2020 Franklin PUD
Integrated Resource Plan

Public Utility District No. 1 of Franklin County

PREPARED IN COLLABORATION WITH

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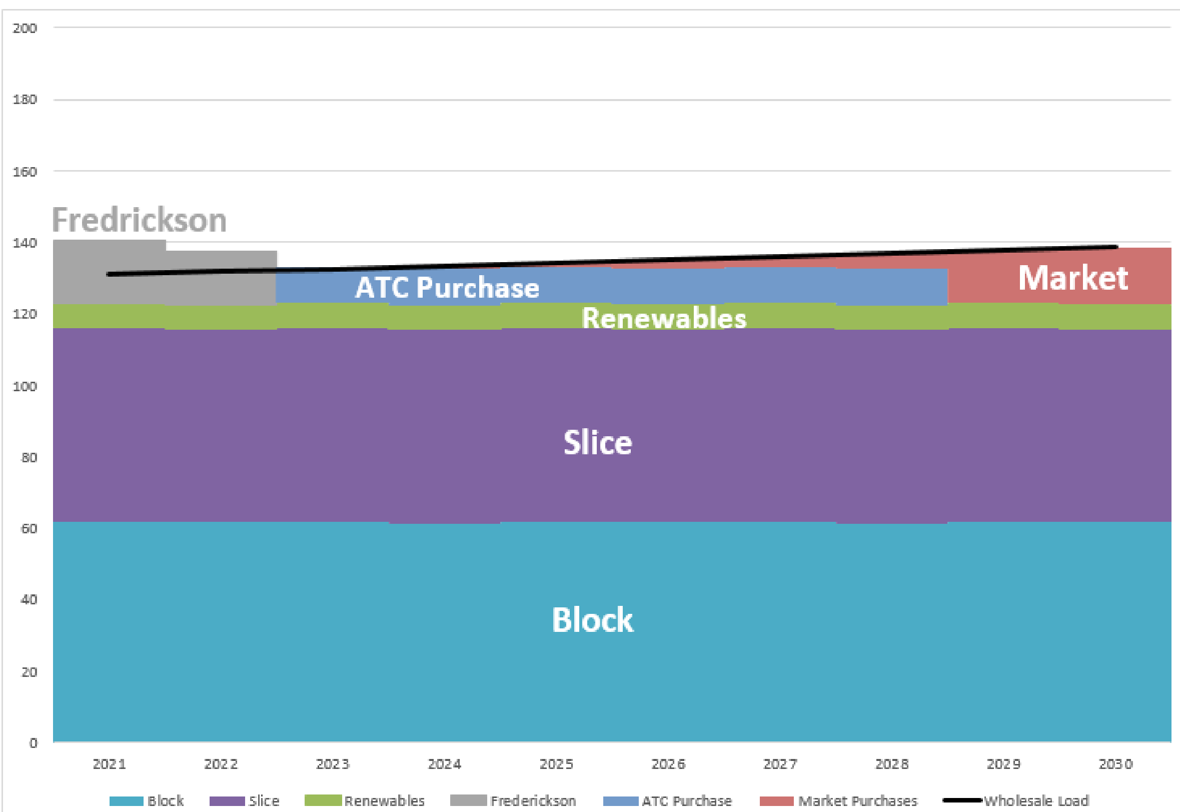
Chapter 1: Executive Summary

The goal of Franklin PUD's 2020 Integrated Resource Plan is to provide a framework for evaluating a wide array of supply resources, conservation, and renewable energy credits (RECs). The IRP provides guidance towards strategies that will provide reliable, low cost electricity to the District's ratepayers at a reasonable level of risk.

