P.U.D.
CHELAN COUNTY

PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY

INTEGRATED RESOURCE PLAN PROGRESS REPORT 2023

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2023 Integrated Resource Plan Progress Report

December 2023

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http://www.chelanpud.org/environment/operating-responsibly/integrated-resource-plan

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2023 Integrated Resource Plan Progress Report

Summary of Determinations

The District has completed its 2023 Integrated Resource Plan (IRP) Progress Report. This progress report is required by the Revised Code of Washington (RCW) 19.280: Electric Utility Resource Plans originally 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 2023-2032 planning period, the Board of Commissioners of Chelan County Public Utility District (Chelan PUD or District) has approved this 2023 IRP Progress Report and determined that:

- The District retain its current mix of generating resources.

And additionally:

- The District continue to evaluate and implement conservation and demand response (DR) programs based on the foundational work performed in the 2023 Conservation Potential Assessment (CPA).
- The District evaluate and determine power supply for new Large Loads (see Load Forecast section).
- The District 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 2023 IRP Progress Report includes the following:

- An update of the long-term forecasts of retail electric customer demand
- Revised costs and operational information for Chelan PUD's existing generating resources
- Updated data in regard to the District's existing operational and power sales contracts
- Amended conservation inputs to align with Chelan PUD's 2024 10-year conservation targets submittal to the Washington State Department of Commerce (Commerce) as required

- An update on regional and Chelan PUD's resource adequacy (RA) development
- Analyze the forecasted load/resource balance (using the District's existing portfolio of resources) with the aforementioned input changes, additionally 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 Clean Energy Transformation Act (CETA)
- Board approval of the 2023 IRP Progress Report
- Submittal of the final 2023 IRP Progress Report to Commerce by September 1, 2024, as required

Planning & Regulatory Environment

Resource Planning Situation

Chelan PUD is forecasted to be surplus to its own retail load needs throughout most of the current planning period (2023-2032). Evaluations are ongoing for the power supply of new Large Loads.

The District has some 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 resource (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.

Resource Adequacy

The current, voluntary RA standard was adopted in December 2011 by the Northwest Power and Conservation Council (NWPCC or Council). Regional adequacy assessments are not intended to apply directly to individual utilities because no utility has the same load and resource profile as the region. However, the probabilistic methodology imbedded in the standard is recommended for utilities to do their own assessments. The standard uses the system's loss of load probability (LOLP) as the adequacy metric with a maximum allowable LOLP of 5%. A single annual value is assessed, which identifies both energy and capacity problems. It is not intended to be a resource planning target.

In January 2023, the NWPCC published the 2027 power assessment. For the regional power supply to be adequate in 2027, the region will need to develop new resources at least as aggressively as the 2021 Power Plan outlines. The 2027 regional power supply would not be adequate if the region relied solely on existing resources, existing reserve levels, and with no new energy efficiency measures. If demand growth remains consistent with the plan's baseline forecast, then the power supply would be adequate with resources and reserves identified in the 2021 Power Plan's resource strategy. However, if future electricity market supplies are significantly limited, if new policy commitments to electrification accelerate demand growth, or if major resources are retired earlier than expected without replacement, then additional resources and reserves will be required to maintain system adequacy, as detailed in the 2021 Power Plan.

To better assess customer risk, the Council examined additional adequacy measures, in conjunction with the LOLP adequacy metric. The additional metrics provide information about the frequency, duration, and magnitude of potential shortfall events as follows:

- Loss of load events (LOLEV), sets a limit for the expected frequency of shortfall events to prevent an excessively frequent use of emergency measures
- Duration Value at Risk (VaR) sets a limit for shortfall duration during rare (once per 40 year) events
- Peak and Energy Value at Risk (VaR) set limits for the maximum capacity and energy shortfalls during rare (once per 40 year) events

Using this full suite of metrics, along with provisional thresholds that postulate the tolerable range of risk to avoid, the Council was able to provide a more complete assessment of system adequacy.

The 2021 Power Plan's resource strategy recommends that between 750 and 1,000 aMW of energy efficiency, at least 3,500 MWs of renewable resources, and 720 MWs of DR be acquired by 2027. The plan also highlighted the importance and need for achieving the increasing reserves requirement to respond to the growing short-term uncertainty in generation from significant additions of variable energy resources (primarily solar and wind generation). As part of this assessment, the resource strategy was tested under a large range of potential future conditions. Like the plan, the 2027 assessment confirms that an adaptive approach is required to maintain adequacy, from the perspective of ensuring that the full suite of adequacy metrics remain within their provisional thresholds.

This 2027 assessment finds that the 2021 Power Plan resource strategy is effective at eliminating nearly all summer shortfalls, when resource needs peak in the rest of the Western grid. Implementing the strategy does not eliminate winter shortfall events, but it does mitigate them by reducing shortfall event magnitude and shortening event duration to only a few hours during the morning and evening ramps.

New clean energy policies will result in a significant level of renewable generation built throughout the west, both within and outside the region. This projected renewable resource acquisition changes market supply and demand dynamics because the hourly pattern of renewable generation does not always coincide with the hourly pattern of greatest energy need. This leads to periods during certain times of the day with a surplus of very inexpensive market supply (mostly solar). During these periods, due to this increased market supply and persistence of lower prices, the Northwest is expected to consistently import more power than it has in the past. However, there also will be times within the same day, often during morning and evening ramps, when available market supply is smaller and more expensive than in the past, providing an opportunity for the Northwest to export to other regions in the West. The ability of Northwest hydroelectric and thermal systems to ramp up and down to respond to those changing market dynamics requires appropriate market signals, either from a regional reserve pooling effort or from an enhanced market structure.

In light of these changing dynamics, this 2027 assessment considers a number of potential market uncertainties. The findings indicate that out-of-region market supply uncertainties have, for the most part, a minimal effect on regional adequacy, assuming the Council's current market reliance limits. However, under certain future scenarios, results show regional adequacy levels becoming borderline or unacceptable. These scenarios include futures with high gas prices, continued supply chain challenges, increased demand (due to accelerated electrification without a supply and reserve increase), and lower than expected West-wide renewable generation acquisition.

As in the plan, the 2027 assessment found risk factors to monitor when determining how to implement and adapt the resource strategy

to the wide range of uncertainties the region faces. If regional planners observe increased demand due to accelerated electrification in any part of the region without an associated increase in resources and reserves, and/or resources of significant size are retired without replacement, the risk of adequacy issues increases significantly. The plan analysis identified these same risks and indicated that significantly larger builds of renewable resources and accompanying reserves would be required to maintain an adequate system. The resource strategy recommends that jurisdictions pursuing aggressive emissions reductions should evaluate adding more renewables to avoid these risks. The plan also recognized that additional energy efficiency would likely be cost-effective for those jurisdictions pursuing electrification policies. If the region is ineffective at coupling the investment recommendations from the plan with a coordinated reserve pooling effort of sufficient size to match the increase in the short-term uncertainty from load and generation, the region will be more susceptible to adequacy risk from the market.

The 2027 adequacy assessment highlights the limits of LOLP. According to the assessment, the region's LOLP is 4.4 percent if it does the bare minimum in adding new resources or if it follows the more robust resource strategy out in the 2021 Northwest Power Plan. However, the peak single-hour shortfall with the minimum strategy is 837 MW. That is more than twice the amount - 357 MW - with the more robust strategy. The total energy shortfall with the minimum strategy was 1,666 MWh, more than twice as much as the 590 MWh cumulative energy shortfall projected with the more robust strategy. All those values are within the threshold for what is considered adequate. For LOLP, as previously mentioned, that is a 5 percent chance of a load-shedding event, or one-in-20 years. For the new metrics, NWPCC staff is recommending a threshold that limits long duration and big magnitude (capacity and energy) events to once every 40 years, or 2.5 percent. Other scenarios included in the assessment also highlight the fact that not all shortfall events are equal. The high-demand scenario (due to rapid electrification across the West) modeled by the NWPCC staff has an LOLP of 17 percent, but an LOLEV of nearly .6 percent — that is higher than a one-in-two chance of shortfall in any given year. The projected longest duration would only be five hours, but the peak hourly shortfall would be nearly 4,800 MW and the annual energy shortfall would be just over 36,600 MWh. The proposed acceptable thresholds are between 2,000 MW and 3,000 MW for peak VaR and between 4,000 MWh and 8,000 MWh for energy VaR. The LOLP in the early coal retirement scenario is nearly 14 percent, and the LOLEV is .23, which is above the threshold of .2 events per year. However, the duration, peak and energy metrics are all under the acceptable limit.

During this time of significant uncertainty, the Council will continue to track these risk factors and revisit them in the annual adequacy assessment and its other efforts as part of the ongoing 2021 Power Plan implementation. NWPCC staff started talking with utilities and regional entities in early 2023. They plan to continue getting input until they recommend in mid-2025 to Council members which metrics to use in the next Power Plan.

Individual utilities within the Northwest are facing a wide range of future resource needs and are preparing for those needs in their IRPs. The District analyzed its own RA in the preparation of this 2023 IRP Progress Report.

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 WPP is pursuing Phase 3A of the WRAP, which began Oct 1st, 2021 and went through the summer 2023 season. It includes the beginning of implementation and the forward showing for the first four non-binding seasons. In Phase 3B, WPP will begin to operate under the governance and funding provisions set forth in the tariff, while continuing to conduct non-binding forward showings through winter 2024–2025. 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, effective load carrying capability, etc.) back to participants. As such, individual entities gain an understanding of their individual RA position. 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 between 2025 and 2028. Below summarizes some key elements of the program:

- The WRAP looks out 1 – 4 years to ensure adequate resource capability is available to meet customer demand.
- In a large portion of the WPP footprint, utilities manage RA individually and with different methods. The WRAP will allow utilities to forecast and manage RA in a coordinated manner.
- The WRAP will respect local autonomy over investment decisions and operations and will continue to respect the rights and characteristics of individual utilities, transmission service providers, Balancing Authorities (BAs) and other entities.
- The WRAP is voluntary to join, but once a utility joins, it is contractually committed to the requirements of the RA Program.
- The WRAP considers:
- Common measures of adequacy, including peak load standards and methods of measurement;
    - Common measures of resource contribution to RA;
    - An approach for the allocation of the regional adequacy requirement;
    - Methods for accessing the regional diversity and unlocking investment savings; and
    - Incentive and enforcement mechanisms.

The District has committed to joining the program and is actively contributing to the WRAP implementation.

Demand Response

The Council's Demand Response Advisory Committee The Council's Demand Response Advisory Committee (DRAC) supported the Council in development of updated DR supply curves for the Eighth Power Plan, finalized in 2022.

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 megawatts of DVR and 200 megawatts 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 integrated resource plans 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 demand-response 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. We would expect to see significant cost savings from greater regional collaboration to drive more efficiency into the system operations. A more aggressive examination would expand such a cost and benefit analysis to include the development of an organized or independently operated electricity market across the region. While any market design should protect the region's investments in its existing generation 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 total, 23 DR products were incorporated into DR supply curves. The Council estimates about 3,721 megawatts of summer load reduction potential and 2,761 megawatts 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.

