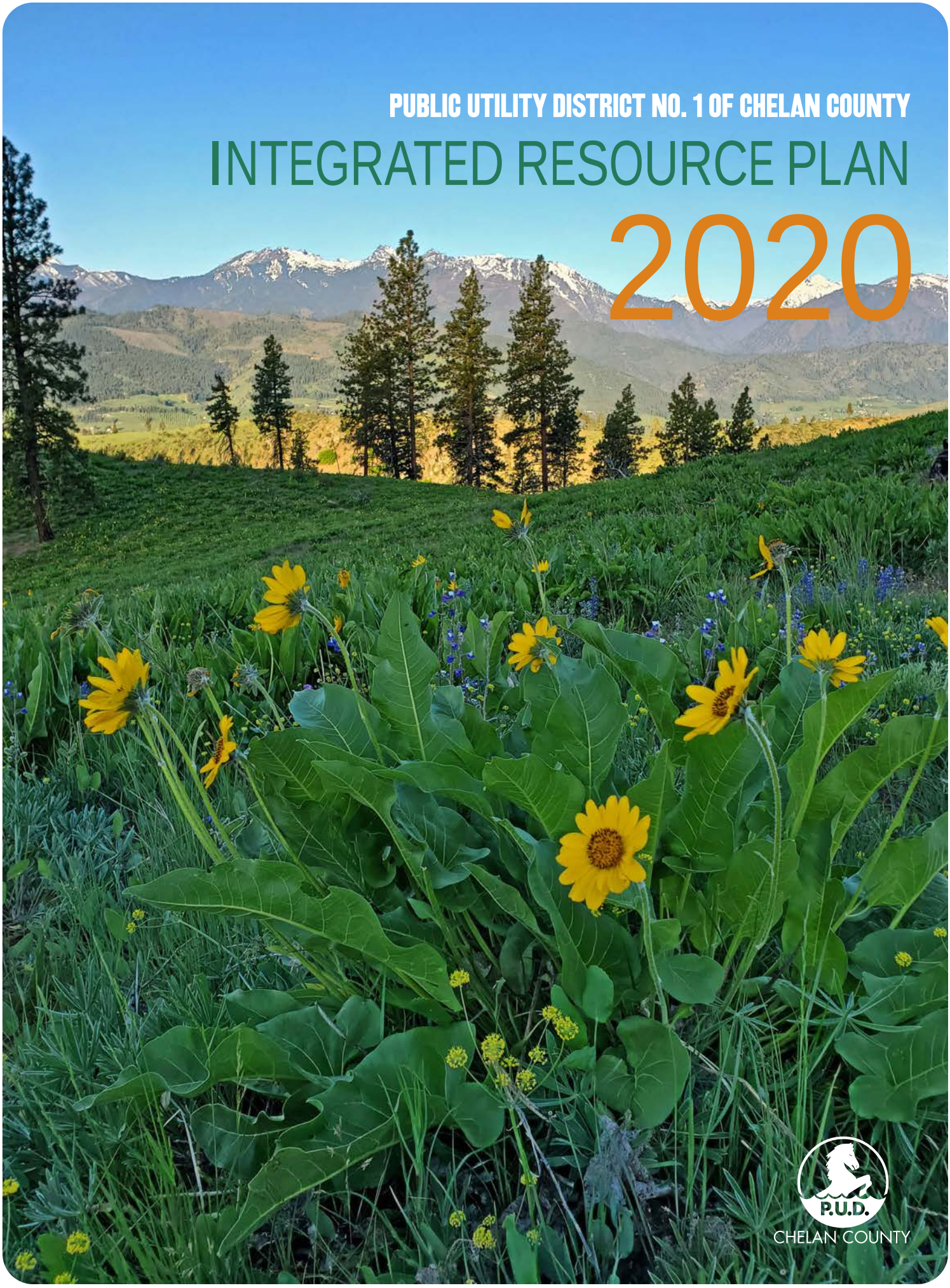
PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY

INTEGRATED RESOURCE PLAN

2020



P.U.D.
CHELAN COUNTY

2020 INTEGRATED RESOURCE PLAN

JULY 2020

PUD No. 1 of Chelan County
327 N. Wenatchee Avenue
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Wenatchee, WA 98807-1231

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

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2020 Integrated Resource Plan

Summary of Determinations

The District has completed its 2020 Integrated Resource Plan (IRP). This IRP 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 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 2020-2030 planning period, the Board of Commissioners of Chelan County Public Utility District (Chelan PUD or District) has approved this 2020 IRP and determined that:

- The District retain its current mix of generating resources.

And additionally:

- The District continue to evaluate and implement conservation programs based on the foundational work performed in the 2019 conservation potential assessment (CPA).
- The District carry on the evaluation and implementation of strategies for additional power and ancillary sales contracts 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, renewable energy resources for the foreseeable future.

Report Overview

To meet the requirements of RCW 19.280, the development of Chelan PUD's 2020 IRP 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 regards to the District's existing operational and power sales contracts
- Amended conservation inputs to align with Chelan PUD's December 2019 10-year conservation plan submittal to the Washington State Department of Commerce (Commerce) as required
- An update on regional and Chelan PUD's resource adequacy 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
- A ten-year clean energy action plan (CEAP) for implementing portions of The Washington Clean Energy Transformation Act (CETA)
- Board approval of the IRP
- Submittal of the final IRP to Commerce by September 1, 2020 as required

Planning & Regulatory Environment

Resource Planning Situation

Chelan PUD is forecasted to be surplus to its own retail load needs throughout the current planning period (2020-2030).

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.

Although the District is currently surplus to its own retail load, resource adequacy is a topic of great concern to the region and individual utilities alike. Demand response has been identified as a resource to help meet capacity demands in the region. Both topics are discussed more fully below.

Resource Adequacy

The current, **voluntary** resource adequacy 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. The Council's latest resource adequacy assessment for 2024 was released in October of 2019.

- By 2021, the Northwest power supply becomes inadequate, with an estimated LOLP of 7.5%, primarily due to the announced retirement of 1,619 megawatts of coal-fired generating capacity. Besides existing resources, the assessment only includes planned resources that are sited and licensed and targeted future energy efficiency savings.
- By 2024, with the planned retirement of an additional 127 megawatts of coal plant capacity, the LOLP grows to 8.2%. Load growth over the next five years is almost entirely met by targeted energy efficiency savings, with a net annual load growth of about 0.3%. Potential shortfall events in 2024 are more likely to occur during winter and are expected to last longer and have higher peak-hour shortfalls than summer events. These results could change significantly if future load growth and/or market conditions change. For example, under a high load growth scenario (3% above medium) with a lower market supply (1,000 megawatts less), the 2024 LOLP grows to 21%. Under a low growth scenario (3% below medium) with a higher market supply (1,000 megawatts more), the LOLP drops to 2%. But the likelihood of a very low or very high load growth rate over the next five years is small.
- By 2026, with another 804 megawatts of announced coal plant capacity retiring, the LOLP grows to 17%. With the planned retirement of an additional 1,060 megawatts of coal plant capacity by 2032, the region will be facing a very large resource gap to fill. However, these assessments do not include utilities' replacement plans. The Council's next power plan is scheduled to be completed by 2021, giving the region time to develop an appropriate replacement strategy that will account for state-level legislation (see Regulatory and State Statutory Requirements) affecting future resource choices, climate change and increasing renewable generation.

In October of 2019, PacifiCorp proposed moving up the retirement dates for several of its coal plants. The Jim Bridger 1 coal plant (530 megawatts), originally scheduled to be retired by 2028, is now under consideration to be retired by the end of 2023. The Jim Bridger 2 coal plant (530 megawatts), originally scheduled to be retired by 2032, is now under consideration to be retired by the end of 2028. Also, PacifiCorp is proposing divesting from the Colstrip 3 (518 megawatts) and Colstrip 4 (681 megawatts) coal plants by the end of 2027. The earlier retirement of the Jim Bridger 1 coal plant increases the 2024 reference case LOLP from 8.2% to 12.8% and increases the 2026 LOLP from 17% to 26%. Between 2026 and 2028, the region could potentially lose an additional 1,729 megawatts of capacity if the Jim Bridger 2 and the Colstrip 3 and 4 coal plants are retired. The Council will keep abreast of any changes to resource availability or to regional demand and will continue to monitor the adequacy of the regional power supply during the development of its next power plan.

It should be emphasized that these results reflect the adequacy of the aggregate regional power supply. Individual utilities within the Northwest are facing a wide range of future resource needs and are preparing for those needs in their IRPs.

In addition, the Council has initiated a process to review its current adequacy standard. Council staff and Resource Adequacy Advisory Committee (RAAC) members will be reviewing the viability of the current LOLP metric and 5% threshold. This review will consider similar efforts going on in other parts of the United States, namely the Institute of Electrical and Electronics Engineers (IEEE) Resource Adequacy Working Group (RAWG), the North American Electric Reliability Corporation's (NERC) Probabilistic Assessment Working Group (PAWG) and the Northwest Power Pool's (NWPP) resource adequacy review. Once the redeveloped GENESYS model has been fully vetted, the Council will consider options for amending its adequacy standard.

In addition to the region wide resource adequacy assessments mentioned above, the NWPP is currently working to develop a robust Northwest capacity resource adequacy program. The NWPP is pursuing the first stage of design of a voluntary capacity Resource Adequacy Program (RA Program) for the NWPP members. Below summarizes some key elements of the program:

- RA looks out 1 – 4 years to ensure adequate resource capability is available to meet customer demand.
- In a large portion of the NWPP footprint, utilities manage RA individually and with different methods. An RA Program would allow utilities to forecast and manage RA in a coordinated manner.
- The RA program will respect local autonomy over investment decisions and operations and will continue to respect the rights and characteristics of individual utilities, transmission service providers, BAs and other entities.
- The RA Program will be voluntary to join, but once a utility joins, it will be contractually committed to the requirements of the RA Program.
- The RA Program will consider:
- 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 is actively involved with this effort and will continue to contribute to the program development.