Obligations and Resources

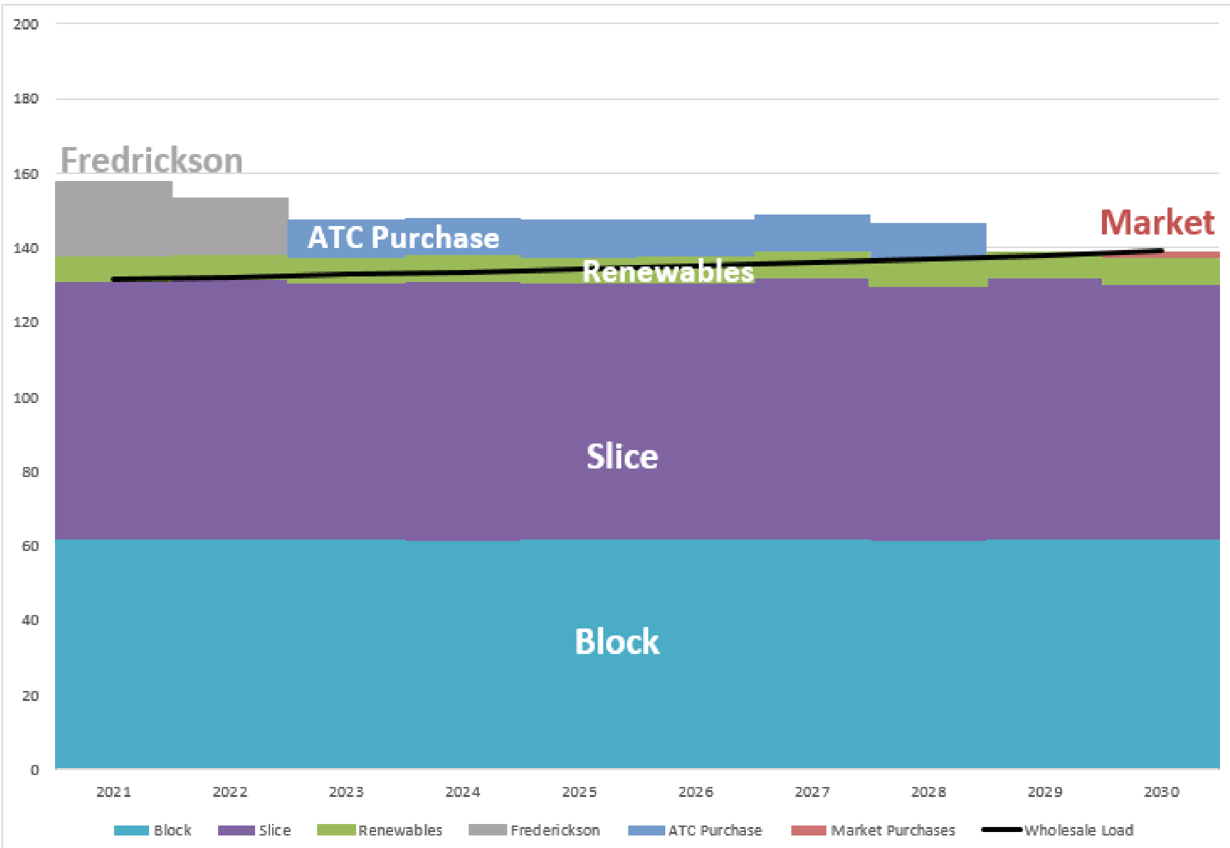
The majority of the District's wholesale electricity is supplied by the Bonneville Power Administration (BPA) under the "Slice of the system"/ Block contract, represented by the "Slice" and "Block" fields in the chart below. The Frederickson 1 Generating Station Combined Cycle Combustion Turbine also represents a sizable portion of the District's supply side resources, although the contract ends in 2022. This value is reflective of 1937, the lowest hydrological year on record at the time "critical" was defined. Critical hydro conditions represent a conservative supply scenario, thus the vast majority of the time, the District will have more generation than what is shown in the chart below. Planning to this level ensures adequate supply to meet demand. Franklin PUD under critical hydro conditions is expected to supply enough energy to remain in load/resource balance on an average annual basis through 2024.

Figure 1: Expected Load Forecast, "Critical Hydro", and Existing Resources



Most years, Slice generation will be greater than critical. Generation from the 80 year average hydro conditions illustrates that the District is expected to supply enough energy to remain in load/resource balance on an average annual basis through the end of the study period (**Error! Reference source not found.**).