CETA requires utilities to develop a DR potential assessment (DRPA). The District developed a DRPA in conjunction with its CPA in 2021. DR was not found to be cost effective for the District. Therefore, the target was set at 0 MW. A high-level assessment was conducted in 2022 that showed there could be value associated with DR activities. Chelan PUD is working with a consultant to develop a pilot program design for implementation in 2024 around energy management and managed electric vehicle charging. The next formal DRPA will be done in 2025.

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 Progress Report.

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 2023 IRP Progress Report 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, Governor Jay Inslee signed into law The Washington Clean Energy Transformation Act (CETA), 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.

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's next CEIP will be completed in 2025.

The Climate Commitment Act (CCA)

In May 2021, Governor Inslee signed into a law a comprehensive climate law, the CCA (Senate Bill (SB) 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.

The program, launched in 2023, is designed to financially encourage companies to reduce emissions by making allowances increasingly expensive. 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. 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.

In the first auction of February 28, 2023, the DOE sold nearly 6.2 million allowances for $48.50 apiece, netting nearly $300 million. 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.

Businesses paid about $557 million for 11 million carbon emission allowances in Washington's second cap-and-invest auction on May 31, 2023. Each allowance represents 1 metric ton of carbon dioxide (CO2). Competition was so intense that bidders broke the program's soft price cap. As a result, the DOE sold additional allowances in August from a reserve supply to help keep auction prices from becoming prohibitively expensive for complying companies. In May, bidders paid $56.01 per allowance for nearly 8.6 million allowances for carbon emissions in 2023 and $31.12 per allowance for future emissions in 2026. That is more than $4 above the soft price cap of $51.90 on August 9. At $56 per allowance, that adds about $28/MWh to Schedule C power — firm, undifferentiated power that is the backbone of power trading in the West.

Electric utilities received their free allowances in May 2023. The DOE divided up just over 14 million allowances between 56 utilities. Utilities can consign some or all of their allowances, giving them to the DOE to sell in the quarterly auctions. Electric utilities didn't receive their allocation in time to consign any allowances before the May 31 auction. With no consigned allowances in the auction, the DOE sold 2023 allowances to keep a "stable supply".

The August 9 sale was only open to companies that must cover their emissions. The DOE sold over 1 million allowances from the price containment reserve, made up of 527,000 from tier 1 and 527,000 from tier 2. Tier 1, as previously mentioned, were priced at $51.90 and tier 2 at $66.68. All available allowances were sold, generating an additional $62.5 million. The reserve allowances are included in the state's annual emissions cap, not in addition to it, meaning the state can sell them and still meet its emissions target.

An August 31st auction netted $541 million. Bidders bought nearly 8.6 million carbon emission allowances for $63.03 each. The first year of the program has brought in $1.5 billion and sold almost 27 million allowances. Of these, 24.4 million are for emissions in 2023 while 2.45 million of these allowances cover emissions in 2026. The quarterly auctions are open to companies for covering emissions and to other registered bidders, including traders hoping to sell allowances on the secondary market. The supplemental auctions of reserve allowances are open only to companies that must cover their emissions. Based on the DOE's published rules, the most recent auction's $63.03 settlement price again broke the soft price cap, triggering another reserve auction, slated for November 8th as of this writing,

according to a proposed schedule set in May.

If Washington links with carbon-cap markets in California and Quebec, prices will come down. Both of those markets are bigger and more established. The DOE expects to decide later this fall whether to pursue linking the markets or staying independent.

The District received 226,451 allowances for 2023 and is expected to receive very similar quantities through 2026. The District does not own or operate emitting generation in Washington state, however, the District does import a relatively small sum of energy from the BPA that is deemed to have emissions. The District will first manage its allowances for compliances purposes and then for the benefit of rate payers (with priority going to low-income customers).

Zero Emissions Vehicle (ZEV) Standard

In 2020, Governor Inslee signed the Zero Emissions Vehicle (ZEV) standard (SB 5811), with the DOE to complete rulemaking for the new regulations. 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.

On December 19, 2022, the DOE adopted two rules. DOE is directed by the Motor Vehicle Emission Standards law (RCW 70A.30.010) to adopt California vehicle emission standards, including the ZEV program, and maintain consistency with California's standards and Section 177 of the federal Clean Air Act. Chapter 173-423 Washington Administrative Code (WAC), Clean Vehicles Program adopts California's rules:

- Starting in model year 2026, new internal combustion engines for heavy-duty vehicles emit much lower quantities of nitrogen oxides, particulate matter, and GHG.
- Increase the percentage of passenger cars, light duty trucks, and medium duty vehicles solid in Washington that are ZEVs. The sales mandate will take effect in model year 2026 and begin by requiring 35% of new passenger vehicle 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.

Zero Emissions Vehicle (ZEV) Preparedness

In May 2021, Governor Inslee also signed into law House Bill (HB) 1287, ZEV preparedness, which directs the State Building Code Council to adopt rules for electric vehicle infrastructure at new and retrofitted buildings and directs the Washington State Department of Transportation (DOT) to develop an online map of charging locations and a forecast for the future growth of ZEVs. The online map can now be found on the DOT's website and plans for the forecasting tool appear to be underway.

Clean Fuel Standard

In May 2021, Governor Inslee signed into law HB 1091, the Clean Fuel Standard, which directs the DOE to develop a low carbon fuel standard for the state. The overall goal is 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 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.

Community Solar Expansion Program

Beginning in 2022 through mid-2033 (2SHB 1814), the Washington State University Extension Energy Program (WSU Energy Program) is 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

In June 2019, the Environmental Protection Agency (EPA) issued its final Affordable Clean Energy (ACE) rule and repealed the Clean Power Plan (CPP) originally introduced by President Obama in 2015. The CPP, which proposed emission guidelines for states to follow in developing plans to address GHG from existing fossil fuel-fired electric generating units, was stayed by the U.S. Supreme Court for exceeding EPA's authority under the Clean Air Act. Under the Trump Administration, the EPA repealed the CPP, arguing that the language of Section 111 (d) was clear and unambiguous in constraining the EPA's authority and that, when determining the best system of emission reduction, the agency could only consider emission-reduction measures that can be applied at and to a single stationary source.

The ACE had several components: a determination of the best system of emission reduction for GHG emissions from coal-fired power plants, a list of "candidate technologies" states could use when developing their plans, a new preliminary applicability test for determining whether a physical or operational change made to a power plant may be a "major modification "triggering New Source Review, and new implementing regulations for emission guidelines under Clean Air Act section 111 (d).

On January 19, 2021, the U.S. DC Circuit Court of Appeals vacated the ACE. The DC Circuit also remanded the question to the EPA to consider a new regulatory framework to replace the ACE Rule, allowing the Biden Administration to implement its own climate change agenda. In its decision, the Court found that nothing in Section 111 (d) supports the revised limited interpretation.

In March 2023, the EPA is extended the due date for state plans under the ACE rule until April 15, 2024. Because the ACE rule's

July 8, 2022 deadline passed while the rule was vacated by the D.C. Circuit, and because states had no reason to continue to work on their plans during the period when the ACE rule was vacated, it is necessary to extend the deadline for state plan submittal. By extending the deadline, this action makes clear the EPA does not expect states to take immediate action to develop and submit plans under the Clean Air Act section 111 (d) with respect to GHG emissions from power plants at this time.

After taking office in January 2021, President Joe Biden paused the construction of the Keystone XL Pipeline 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.

The Inflation Reduction Act of 2022 is the largest investment in climate change mitigation in U.S. history. The Act sets 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, explicitly defined CO2 as an air pollutant under the Clean Air Act to make the Act's EPA enforcement provisions harder to challenge in court. According to several independent analyses, the law is 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 will invest $391 billion in provisions relating to energy security and climate change. This includes $270 billion in tax incentives and $27 billion for a green bank created by amending the Clean Air Act. However, other forecasts differ from the CBO's report. A report by Credit Suisse projects that the total climate spending in the bill would be $800 billion and Goldman Sachs predicts a total of $1.2 trillion. The summary provided by Senate Democrats identifies primary goals as driving down consumer energy costs, increasing energy security, and reducing GHG emissions. The largest allocation areas are: $128 billion for renewable energy and grid energy storage, $30 billion for nuclear power, $13 billion for electric vehicle incentives, $14 billion for home energy efficiency upgrades, $22 billion for home energy supply improvements, and $37 billion for advanced manufacturing. An assortment of additional measures includes $32 billion for investments in rural economies, racial justice in farming, forestlands and coastal habitats, $3 billion in tax incentives for installing carbon capture and storage at existing power plants, $3 billion to electrify the U.S. Postal Service fleet, $3 billion to reconnect neighborhoods harmed by infrastructure potentially via freeway removal, investments in sustainable aviation fuel, grants for high voltage electric power transmission and decarbonization of port equipment, garbage trucks, school buses and local government fleets, purchases of rural electric cooperative debt alongside other assistance to cooperatives, and requirements that the government reduce embedded emissions in its procurement process.

In February 2023, the U. S. Department of Energy (DOE) proposed new energy

efficiency standards for refrigerators and clothes washers that the agency says will save consumers about $3.5 billion annually on energy and water bills. Products covered by the proposed rules include residential clothes washers, refrigerators, refrigerator-freezers, and standalone freezers. Products covered by the proposed rules account for 5% of annual residential energy use currently. The new standards could come into effect as soon as 2027, under DOE's preferred timeline. "Households using new refrigerators and clothes washers will save an estimated $425 on their utility bill over the average life of the appliance with these standards in place," the agency said. "Over the next 30 years, the two rules are expected to reduce CO2 emissions by 233 million metric tons -- an amount roughly equivalent to the combined annual emissions of 29 million homes."

In June 2023, Representative Cathy McMorris Rodgers (R-Wash.) introduced legislation, The Hydropower Clean Energy Future Act, that seeks to "expand clean, renewable, reliable and affordable hydropower production in America, as well as to promote the innovation of the next generation of hydroelectric technology" by instituting permitting reforms as well as ensuring hydropower as a renewable resource for all federal programs and procurement requirements. Codifying hydro in federal law as a renewable resource could have ripple effects, particularly in the western U.S. Typically, the list of resources that qualify as renewable under state initiatives only includes small hydroelectric generation. The bill also seeks to reform the FERC's hydro licensing process. The bill would institute a two-year licensing process for facilities with "next generation" hydropower resources; exempt small hydro projects determined to "not have significant environmental impacts," as well as closed-loop pumped-hydro storage projects that are neither on federal land nor impound navigable waters; and promote turbine and technology innovations for improved performance and efficiency that also protect environmental resources and fish. In addition to supporting conventional hydro development, the bill seeks to bolster pumped-hydro storage, conduit hydro generation and emerging hydropower technologies. A recent DOE report found it takes an average of five years to obtain an original license, 7.6 years for relicensing and some complex projects can take more than a decade. Chelan PUD is one of numerous entities supporting McMorris Rodger's bill.

Load Forecast

A new 10-year econometric retail load forecast was developed for this IRP progress report's 2023-2032 planning period. These low, base and high forecasts are prior to planned conservation savings. Future cost-effective conservation is considered as a resource for integrated resource planning purposes, so it 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.