The District analyzed its resource adequacy in the preparation of this 2020 IRP.

Demand Response

One of the key findings from the 2016 Seventh Power Plan is the region's need to develop capacity resources to meet growing demands. Demand Response (DR) was identified as a resource to meet winter and summer peak demands, primarily under critical water and extreme weather conditions. The plan indicated a minimum of 600 MW of additional DR resources would be cost-effective to develop as soon as possible; significantly more than had been developed or planned.

In June 2017, the Council's Demand Response Advisory Committee (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 DRAC is supporting the Council in development of updated DR supply curves for the Eighth Power Plan, expected to be published in 2021.

With extensive input from the DRAC, Council staff developed a template for utilities to use to record historical and current DR programs, along with planned programs. The template includes the type of program, the amount of curtailed electricity capacity (realized and planned), and other information such as: seasonality, cost and callable hours. Based on utility template reporting, as well as information directly from utility IRPs, it is apparent most of the region's investor-owned utilities and some public utilities incorporate DR into their resource planning. Some utilities like Idaho Power and PacifiCorp are planning to continue their existing DR programs that provide over 500 megawatts of impact in the region during the summer season, primarily from irrigation load control. Other utilities that currently do not have large-scale DR programs find a need for DR in the next 5 to 10 years (e.g. Portland General Electric, Avista and Puget Sound Energy). Bonneville Power Administration (BPA) found DR to be part of the portfolio to meet its summer capacity needs in its 2018 resource program.

The DRAC has spent significant time discussing the barriers to demand response. In addition, BPA contracted a study to explore the barriers among different parties potentially affected by DR programs (BPA power customers, internal subject matter experts, DR service providers and external stakeholders). In all cases, the identified economic/market barriers are the most significant to DR adoption. Without a clear valuation metric (e.g. currently no capacity market), it is difficult for many to justify DR investment. Other identified barriers include: regulatory (lack of established tariffs), infrastructure (data handling protocols), organizational (intra-organizational communication), and perceptual (customer understanding). The DRAC is exploring ways the region may mitigate these barriers.

Although there are significant barriers, the region has several characteristics that support expansion of DR. These include the long history of energy efficiency and regional collaboration, growing participation in the western Energy Imbalance Market (EIM) and high potential for DR due to its high electric water heater penetration and growing penetration of electric vehicles. Utilities are finding value in DR not only as a means to mitigate peak load capacity constraints, but also as part of the solution set for non-wires alternatives.

Chelan PUD has one agreement falling under the umbrella of DR. It is a load shedding agreement with Alcoa Power Generating, Inc. (APGI) and Alcoa, Inc. (Alcoa). In December 2015, Alcoa idled their Wenatchee Works plant. The District does not have any DR available while the Alcoa plant is idled.

Regulatory & State Statutory Requirements

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

Renewable Portfolio Standard (RPS)

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

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

Clean Energy Transformation Act (CETA)

In May 2019, 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.

Among other requirements, CETA also requires utilities to include 10-year clean energy actions plans 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. The Clean Energy Action Plan section of this IRP includes the District's first CETA ten-year CEAP.

CETA is a complex law with many components. Rulemaking is ongoing and is currently scheduled to continue into 2022. The District will continue to closely follow the rulemaking process and that process will likely inform the District's understanding and future assessment of how CETA's requirements will impact the District's resource planning.

Clean Air Rule (CAR)

On September 15, 2016, the Washington State Department of Ecology (DOE) adopted emission standards (Chapter 173-442 Washington Administrative Code (WAC) – Clean Air Rule (CAR)) to cap and reduce GHG emissions from significant in-state stationary sources, petroleum product producers, importers, and distributors and natural gas distributors operating within Washington.

In March 2018, Thurston County Superior Court ruled that parts of the CAR are invalid. In January 2020, the Washington Supreme Court reinstated a very limited version of the CAR. In a 5-4 ruling, the court said the

CAR cannot apply to companies that sell or distribute petroleum or natural gas because they don't make their own emissions – other people burn the fuel they provide. The DOE only has the authority to regulate "actual emitters," the court said. Cars remain the biggest source of GHG pollution in the state. About three quarters of the emissions that would have been covered by the rule came indirectly from petroleum and natural gas importers and sellers.

Governor Inslee said his office is reviewing the opinion and that it wasn't clear if he would ask lawmakers to expand DOE's authority to allow it to regulate "indirect emitters" or what his next step would be. He also pushed several climate-related bills this legislative session, including one that would adopt a clean fuel standard and another that would establish a zero-emissions vehicle program.

National Climate and Energy Legislation

The Clean Power Plan was unveiled by President Obama on August 3, 2015. The Environmental Protection Agency (EPA) proposed emission guidelines for states to follow in developing plans to address GHG from existing fossil fuel-fired electric generating units. Challengers argued that the EPA overstepped its legal authority in issuing the Clean Power Plan, as it regards the power plants covered by the Plan, and the scope of the "building blocks" for action go beyond standards applied to specific electric generation units, as called for by the Clean Air Act.

On February 9, 2016, the Supreme Court ordered the EPA to halt enforcement of the Plan until a lower court rules in a lawsuit against it. In October 2017, it was reported that the EPA, under the Trump Administration, was planning to end the Clean Power Plan. EPA Administrator Scott Pruitt announced the formal process to change EPA rules and repeal the plan would begin on October 10, 2017. The standard federal regulatory procedures and potential legal challenges to implement or change a regulation would likely take up to two years.

In May 2019, Administrator Andrew Wheeler, who had replaced Administer Scott Pruitt, announced plans to change the way the EPA calculates health risks of air pollution, resulting in the reporting of far fewer health-related deaths and making it easier to roll back the Clean Power Plan. Administrator Wheeler defended the change as a way to rectify inconsistencies in the current cost-benefit analyses used by the agency. The new plan will be known as the Affordable Clean Energy rule.

In November 2019, Democrats introduced the 100% Clean Economy Act of 2019 to adopt a 100% clean energy economy goal nationwide by 2050. The bill would require all sectors of the economy to achieve net-zero GHG emissions by the middle of the century. Federal agencies would be tasked with identifying a path toward the goal, while the EPA would be in charge of reviewing their plans. Environmental groups and clean energy advocates hailed the bill as a step in the right direction to combating climate change. Gas association and other stakeholders, however, adopted a more cautious tone. In December 2019, Congresswoman Debbie Dingell (D-MI) introduced legislation, the National Climate Bank Act of 2019, establishing a National Climate Bank to publicly finance and stimulate private investment in clean, renewable energy and emissions reduction projects. The National Climate Bank will use public capital to stimulate private investment in a range of projects to reduce GHG emissions and accelerate the nation's clean economy transition across many sectors. It will be funded with $35 billion over six years, in an effort to mobilize up to $1 trillion in private investment (as estimated by the Coalition for Green Capital). National Climate Bank capital and technical assistance will make more projects economically competitive in more communities nationwide, to the benefit of investors, energy consumers, workers and local economies. Similar legislation, the Green Bank Act of 2019, was introduced by Senator Chris Murphy (D-CT) and Representative Jim Himes (D-CT).

Load Forecast

A new 11-year econometric retail load forecast was developed for this IRP's 2020-2030 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. In addition, the resulting forecasts are an integration of economic evaluations and inputs from the District's own customer service planning areas.

Total annual projected megawatt-hours through the planning period were forecasted on an annual incremental or decremental basis by sector, including system losses at 3.5%, using 2019 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**