Figure 2: Expected Load Forecast, "Average Hydro", and Existing Resources



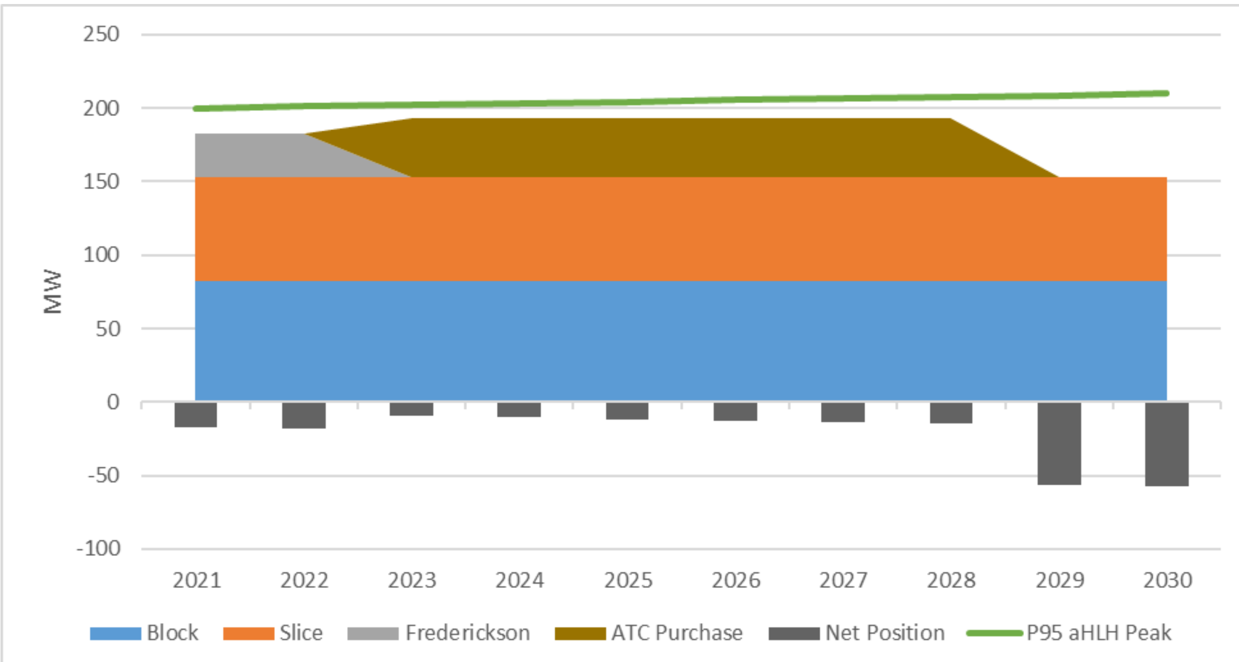
While the District has sufficient supply side resources to meet its annual average load obligations, seasonal and daily variations in load due to temperature can be significant. Maximum energy needs typically occur on hot summer days when air condition and irrigation loads are peaking. The IRP team performed a capacity study to determine the District's loads and resources on a day where maximum temperatures reach 102°F.

While significantly warmer than average, it is a near guarantee that the District experiences temperatures in excess of 100°F every year. Temperatures have historically hit or exceeded 105°F at least once every other year. It is important for the District staff to understand its energy position for a near annual event.

During such extreme heat events, loads can reach as high as 212 aMW during the HLH average on-peak period. It is, however, more prudent for the District to plan to a slightly less extreme scenario, and settled on the historical 95th Percentile (P95) HLH average load for the summer months of July and

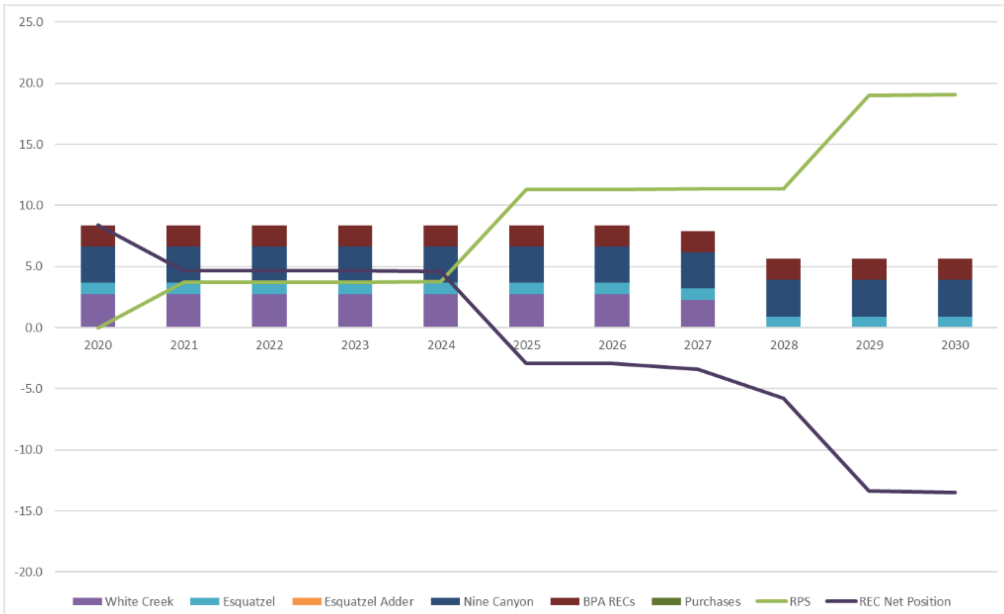
August as the planning load number to consider. This value, 199 aMW, is used for the 1st year of the IRP study period (2021), and then escalated each year by 0.54%, which is the District's forecasted 10-year annual energy growth rate. The hydro system also has the ability to generate more power during periods of high power demand. The Slice generation assumption was based on output from The Energy Authority's Slice Water Routing Simulator (SWRS). The summer peak generation value is assumed to be 10,500 MW equating to a total generation of about 150 MW from all BPA resources. Under this scenario, the District would be short approximately 17 aMW while Fredrickson is still under contract, and 12 aMW during the years covered by the ATC purchase. As one can see in Figure 3, the District will be short in excess of 50 aMW after the ATC purchase expires in 2028.