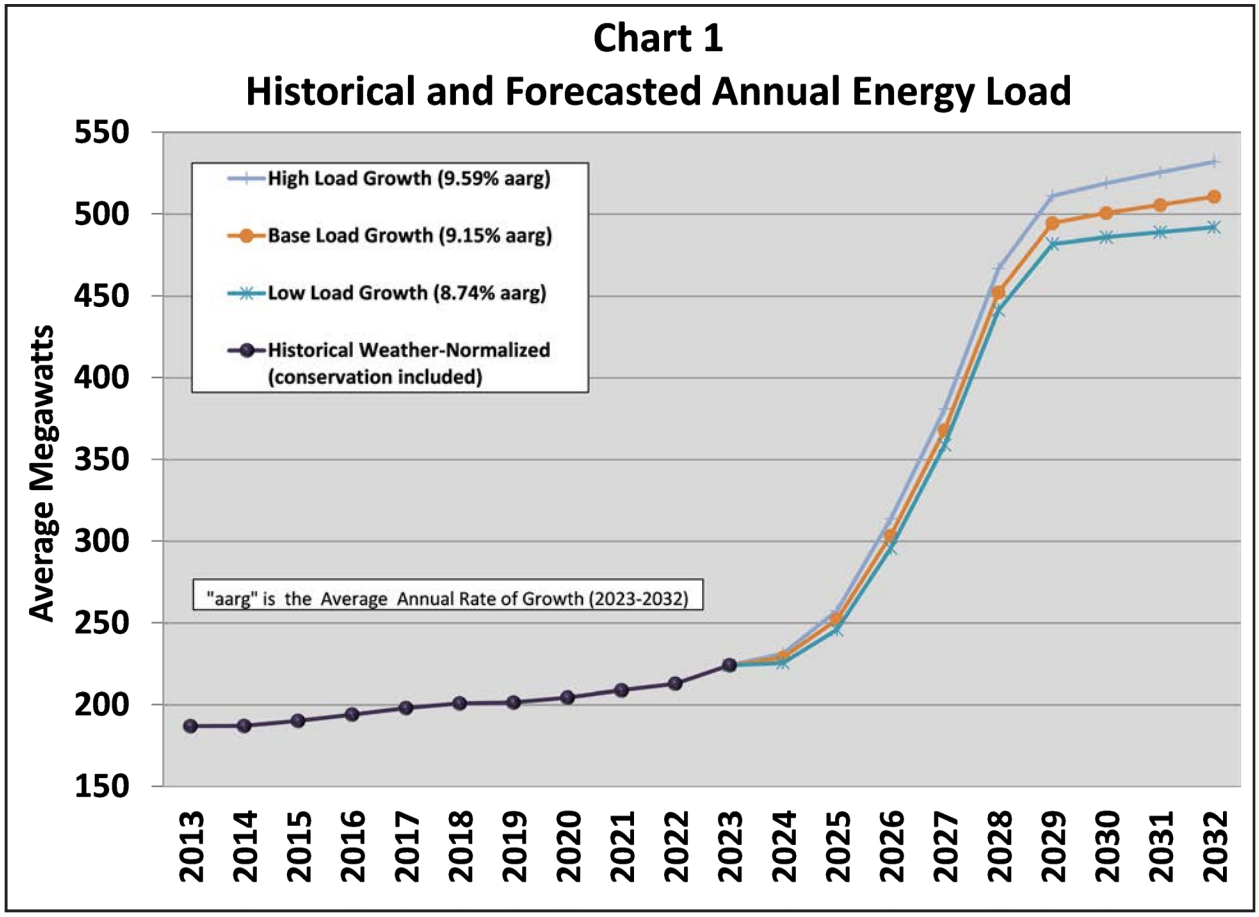
Total annual projected megawatt-hours through the planning period were forecasted on an annual incremental basis by sector, including system losses at 3.5%, using 2022 weather-normalized loads as the starting point. The low, base and high average annual composite retail energy sales forecast growth rates, including system losses, otherwise known as the forecasted annual energy load growth rates, are 8.74%, 9.15% and 9.59%, respectively. The low,

base and high forecasts have increased from the 2021 IRP. The weather-normalized average annual rate of growth at the District (before the effects of cumulative conservation) was approximately 1.9% for the 10-year period from 2013-2022. The net of cumulative conservation growth percentage was approximately 1.4% for the same 10-year period. This historical net of cumulative conservation growth average has increased since 2021. While the residential, commercial, high-density loads (HDL), Large Loads and electric vehicle (EV) loads have increased some during this period, increased conservation achievements that began in earnest in 2010 continue to mitigate load growth. The three forecasts for 2023-2032 as well as the actual weather-normalized total District energy load for 2012-2022 are presented in Chart 1. The NWPCC's Eighth Power Plan region-wide forecast for 2021-2041 are between -.17% and 1.02% per year.

Like the District's forecasted annual energy load growth rates, these forecasts do not include any new conservation measures.

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 2023 to arrive at updated population estimates through the planning period. Actual Chelan County population data from the OFM (through 2022), 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 0.68%, 01.44% and 1.81%. All three have increased some since 2021. The District has been seeing some moderate residential growth in the last few years. There are 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 five to 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 and vacation homes throughout more of the year than historically experienced. Remote work options and/or a desire to spend more time in Chelan county seem to have increased for non full-time residents.

For this load forecast, the commercial sales forecast is a function of population and sales revenue based on statistical significance. The results were adjusted in the low, base and high cases due to known and expected changes coming to the sector. The final average annual growth rates for the commercial sector are forecasted at 1.62%, 1.97% and 2.72%. Since 2021, all cases have increased some with some continued recovery expected in the sector after a few years of decreases. As with residential load, the District still believes that ongoing efficiency improvements, particularly in commercial lighting, heating, ventilating and air conditioning (HVAC) and water heating will lead to longer term decreases in per customer usage.

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. 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 1.30%, 1.30% and 1.87%. These have all decreased since 2021, primarily due to no known new customers and few changes expected in the sector.

Other load categories include High Density Loads (HDL), Cryptocurrency Processing and Large Loads (> 5 aMW). HDLs are those loads with intense energy use — 250 kWh per square foot or more per year with loads up to 5 annual aMWs at a single point of delivery. These loads are typically server farms and similar technological operations. Cryptocurrency Processing applies to computing or data processing load related to cryptocurrency mining, Bitcoin, blockchain, proof-of-work or other similar 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 Large Load sector began ramping up in 2019 and is expected to continue to increase. The average annual growth rates for the HDLs, cryptocurrency loads and Large Loads combined are forecasted at 31.71%,

31.88% and 32.23% for the planning period. Within this load grouping, the high load forecast includes the possibility of some smaller HDL load growth. The low, base and high cases were estimated taking into account existing approved applications, infrastructure timing limitations and general interest and economic conditions.

The aggregate of "other" energy sales (street lights, interdepartmental use, frost protection and irrigation) growth projections remains 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.

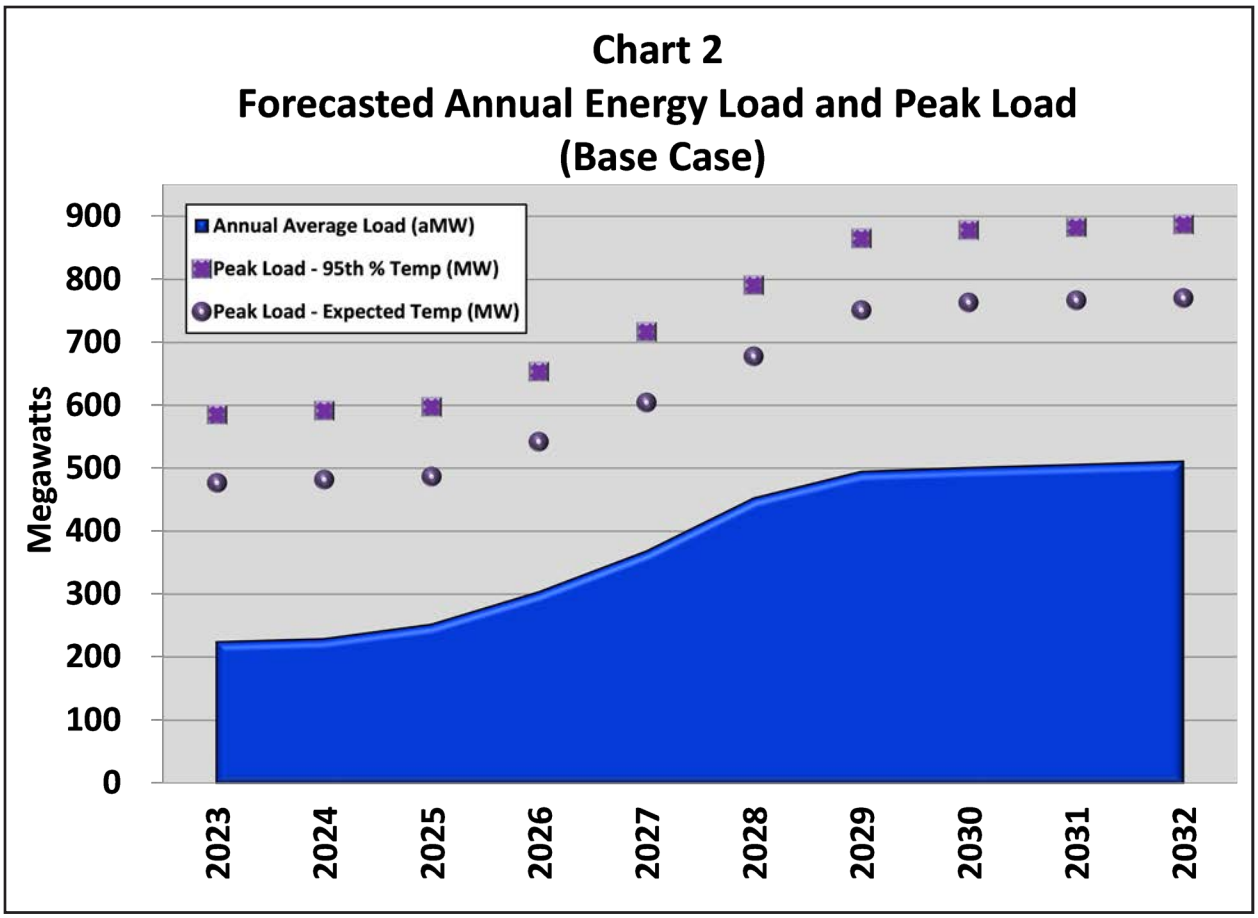
Peak Load Forecast

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 December 22, 2022. The peak of 553 MW was established when the temperature was approximately -1 degrees Fahrenheit. This occurred on a weekday (Thursday) morning when peak demands are usually higher given business and other commercial needs. At the time of this peak, distribution system staff estimated an 11 MW load loss in the Leavenworth area, so the peak load would have been higher.

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 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 resulted in average annual peak load growth rates in winter of between 5.1% and 6.1% (net of conservation) for the three energy growth forecasts. The weather-normalized winter peak growth rate over the last 10 years was approximately 1.70% (net of conservation). In 2021 and 2022, the West experienced conditions known as "heat domes." They are generally formed when strong, high-pressure atmospheric conditions are caused by a change in ocean temperatures in the tropical Pacific Ocean during the preceding winter. Sometimes, the domes can become trapped over specific geographic areas and cause massive heat waves. Chelan PUD experienced its highest historical summer peaks in each of those years. Chart 2 illustrates both the base case annual energy load forecast with the base case peak load forecast at both an average, or expected, peak temperature and at a 95th percentile extreme peak temperature for 2023-2032.