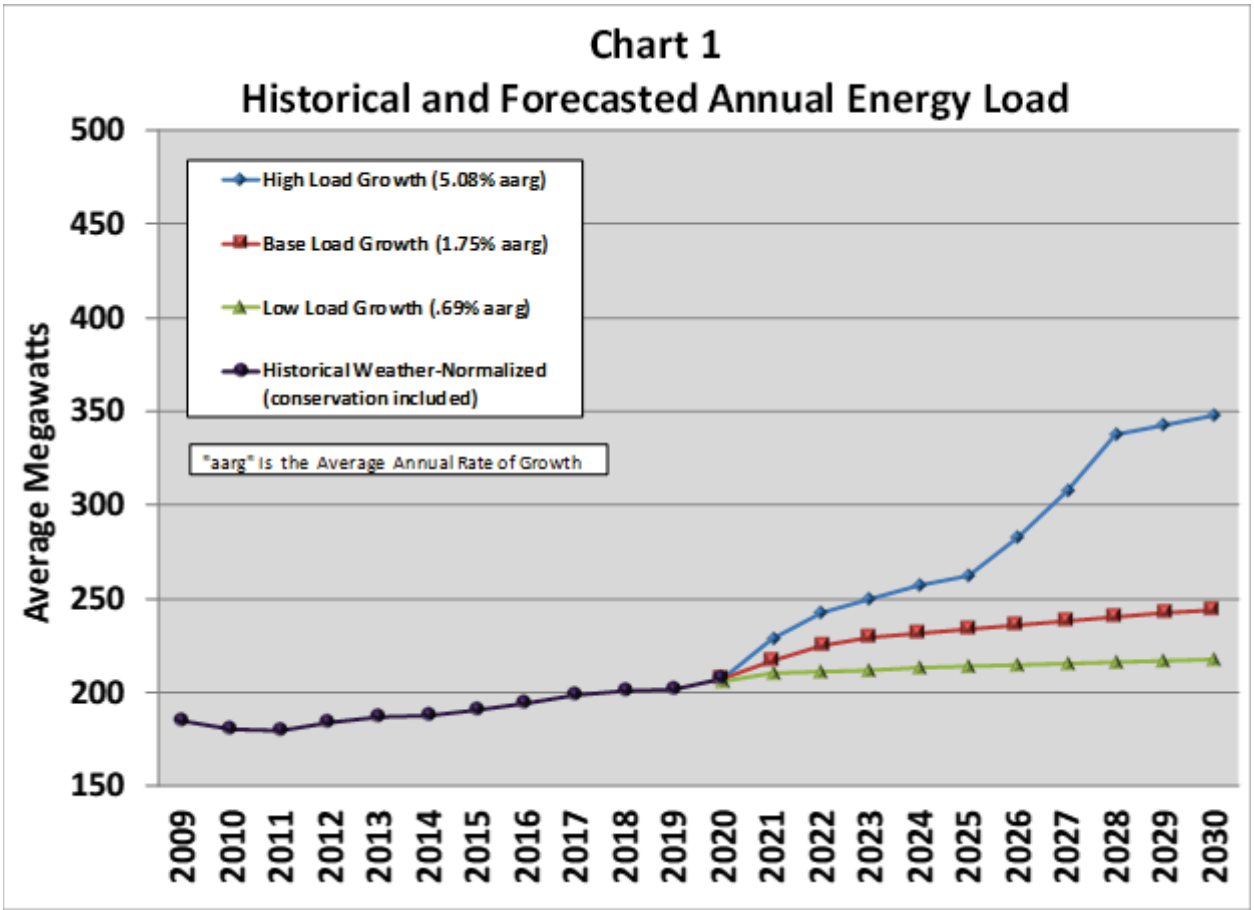
load growth rates, are .69%, 1.75% and 5.08%, respectively. All three forecasts have decreased from the 2018 IRP Progress Report. The weather-normalized average annual rate of growth at the District (before the effects of cumulative conservation) was approximately 1.47% for the 10-year period from 2009-2019. The net of cumulative conservation growth percentage was approximately 0.89% for the same 10-year period. This historical net of cumulative conservation growth average is essentially the same as in 2018. While the residential and high-density loads (HDL) have increased some during this period, increased conservation achievements that began in earnest in 2010 continue to mitigate load growth. The three forecasts for 2020-2030 as well as the actual weather-normalized total District energy load for 2009-2019 are presented in Chart 1. The NWPCC's Seventh Power Plan region-wide forecast for 2015-2035 is between 0.5% and 1.0% per year. Like the District's forecasted annual energy load growth rates, these forecasts do not include any new conservation measures. The Eighth Power Plan is scheduled to be completed in 2021.

COVID-19

The COVID-19 pandemic is most certainly generating a disruption to local economic development, construction and jobs. Early indicators show restaurants, bars and hotels are among the highest impacted. District staff believes it is premature to understand the full extent to businesses and resulting impacts to the utility's electrical load and load forecasts. Chelan PUD is actively working with the economic development community, businesses, building contractors and developers to gain insights into how economic development projects and restarting of businesses move forward following the pandemic. This forecast was decreased some in the near time to account for the anticipated affects.

High-Density Load (HDL)

As reported in 2018, Chelan PUD, as well as other utilities in the region, had been dealing with the entry of new High Density Loads (HDL) to the county. HDLs are those loads with intense energy use – 250 kWh per square foot or more per year where the energy is used for server farms, cryptocurrency mining or similarly situated loads. The District instituted a moratorium on



any new or expanding applications for HDLs effective July 2015 that extended until October 2016. That HDL moratorium affected the cryptocurrency mining and temporarily stabilized their growth as well as other similar server farm operations in the District's service territory. In January 2017, the moratorium was lifted and a new power rate for HDL loads up to five megawatts was implemented.

From October 2017 to January 2018, the District received another series of cryptocurrency applications and inquiries totaling approximately 220 MW as the price of Bitcoin soared. Responding to these applications was hampered by limitations in infrastructure to serve and the District's inability to collectively process the high volume of applications in the expected timeframe.

In March 2018, Chelan PUD, once again, implemented a moratorium on new HDL load applications. District board members unanimously imposed the moratorium after reviewing impacts on utility operations from existing loads and applications for cryptocurrency service. This pause was expected to allow lessons learned to be adopted for the existing, under five megawatt rates and policies as well as to develop new rates and policies for above five megawatt loads. Approved applications with fees and charges paid were allowed to go forward. At the time the moratorium was implemented, the District had 22 approved and active HDLs in Chelan County, totaling about nine aMW.

Impacts from cryptocurrency mining applications began hampering responses to the District's overall planned work and threatening Chelan County's electric grid capacity to meet planned growth. Public health and safety concerns due to rogue cryptocurrency operators also led to the cities of Chelan and Wenatchee to curb operations, especially in residential neighborhoods. District staff began finding rogue cryptocurrency operations requiring time and effort to investigate and respond. Many were in homes without the infrastructure needed to serve heavy load, threatening the safety of neighbors and Chelan PUD workers.

With the moratorium in place, the District planned to: 1) review and update the existing Schedule 35 rate (under five megawatts) including considering adding transmission costs and continue to develop rates, fees and processes for service requests of five megawatts or more, 2) widely communicate the consequences of unauthorized operations including adding fees for investigation, monitoring and equipment damage, 3) keep working with city, county and state building code officials and 4) keep adding technology to meet the challenges of detecting and serving cryptocurrency loads.

During the second moratorium the District completed the updating for existing rate Schedule 35 and included HDL qualifications. During this time, the District also implemented a new Schedule 36 specifically relating to cryptocurrency loads. In addition to the rate schedule changes, the District implemented a system impact fee for both new HDL and cryptocurrency loads. Applicants would pay a system impact fee based on a KW demand. Additionally, the District established some areas within its service territory to be restricted from connecting any HDL or cryptocurrency loads. These restriction zones are in the most rural areas of the county. The new rate schedule, system impact fees and policies became effective January 1, 2019.

As of the end of 2019, HDL load in Chelan County is still about nine aMW. Most small HDL operations of less than one MW have suspended energy use or shut down completely. The District has one new HDL that began ramping up operations and load in 2019 and is expected to continue to do so over the next two or three years. There are currently no other known changes coming to the sector, but the high load forecast includes the possibility of other future HDL load growth.

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 in 2017. Growth rates over the planning period were increased some in the low and base cases and decreased some in the high case to reflect District staff's judgement about the range of Chelan County potential population changes. The growth rates were applied to the OFM actual population estimate for Chelan County for 2019 to arrive at updated population estimates through the planning period. Actual Chelan County population data from the OFM (through 2019), 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 just slightly based upon known and expected changes coming to the sector. The three average annual growth rates for the residential sector are forecasted at 0.37%, 0.83% and 1.59%. The low and base are virtually unchanged and the high has increased slightly since 2018. There are several large new residential developments in the application process. It is likely not all of these will be come to fruition, and it 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 at two locations to serve new load. Additionally, the District continues to be on the lookout for changing end uses including changing federal standards (i.e. more efficient appliances, lighting, etc.) and slower growth in home electronics. It is expected that a significant amount of these changing end uses will continue to be ongoing and take place outside of the District's organized conservation programs.

For this load forecast, the commercial sales forecast is a function of population only based on statistical significance. The results were adjusted in the 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 0.49%, 1.42% and 2.89%. Since 2018, the low case has increased some with population actuals coming in higher than previously projected low scenarios and the base and high cases remain virtually the same. As with residential load, the District still believes that ongoing efficiency improvements, particularly in commercial lighting, 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 some known probable and other potential larger load additions. The average annual growth rates for the industrial sector are forecasted at 1.39%, 1.53% and 2.05%. These have all decreased since 2018, once again, primarily due to projected HDL load having been taken out of industrial and classified as its own sector. Industrial sales are now estimated to decrease slightly as a percentage of the District's total load through the planning period in the base and high forecasts due to increases of HDL load forecasted in those cases.

As indicated in the earlier cryptocurrency discussion, the future of HDL loads in Chelan County remains unknown to a great extent. The low, base and high cases were estimated taking into account existing approved applications, infrastructure timing limitations and general interest and economic conditions. The average annual growth rates for the HDL sector are forecasted at 2.64%, 9.95% and 25.11% for the planning period.

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.

