permitting, reevaluating clean energy policy timelines, supporting firm resource technologies, improving load forecasting, and preserving local ratemaking authority.

Portfolio Results

The District analyzes its forecasted portfolio of resources in relation to its load forecasts. The load/resource balance, service reliability and environmental impacts are all factors considered and evaluated.

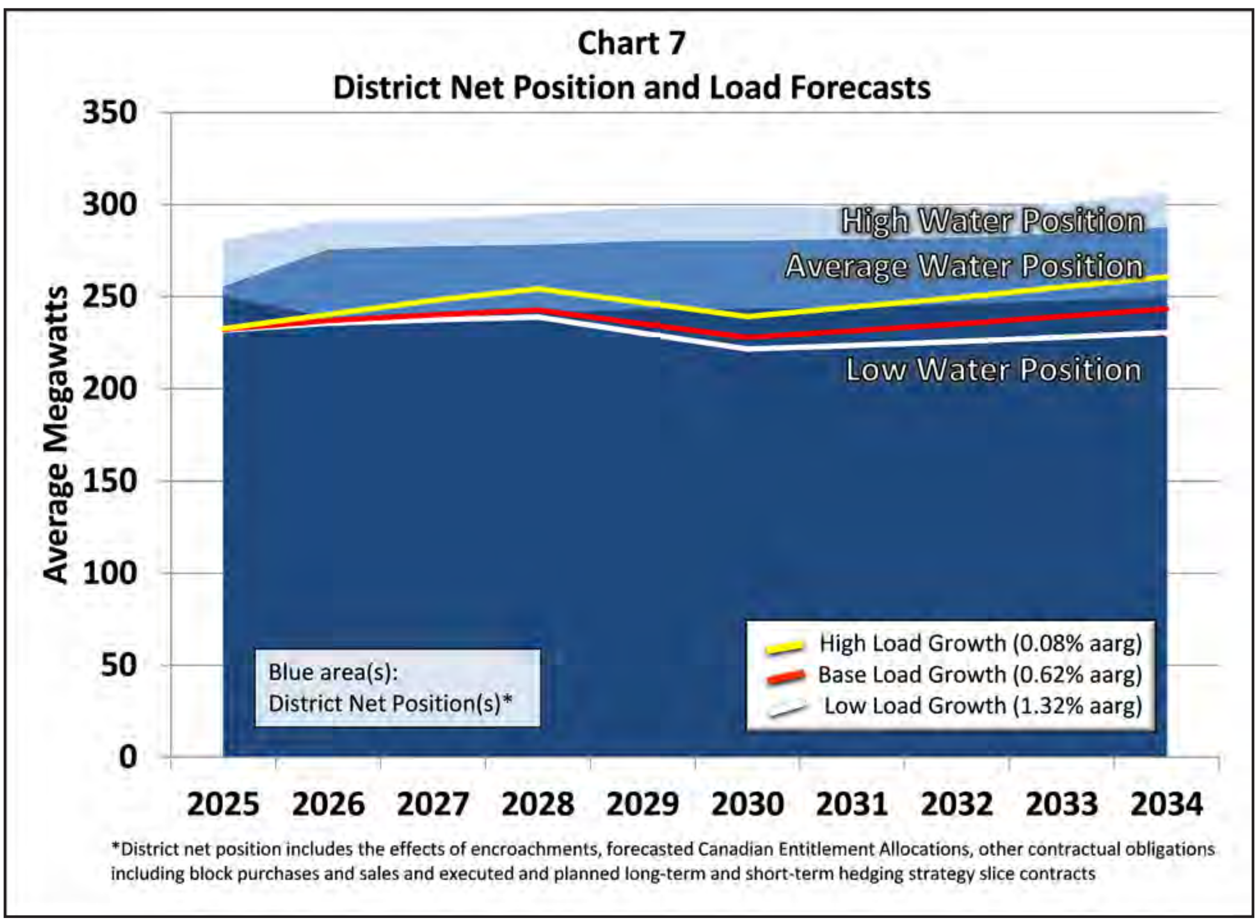
Although it is not adding new generating resources to serve native load, the District is focused on three major categories of risk which include uncertainties related to:

- Electricity usage by the utility's retail electric customers (loads)
- Streamflows that affect the availability of hydroelectric generation (volume and timing)
- Operational or outage risk

Load/Resource Balance

For this IRP, the District's existing mix of resources, at low, average, and high levels of hydro generation, was stressed with the low, base, and high load forecasts. **Chart 7** represents each of these net positions and load projections.

As mentioned previously, analysis continues to indicate that Chelan PUD is expected to be able to serve its native retail load throughout the planning period without any new generating resource additions. The amount of demand-side resources included in this evaluation has decreased from what was included in the 2023 IRP progress



report to match Chelan PUD's 2026 required 10-year conservation plan submittal to Commerce that is approximately 1.49 aMW per year through the study period (based on 2025 actual estimates and the 2025 CPA previously discussed). Conservation has the effect of reducing the amount of renewable generation required under Washington's RPS because that requirement is based on a percentage of retail load.

More detail behind the District's load forecasts, resources and contracts can be found in **Appendix A** — Portfolio Detail & Assumptions.

Service Reliability

The District's load/resource balance throughout the planning period was modeled using three hourly time periods per month. The District expects to have enough resources available to exceed the expected hourly peak load forecast for each month, along with meeting reliability operating reserve requirements through the planning period, thus providing for service reliability. In addition, to consider the impact of streamflow variability in RA planning, the District currently assesses this metric under adverse (1 in 20) streamflow conditions. As previously mentioned in the Resource Adequacy section, Chelan PUD is involved in the WPP effort to develop a robust Northwest capacity RA program that will allow utilities to forecast and manage RA in a coordinated manner. Planning reserve margins for the District under the WRAP are presented in **Appendix A — Table 5**.