Electric Vehicles (EVs)

As mentioned in the Regulatory and State Statutory Requirements section, in December 2022, the 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.



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 solid 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.

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 spring 2023, there were almost 125,000 EV light vehicles registered in the state of Washington, over 700 of which were in Chelan County. That was a 65% increase over the previous 2 years. Several variables will 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 10% of global

vehicle sales in 2022, and they're on track to reach 30% by the end of this decade. Policies around the world are expected to accelerate this growth. Recent climate legislation in the U.S. is pumping billions into battery manufacturing and incentives for EV purchases. The European Union and several states in the U.S. passed bans on gas-powered vehicle sales starting in 2035, including Washington state, as previously mentioned.

As of mid-2023, according to Reuters, the U.S. EV market is growing, but not fast enough to prevent unsold EVs from stacking up at some automakers' dealerships or to allow Tesla to avoid new price cuts. Rising inventories and price-cutting could represent only a short-term pause in EV market growth, but they could be signals that boosting U.S. EV sales above the current 7% market share (nationwide) will be more costly and difficult than expected, even with federal and state subsidies. Automakers North America have billions of dollars in EV-related investments riding on how the next several quarters play out. If production of EVs continues to outpace demand, automakers will have to choose between slashing prices and profit margins or slowing assembly lines. More than 90 new EV models are expected to hit the U.S. market through 2026, according to Auto Forecast Solutions. Analysts say many will struggle to reach profitable sales volumes. It's still a young market and industry officials and analysts caution that the U.S. EV market is still in a formative phase, with many consumers still evaluating whether EVs fit their needs and major automakers still ramping up production. The Biden administration has proposed emissions rules that effectively require U.S. automakers to shift their sales to two-thirds EVs by 2032 — a proposal GM and the association representing most automakers in the U.S. have said is unrealistic.

Several factors will make 2023 a true test to the resolve of governments and the automotive industry in driving BEVs forward, according to Gartner, Inc. "2023 is the moment of truth to drive full electrification forward," said Pedro Pacheco, VP Analyst at Gartner. "The spike in electricity prices in Europe make BEV running costs less attractive, some countries, like the U.K., Switzerland and Australia, are starting to introduce EV taxation. In addition, China ended electric vehicle subsidies at the beginning of 2023 and global charging infrastructure still has many coverage gaps and the average quality of service is poor." In addition, the sharp increase in raw material prices like lithium and nickel will inherently drive BEV costs higher, which will make it harder for original equipment manufacturers to close the price gap with internal combustion. As a result, BEV sales may grow at a considerably lower pace or stall in some markets, making investments related to BEVs take longer to achieve break even. Gartner expects supply chain shortages in the automotive industry to continue through 2023. "More than two years after the pandemic began, carmakers still cannot forecast an end to shortages of semiconductor chips or the subsequent shortage of vehicles they can produce. They also face short supply of key materials for BEV batteries, causing the prices of commodities to surge," said Mike Ramsey, VP Analyst at Gartner.

The transition will require lots of batteries and better and cheaper ones. Most EVs today are powered by lithium-ion batteries, a decades-old technology that's 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. Academic labs and companies alike are hunting for ways to improve the

technology including boosting capacity, speeding charging time and cutting costs. The goal is even cheaper batteries that will provide cheap storage for the grid and allow EVs to travel far greater distances on a charge.

At the same time, concerns about supplies of key battery materials like cobalt and lithium are pushing a search for alternatives to the standard lithium-ion chemistry. In the midst of the push for EVs and renewable power and an explosion in battery development, one thing is certain: batteries will play a key role in the transition to renewable energy. Some dramatically different approaches to EV batteries could see progress in 2023, though they will likely take longer to make a commercial impact.

One advance to keep an eye on is in so-called solid-state batteries. Lithium-ion batteries and related chemistries use a liquid electrolyte that shuttles charge around; solid-state batteries replace this liquid with ceramics or other solid materials. This swap unlocks possibilities that pack more energy into a smaller space, potentially improving the range of EVs. Solid-state batteries could also move charge around faster, meaning shorter charging times. Also, because some solvents used in electrolytes can be flammable, proponents of solid-state batteries say they improve safety by cutting fire risk. Solid-state batteries can use a wide range of chemistries, but a leading candidate for commercialization uses lithium metal. Batteries of this type may be used commercially in the next couple of years. However, completely reinventing batteries has proved difficult, and lithium-metal batteries have seen concerns about degradation over time, as well as manufacturing challenges. Quantumscape announced in late December 2022 that it had delivered samples to automotive partners for testing, a significant milestone on the road to getting solid-state batteries into cars. Other solid-state-battery players, like Solid Power, are also working to build and test their batteries.

Solid-state batteries aren't the only new technology to watch out for. Sodium-ion batteries also differ sharply from lithium-ion chemistries common today. These batteries have a design similar to that of lithium-ion batteries, including a liquid electrolyte, but instead of relying on lithium, they use sodium as the main chemical ingredient. Chinese battery giant CATL reportedly planned to begin mass-producing them in 2023. Sodium-ion batteries may not improve performance, but they could cut costs because they rely on cheaper, more widely available materials than lithium-ion chemistries do. However, it's not clear whether these batteries will be able to meet needs for EV range and charging time, which is why several companies going after the technology, like U.S. -based Natron, are targeting less demanding applications to start, like stationary storage or micro-mobility devices such as e-bikes and scooters.

The District continues to use the Council's basic EV load forecasting methodology, with updated inputs the Council prepared for the Eighth Power Plan that was finalized in 2022. Based on EV market share, or penetration rates, experienced in the District's service area, the District updated Chelan County's EV low and base load forecasts. The District also updated the high case with the same market rates the Council used in the Eighth Power Plan for the region as a whole. The market rates are significantly increased for the low and base cases and slightly increased for the high case forecast through the 2023-2032 planning period from the 2021 IRP. By the end of the planning period, the market share rates vary from 36% to 89% in the three cases. This translates into approximately 6,800 to 17,400 EVs in Chelan County (after EV retirements) in 2032. The three cases now result in forecasts of between 4.19 and 10.69 aMW by 2032. The average annual growth rates for EV load are forecasted at 22.97%, 32.44% and 36.44% for the planning period.

Based on the Council including fleet vehicles and buses in their forecast methodology as well as existing electric bus load and existing commercial fast charging load in Chelan County, District staff is comfortable that modeling results take into account all EV loads.

Peak load estimates now range from 7.33 MW to 18.71 MW in 2032. Future assumptions about charging behavior have a substantial effect on the peak forecast. The District's peak forecast for 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 Portfolio

Chelan PUD's resource mix 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 (2023-2032). 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. Chelan PUD's 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 retail load. Initial transmission system studies do not indicate significant transmission system upgrades in order to serve currently forecasted Large Loads. 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 and the operation of the downstream reservoir from Rock Island belonging to the Wanapum project.

As previously reported, in September 2013, three additional large generating units at Rocky Reach were taken out of service after discovering that the fourth large turbine, out of service since March 2013, had a deep crack in a stainless steel rod that delivers oil to a servo motor. The motor adjusts the angle of the turbine blades. The four units share the same design and were put into service between 1998 and 2002. After making interim repairs, including temporarily fixing the blade positions, all four units were back online in early 2014. Beginning in 2015, the units are being taken out of service one at a time to

make more permanent repairs. All servo rod repairs have been completed on C8 and C9 along with governor upgrades. C11 is now undergoing repairs and expected to be back in service in early 2024. C10 is scheduled to be repaired beginning in late 2023 into early 2025. The remaining seven smaller units at Rocky Reach do not share the same design in regard to either of these issues.

The seven smaller generating units at Rocky Reach were all in need of trunnion bushing replacement. C1 through C7 bushings were all replaced from 2020 to 2023.

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 is 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. The remaining three units are scheduled to return to service between 2023 and 2026.

The District initiated a series of sequential outages in January 2007 to modernize units B5 through B10. The scope of work for the modernization contract included the replacement of turbine runners, governor systems, generator stators and rotor poles and control systems. By May 2017, the contractor selected for this work had completed work on units B10, B9, and B6. In June of 2017, unit B9 suffered a Kaplan pipe failure and remained out of service until repairs were complete on October 3, 2018. In June 2019, unit B10 was removed from service to perform an overhaul and conduct turbine inspections. During the inspection, the District discovered a few internal turbine components had failed or were near failure. Subsequent inspections on unit B9 and B6 yielded similar observations of failed internal turbine components as B10. The modernization contractor conducted a root cause analysis of these failures and reviewed their findings with the District in August 2019. The District concurred with the contractor's findings. Four repairs were identified to restore B6, B9 and B10. The District estimated an additional six-month outage to implement the repairs. It was determined that it was safe to run the units in this condition until the final repair could be made. Since the other units in the modernization project (B5, B7 and B8) are of similar design, the repairs identified above were and will be performed during their respective modernization outages. The repairs and modernization were completed on B5, B7 and B10, and the units returned to service between April 2021 and December 2022. B6 is currently under repair and modernization and scheduled to return to service in November 2023. Modernization and turbine repairs on B8 and B9 are scheduled during the late 2023 to 2026 timeframe.

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 is in place for the future replacement of the generator stators and rotors, governor

systems and to convert the turbines to "oil-free" hubs. The work is scheduled to be performed in the 2023-2031 timeframe.

The risk management plans Chelan PUD has in place are working very effectively. The long-term wholesale sales contracts and hedging program (discussed in the Portfolio Analysis section), 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.

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, expire in 2024. Either party must 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 the 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 has laid down negotiation markers that call for notification of termination if its principles are not met. A primary U.S. concern is the Canadian Entitlement, half of the originally calculated increase in U.S. downstream power benefits that is delivered to Canada. The utilities argue 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 include that the Treaty should primarily maximize benefits to both countries, the Canadian Entitlement currently does 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 are taking place in private. U.S. tribes were not originally involved, but tribal representatives are now involved as of later 2019. The Department of State reported that, in 2020 during a 10th round of negotiations, Canada responded to a framework proposal previously tabled by the U.S. and presented a Canadian-developed proposal. No details have been provided. In June 2021, Representatives DeFazio (OR-04) and McMorris Rodgers (WA-05) and Senator Patty Murray (D-WA) led a bicameral, bipartisan letter to President Biden urging his administration to speedily renegotiate the Treaty and to provide regular, substantial updates to members of Congress on the status of negotiations. Talks began to pick up in late 2021. In August 2023, the 18th round of negotiations took place in

Seattle, and a 19th round was scheduled to take place in the fall as of this writing. There is no timeline yet on when or if the modernization of the Treaty will be finalized.