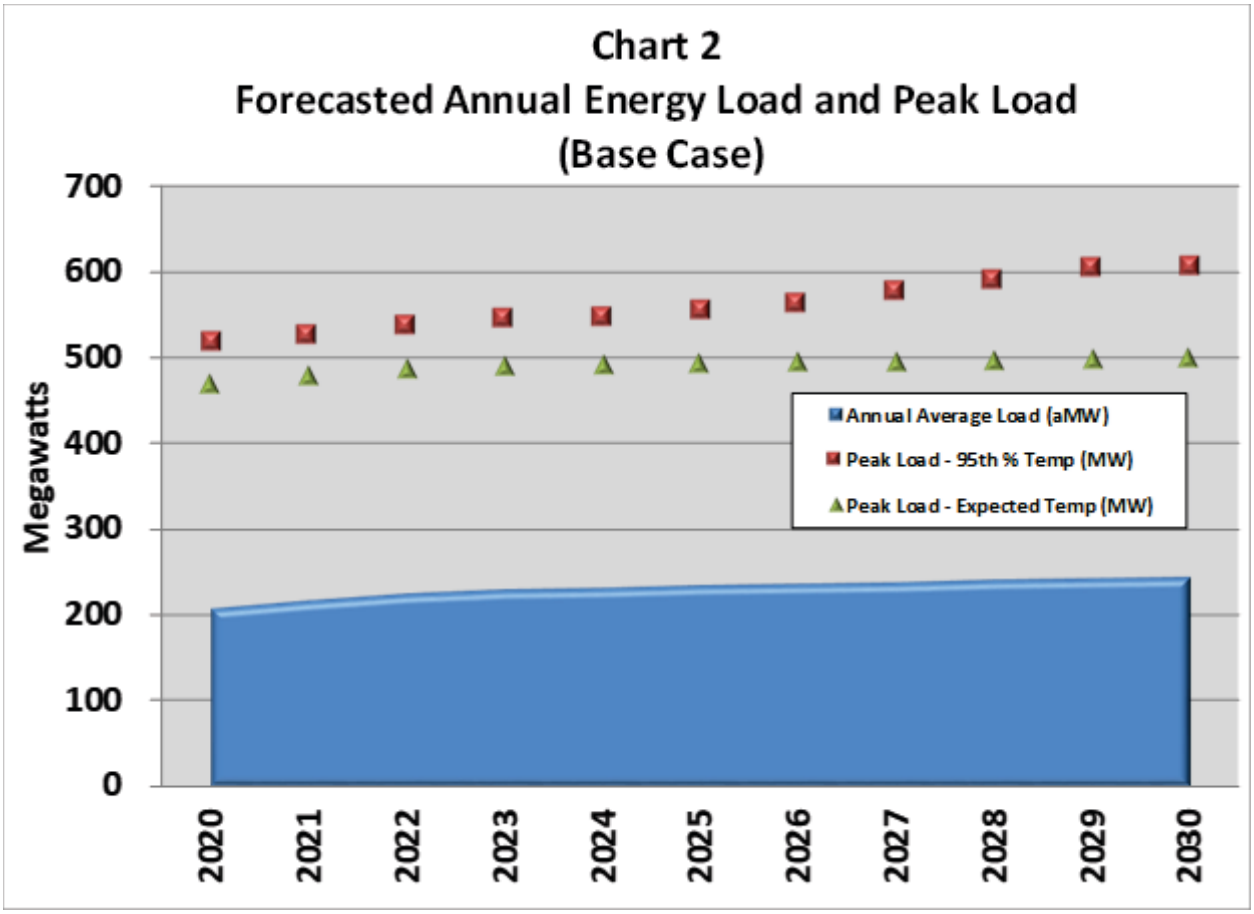
The District has not studied the potential effects of distributed solar photovoltaic generation or other distributed energy resources on retail load in its service area but believes it to be negligible during the current planning period.

As previously mentioned in the Demand Response section, in December 2015, Alcoa idled their Wenatchee Works plant. Alcoa's load is not forecasted nor considered for District IRP purposes as it is not considered to be Chelan PUD retail load.

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 in January 2017. The peak of 491 MW was established when the temperature was approximately -0.7 degrees Fahrenheit. This occurred on a weekday (Thursday) morning when peak demands are usually higher given business and other commercial needs.

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 the newer methodology potentially provides more forecast accuracy, particularly if the total retail load shifts over time between the sectors as provided in the base and high energy forecasts. Most HDL 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 -0.3% and 2.8% (net of conservation) for the three energy growth forecasts. The weather-normalized winter peak growth rate over the last 10 years was approximately .96% (net of conservation). 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 2020-2030.



Electric Vehicles (EVs)

The District began taking a close look at potential future EV retail load nearly 10 years ago. For these purposes, EVs include both plug-in hybrid electric vehicles and battery electric vehicles. As of December 18, 2018, there were 42,542 EV light vehicles registered in the state of Washington, 201 of which are in Chelan County. That is a 91% increase over the previous 18 months.

Global and U.S. EV sales forecasts vary greatly. 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.

The District continues to use the Council's basic EV load forecasting methodology. Based on EV market share, or penetration rates, experienced in the District's service area and various recent national forecasts, the District updated Chelan County's current number of EVs with the most recent available data and slightly decreased market share for EVs in its overall low, base and high load forecasts through the 2020-2030 planning period from the 2018 IRP Progress Report. They are still somewhat less than the Council's Seventh Power Plan. By the end of the planning period, the rates vary from 7% to 24% in the three cases. This translates into approximately 1,500 to 5,800 EVs in Chelan County (after EV retirements). The three cases now result in forecasts of between .50 and 1.86 aMW by 2030.

Peak load estimates now range from 1.03 MW to 3.88 MW in 2030. 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. For more detail regarding the Council's EV forecasting methodology and other assumptions used, see the Council's Seventh Power Plan.

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. and Puget Sound Energy. The Alcoa contract expires in 2028 during this planning period (2020-2030). District power contracts and the hedging strategy are more fully discussed in the Portfolio Analysis section.

Hydropower has many characteristics that make it highly desirable. It is free of the emissions associated with fossil fuel-fired generating resources. Operational flexibility allows hydropower to quickly follow load changes and provide reserves to the electric grid in a timely manner, which contributes to overall system reliability. In addition, hydropower provides backup for intermittent resources such as wind and solar. The District avoids transmission availability issues, in relation to serving retail load, by being able to use its own hydropower generation, which is located in Chelan County, near the District's retail load. 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. C10 and C11 are now scheduled to be repaired in the 2023-2025 timeframe. The remaining seven smaller units at Rocky Reach do not share the same design in regards to either of these issues.

The seven smaller generating units at Rocky Reach were all in need of trunnion bushing replacement. Unit C1 was completed in March of 2020 and is back in service. Units C4, C5 and C6 are all in service and scheduled for their replacements in the 2020-2022 timeframe. Units C2, and C7 are out of service and their trunnion bushing replacements have begun with completion expected late 2020 and early 2021. Unit C3 is running under modified operations (hydraulically blocked the blades to allow C3 to return to service) with a limit of 90 MWs until repairs can be made.

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. Unit B4 is currently undergoing modernization and is scheduled to return to service in 2020. The remaining three units will follow in 2021 and 2022.

During periodic machine condition monitoring at Rock Island, plant staff observed deterioration of a critical clearance measurement in the generators of B6 and B7. This clearance, referred to as the "air gap" between the rotor and the stator of the generator, has deteriorated over time and is now below acceptable reliable operating limits. Data for B6 and B7 was evaluated and shows a deteriorating air gap clearance. To correct the deterioration of the air gap in B6 and B7, the District decided to restart unit rehabilitations to install a new stator, replace rotor poles and rim and reshape and align the units to within industry standards

for normal operation, as was done previously for units B9 (2012) and B10 (2007). B6 was returned to service in April 2018 after the unit rehabilitation was complete. The B7 rehabilitation was initiated in April 2018 and is scheduled to return to service in 2020. This unit has been delayed due to the turbine runner issues discussed below. To keep work moving along with the turbine runner issues, the District decided to begin the rehabilitation of unit B5, which had been offline due to turbine runner oil leaks. B5 is expected to return to service in 2021. Unit B8 is in service, with hydraulically locked blades, and scheduled for modernization in 2021-2022.

In June 2017, unit B9 tripped offline due to a turbine blade/wicket gate position deviation from normal. On inspection of the unit, one of the oil pipes inside the turbine/generator shaft failed under strain and twisted into two parts. The design for the turbine oil piping for the rest of the B5-B10 units is the same as for B9. The modernization contractor was notified and signed a field work order to conduct a root cause analysis of the B9 pipe failure and provide corrective repairs as required to return the unit to service. B9 was returned to service in October 2018. Corrections to the turbine oil piping were applied to B6 before the return to service in 2018 and will be incorporated with the B10 work discussed below. Corrective actions for B5, B7 and B8 will occur during the currently scheduled modernization outages.

Unit B10 was taken offline on January 15, 2019 to repair the thrust bearing equalizing system, which was leaking and jeopardizing the effectiveness of the equalizing system. In conjunction with this work, the turbine runner was inspected. The inspection revealed failures of key components within the turbine hub, believed to be consistent with stick-slip of the runner blades, and a suspected contributor to unit vibration issues going back to 2007 on B10, 2012 on unit B9 and 2018 on unit B6. The thrust bearing equalizing system required new seal designs from the manufacture to rebuild the system. The turbine runner was rebuilt with some modifications, and is expected to return to service in 2020; it may require an additional outage to install new KAron V trunnion bushings in the turbine runner in the future following the rest of power house 1 modernizations. Both B6 and B9 have the same issue as B10, and they are to be repaired following power house 1 modernizations as well. Units B5 and B7 are currently undergoing modernization, and their turbine runners will receive the recommended modifications to address all the known issues with failed components on B10 prior to returning to service. Testing of the modifications, to determine if they have been effective, will occur as unit B10 is commissioned and returned to service in 2020.

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. There is no timeline yet on when 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, 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 forced 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 down 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. The District plans to update this analysis once the RMJOC II regulated hydro data is available.

Data is now available to model future climate change scenarios on Lake Chelan operations and reservoir management. The District has worked with the UW Climate Impacts Group to determine which data sets to use to complete its own modeling. In 2020, Chelan PUD conducted internal modeling and is determining the usefulness of the data and working to see if it can be used to help with future planning.

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. 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 $20/MWh. These generators can afford to withstand some degree of negative pricing and still make a profit due to these other payments. 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 (2.4 cents/kWh in 2017). In 2015, the PTC for certain wind producers and other renewable energy technologies had been extended through 2019 for projects that began construction before the end of that year. Phase outs began in 2017. Additionally, in 2015, legislation also included an extension of the solar investment tax credit (ITC), which was also subject to a phase out. Solar projects that were under construction by December 2019 fully qualified for the 30% ITC. The credit falls to 26% for projects starting construction in 2020 and 22% for projects staring construction in 2021. On December 20, 2019, President Trump signed the Taxpayer Certainty and Disaster Tax Relief Act of 2019, which extends the current PTC for wind for an additional year. The legislation extends the wind PTC for facilities the construction of which begins during 2020 at a rate of 60%. Under prior law, the PTC for wind facilities phased down to 40% for facilities for which construction began in 2019 and to 0% for facilities for which construction began in 2020. Interestingly, the bill leaves in place the phase down to 40% for facilities that began construction in 2019.

In addition, the bill retroactively extends the PTC for other renewable energy facilities including geothermal, biomass, landfill gas and certain hydropower and marine hydrokinetic for which construction begins before January 1, 2021. Taxpayers alternatively may elect to claim a section 48 ITC of 18% (which is 60% of the original 30% ITC value) in lieu of the PTC. The legislation does not include an extension for the solar ITC beyond its 2021 phase out, nor does it include the proposed expansion of the ITC for energy storage technology or the extension of energy credits for offshore wind facilities.