Environmental Impacts

The District's hydropower and wind generation do not produce any air emissions. **Table 3** shows Chelan PUD's calculated fuel mix for 2023 (the most recent available from Commerce) on an annual basis. The District continues to sell a portion of its hydro-electric and wind energy in resource specific transactions. These are accounted for in the District's fuel mix disclosure. Additionally, on some hours, depending upon load and hydro conditions, the District is a net purchaser in the wholesale market. The District's current target for the percentage of retail load to be served using renewable resources during 2025–2029 is 80%. This target reflects Chelan PUD's plan to continue to serve its retail electric customers primarily using existing hydropower resources. Establishing an 80% target places Chelan PUD in the position of meeting CETA's 2030 requirement early to serve at least 80% of retail load with renewable and nonemitting resources.

As detailed in the Regulatory & State Statutory Requirements section, the reduction of GHG and carbon emissions has been explicitly enacted into Washington State law through CETA and the CCA. Any proposed change to the District's mix of generating resources in the future would need to be evaluated for its environmental impacts.

Beginning in 2019, RCW 19.280.030 requires utilities to consider the social cost of GHG emissions when (i) evaluating and selecting conservation policies, programs and targets; (ii) developing integrated resource plans and clean energy action plans; and (iii) evaluating and selecting intermediate term and long-term resource options. In response to that requirement, the District notes that its generating resource portfolio does not contain emitting resources.
Any changes in the District's power supply will be evaluated and comply with environmental regulatory requirements.

Table 3 2023 Fuel Mix	
Generation Type	**District Calculated Fuel Mix**
Hydro-electric	80.85%
Wind	0.01%
Unspecified	19.14%
TOTAL	100.00%

10-year Clean Energy Action Plan (CEAP)

The following is the District's 10-year CEAP as required by RCW 19.280. The CEAP is intended to identify the specific actions to be taken by a utility for implementing sections 3 through 5 of CETA at the lowest reasonable cost while meeting an acceptable RA standard and consistent with its integrated resource plan. Additional information on CETA is provided in the Regulatory and State Statutory Requirements section.

CETA Section 3

CETA section 3 required a utility to eliminate coal-fired resources from its allocation of electricity by the end of 2025. As detailed in the Resources and Portfolio Analysis sections, the District's current resource portfolio consists of predominantly hydro resources. Through this IRP, the District determined it will retain that mix of generating resources through the 2025-2034 planning period.

Historically, the District has engaged in purchasing unspecified electricity from the energy market for purposes of hedging risk. Unspecified electricity is electricity where the generation source is unknown at the time of purchase. Due to the lack of upfront identification of a generation source, unspecified electricity purchases pose a unique challenge for CETA compliance. As previously mentioned, in 2025, CETA was amended through HB 1329 to allow unspecified power purchases after 2025 for contracts up to three months in length. A contract length of up to six months is allowed if the power will be used to meet WRAP requirements. To the extent Chelan PUD purchases unspecified electricity during 2025-2034, it intends to do so consistent with these new requirements.

CETA Section 4

CETA section 4 requires utilities, beginning in 2030, to meet a GHG neutral standard by (i) pursuing all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load, using the methodology established in RCW 19.285.040, if applicable; and (ii) using electricity from renewable resources and non-emitting electric generation in an amount equal to 100% of the utility's retail electric loads over defined multi-year compliance periods. Utilities may satisfy up to 20% of their compliance obligation for part (ii) with an alternative compliance option.

Through this IRP, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2025-2034 planning period, provided the District's contract for wind output with Energy Northwest is extended, along with any other resource additions. Beginning in 2030, the District may satisfy up to 20% of its compliance obligation with an alternative compliance option, most likely RECs. As explained in the Hedging Strategy section, the District has a newly adopted framework for Large Loads that could result in the District serving Large Loads from its own resources, or third-party resources, during the planning period. Either way, Large Loads will be contractually responsible for meeting CETA requirements.

CETA Section 5

CETA section 5 adopts a state policy that nonemitting electric generation and electricity from renewable resources supply 100% of all sales of electricity to Washington retail electric customers by January 1, 2045.

Through this IRP, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2025-2034 planning period, provided the District's contract for wind output with Energy Northwest is extended, along with any other resource additions. Depending on load growth, along with any diversification goals identified by the District, the District may explore resource growth towards the end of the planning period.

Additional CEAP Considerations

RCW 19.280 requires that a utility's CEAP be informed by and consistent with other parts of a utility's IRP. This section references back to specific sections of this IRP that informed the actions identified in this CEAP.

The Electric Vehicles section details how anticipated levels of zero emissions vehicle use in the District's service area during the planning period impacted the IRP native load forecasts.

Table 1 in the Conservation section details the conservation and efficiency targets the District intends to pursue from 2025 through 2034.

The Resource Adequacy section explains that the District uses the WRAP RA standards as defined by the WRAP program as its RA standard.

The Demand Response section explains that the District will try to acquire 4.3 MW of summer DR and 3.3 MW of winter DR by 2030 and 14.6 MW of summer DR and 12.5 MW of winter DR by 2034.

As noted in the District Transmission section, the District has not identified any further transmission needs to meet its energy or reliability needs that would require expansion or upgrade.