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:

Columbia River mainstem modeling — power generation impacts, aquatic resources impacts and water quality impacts

1. Lake Chelan Basin modeling — Lake management impacts (power generation, Chelan River operations impacts and water quality impacts)
2. Wenatchee and Methow rivers modeling — Habitat Conservation Plan (HCP) hatchery program impacts
3. 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 has been 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 has 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 have 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). The current data shows increasing average temperatures for every month, increasing over time and does not account for load growth. The results were as expected; reduced winter demands and increased summer demands. (See the earlier summer peaks and heat dome discussion in the Peak Load section.) The District continues work to determine its usefulness and how it can be used to help with planning.

Chelan PUD will remain attentive to 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.

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 has to 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 can be in excess of $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, which extends existing tax credits for renewable and energy storage projects while creating new clean energy credits, is expected to usher in a surge of spending on wind, solar and storage projects, making interregional cooperation among utilities more critical than ever. The federal Production Tax Credit (PTC), established in 1992, provides a tax credit to a facility for 10 years on a per kWh of electricity generated basis. It had been inflation adjusted every year. 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 or biomass). The Inflation Reduction Act extended the PTC and increased the credit to at least $0.0275 per kWh ($27.50 per megawatt hour in 2023) through 2025 and at least $0.026/kWh through 2032 (compliance with prevailing wage and qualified apprenticeship requirements necessary for full value). The Investment Tax Credit (ITC) value of 30% goes through at least 2032 (compliance with prevailing wage and qualified apprenticeship requirements is necessary for full value.) Technologies available for the 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. Starting in 2025, the PTC and ITC will be available for any zero-greenhouse-gas-emitting technology, including those that use carbon capture.

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 is able to 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), 2023 had had 4 day-ahead days with negative local prices (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, 2023 experienced 74 hours with negative local prices (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. In 2023, on a few low load, high renewable generation days, 100% of the California ISO's demand was met with renewables.

In the Northwest, the 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 megawatts from utilities to BPA can add hundreds of megawatts 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 the Mid-C. 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 $3 to $7 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 freshet in May 2023 severally depressed Mid-C power prices, but the snap-back to higher than historical pricing was very rapid. There have been as many days trade above $50/MWh in the past year as in the past ten years (remainder of 2023 included).

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 Western Energy Imbalance Market (WEIM) currently does not replace the day ahead or hour ahead markets and scheduling procedures that exist in the Western Interconnection today. 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 across eight western states. 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, a number of entities have followed suit by joining the WEIM.

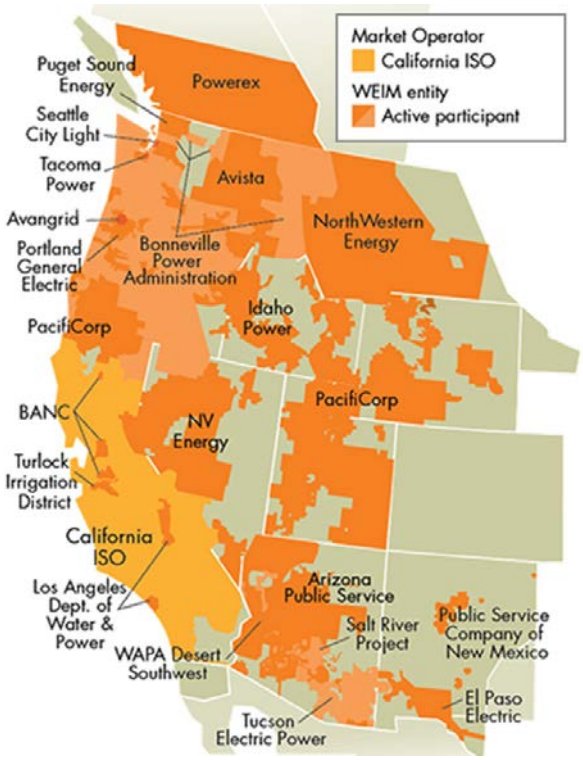
Active:

- 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 – 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

On February 1, 2023, the CAISO board and the WEIM governing body approved a proposal to operate an Extended Day-Ahead Market (EDAM). EDAM is a voluntary day-ahead electricity market designed to deliver significant economic, environmental and reliability benefits to BAs and utilities throughout the West. It is designed to increase regional coordination, encourage the development of renewable energy resources, and lower costs for consumers. The market is now expected to begin in 2026.

Figure 1- Energy Imbalance Market Footprint

https://www.westerneim.com/Pages/About/default.aspx



SPP

In addition to the WEIM expansion, the SPP launched its Western Energy Imbalance Service (WEIS) market to interested utilities beginning February 1, 2021. SPP is also proposing a day-ahead market, Markets+, which could be implemented as early as late 2025. 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 conceptual bundle of services proposed by SPP that would centralize day-ahead and real-time unit commitment and dispatch and pave the way for the reliable integration of a rapidly growing fleet of renewable generation. Markets+ has had a fully independent governance from day one, including oversight from SPP's independent board of directors.

Entities in the region moving towards organized markets and the expansion of these markets are a key development in the industry. As previously mentioned, the District is actively following the transition towards more organized markets and will continue to assess the impact to the region and the District.

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 load forecast, net of accumulated forecasted conservation, the amount of renewable resources required will be approximately

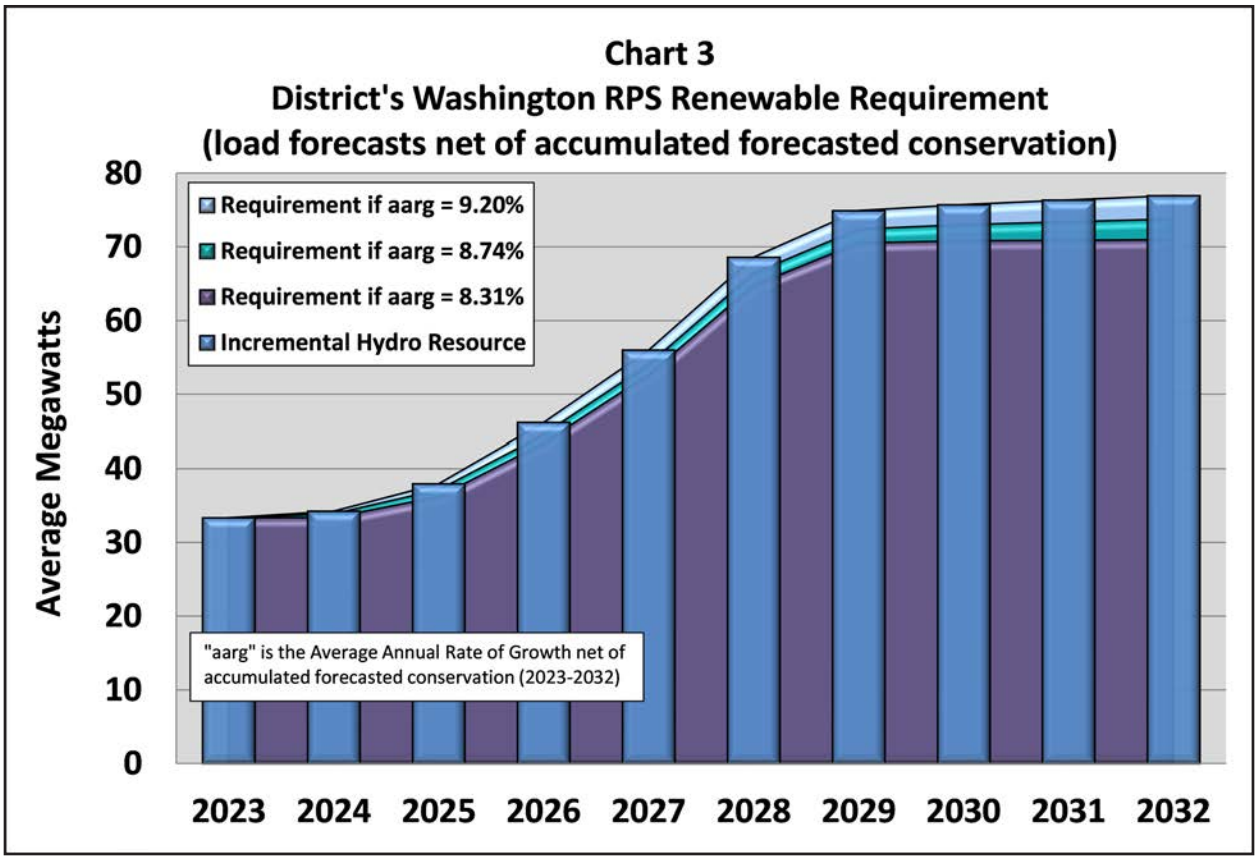
33-74 aMW in 2023-2032. Chart 3 shows the potential target requirements based on the District's three load forecasts.

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 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 become a reality for utilities. California passed SB 100 requiring zero-carbon resources supply 100% of electric retail sales to end-use customers by 2045. Oregon's RPS now requires 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 nonemitting 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. 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." The RPS defines conservation as any reduction in electric power consumption resulting from an increase in the efficiency of energy use, production or distribution.

There are two primary components of the RPS as it relates to conservation:

1. Documenting the development of conservation targets (i.e., setting the targets) and
2. Documenting the savings (i.e., demonstrating how the targets are being met).

To set its 10-year plan and two-year conservation target for the 2024-25 biennium, in 2023 the District used a utility-specific analysis, also known as a conservation potential assessment (CPA). This CPA, which was conducted by Lighthouse Energy Consulting, established the conservation targets that are used in this 2023 IRP progress report. The CPA used data specific to Chelan County on demographics and building construction to more accurately estimate local conservation potential. The CPA was developed in a manner consistent with the Council's methodology. The resulting conservation supply curves are used in the analysis of this IRP progress report.

Table 1
2023 Conservation Potential Assessment
Cost-Effective & Achievable Savings
aMW

Sector	2 Year	6 Year	10 Year	20 Year
Residential	0.41	1.07	4.92	10.65
Commercial	1.29	2.83	8.04	15.80
Industrial	0.90	2.03	5.43	7.67
Distribution	0.06	0.20	1.31	2.48
Agriculture	0.01	0.02	0.16	0.29
TOTAL	**2.67**	**6.15**	**19.85**	**36.89**

Conservation Potential Results

The District has pursued conservation and energy efficiency resources since the early 1980s. Historically, the utility offered several programs for both residential and non-residential applications. Industrial projects have dominated past conservation savings, but since 2014, there has been an increased emphasis on residential and commercial projects.

The 2023 CPA provides estimates of energy and peak demand savings by sector for the period 2024-2043. The methodology complies with RCW 19.285.040 and WAC 194-37-070 section 6 parts (a)(i) through (xv) and is consistent with the methodology used by the Council in developing the recent Power Plans.

The primary baseline changes in the 2023 CPA included the following:

- Avoided cost increases. The avoided cost in 2021 was $39/MWh, for the 2023 CPA the avoided cost is $65/MWh.
- Code changes — significant impacts of recent code changes that have taken effect result in lower remaining potential (e.g., new lighting standards).
- Revised/updated measure data from the Regional Technical Forum (RTF) is included.