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.

Oversupply in the region continues to have a financial impact to utilities. In spite of the Northwest seeing a rapid end to the wind fleet buildout as many financial incentives are ending, state and regional policies, California markets and solar energy continue to create oversupply conditions throughout the Western Interconnect.

For comparison, the spring runoff period (April-July) of 2019 had two day-ahead days with negative local prices (2018 had 35 days, 2017 had 35 days, and 2016 had 2 days). In the hourly balancing or real-time market, 2019 had 17 hours with negative local prices (2018 had 129 hours, 2017 had 368 hours, and 2016 had 23 hours). Snowpack and timing of spring runoff can affect the number of days and hours with oversupply and negative prices as evidenced by 2019's low number of negative days and hours.

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 due to an exponential drop in solar panel cost and similar growth in solar panel output. 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 2020, on a low load, high renewable generation day, almost 60% of California's demand can be 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 returns 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 EIM 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 have to 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.

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. The EIM 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 EIM has the potential to lower total flexibility reserve requirements and minimizes curtailment of intermittent or variable energy resources for the region as a whole. An EIM dispatches generators in a way that attempts to minimize the total cost to serve load (and exports) while honoring all system constraints.

In the fall of 2014, PacifiCorp joined the California Independent System Operator (CAISO) in its EIM. The Western EIM 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 Western EIM better facilitates the integration of renewable energy that may otherwise be curtailed at certain times of the day, providing an added environmental benefit.

Since then, a number of entities have followed suit by either joining or announcing their intention of joining the western EIM.

ACTIVE

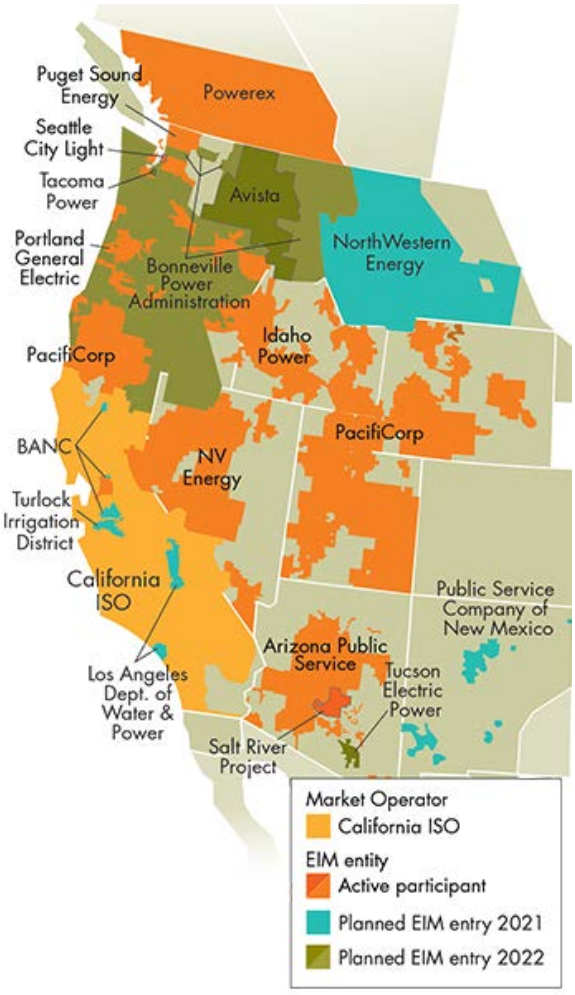
- Salt River Project – entered 2020
- Seattle City Light – entered 2020
- Balancing Authority of Northern California (Phase 1) – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound Energy – entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- CAISO – entered 2014

PENDING

- Los Angeles Department of Power & Water – entry 2021
- Public Service Company of New Mexico – entry 2021
- NorthWestern Energy – entry 2021
- Turlock Irrigation District – entry 2021
- Balancing Authority of Northern California (Phase 2) – entry 2021
- Avista Corp – entry 2022
- Tucson Electric Power – entry 2022
- Tacoma Power – entry 2022
- Bonneville Power Administration – entry 2022

By 2022, participants representing 77% of Western Electric Coordinating Council's (WECC) total load are expected to be active in the EIM. In addition to the Western EIM expansion, the Southwest Power Pool is planning on offering its Western Energy Imbalance Service market to interested utilities beginning in 2021. Also, CAISO is exploring opening its day ahead market to the Western EIM footprint. Entities in the region moving towards organized markets and the expansion of these markets are a key development in the industry. The District is actively following the transition towards more organized markets and will continue to assess the impact to the region and the District.

Figure 1- Energy Imbalance Market Footprint (https://www.westerneim.com/Pages/About/default.aspx)



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.

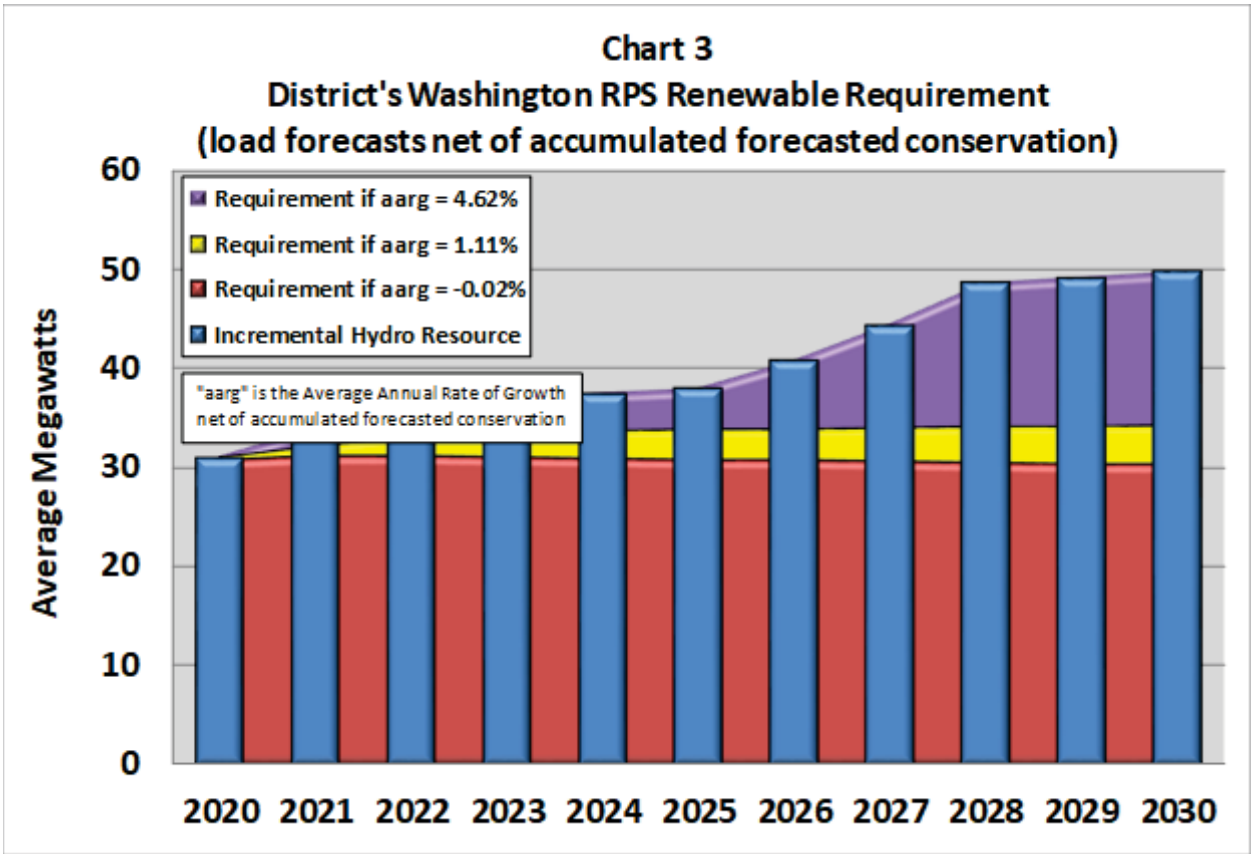
Based upon the current base load forecast, net of accumulated forecasted conservation, the amount of renewable resources required will be approximately 31-34 aMW in 2020-2030. Chart 3 shows the potential target requirements based on the District's three load forecasts.

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 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 Senate Bill (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 is monitoring the potential impacts of other state policies and actively participating in CETA rulemaking.

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.

Each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent 10 years. Every succeeding two years, utilities must review and update their 10-year assessment. In December 2019, Chelan PUD submitted its most recent update. In May 2020, the District submitted its fifth bi-annual conservation report to Commerce. The report documented the District's progress in 2018 and 2019 toward meeting the targets that were established in 2017 to comply with the RPS.

Even year reports are audited for RPS compliance by the Washington State Auditor. The District's June 2018 report was audited and met the requirements of the RPS.

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 2020-21 biennium, in 2019 the District used a utility-specific analysis, also known as a conservation potential assessment (CPA). This CPA, which was conducted by EES Consulting (EES), established the conservation targets that are used in this 2020 IRP . 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.

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.

During the two-year period from 2018 through 2019, preliminary results show that the District saved 4.38 aMWs. Of that total, the breakout was as follows: industrial 0.52 aMW, residential 0.69 aMW, District's share of the Northwest Energy Efficiency Alliance (NEEA) 0.76 aMW, commercial 2.30 aMW and 0.1 aMW from agricultural.

The 2019 CPA provides estimates of energy and peak demand savings by sector for the period 2020-2039. 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 Sixth and Seventh Power Plans.