Final Remarks

Chelan PUD intends to retain its existing generating resources while implementing its 2025 CPA results and 2025 DRPA results. Complying with both the renewable resources and conservation portions of the Washington State RPS remains a significant focus for the District and the addition of DR potential through CETA is a more recent focus. As detailed in the CEAP, the District's retention of its existing supply-side resources, combined with the potential purchase of RECS, should comply with all CETA requirements that are applicable during this planning period. The District will continue to monitor uncertain variables that affect its load/resource balance, including streamflows, native load and the availability of some generating units undergoing significant repair and rehabilitation. Additionally, the District will continue to evaluate and implement its hedging strategy to help reduce the risks associated with these and other uncertainties.

Chelan PUD will publish an IRP Progress Report in 2027.

Appendix A — Portfolio Detail & Assumptions

Resources

Hydro

- To represent the streamflow uncertainty, historical monthly re-regulated stream flow data, 1994-2017, supplied by PNUCC and actual hydro project data from 2018-2023 was grouped together to create average, low and high stream flow scenarios. The District recently switched to a 30-year dataset to capture more recent/relevant streamflow years as other regional entities switched as well. The average scenario is the average of the entire dataset, the low scenario is the bottom 20th percentile, and the high scenario is the top 20th percentile. The monthly values in each scenario were then allocated to each hour using normalized historical hourly flow values.
- A model that is informed with system constraints (capacity, pond limits, outage estimates, etc.) is used to convert the hourly stream flow estimates into generation.
- For each month, three time periods are modeled: one representing Monday – Friday, one representing Saturday and one representing Sunday. The model requires hourly inputs for each time period. The model optimizes the generation within each time period. The outputs are then aggregated up to a monthly and annual granularity for reporting.
- Generation is net of all project obligations (i.e., Canadian Entitlement Allocations (CEAs) and encroachments)
- Rocky Reach – Chelan PUD's share (net of long-term purchaser contracts and executed and planned slice contracts)
    - 18.46% -1/2025 through 12/2034
- Rock Island – Chelan PUD's share (net of long-term purchaser contracts and executed and planned slice contracts)
    - 24% - 1/2025 through 12/2034
- Lake Chelan – Chelan PUD's share
    - 100% - 1/2025 through 12/2034

Wind

- All available historical Nine Canyon hourly wind generation (2004-2024) was used to calculate average energy

Conservation

- Used the quantities from the 2025 CPA (also used for RPS compliance in January 2026)

Contracts

Long-term Power Sales

- Rocky Reach
  - Alcoa – 26% - 1/2025 through 10/2028
  - Avista – 5% - 1/2026 through 12/2030
  - Avista – 10% - 1/2031 through 12/2034
  - Douglas – 5.54% - 1/2025 through 12/2034
  - Puget – 25% - 1/2025 through 12/2034
- Rock Island
  - Alcoa – 26% - 1/2025 through 10/2028
  - Avista - 5% - 1/2026 through 12/2030
  - Avista – 10% - 1/2031 through 12/2034
  - Puget – 25% - 1/2025 through 12/2034

Executed and Planned Slices of Rocky Reach & Rock Island

- "Slice of the system" market-based contracts as part of long-term hedging strategy
- Slice contracts represent between 20% and 46% of the capacity and energy of Rocky Reach and Rock Island between 2025-2034
- Slice contracts (executed and planned) are removed from Chelan PUD's shares of Rocky Reach and Rock Island listed under "Resources" above

Load

- The three native load forecasts represent average annual rates of growth of : .08%-low, .62%-base, 1.32%-high

Table 4 shows the District's average annual resources for the planning period. The generation is the amount available to serve load under normal hydro conditions and includes the effects of encroachments, fish and other spill, forecasted CEA's, the long-term power sales contracts and executed and planned slice contracts.

Table 4
District's Average Annual Resources (aMW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Net Rocky Reach Gen	113	139	139	139	139	139	139	139	139	139
Net Rock Island Gen	72	83	84	84	85	85	85	85	85	85
Net Lake Chelan Gen	44	47	47	47	47	47	47	47	47	47
Net Nine Canyon Gen	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Conservation	1.73	2.56	3.44	4.48	5.67	7.08	8.72	10.60	12.68	14.93

Resource Adequacy

Table 5
Final WRAP
Planning Reserve Margins as a Percentage of Median Load

	2025	2026	2027
January	17.5%	12.5%	13.2%
February	18.4%	11.7%	10.6%
March	26.1%	27.2%	18.8%
June	26.2%	22.3%	TBA
July	14.5%	14.2%	TBA
August	16.1%	18.1%	TBA
September	14.2%	20.5%	TBA
November	23.1%	29.4%	TBA
December	12.0%	12.7%	TBA

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Appendix B — Washington State Electric Utility Integrated Resource Plan Cover Sheet 2025

	Base Year			5 Year Estimate			10 Year Estimate		
Estimate Year		2024			2029			2034	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	470.50	268.80	228.60	522.10	285.80	235.14	519.60	279.70	243.27
Exports									
Resources:									
Future Conservation/Efficiency				7.98	5.56	5.67	24.00	19.80	14.93
Demand Response				2.50	3.50		12.50	14.60	
Cogeneration									
Hydro	419.00	220.00	189.00	437.00	237.00	198.00	437.00	237.00	198.00
Wind	2.27	0.04	2.00	1.27	0.63	2.22	1.27	0.63	2.22
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA									
Other									
Imports	50.00	49.00	38.00						
Distributed Generation									
Undecided				74.00	40.00	30.00	45.00	8.00	29.00
Total Resources	471.27	269.04	229.00	522.75	286.69	235.89	519.77	280.03	244.15
Load Resource Balance	0.77	0.24	0.40	0.65	0.89	0.75	0.17	0.33	0.88

The following notes help to describe the numbers in the table above.