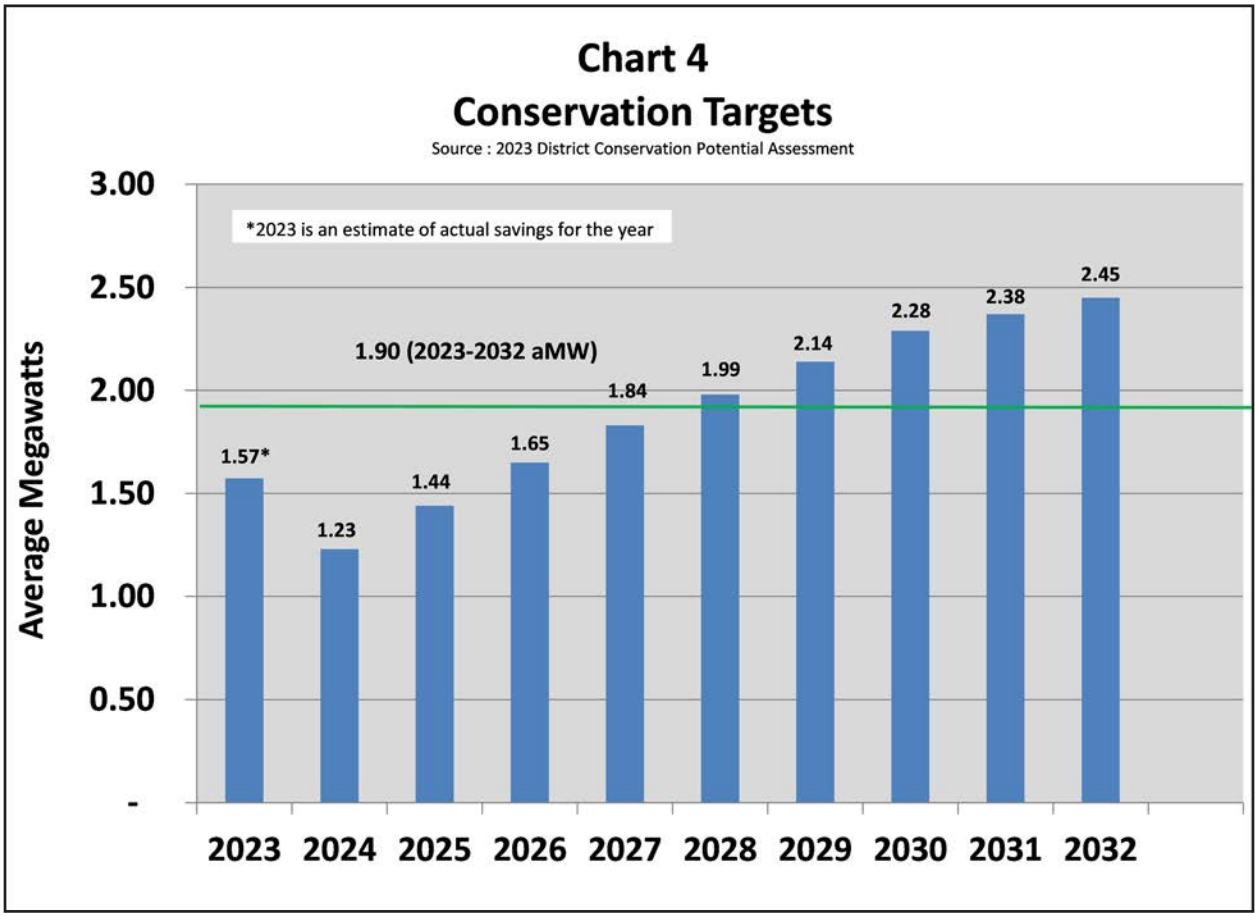


Table 1 shows the high-level results of this CPA. The economically achievable potential by sector in two, six, 10 and 20-year increments is included. The 10-year potential is approximately 19.85 aMW. The total 20-year energy efficiency potential is approximately 36.89 aMW.

Chart 4 illustrates the conservation potential targets through the planning period.

Embedded in these potential estimates are savings from regional market transformation efforts, as well as new codes and standards. Regional market transformation is achieved through the Northwest Energy Efficiency Alliance (NEEA). As a member, the District applies a pro-rata share of regional NEEA saving projections toward meeting 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."

Residential

The two-year pro-rata share of the 2043 potential is 0.41 aMW and the 10-year potential is 4.92 aMW.

Commercial

The two-year pro-rata share of the 2024-43 potential is 1.29 aMW and the 10-year potential is 8.04 aMW.

Industrial

Industrial potential for this assessment was calculated based on the Council's top-down methodology that utilizes annual consumption by industrial segment and then disaggregates total electricity usage by process shares to create an end-use profile for each segment. Estimated measure savings were then applied to each sector's process shares. The two-year pro-rata share of the 2024-43 potential in the industrial sector is 0.9 aMW, eventually reaching a total of 5.43 aMW after 10 years.

Agriculture

The two-year pro-rata share of the 2024-43 potential is 0.01 aMW and the 10-year potential is 0.16 aMW.

Cost

Energy saved in homes and businesses reduces the need to purchase power on the wholesale market or can be sold into the wholesale electric market when the District is already surplus to its own local retail load. Both cases, in turn, help keep local electric rates low.

The 2024 CPA identified a total of 2.67 aMW of cost-effective and achievable conservation for 2024 and 2025 combined.

For its 2023 CPA, Chelan PUD utilized a forward market projection of wholesale market power prices and carbon pricing as its avoided cost for the evaluation of the cost-effectiveness of potential conservation measures. The levelized costs for all conservation measures that resulted from the 2023 CPA were $42/MWh over the 2024-2033 period and $40/MWh over the 2024-2043 period (2016 real dollars). The higher levelized cost of conservation is primarily due to the removal of low-cost lighting measures, a higher value attributed to peak demand savings on the distribution system and an increase in capacity values on the wholesale market.

Current Demand-Side Offerings

offer diversified, cost-effective measures that maximize the value to District ratepayers while striving to meet the RPS conservation targets. The District offers a variety of conservation programs to its customers. These programs include several rebates for residential customers, commercial funding assistance and industrial projects. Recent programs offered by the District are detailed below. All of the programs support meeting Chelan PUD's RPS targets. Additionally, the two low-income programs help the District support CETA targets.

Insulation Rebates

For residential customers, the District pays $0.90 to $2.50 per square foot for added insulation, depending on current insulation levels. Requirements to qualify include:

Existing attic insulation must be R11 or less. Customers must add insulation to achieve R38 or greater.

- For walls, there can be no existing insulation. Added wall insulation must achieve R11 or greater.
- For floors, there can be no existing insulation. Added floor insulation must achieve R19 or greater.

Exterior Entry Doors, Window and Patio Door Rebates

Incentives are available to residential customers who replace older inefficient windows, and patio doors and substandard exterior entry doors.

This rebate offers customers:

- $6 to $10 per square foot on qualifying double-pane metal patio doors and windows depending on the house type, single family or manufactured home. To qualify, new windows must have a U-factor of 0.30 or lower. Qualifying patio doors must have a U-factor of 0.35 or lower.

- The rebate for upgrading single-pane windows is $8 to $15 per square foot, depending on home type.
- Customers are eligible for a rebate for adding low-e storm windows to existing single-pane windows. The rebate is as follows:
  - $8 per square foot for existing single-pane windows with metal frames
  - $6 per square foot for existing single-pane windows with wood frames
- The new storm windows must be listed on the qualifying product list on our website. These storm windows must have a low-e factor of 0.22 or lower and solar transmittance greater than 0.55.
- $100 rebate per door for replacement of substandard entry doors with new Energy Star® rated insulated doors.

Multi-Family Window and Patio Door Rebates

- Incentives are available to residential multi-family apartment owners who replace older inefficient windows and patio doors. This rebate offers owners $20 to $25 per square foot on qualifying patio doors and windows, depending on the old window type. To qualify, new windows must have a U-factor of 0.30 or lower. Qualifying patio doors must have a U-factor of 0.35 or lower.

Low-income weatherization

The District provides funds to the Chelan-Douglas Community Action Council (CDCAC) for low-income home weatherization. The District has partnered with the CDCAC to weatherize income-eligible electrically heated residences. Income eligibility is based on 200% of federal poverty guidelines. Chelan PUD offers an annual grant of $100,000, which is matched by the Washington State Energy Matchmaker program administered by Commerce. CDCAC crews complete the weatherization measures which are inspected by Commerce and the District. In addition to the weatherization funding, CDCAC may install Ductless Heat Pumps in selected dwellings.

Low Income Energy Efficiency program

The District is developing a low income (LI) program to meet both internal goals and also to stay in compliance with CETA. This program has three phases of targeting customers who are considered high energy burdened, or pay more than 6% of their annual income to their energy bill. The first stage will be reaching out to all identified customers with a low-cost energy saver gift (light bulbs, thermostatic shower valves and low flow showerheads). Along with the gift, customers can opt into additional measures like smart thermostats. These customers will also fill out information that will help us roll into phase two of the program. Phase two begins the deeper dive of replacing old appliances, water heaters and insulating homes that are in need. This will be rolled out to homeowners and will be targeted at 60-80 homes a year beginning sometime in 2024. The final phase of the LI program will be retrofitting homes with more efficient HVAC equipment. This phase will not begin for another few years (five to seven) and has not received final funding approval from Chelan PUD's Board of Commissioners.

Super-Efficient Heat Pumps and Heat Pump Water Heaters

Air Source Heat Pumps

The District offers a rebate to customers installing or upgrading to a super-efficient heat pump. In order to qualify, the customer must install a 7.6 heating season performance factor (HSPF 2) or greater and a 13.2 seasonal energy efficiency ratio (SEER 2) or greater heat pump. The installation must be done by a performance tested comfort system

(PTCS) qualified contractor and must be commissioned to PTCS standards. If the customer is replacing an electric furnace, the rebate is $3,500 for a standard heat pump or $4,000 for a variable speed heat pump. If the customer is updating a heat pump, installing a heat pump above code for new construction or installing a heat pump with natural gas backup, the customer qualifies for a $700 rebate for a standard heat pump and $750 for a variable speed heat pump. The District also offers a $2,000 conversion rebate if the customer is replacing an electric furnace, and the installer is not PTCS certified. The same HSPF 2 and SEER 2 rating qualifications would apply for this type of installation.Ductless Heat Pump

Customers who are displacing zonal electric, radiant or electric furnaces with a qualified ductless heat pump system in Chelan County qualify for a $1000 rebate. Customers must get pre-approved for the application and must use an authorized contractor (through the NW Ductless Heat Pump Project) for the installation.

Ductless Heat Pump

Customers who are displacing zonal electric, radiant or electric furnaces with a qualified ductless heat pump system in Chelan County qualify for a $2,000 rebate for single family homes or $2,500 for manufactured homes. Customers must use an HVAC contractor for the installation.

Heat Pump Water Heaters

Single-family existing home customers in Chelan County are eligible for a heat pump water heater rebate. These products are given qualifications through the Northern Climate Heat Pump Water Heater Specifications. The District offers a $900 rebate for a Tier 3 and above for any water heater size.

Line Voltage Thermostats and Smart Thermostats

Line Voltage Thermostats

Customers who replace old zonal heat thermostats with a qualifying line-voltage thermostat (LVT) qualify for a $40 rebate per unit. Those replacing with a qualifying line-voltage communicating thermostat (LVCT) qualify for a $75 rebate per unit.

Smart Thermostats

Existing home and new construction customers that are primarily heated with electric, centrally-ducted resistance furnace and heat pump, are eligible for a $150 rebate for a qualified smart thermostat.