The primary baseline changes in the 2019 CPA included the following:

- Lower avoided costs – the current market price forecast used for the avoided cost is much lower than the previous assessment.
- Code changes – significant impacts of recent code changes that have taken effect result in lower remaining potential (e.g., new lighting standards).
- Accounting for past achievements including:
  - Internal programs, especially in the industrial sector
  - NEEA programs
- 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 15.2 aMW. The total 20-year energy efficiency potential is approximately 21.45 aMW.

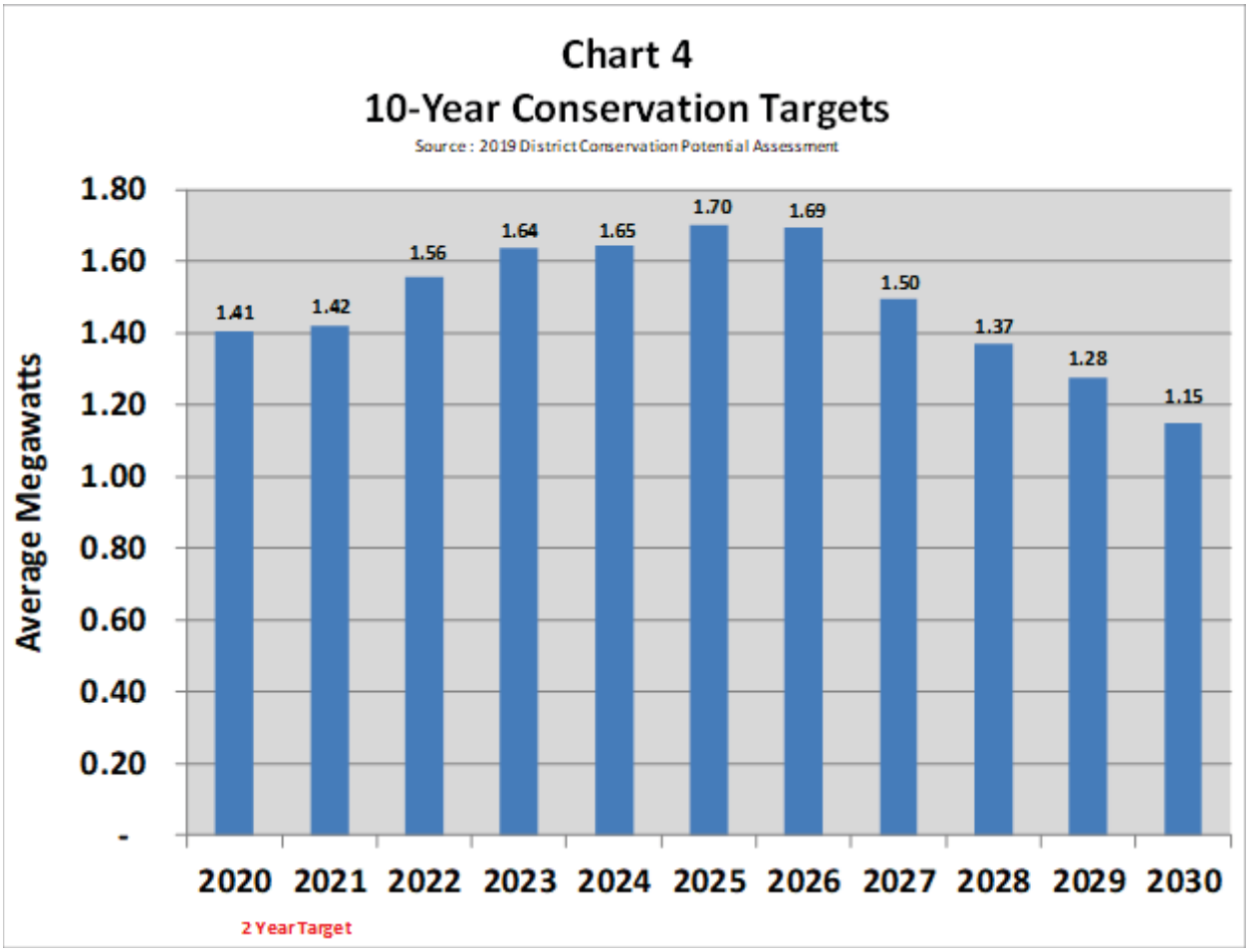
Table 1
2019 Conservation Potential Assessment
Cost-Effective & Achievable Savings
aMW

Sector	2 Year	6 Year	10 Year	20 Year
Residential	0.70	2.83	5.16	7.62
Commercial	1.26	3.57	5.03	6.72
Industrial	0.74	2.51	4.20	5.45
Distribution	0.03	0.19	0.45	1.25
Agriculture	0.09	0.26	0.36	0.41
TOTAL	**2.82**	**9.36**	**15.20**	**21.45**

Chart 4 illustrates the 10-year conservation potential and two-year target on an annual basis.

This CPA shows potential starting at just over 1.41 aMW in 2020, ramping up and down annually through 2030.

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 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

During the 2020-2029 period, only water heating (49%) and heating ventilating and air conditioning (51%) measures make up the projected energy savings in the residential sector. The two-year pro-rata share of the 2029 potential is 0.69 aMW and the 10-year potential is 5.15 aMW.

Commercial

During 2016 and 2017, the District conducted detailed energy conservation potential assessments at approximately 1200 businesses in Chelan County. The savings estimates were then adjusted for actual savings achieved during the 2018-19 time period.

Lighting measures are projected to comprise approximately 53% of the commercial savings for the 2020-2029 period. A significant portion of this will be the conversion of existing light sources to light-emitting diode (LED) technologies. Heating, ventilating and air conditioning (HVAC) upgrades and controls are expected to provide about 29% of the savings. Refrigeration savings at fruit warehouses represent 8% of the savings potential. The remaining 10% is comprised of a variety of many small individual items such as electronics, commercial kitchen upgrades and commercial water heaters. The two-year pro-rata share of the 2020-29 potential is 1.26 aMW and the 10-year potential is 5.03 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 2020-29 potential in the industrial sector is 0.74 aMW, eventually reaching a total of 4.2 aMW after 10 years.

Agriculture

For the agricultural sector, EES used a combination of measures and methods from the Seventh Plan as well as the results of an irrigation-specific potential study provided by the District that was conducted in 2011 and adjusted for irrigation projects done since that time. The two-year pro-rata share of the 2020-29 potential is 0.03 aMW and the 10-year potential is .45 aMW.

Distribution Efficiency Improvements (DEI)

Distribution efficiency measures improve the efficiency of utility distribution systems by operating in the lower end of the acceptable voltage range (120-114 volts), feeder and phase load balancing and volt-ampere reactive (VAR) improvements. The District's proposed automatic metering infrastructure (AMI) system that is scheduled to be operational in 2021 should allow the District to be able to better manage the voltage on its distribution system. The two-year distribution savings is calculated to be 0.09 aMW, and the 10-year potential was calculated to be 0.36 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.

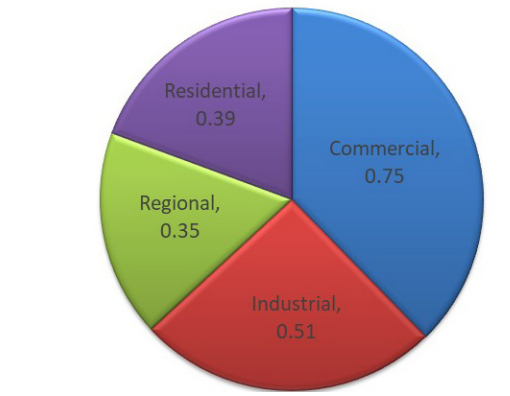
The District has budgeted over $3.7 million in financial incentives to acquire up to 2.0 aMW of cost-effective conservation during 2020. The 2019 CPA identified a total of 2.83 aMW of cost-effective and achievable conservation for 2020 and 2021 combined.

For its 2019 CPA, Chelan PUD utilized a forward market projection of wholesale market power prices 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 2019 CPA were $34.49/MWh over the 2020-2029 period and $28.13/MWh over the 2020-2039 period (2012 real dollars). Note that the 10-year average of the levelized cost for conservation is significantly higher than the amount identified in the 2018 IRP Progress Report. 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

The goal of Chelan PUD conservation programs is to 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. The 2020 expected energy savings are represented in Figure 2.

Figure 2- 2020 Budgeted Conservation Programs (Estimated Annual Energy Savings, aMW)



Insulation Rebates

For residential customers, the District pays 50 cents to $1.00 per square foot for added insulation, depending on current insulation levels. Requirements to qualify include:

- Existing attic insulation must be R19 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 Glass Door Rebates

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

This rebate offers customers:

- $6 per square foot on qualifying double pane glass doors and windows. To qualify, new windows must have a U-factor of 0.30 or lower. Qualifying glass doors must have a U-factor of 0.35 or lower.
- The rebate for upgrading single-pane windows is $8 to $12 per square foot, depending on heat source.
- $40 rebate per door for replacement of substandard entry doors with new Energy Star® rated insulated doors.

Multi-Family Window and Glass Door Rebates

- Incentives are available to residential multi-family apartment owners who replace older inefficient windows and glass doors. This rebate offers owners $4 per square foot on qualifying glass doors and windows. To qualify, new windows must have a U-factor of 0.30 or lower. Qualifying glass doors must have a U-factor of 0.35 or lower.

The District is currently in the process of evaluating its weatherization (windows and insulation) rebate amounts to increase the incentive to provide more participation throughout the county.

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 $90,000, which is matched by the Washington State Energy Matchmaker program administered by the state Department of Commerce. CDCAC crews complete the weatherization measures which are inspected by the Department of Commerce and the District. In addition to the weatherization funding, CDCAC may install Ductless Heat Pumps in selected dwellings.

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 9.0 heating season performance factor (HSPF) or greater and a 14 seasonal energy efficiency ratio (SEER) or greater heat pump. The install 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 $1,400. 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 $500 rebate.