Requirements

Loads

- Peak loads are based on expected load factors, by temperature and by sector, applied to the annual sector energy forecasts.
- Annual energy loads are based on the District's Base Native Load Growth Forecast of 0.62%.
- Peak and annual energy loads, including the base year, 2024, are adjusted for normal weather (i.e. an expected or 1 in 2 peak).
- Future peak and annual energy loads do not include conservation savings or demand response.

Resources

Hydro

- For all years, it was assumed that during a single hour winter peak demand period, all projects would be at full seasonal capability. For all years, it was assumed that during a single hour summer peak demand period, *1936-37 PNUCC critical period generation was available to all projects. Values reported are net of encroachments and CEAs.
- For all years, annual energy was calculated by using *1936-37 PNUCC critical period generation data. Values reported are net of encroachments and forecasted CEAs.

- For all years, hydro is reported net of long-term sales contracts and executed and planned slice contracts.

Wind

- Base year (2024) wind data reflects actual Nine Canyon experience in that year.
- 2029 and 2034 projected peak wind capacity is based on median (50th percentile) hourly Nine Canyon historical generation (2004-2024).
- 2029 and 2034 projected average annual wind energy is based on median (50th percentile) average annual energy from Nine Canyon historical generation (2004-2024).

Acronyms

aarg	Average Annual Rate of Growth
AI	Artificial Intelligence
ACE	Affordable Clean Energy
AIP	Agreement in Principle
AMI	Advanced Metering Infrastructure or Area Median Income
aMW	Average Megawatt
ASHP	Air-Source Heat Pump
BA	Balancing Authority
BAA	Balancing Authority Area
BC	British Columbia
BEV	Battery Electric Vehicle
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBO	Congressional Budget Office
CCA	Climate Commitment Act
CDCAC	Chelan-Douglas Community Action Council
CEA	Canadian Entitlement Allocation
CEAP	Clean Energy Action Plan
CEIP	Clean Energy Implementation Plan
CEITC	Clean Electricity Investment Tax Credit
CEPTC	Clean Energy Production Tax Credit
CETA	Clean Energy Transformation Act
C&I	Commercial and Industrial
CO2	Carbon Dioxide
CBO	Congressional Budget Office
CPA	Conservation Potential Assessment
CPP	Clean Power Plan
CRA	Congressional Review Act
DHP	Ductless Heat Pump
DOE	Department of Ecology; Department of Energy
DR	Demand Response
DRAC	Demand Response Advisory Committee
DRPA	Demand Response Potential Assessment
DVR	Demand Voltage Regulation
EDAM	Extended Day-Ahead Market
EFSEC	Energy Facility Site Evaluation Council
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EO	Executive Order
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HB	House Bill
HCP	Habitat Conservation Plan
HDL	High Density Load
HFC	Hydrofluorocarbons
HP	Heat Pump
HSPF	Heating Season Performance Factor
HPWH	Heat Pump Water Heater
HVAC	Heating, Ventilating and Air Conditioning
IECC	Internal Energy Conservation Code
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISP	Integrated System Plan
ITC	Investment Tax Credit
KW, kWh	Kilowatt, Kilowatt-hour
LFP	Lithium-ion Phosphate

LI	Low Income
Li-S	Lithium-Sulphur
LOLEV	Loss of Load Events
LOLP	Loss of Load Probability
LVT	Line-Voltage Thermostat
LVCT	Line-Voltage Communicating Thermostat
MIP	Markets+ Independent Panel
MW, MWh	Megawatt, Megawatt-hour
NEPA	National Environmental Policy Act
NEEA	Northwest Energy Efficiency Alliance
NEVI	National Electric Vehicle Infrastructure
NIPPC	Northwest & Intermountain Power Producers Coalition
NWPCC	Northwest Power and Conservation Council
NWS	Non-Washington Sink
OBBB	One Big Beautiful Bill of 2025
O&M	Operations and Maintenance
OFM	Office of Financial Management (Washington State)
PHEV	Plug-in Hybrid Electric Vehicle
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
PTC	Production Tax Credit
PTCS	Performance Tested Comfort System
PTHP	Packaged Terminal Heat Pumps
PUD	Public Utility District
QCC	Qualifying Capacity Contribution
RA	Resource Adequacy
RCP	Representative Concentration Pathways
RCW	Revised Code of Washington
REC	Renewable Energy Credit
RMJOC	River Management Joint Operating Committee
RPS	Renewable Portfolio Standard
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SALT	State and Local Tax
SB	Senate Bill
SCC	Social Cost of Carbon
SEER	Seasonal Energy Efficiency Ratio
SEM	Strategic Energy Management
SPP	Southwest Power Pool
TOU	Time of Use
TRL	Technology Readiness Level
UW	University of Washington Hydro/Computational Hydrology Research Group
VaR	Value at Risk
WAC	Washington Administrative Code
WECC	Western Electric Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WREGIS	Western Renewable Energy Generation Information System
WSU	Washington State University
WWGPI	West-Wide Governance Pathways Initiative
ZEV	Zero Emission Vehicle

Glossary

Artificial Intelligence (AI)

The simulation of human intelligence processes by machines, particularly computer systems. These processes include learning (the acquisition of information and rules for using it), reasoning (using rules to reach approximate or definite conclusions) and self-correction. AI technologies include machine learning, natural language processing, robotics and computer vision, among others. AI technology is advancing at a very rapid pace.