Residential Audits

The District started offering home energy audits in 2019. This is a web-based software tool that provides customer data that gives them details on what programs and rebate amounts the homeowner would qualify for based on current Chelan PUD program offerings. Audits are currently offered in person.

Commercial/Industrial Energy Efficiency Programs

The District has programs for helping commercial and industrial customers install energy efficiency equipment in their facilities by paying a portion of the project's costs. Measures include interior and exterior lighting, weatherization, HVAC, water heating, a suite of measures for restaurants and grocery stores along with a strategic energy management program.

Lighting Rebates

The District uses a lighting calculator to generate energy savings for interior and exterior lighting projects. For retrofit projects the District pays $0.30/kWh saved on

existing buildings. New construction projects are paid $0.06/kWh saved. For outdoor lighting controls on existing buildings, the District pays $0.60/kWh saved. For existing buildings for local government agencies, the rebate is $0.40/kWh saved.

Weatherization Rebates

The District's weatherization measures include windows and insulation. Customers replacing single-pane (with or without storm windows) or double-pane with metal frame windows with windows that have a u-value of 0.30 or less and heat with electric resistance heat receive $32/sq ft. Customers with heat pumps receive $25/sq ft. Customers may upgrade wall and attic insulation. Walls must have no existing insulation and attics must have insulation levels less than R5. Customers must fill the wall cavity and bring the attic levels up to R49 to receive the following rebate:

- $4/sq ft for attic insulation
- $3/sq ft for wall insulation and building is heated with resistance heat
- $2.25/sq ft for wall insulation and building is heated with heat pump

HVAC Rebates

The District has a suite of HVAC rebates for commercial and industrial customers. These include heat pump (HP) & ductless heat pump (DHP) upgrades and conversions, packaged terminal heat pumps (PTHP) and thermostats. All HVAC equipment must meet program efficiency requirements. Customers who upgrade an existing HP receive a rebate of $400/ton. If upgrading a DHP, customers receive a rebate of $1,000/ton. It is the same for new construction as well. Customers converting electric resistance heat to a HP or DHP receive $3,000/ton.

Residential care facilities who install a PTHP as a retrofit or new construction will receive $1,200/unit. Customers in the lodging sector receive $800/unit.

Customers replacing a non-web enabled thermostat with a qualifying unit will receive $350/unit.

Water Heating Rebates

Customers can replace an existing hot water tank with a hybrid hot water tank. The District will rebate $1,750 for a tier 2 tank and $2,000 for a tier 3 tank and $2,850 for a tier 3 SPLIT hybrid tank.

Grocery and Restaurant Rebates

Customers with small and large grocery stores along with restaurants can take advantage of the numerous measures offered by the District. These measures include ovens, food holding cabinets, fryers and kitchen ventilation as well as strip curtains, anti-sweat controls and evaporator motors for coolers. All equipment must meet program standards.

Strategic Energy Management (SEM)

SEM is a program for commercial and industrial customers. The program takes a close look into systems that use energy and how the customers operate those systems in their facility. The District identifies ways to operate those systems more efficiently. Low-cost upgrades are prioritized as well as larger custom projects that would improve the energy efficiency of their facility. The District takes this information and forms a dual path to success for the customer. The first path is called a tune up. This is where staff helps them implement system changes and work through the no to low-cost items. The second path utilized is the identification and implementation of custom projects. The District aids the customer with obtaining quotes and analysis around the costs versus the energy savings. A report is delivered to the customer.

Local Government Initiative

Under this program, local government officials are encouraged to participate in a Chelan PUD initiative to improve the energy efficiency of public buildings. To assist local governments improve the energy efficiency of their facilities and equipment, the District provides financial incentives that can cover up to 100% of the local government's cost of implementing energy efficiency measures. The maximum amount of the incentives is capped at the net present value of the energy savings over the projected life of the projects.

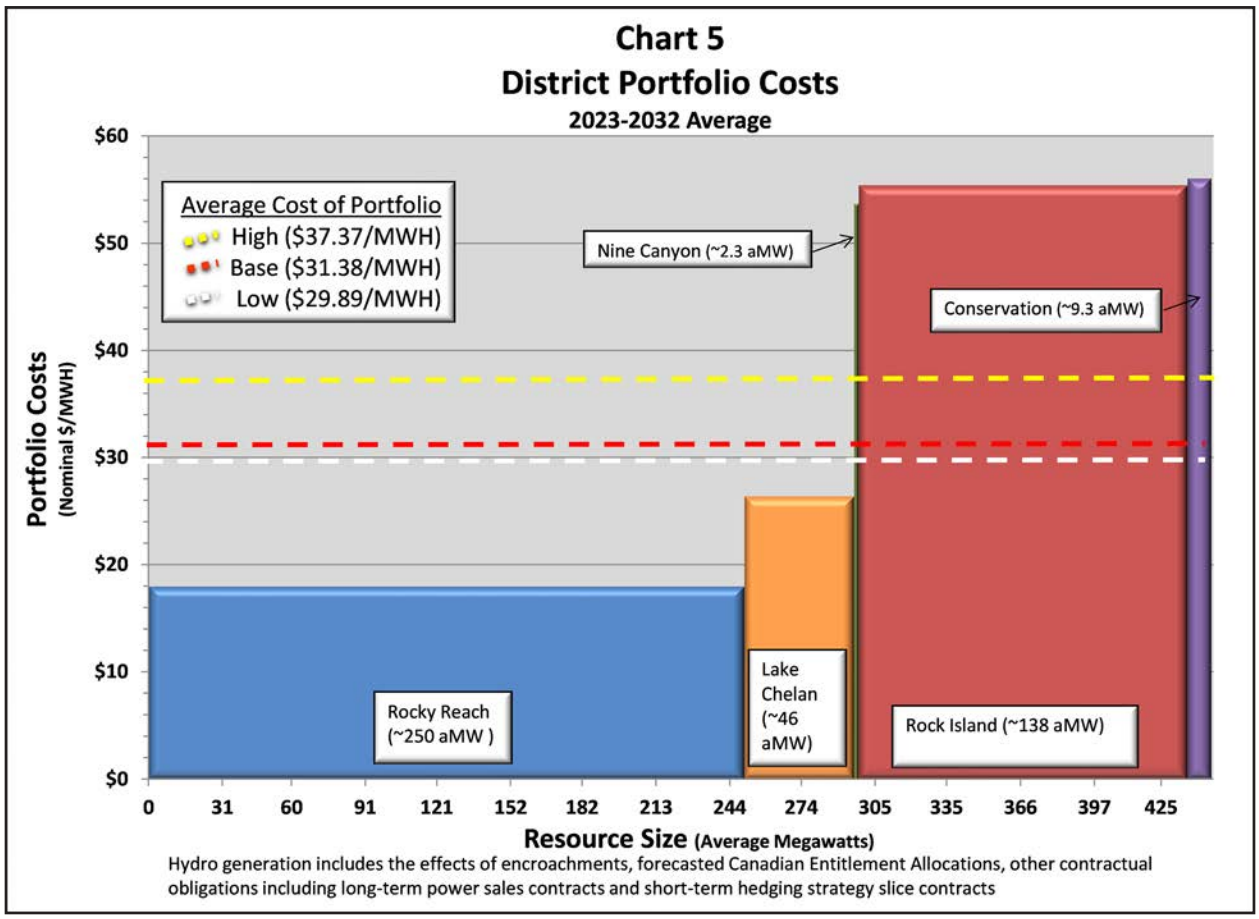
Portfolio Analysis

The District is expected to be able to serve its retail load throughout the planning period (2023-2032) with the power supply for new Large Loads being 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.

Portfolio Costs

The hydroelectric facilities' costs shown in Table 2 and Chart 5 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 2022 cost for the District's existing portfolio is shown in Table 2. These costs were calculated two ways. The second column, reading left to right, are the actual cost per



megawatt hour based on actual costs and actual generation in 2022. Columbia River runoff conditions were 107% of average and Lake Chelan runoff conditions were 108% of average in 2022. Wind generation conditions at Nine Canyon were below average at 87%. The column on the right was calculated using actual 2022 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).

Chart 5 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.

Table 2
District's Existing Portfolio Cost 2022

Project	$/MWh w/actual generation	$/MWh w/ average generation
Rocky Reach	$11.45	$11.61
Rock Island	$42.65	$40.90
Lake Chelan	$24.00	$26.66
Nine Canyon	$70.49	$60.55

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 – 2.0-3.0%
- Rock Island – 2.0-3.0%
- Lake Chelan – 1.5-2.5%

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.

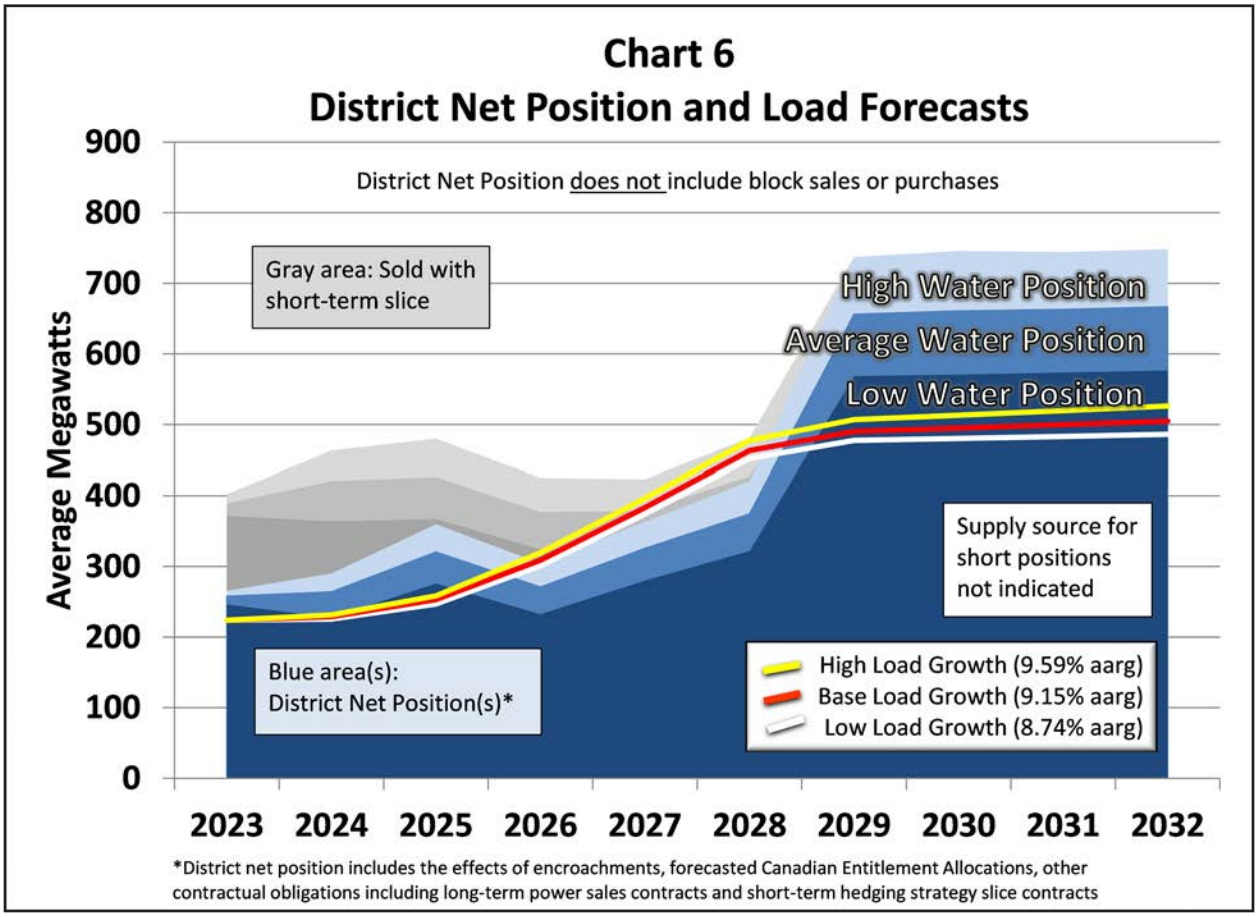
Nine Canyon Wind

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. In mid-2022, the Phase I and II debt was paid in full. Rates have declined by about 20% which is a combination of increasing O&M, increased decommissioning funding and decreased (to zero) debt. Rates are planned to hold fairly steady through the remaining life of the purchase contract which expires in 2030.