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.

Heat Pump Water Heaters

New and 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 $300 rebate for a Tier 1 50-75 gallon model and a $500 rebate for a Tier 2 or Tier 3 or greater model in any size.

Retail buy-down of LED specialty bulbs, light fixtures and water efficient showerheads

The District buys down a portion of the cost of certain energy-efficient specialty lamps, hard-wired fixtures and showerheads sold in local retail stores. The District pays an incentive at the wholesale level and retailers agree to pass the savings on to customers in Chelan PUD's service area. This program is operated regionally by a third-party vendor. This program will be ending in September 2020 as LED lightbulbs and low-flow showerheads become the standard throughout the region.

Residential Single Family New Construction

The District has started a New Construction pilot program and anticipates having its first few homes that will qualify for a $2,500 rebate. In order to receive this incentive, the builder works with a local home energy rater to model that a home that uses 20% less energy than a code standard home of the same size.

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.

Public Area Lighting Conversion to LED Study

In 2021, the District is planning to replace approximately 1,000 public and District-owned area lights in Chelan County with LED technology. Many of these lights will also be equipped with stepped-dimming motion controls to reduce lighting energy when the area is not occupied.

Resource$mart and Light$mart

Resource$mart is the District's program for helping commercial and industrial customers install energy efficiency equipment and lighting in their facilities by paying a portion of the up-front costs. The District can pays the lesser of $0.18/kWh or 75% of the energy efficient project. The District pay $0.06/kWh on new construction. Measures include lighting projects, adjustable speed fans in large refrigerated spaces, energy efficient controlled-atmosphere equipment at fruit warehouses, improved heating and cooling equipment and commercial or industrial tune-ups.

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 the 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

Chelan PUD is still long in terms of its resource position. The District is expected to be able to serve its retail load throughout the planning period (2020-2030) without adding new resources and is also expected to meet Washington State RPS renewable requirements and CETA requirements through this period as well. 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 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 2019 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 2019. Columbia River runoff conditions were 77% of average and Lake Chelan runoff conditions were 74% of average in 2019. Wind generation conditions at Nine Canyon were below average at 85%. The column on the right was calculated using actual 2019 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. This is because almost all costs are fixed, that is, they don't vary with the amount of generation (e.g., debt service, taxes).

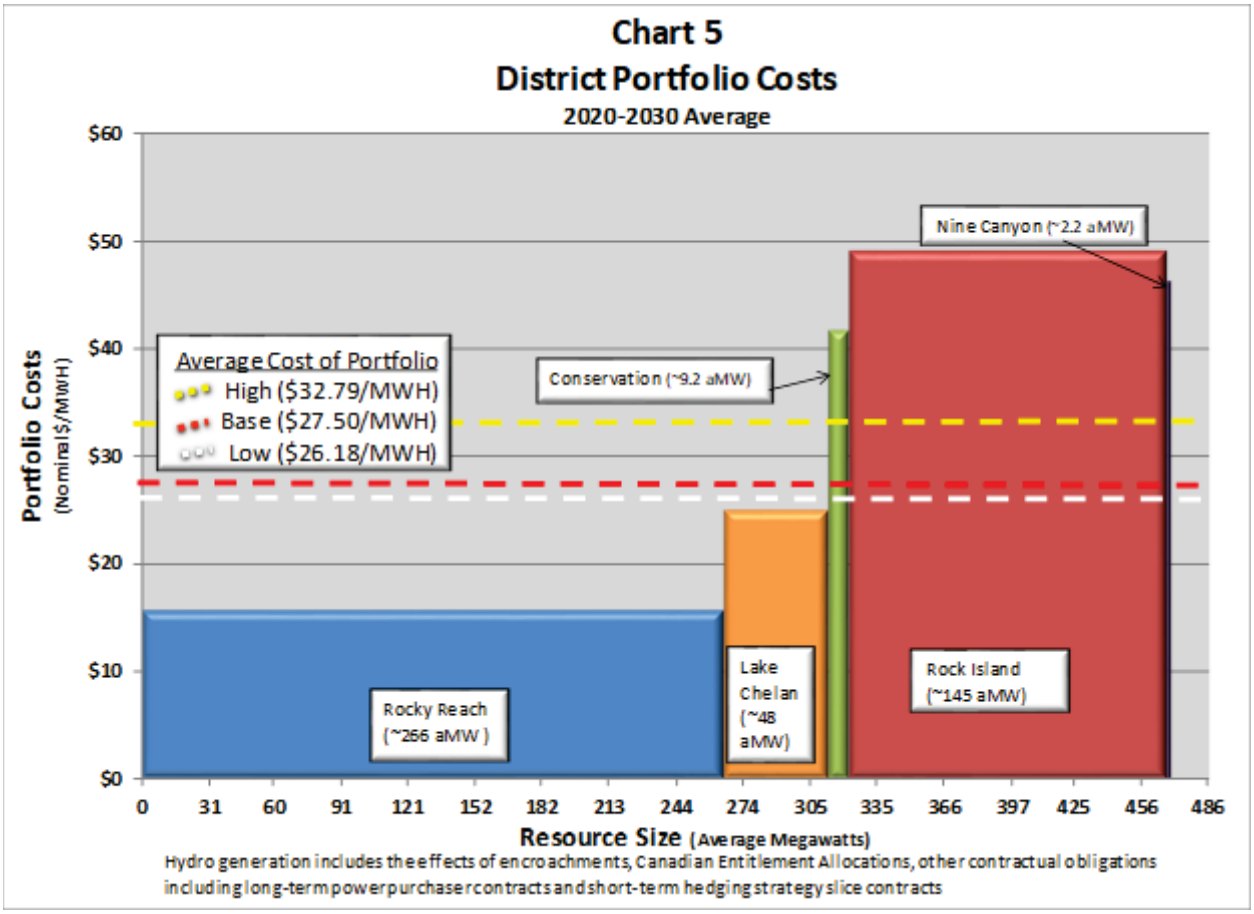
Table 2
District's Existing Portfolio Cost
2019

Project	$/MWh w/<u>actual</u> generation	$/MWh w/ <u>average</u> generation
Rocky Reach	$14.93	$11.41
Rock Island	$51.36	$40.56
Lake Chelan	$30.34	$25.78
Nine Canyon	$79.66	$67.58

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.

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 and improvements

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

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

Nine Canyon Wind

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

Since increasing approximately 70% in 2008 due to higher than expected maintenance and repair costs and the cessation of anticipated federal Renewable Energy Production Incentive payments, the cost of production rates have lowered just slightly. They are projected to hold steady through 2023 at which time the Phase I and II debt is scheduled to be paid in full. Rates are then expected to decline by over 50% and hold 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. As of early 2020, hedges have been executed for as far out as 2030.

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.

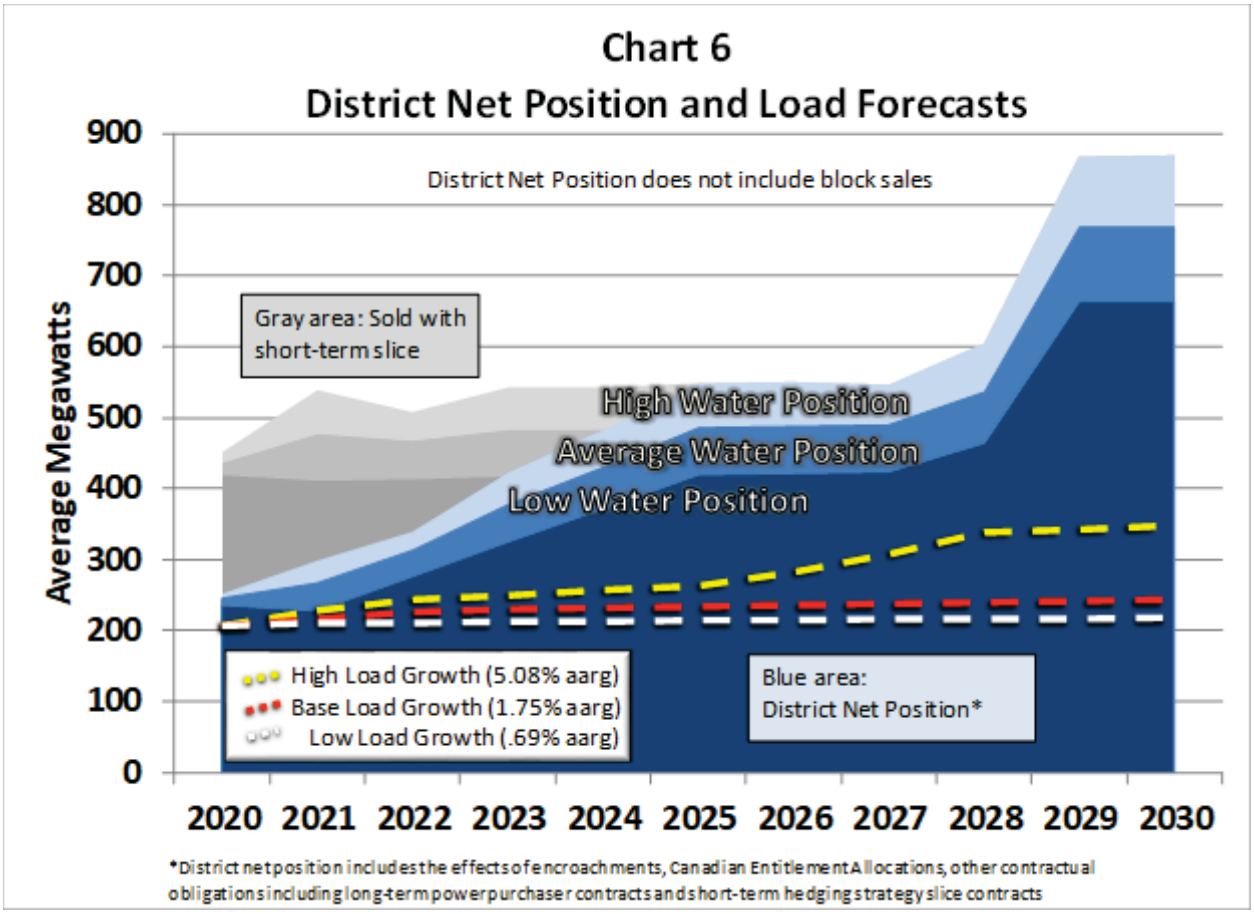
Although it is not adding new resources, the District is focused on three major categories of risk which include uncertainties related to:

- 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, 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 supply-side resource additions. The amount of demand-side resources included in this evaluation has increased from what was included in the 2018 IRP Progress Report to match Chelan PUD's 2020 required 10-year conservation plan submittal to Commerce that is approximately 1.49 aMW per year through the study period (based on the 2019 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 load/resource balance showed that based on the voluntary regional resource adequacy standard discussed previously, the District has adequate capacity and energy to meet its retail customers' load through the planning period thus providing for service reliability. As previously mentioned in the Resource Adequacy section, Chelan PUD is involved in a NWPP effort to develop a robust Northwest capacity resource adequacy program that would allow utilities to forecast and manage resource adequacy in a coordinated manner.