Average Annual Rate of Growth (aarg)

The average percentage increase in value of a given item over the period of a year. The energy load forecast is referred to in terms of the average annual rate of growth.

Average Megawatt (aMW)

A unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period (total energy in megawatt-hours divided by the number of hours in the time period).

Avoided Cost

The marginal cost that a utility avoids by not having to acquire one more unit of power whether by producing the power from owned resources, building new resources or purchasing it from another entity.

For evaluating future energy acquisitions, including conservation and demand response, Chelan PUD uses a forecast of wholesale power market prices as its avoided cost measure as well as an adder for the forecast of carbon value due to its surplus energy resource position.

Base Load Generation Resource

Electric generation plants that always run, except in the case of repairs or scheduled maintenance, to at least cover a minimum level of demand on an electrical supply system that exists 24 hours a day through the year.

Battery Electric Vehicle (BEV)

A vehicle that uses only batteries as the source of energy to move the vehicle.

Biomass Resource

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants and municipal wastes. Resulting biogas is recovered and burned for heat and energy production. These biofuels are considered to be short-term "CO_2 neutral", meaning they typically remove CO_2 from the atmosphere and give up the same amount when burnt.

Block Power Sales

A power sales contract that establishes a fixed amount of energy to be sold for a specific period of time at a fixed price.

Canadian Entitlement Allocations (CEAs)

Energy returned to Canada to fulfill the obligation under the Columbia River Treaty between Canada and the United States for additional water storage constructed in Canada to help regulate hydroelectric generation. Canada was entitled to one half the downstream power benefits resulting from Canadian storage under the treaty. The Treaty has no expiration date, but operational elements of a basic feature of the Treaty, flood control, expired in 2024. In June 2024, the three Mid-C PUDs, Chelan PUD, Grant PUD and Douglas PUD, filed a lawsuit in District Court for the Eastern District of Washington suing the U.S. Entity. At issue is the share of the Canadian Entitlement that the Mid-C PUDs will be responsible for in a new Treaty.

Capacity

The maximum amount of power that a generator can physically produce.

Chelan PUD

In this report, all these references mean the legal entity of Public Utility District No. 1 of Chelan County. It is also referenced as the "District".

Clean Energy Action Plan (CEAP)

A Clean Energy Action Plan (CEAP) is intended to identify the specific long-term resource planning actions to be taken by a utility for implementing sections 3 through 5 of CETA at the lowest reasonable cost while meeting an acceptable resource adequacy standard. CEAPs are included as a part of IRPs.

Clean Energy Implementation Plan (CEIP)

A requirement under Washington's CETA, a Clean Energy Implementation Plan (CEIP), is intended to identify a utility's plans over the following four years to meet CETA's 2030 GHG neutral standard and 2045 100% clean electricity standard. A CEIP includes: 1) Interim target for the percentage of retail load to be served using renewable and nonemitting resources; 2) Specific targets for energy efficiency, demand response and renewable energy; 3) Specific actions to be taken to reach those targets; 4) Identification of highly impacted communities and vulnerable populations; 5) Report of the forecasted distribution of energy and nonenergy costs and benefits for the portfolio of specific actions; 6) Description of how the utility intends to reduce risks to highly impacted communities and vulnerable populations associated with the transition to clean energy. CEIPs must be completed every 4 years. The District's first CEIP was completed in 2021.

Clean Energy Transformation Act (CETA)

The Washington Clean Energy Transformation Act (CETA) (RCW 19.405), signed into law in May 2019, added requirements that relate to resource planning. Key sections of CETA include: 1) section 3—elimination of coal-fired resources from a utility's allocation of electricity by the end of 2025; 2) section 4— a GHG neutral policy requiring a utility to use electricity from renewable and nonemitting resources in an amount equal to 100% of its retail electric load over multiyear compliance periods starting in 2030 (up to 20% may be met with alternative compliance options); and 3) section 5 - a policy that electricity from renewable and nonemitting resources supply 100% of all sales of electricity to Washington retail customers by 2045. Unlike the Washington RPS, CETA considers all existing hydroelectric resources to be renewable.

Climate Change

Any long-term significant change in the "average weather" that a given region experiences. It involves changes in the variability or average state of the atmosphere over durations ranging from decades to millions of years.

Climate Commitment Act (CCA)

In May 2021, Governor Inslee signed into a law a comprehensive climate law, the Climate Commitment Act (CCA) (Senate Bill 5126), that establishes a "cap and invest" program that sets a limit on the amount of GHG that can be emitted in and imported into Washington and then auctions off allowances for companies and facilities that emit GHG until that cap is reached. Over time, the cap will be reduced, allowing total emissions to fall to match the GHG emission limits set in state law. Those limits were set in 2020 by the Washington legislature and are as follows: 2020 — reduce to 1990 levels, 2030 — 45% below 1990 levels, 2040 — 70% below 1990 levels and 2050 — 95% below 1990 levels and achieve net zero emissions. Auction proceeds go toward investing in climate resiliency, reducing pollution in disproportionately affected communities and expanding clean transportation. The first compliance period began in 2023.

Cogeneration

The production of electricity using waste heat (as in steam) from an industrial process or the use of steam from electric power generation as a source of heat.