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 approached to hedging with more hedged in the near-term years and less hedged in future years.



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, 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)
- Stream flows that affect the availability of hydroelectric generation (volume and timing)
- Operational or outage risk

Load/Resource Balance

For this IRP progress report, 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 6 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 retail load throughout the planning period without any new generating resource additions, while evaluations are ongoing for the power supply for new Large Loads. The amount of demand-side resources included in this evaluation has increased from what was included in the 2021 IRP to match Chelan PUD's 2024 required 10-year conservation plan submittal to Commerce that is approximately 1.90 aMW per year through the study period (based on 2023 actual estimates and the 2023 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 (while evaluating power supply for new Large Loads), thus providing for service reliability. In addition, to consider the impact of streamflow variability in resource adequacy 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 a WPP effort to develop a robust Northwest capacity RA program that would allow utilities to forecast and manage RA in a coordinated manner.

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 2021 (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 2022–2025 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
2021 Fuel Mix

Generation Type	District Calculated Fuel Mix
Hydro-electric	99.95%
Wind	0.05%
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 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. Additional information on CETA is provided in the Regulatory and State Statutory Requirements section.

CETA section 3

CETA section 3 requires 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 hydro and wind resources. Through this IRP progress report, the District determined it will retain that mix of generating resources through the 2023-2032 planning period.

Historically, the District 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. The District anticipates that after 2025, it may need to modify its use of longer-term unspecified electricity hedging purchases due to CETA.

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 nonemitting 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 progress report, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2023-2032 planning period. The Conservation section details the conservation and efficiency actions the District has and intends to pursue from 2023 through 2032. The District will evaluate and determine power supply for new Large Loads expected to increase during the 2023-2032 planning period in preparation for the start of the CETA GHG neutral standard in 2030.

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 progress report, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2023-2032 planning period. The District will evaluate and determine the power supply for new Large Loads which are expected to increase during the 2023-2032 planning period in preparation for the start of the new state policy in 2045.

Final Remarks

Chelan PUD intends to retain its existing generating resources while implementing its 2023 CPA 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 demand response potential through CETA is a new focus. As detailed in the CEAP, the District's retention of its existing supply-side resources 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 stream flows, District load and the availability of some generating units undergoing significant repair and rehabilitation. Additionally, the District will evaluate and determine power supply for new Large Loads and continue to evaluate and implement its hedging strategy to help reduce the risks associated with these and other uncertainties.

Chelan PUD will publish a new IRP in 2025.

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Appendix A — Portfolio Detail & Assumptions

Resources

Hydro

- To represent the stream flow uncertainty, historical monthly re-regulated stream flow data, 1929-2007, supplied by PNUCC and actual hydro project data from 2008-2016 was grouped together to create average, low and high stream flow scenarios. 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 slice contracts)
  - 23.46% — 1/2023 through 12/2023
  - 18.46% — 1/2024 through 1/2025
  - 23.46% — 2/2025 through 12/2025
  - 18.46% — 1/2026 through 12/2026
  - 23.46% — 1/2027 through 10/2028
  - 49.46% — 11/2028 through 12/2028
  - 54.46% — 1/2029 through 12/2032
- Rock Island: Chelan PUD's share (net of long-term purchaser contracts and executed slice contracts)
  - 29% — 1/2023 through 12/2023
  - 24% — 1/2024 through 1/2025
  - 29% — 2/2025 through 12/2025
  - 24% — 1/2026 through 12/2026
  - 29% — 1/2027 through 10/2028
  - 55% — 11/2028 through 12/2028
  - 60% — 1/2029 through 12/2032

- Lake Chelan: Chelan PUD's share
  - 100% — 1/2023 through 12/2032

Wind

- All available historical Nine Canyon hourly wind generation (2004-2022) was used to calculate average energy

Conservation

- Used the quantities from the 2023 CPA (also used for RPS compliance in January 2024)

Contracts

Long-term Power Sales

- Rocky Reach
  - Puget: 25% — 1/2023 through 12/2032
  - Alcoa: 26% — 1/2023 through 10/2028
  - Douglas: 5.54% — 1/2023 through 12/2032
- Rock Island
  - Puget: 25% — 1/2023 through 12/2032
  - Alcoa: 26% — 1/2023 through 10/2028

Executed Slices of Rocky Reach & Rock Island

- Executed "slice of the system" contracts as part of long-term hedging strategy
- Slice contracts represent between 5% and 15% of the capacity and energy of Rocky Reach and Rock Island between 2023-2032
- Slice contracts are removed from Chelan PUD's shares of Rocky Reach and Rock Island listed under "Resources" above

Load

- The three load forecasts represent average annual rates of growth of: 8.74%-low, 9.15%-base, 9.59%- 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 the executed slice contracts.

Table 4 District's Average Annual Resources (aMW)										
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Net Rocky Reach Gen	137	131	168	133	169	200	392	392	391	391
Net Rock Island Gen	86	80	99	82	99	115	203	206	205	206
Net Lake Chelan Gen	32	48	47	48	48	48	47	47	48	48
Net Nine Canyon Gen	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Conservation	1.57	2.80	4.24	5.88	7.72	9.71	11.85	14.13	16.51	18.96

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Appendix B – Washington State Electric Utility Integrated Resource Plan Cover Sheet 2023

	Base Year			5 Year Estimate			10 Year Estimate		
Estimate Year		2022			2027			2032	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	553.00	275.00	212.80	604.00	398.00	368.00	770.00	541.00	511.00
Exports									
Resources:									
Future Conservation/Efficiency				16.00	9.21	7.73	38.80	22.75	18.97
Demand Response									
Cogeneration									
Hydro	381.00	409.00	267.00	507.00	261.00	226.00	1,051.00	520.00	457.00
Wind	0.02	0.04	1.95	1.28	0.68	2.24	1.28	0.68	2.24
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts	172.00								
BPA									
Other									
Imports									
Distributed Generation									
Undecided				80.00	128.00	133.00			33.00
Total Resources	553.02	409.04	268.95	604.28	398.89	368.97	1,091.08	543.43	511.21
Load Resource Balance	0.02	134.04	56.15	0.28	0.89	0.97	321.08	2.43	0.21

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 Load Growth Forecast of 9.15%.
- Peak and annual energy loads, including the base year (2022), 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.

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

Wind

- Base year (2022) wind data reflects actual Nine Canyon experience in that year.
- 2027 and 2032 projected peak wind capacity is based on median (50th percentile) hourly Nine Canyon historical generation (2004-2022).
- 2027 and 2032 projected average annual wind energy is based on median (50th percentile) average annual energy from Nine Canyon historical generation (2004-2022).

Acronyms

aarg	Average Annual Rate of Growth
ACE	Affordable Clean Energy
AMI	Advanced Metering Infrastructure
aMW	Average Megawatt
BA	Balancing Authority
BAA	Balancing Authority Area
BC	British Columbia
BEV	Battery Electric Vehicle
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
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
CETA	Clean Energy Transformation Act
CO2	Carbon Dioxide
CPA	Conservation Potential Assessment
CPP	Clean Power Plan
DHP	Ductless Heat Pump
DOE	Department of Ecology, Department of Energy
DOT	Department of Transportation
DR	Demand Response
DRAC	Demand Response Advisory Committee
DRPA	Demand Response Potential Assessment
DVR	Demand Voltage Regulation
EDAM	Extended Day-Ahead Market
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HB	House Bill
HCP	Habitat Conservation Plan
HDL	High Density Load
HP	Heat Pump
HSPF	Heating Season Performance Factor
HVAC	Heating, Ventilating and Air Conditioning
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
KW, kWh	Kilowatt, Kilowatt-hour
LI	Low Income
LOLEV	Loss of Load Events
LOLP	Loss of Load Probability
LVT	Line-Voltage Thermostat
LVCT	Line-Voltage Communicating Thermostat
MW, MWh	Megawatt, Megawatt-hour
NEEA	Northwest Energy Efficiency Alliance
NWPCC	Northwest Power and Conservation Council
NWS	Non-Washington Sink
O&M	Operations and Maintenance
OFM	Office of Financial Management (Washington State)
PHEV	Plug-in Hybrid Electric Vehicle
PTC	Production Tax Credit
PTCS	Performance Tested Comfort System

PTHP	Packaged Terminal Heat Pumps
PUD	Public Utility District
RA	Resource Adequacy
RCP	Representative Concentration Pathways
RCW	Revised Code of Washington
REC	Renewable Energy Credit
RMJOC	River Management Joint Operating Committee
RTF	Regional Technical Forum
SB	Senate Bill
SEER	Seasonal Energy Efficiency Ratio
SEM	Strategic Energy Management
SPP	Southwest Power Pool
TOU	Time of Use
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
ZEV	Zero Emission Vehicle

Glossary

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, 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 run at all times, 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
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 "CO2 neutral", meaning they typically remove CO2 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 is entitled to one half the downstream power benefits resulting from Canadian storage under the 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.

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.

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 (Seventh, Eighth, 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.

Duration Value at Risk
Metric that sets a value at risk over a set time period.

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 (Seventh, Eighth, 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.

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).

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).

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:

Cryptocurrency Processing — loads related to computing or data processing related to cryptocurrency mining, Bitcoin, blockchain, proof-of-work or other similar loads.

High Density Loads — loads with intense energy use – 250 kWh per square foot or more per year with loads up to 5 annual aMW.

Large Loads — loads greater than 5 aMW.

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 (Seventh, Eighth, 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 and Energy Value at Risk (VaR)
Metric that sets limits for the maximum capacity and energy shortfalls during rare events.

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 (Seventh, Eighth, 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 of 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.

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 across eight western states. 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.

Western Energy Imbalance Service (WEIS)

Beginning February 1, 2021, SPP began operations of its Western Energy Imbalance Service (WEIS). SPP is also proposing a day-ahead market, Markets+. 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. It could be implemented as early as 2026.

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 between 2025 and 2028.

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

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

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