Environmental Impacts

The District's hydropower and wind generation do not produce any air emissions, but during certain hours of the year, depending upon load and hydro conditions, the District is a net purchaser in the wholesale power market. Those market purchases come from a "market mix" of different generating resources. Some of those resources produce air emissions. In 2018, the most recent year for which information is available, the District's calculated fuel mix included approximately 4% of resources serving load coming from this market mix or "unspecified" resources. Washington State's calculated fuel mix for utilities no longer identifies specific energy sources for market purchases as of the 2018 reporting. Table 3 shows Chelan PUD's calculated fuel mix for 2018. The District does 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.

The cost of air emissions from carbon dioxide (CO_2) remain an industry uncertainty. It is expected that any carbon-reducing regulations or other developments regarding climate change will affect the energy markets in which the District participates. 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 resource portfolio does not contain emitting resources.

Table 3
2018 Fuel Mix

Generation Type	District Calculated Fuel Mix
Hydro-electric	95.70%
Unspecified	4.27%
Wind	0.03%
TOTAL	100.00%

10-year Clean Energy Action Plan (CEAP)

The following is the District's 10-year CEAP as required by RCW 19.280. The CEAP is intended to identify the specific actions to be taken by a utility for implementing sections 3 through 5 of CETA at the lowest reasonable cost while meeting an acceptable 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 portfolio consists of hydro and wind resources and does not contain any coal-fired resources. Through this IRP, the District determined it will retain that mix of generating resources through the 2020-2030 planning period.

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, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2020-2030 planning period. The Conservation section details the conservation and efficiency actions the District intends to pursue from 2020 through 2029. The District does not anticipate needing to take any other specific actions during the 2020-2030 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, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2020-2030 planning period. The District does not anticipate needing to take any other specific actions during the 2020-2030 planning period in preparation for the start of the new state policy in 2045.

Final Remarks

Chelan PUD intends to retain its existing supply-side resources while implementing its 2019 CPA results. Complying with both the renewable resources and conservation portions of the Washington State RPS remains a significant focus for the District. As detailed in the CEAP, the District's retention of its existing supply-side resources should comply with 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 generating units undergoing significant repair. Additionally, the District will continue to evaluate and implement its hedging strategy to help reduce the risks associated with these and other uncertainties.

Chelan PUD will publish an IRP Progress Report in 2022.

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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 20% percentile and the high scenario is the top 20% 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)
  - 18.46% -1/2020 through 12/2021
  - 23.46% -1/2022 through 12/2022
  - 28.46% -1/2023 through 12/2023
  - 33.46% -1/2024 through 12/2024
  - 38.46% -1/2025 through 10/2028
  - 64.46% -11/2028 through 12/2030
- Rock Island – Chelan PUD's share (net of long-term purchaser contracts and executed slice contracts)
  - 24% - 1/2020 through 12/2021
  - 29% - 1/2022 through 12/2022
  - 34% - 1/2023 through 12/2023
  - 39% - 1/2024 through 12/2024
  - 44% - 1/2025 through 10/2028
  - 70% - 11/2028 through 12/2030
- Lake Chelan — Chelan PUD's share
  - 100% - 1/2020 through 12/2030

Wind

- All available historical Nine Canyon hourly wind generation (2004-2019) was used to calculate average energy

Conservation

- Used the quantities from the 2019 CPA (also used for RPS compliance in January 2020)

Contracts

Long-term Power Sales

- Rocky Reach
  - Puget – 25% - 1/2020 through 12/2030
  - Alcoa – 26% - 1/2020 through 10/2028
  - Douglas – 5.54% - 1/2020 through 12/2030
- Rock Island
  - Puget – 25% - 1/2020 through 12/2030
  - Alcoa – 26% - 1/2020 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 0% and 20% of the capacity and energy of Rocky Reach and Rock Island from 2020-2030
- 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 : 0.69%-low, 1.75%-base, 5.08%- 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, CEA's, the long-term power purchaser contracts and the executed slice contracts.

Table 4

District's Average Annual Resources (aMW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Rocky Reach Gen	130	130	165	200	236	271	271	271	301	454	454
Net Rock Island Gen	80	80	97	114	131	147	147	147	162	234	234
Net Lake Chelan Gen	47	47	47	47	47	47	47	47	47	47	47
Net Nine Canyon Gen	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Conservation	1.41	2.82	4.38	6.02	7.66	9.37	11.06	12.55	13.92	15.20	16.35

Appendix B – Washington State Electric Utility Integrated Resource Plan Cover Sheet 2020

	Base Year			5 Year Estimate			10 Year Estimate		
Estimate Year		**2019**			**2025**			**2030**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	452.00	240.00	201.50	513.00	270.00	234.00	534.00	282.00	244.00
Exports									
Resources:									
Future Conservation/Efficiency				19.98	11.27	9.37	34.82	19.64	16.35
Demand Response									
Cogeneration									
Hydro	419.00	220.00	189.00	770.00	386.00	338.00	1,227.00	603.00	532.00
Wind	0.00	0.08	1.91	1.45	0.78	2.23	1.45	0.78	2.23
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	419.00	220.08	190.91	791.43	398.05	349.60	1,263.27	623.42	550.58
Load Resource Balance	-33.00	-19.92	-10.59	278.43	128.05	115.60	729.27	341.42	306.58

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 1.75%.
- Peak and annual energy loads, including the base year (2019), 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 (2019) wind data reflects actual Nine Canyon experience in that year.
- 2025 and 2030 projected peak wind capacity is based on median (50th percentile) hourly Nine Canyon historical generation (2004-2019).
- 2025 and 2030 projected average annual wind energy is based on median (50th percentile) average annual energy from Nine Canyon historical generation (2004-2019).

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Acronyms

aarg	Average Annual Rate of Growth
aMW	Average Megawatt
AMI	Automatic Metering Infrastructure
APGI	Alcoa Power Generating, Inc.
BA	Balancing Authority
BAA	Balancing Authority Area
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CAR	Clean Air Rule
CDCAC	Chelan-Douglas Community Action Council
CEA	Canadian Entitlement Allocation
CEAP	Clean Energy Action Plan
CETA	Clean Energy Transformation Act
CO2	Carbon Dioxide
CPA	Conservation Potential Assessment
DEI	Distribution Efficiency Improvements
DOE	Department of Ecology
DR	Demand Response
DRAC	Demand Response Advisory Committee
EES	EES Consulting
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
EV	Electric Vehicle
GHG	Greenhouse Gas
HCP	Habitat Conservation Plan
HDL	High Density Load
HSPF	Heating Season Performance Factor
HVAC	Heating, Ventilating and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
KW, kWh	Kilowatt, Kilowatt-hour
LED	Light-Emitting Diode
LOLP	Loss of Load Probability
MW, MWh	Megawatt, Megawatt-hour
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electric Reliability Corporation
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
OFM	Office of Financial Management (Washington State)
PAWG	Probabilistic Assessment Working Group
PTC	Production Tax Credit
PTCS	Performance Tested Comfort System
PUD	Public Utility District
RA	Resource Adequacy
RAAC	Resource Adequacy Advisory Committee
RAWG	Resource Adequacy Working Group
RCP	Representative Concentration Pathways
RCW	Revised Code of Washington
REC	Renewable Energy Credit
RMJOC	River Management Joint Operating Committee
RPS	Renewable Portfolio Standard
RTF	Regional Technical Forum
SB	Senate Bill
SEER	Seasonal Energy Efficiency Ratio
UW	University of Washington Hydro/ Computational Hydrology Research Group
VAR	Volt-Ampere Reactive
WAC	Washington Administrative Code
WECC	Western Electric Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

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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 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".

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.

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

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

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

District
See Chelan PUD.

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

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.

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.

High Density Load (HDL)

Chelan PUD has defined as those loads with intense energy use of 250 kWh per square foot or more per year where the energy is used for server farms or similarly situated loads.

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 a the lowest reasonable cost to the utility and it 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).

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 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 (Sixth, Seventh, etc.)

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

Peak Demand (Load)
The maximum demand imposed on a power system or system component during a specified time period.

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

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

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

Power Plan (Sixth, Seventh, 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 Seventh Power Plan, the most recent, was adopted in February 2016. 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 the 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 as defined in RCW 82.29A.135 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; and (i) biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include (i) wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (ii) black liquor byproduct from paper production; (iii) wood from old growth forests; or (iv) municipal solid waste (from RCW 19.285: The Energy Independence 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.

Seventh Power Plan
See Power Plan (Sixth, Seventh, etc.)

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.

Sixth Power Plan
See Power Plan (Sixth, Seventh, etc.)

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.

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.