Conservation

Any reduction in electric power consumption that results from increases in the efficiency of energy use, production, transmission or distribution (from RCW 19.280: Electric Utility Resource Plans and RCW 19.285: The Energy Independence Act).

Conservation Potential Assessment (CPA)

A study designed to estimate the potential for electricity conservation in a given geographical area.

Cryptocurrency

A digital currency in which encryption techniques are used to regulate the generation of units of currency and verify the transfer of funds, operating independently of a central bank.

Council

See Power Plan (Eighth, Ninth, etc.)

Demand

The rate at which electric energy is delivered to or by a system at a given instant; usually expressed in megawatts.

Demand Response

Changes in electric usage by end-use customers (e.g., residential, commercial, industrial) from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Demand Response Potential Assessment (DRPA)

A study designed to estimate the potential for demand response in a given geographical area.

Demand-Side Resource

Peak and energy savings from conservation measures, efficiencies and load control programs that are considered a resource because they serve increased demand without obtaining new power supplies.

Dispatchable Resource

A resource whose electrical output can be controlled or regulated to match the instantaneous electrical energy requirements of the electric system.

Distribution System

The utility facilities and equipment that distribute electricity from convenient points on the transmission system to the end-use customer.

District

See Chelan PUD.

Econometric

The application of mathematical and statistical techniques to economics in the analysis of data and the development and testing of theories and models.

Eighth Power Plan

See Power Plan (Eighth, Ninth, etc.)

Electric Vehicle (EV)

A broad class of vehicles that are powered, at least in part, by rechargeable batteries that can be restored to full charge by connecting a plug to an external electric power source. A plug-in hybrid electric vehicle (PHEV) shares the characteristics of both a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine, and of a battery electric vehicle (BEV), which uses batteries as its only source of energy to move the vehicle. The combustion engine in a PHEV works as a backup when the batteries are depleted. Additionally, the term zero emissions vehicle (ZEV) for vehicles that do not emit any emissions has gained popularity.

Eligible Renewable Resource

a) Electricity from a generation facility powered by a renewable resource other than fresh water that commences operation after March 31, 1999, where: (i) The facility is located in the Pacific Northwest; or (ii) the electricity from the facility is delivered into Washington state on a real-time basis without shaping, storage, or integration services; b) Incremental electricity produced as a result of efficiency improvements completed after March 31, 1999, to hydroelectric generation projects owned by a qualifying utility and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation in either case does not result in new water diversions or impoundments; and c) Qualified biomass energy (from RCW 19.285: The Energy Independence Act).

Encroachments

When a downstream hydro project is built and increases the tail water elevation of an upstream hydro project, capacity and energy of the upstream hydro project is reduced. To compensate for the loss of capacity and energy, the downstream project delivers energy to the upstream project.

Energy Imbalance Market

An EIM is a balancing energy market that optimizes generator dispatch within and between participating Balancing Authority Areas (BAAs) every 15 and five minutes.

Energy Independence Act

Refers to RCW 19.285, a ballot initiative passed in Washington State in November 2006. It is otherwise known as the Washington State Renewable Portfolio Standard (RPS.) Under the initiative, utilities with a retail load of more than 25,000 customers are required to use eligible renewable resources or acquire equivalent RECs, or a combination of both, to meet 3% of load by January 1, 2012, 9% by January 1, 2016 and 15% by January 1, 2020. The initiative also required that by January 1, 2010, utilities evaluate conservation resources using methods consistent with those used by the NWPCC and pursue all conservation that is cost-effective, reliable and feasible. Each utility must establish and make publicly available a biennial acquisition target for cost-effective conservation.

Fossil Fuels

They are hydrocarbons found within the top layer of the Earth's crust.

Fusion Energy

Energy produced by fusing two light atomic nuclei to form a heavier nucleus, releasing a significant amount of energy in the process. This is the same reaction that powers the Sun and other stars. The primary fuels for fusion are isotopes of hydrogen, specifically deuterium and tritium. They are hydrocarbons found within the top layer of the Earth's crust. Company's such as Helion One, LLC are racing to become the first to produce a sustained fusion reaction in a commercial operation.

Geothermal Resource

Energy from rock and/or water that is heated by contact with molten rock deep in the earth's core. The heat can be extracted and used for space heating or to generate electricity.

Greenhouse Gas (GHG)

Gases that are present in the earth's atmosphere which reduce the loss of heat into space and therefore, contribute to global temperatures through the "greenhouse effect".

Hedging

Establishing positions in the wholesale power markets with the intent of reducing risk resulting from uncertain fluctuations in all the variables that affect the District's net wholesale power revenue, of which stream flows, retail load and wholesale power market prices are primary drivers.

Hydro Resource

Facilities used to produce electricity from the energy contained in falling water (river, locks or irrigation systems).

Imagine 2075

Chelan PUD's 50-year visioning process, intended to help the District answer the questions of, "what is the District doing with the gifts it has inherited and how is it being a good steward to those customer-owners that come in the future?" and how to best align Chelan PUD for a resilient and prosperous future. The Imagine 2075 effort resulted in a 50-year vision that will be cascaded through business plans and other documents in 2025 and beyond.

Incremental Generation

Electricity produced as a result of efficiency improvements completed after March 31, 1999, to hydroelectric generation projects owned by a qualifying utility and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation in either case does not result in new water diversions or impoundments (from RCW 19.285: The Energy Independence Act).

Integrated Resources Plan (IRP)

An analysis describing the mix of generating resources and conservation and efficiency resources that will meet current and projected needs at the lowest reasonable cost to the utility and its ratepayers (from RCW 19.280: Electric Utility Resource Plans).

Integrated Systems Plans (ISP)

A holistic approach to energy planning that coordinates various components of the energy system, including generation, transmission, and distribution, to improve reliability, affordability and sustainability. It recognizes the interdependencies within the energy landscape and aims to create a comprehensive blueprint for meeting future energy demands.

Intermittent Resource

An electric generator that is not dispatchable and cannot store its fuel source, and therefore, cannot respond to changes in system demand.

Kilowatt (kW) and Kilowatt-Hour (kWh)

One thousand watts; the standard measure of electric power consumption of retail customers. A kilowatt-hour (kWh) is a measure of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit for one hour.

Landfill Gas

Methane gas from landfills, created when organic waste decomposes, is recovered and burned for heat and energy production. Burning methane converts it from a highly potent GHG (methane has 22 times the GHG impact of CO2) to CO2, which is much less potent.

Levelized Cost

The constant stream of values that produces the same present value as the non-constant stream of values, using the same discount rate. Costs are levelized in real dollars. For example, the amount borrowed from a bank is the present value of buying a house; the mortgage payment including interest on a house is the levelized cost of that house.

Load

The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customer.

The amount of kilowatt-hours of electricity delivered in the most recently completed year by a qualifying utility to its Washington retail customers (from RCW 19.285: The Energy Independence Act).

At Chelan PUD, load sectors include residential, commercial, industrial, electric vehicle, street lights, interdepartmental use, frost protection, irrigation and the following:

Data Centers & Similar Loads — loads that apply to data centers and similar computing or data processing loads, regardless of the number of servers/processors, including those related to rack space rental, hosting services, cryptocurrency mining, blockchain, data processing, or other loads up to 3 aMWs.

High Density Loads (HDL) — loads with intense energy use — 250 kWh per square foot or more per year with electrical loads up to 3 aMWs.

Large Loads — loads greater than 5 aMW.

In this IRP, the term "native load" is used to describe Chelan County retail loads served by Chelan PUD resources and the forecasted growth of these loads. Native load is separated out from existing Large Loads not forecasted to be served by Chelan PUD resources in the future and new Large Loads (those forecasted to begin in 2025 or later) for planning purposes as described in the IRP.

Load Forecasting

The procedures used to estimate future consumption of electricity. Load forecasts are developed either to provide the most likely estimate of future load or to determine what load would be under a set of specific conditions (e.g., extremely cold weather or changing demographics).

Load/Resource Balance

A comparative evaluation of future load forecasts in relation to the availability of demand-side and supply-side resources available to meet those future load needs.

Loss of Load Events (LOLEV)

The expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Loss of Load Probability (LOLP)

A measure of the probability that a system load demand will exceed capacity during a given period; often expressed as the estimated number of days over a longer period.

Megawatt (MW) and Megawatt-Hour (MWh)

One thousand kilowatts, or 1 million watts; the standard measure of electric power plant generating capacity. A megawatt-hour (MWh) is a measure of electric energy equal to one megawatt of power supplied to or taken from an electric circuit for one hour.

Nominal Dollars

Dollars that are paid for a product or service at the time of the transaction. Nominal dollars are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar (inflation); they reflect buying power in the year in which the transaction occurred.

Northwest Power and Conservation Council (NWPCC or Council)

See Power Plan (Eighth, Ninth, etc.)

Overgeneration Event

A requirement of RCW 19.280.020: "means an event within an operating period of a balancing authority when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility's energy delivery obligations and when there is a negatively priced regional market."

Peak Demand (Load)

The maximum demand imposed on a power system or system component during a specified time period.

Peak(ing) Resource

Power generated by a utility system component that operates at a very low capacity factor; generally used to meet short-lived and variable high demand periods.

Plug-In Hybrid Electric Vehicle

A vehicle that shares the characteristics of both a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine, and of a battery electric vehicle (BEV), which uses batteries as its only source of energy to move the vehicle. The combustion engine in a PHEV works as a backup when the batteries are depleted.

Portfolio

A set of supply-side and demand-side resources currently or potentially available to a utility.

Power Plan (Eighth, Ninth, etc.)

A 20-year electric power plan that guarantees adequate and reliable energy at the lowest economic and environmental cost to the Northwest. A new plan is developed every five years as a result of the Northwest Power Act of 1980 that authorized the formation of the Northwest Power and Conservation Council (NWPCC or the Council.) The Eighth Power Plan, the most recent, was adopted in early 2022. The NWPCC is also mandated to develop a fish and wildlife program to protect and rebuild populations affected by hydropower development in the Columbia River Basin and conduct an extensive program to educate and involve the public in their decision-making processes.

Probability

The likelihood or chance that something will happen.

Progress Report

A requirement of RCW 19.280.030: Electric utility resource plans, which reads "At a minimum, progress reports reflecting changing conditions and the progress of the integrated resource plan must be produced every two years…".

Real Dollars

Dollars that have been adjusted to remove the effects of inflation. Real dollars are sometimes called uninflated dollars, today's dollars or constant dollars.

Regression Analysis

A technique used for the modeling and analysis of numerical data consisting of values of a dependent variable (response variable) and of one or more independent variables (explanatory variables).

Renewable Energy Credit (REC)

A tradable certificate of proof of at least one megawatt-hour of an eligible renewable resource where the generation facility is not powered by fresh water, the certificate includes all the nonpower attributes associated with that one megawatt-hour of electricity, and the certificate is verified by a renewable energy credit tracking system selected by the department (from RCW 19.285: The Energy Independence Act).

Renewable Portfolio Standard (RPS)

A regulation that an electric power provider generate or purchase a specified percentage of the power it supplies/sells from renewable energy resources. Washington State's RPS is codified in RCW 19.285: The Energy Independence Act.

Renewable Resource

A resource whose energy source is not permanently used up in generating electricity.

Electricity generation facilities fueled by: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) biomass energy utilizing animal waste, solid organic fuels from wood, forest, or field residues or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (g) byproducts of pulping or wood manufacturing processes, including but not limited to bark, wood chips, sawdust, and lignin in spent pulping liquors; (h) ocean thermal, wave, or tidal power; or (i) gas from sewage treatment facilities (from RCW 19.280: Electric Utility Resource Plans).

Means: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) wave, ocean, or tidal power; (g) gas from sewage treatment facilities; (h) biodiesel fuel that is not derived from crops raised on land cleared from old growth or first-growth forests where the clearing occurred after December 7, 2006; or (i) biomass energy (from RCW 19.285: The Energy Independence Act).

Means: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) renewable natural gas; (f) renewable hydrogen; (g) wave, ocean, or tidal power; (h) biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests; or (i) biomass energy (from RCW 19.405: the Clean Energy Transformation Act).

Resource Adequacy

A measure defining when a utility has sufficient resources to meet customer needs under a range of conditions that affect supply and demand for electricity.

Resource Mix

The different types of resources that contribute to a utility's ability to generate power to meet its loads.

Scenario

A possible course of future events. In the report, scenarios are used to compare the District's existing portfolio of generating resources under a range of possible future conditions including various load forecasts and various hydro production cost forecasts.

Shape

Refers to the nature of power generation capability and loads to change in quantity over time; changing from day to day and month to month.

Slice Power Sales

A power sales contract for a specific percentage share of a generation project's capacity and energy for a specific period of time at a fixed price (i.e., there is no guarantee of the amount of energy that will result from the contract for resources such as hydro and wind where the fuel is driven by nature).

Solar Resource

The generation of electricity from sunlight. This can be direct as with photovoltaics, or indirect as with concentrating solar power, where the sun's energy is focused to boil water which in then used to provide power.

Substitute Resource

Reasonably available electricity or generating facilities, of the same contract length or facility life as the eligible renewable resource the utility invested in to comply with chapter 19.285 RCW requirements, that otherwise would have been used to serve a utility's retail load in the absence of chapter 19.285 RCW requirements to serve that retail load with eligible renewable resources (from WAC 194-37: Energy Independence).

Supply-Side Resources

Those power resources that come from a power generating plant or facility.

Surplus Energy

Energy that is not needed to meet a utility's load or contractual commitments to supply firm or non-firm power.

Transmission (System)

Often referred to as the "grid", it is the system of electrical lines that allows the bulk delivery of electricity to consumers typically between a power plant and a substation near a populated area. Due to the large amount of power involved, transmission normally takes place at high voltage (110 KV or above) and because of the long distances often involved, overhead transmission lines are usually used.

Value at Risk (VaR)

Duration VaR — metric that sets a value at risk over a set time period.

Energy VaR — metric that sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

Peak VaR — metric that sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme magnitude of emergency measures.

Waste-to-Energy Resource

Incineration process in which solid waste is converted into thermal energy to generate steam that drives turbines for electricity generators.

Wastewater-Treatment Gas Resource

Methane gas, given off in the digestion of sewage, is recovered and burned for heat and energy production. Sewage gas consists of approximately 66% methane and 34% CO2. Burning methane converts it from a highly potent GHG (methane has 22 times the GHG impact of CO2) to CO2, which is much less potent.

Weather-Normalized Load

Actual energy load data that has been mathematically adjusted to represent an energy load that would have occurred in an average weather year.

Western Energy Imbalance Market (WEIM)

In the fall of 2014, PacifiCorp joined the CAISO in its WEIM. The WEIM uses advanced technologies to automatically find and deliver the lowest cost energy to consumers on a real-time basis. By optimizing resources from a larger and more diverse pool, the WEIM better facilitates the integration of renewable energy that may otherwise be curtailed at certain times of the day, providing an added environmental benefit. Set to launch in 2026, the CAISO's Extended Day-Ahead Market (EDAM) is a voluntary day-ahead electricity market that will optimize the use of existing transmission and resources in the much larger day-ahead timeframe across an expanded western footprint.

Western Energy Imbalance Service (WEIS)

Beginning February 1, 2021, SPP began operations of its real-time Western Energy Imbalance Service (WEIS). SPP is also working to implement a day-ahead market, Markets+, expected to go-live in 2027. It's a conceptual bundle of services proposed by SPP that would centralize day-ahead and real-time unit commitment and dispatch to aid in the reliable integration of a rapidly growing fleet of renewable generation.

Western Resource Adequacy Program (WRAP)

The first West-wide capacity resource adequacy program being implemented by the Western Power Pool. In February 2023, the FERC approved the tariff for the WRAP. The WRAP is a voluntary program, but once an entity commits to joining the program it must follow the FERC tariff and commit to a binding season by January 2026.

Wind (Generation) Resource

Energy generated when wind turns the blades of a wind turbine which drive a generator. The longer the blades and the faster the wind speed (up to a point), the more electricity that is generated.

Zero Emission Vehicle (ZEV)

A vehicle that does not emit any air emissions or pollutants.

CHELAN COUNTY
www.chelanpud.org