Figure 3: Annual Summer Peak HLH Average Load-Resource Balance Using Historical P95 Summer HLH Load



Beginning in 2020, the District also has to meet renewable energy obligations to remain in compliance with the Washington State Energy Independence Act (I-937). The District was exempt from RPS requirements until it exceeded 25,000 customers in 2016. The District's first compliance mandate of 3 percent begins in 2020. The RPS will ramp up to 9 percent in 2024, and then ultimately to 15 percent in 2028 (**Error! Reference source not found.**).

Figure 4: RPS Requirements and Eligible Renewable Resources

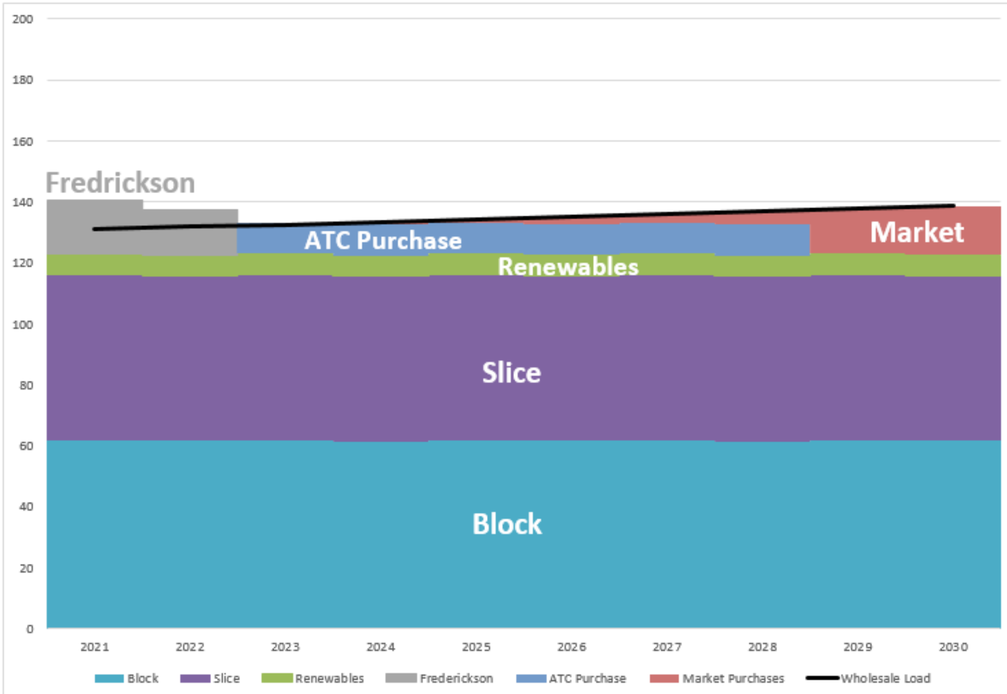


The District has sufficient RECs based on current forecasts to comply through 2024, and new resources may not be immediately necessary in 2025, as the District can bank RECs for future use. This study, however does not forecast when the REC bank will be exhausted. Once the REC bank is exhausted, the District will need to acquire additional RECs to maintain its RPS compliance.

Preferred Portfolio

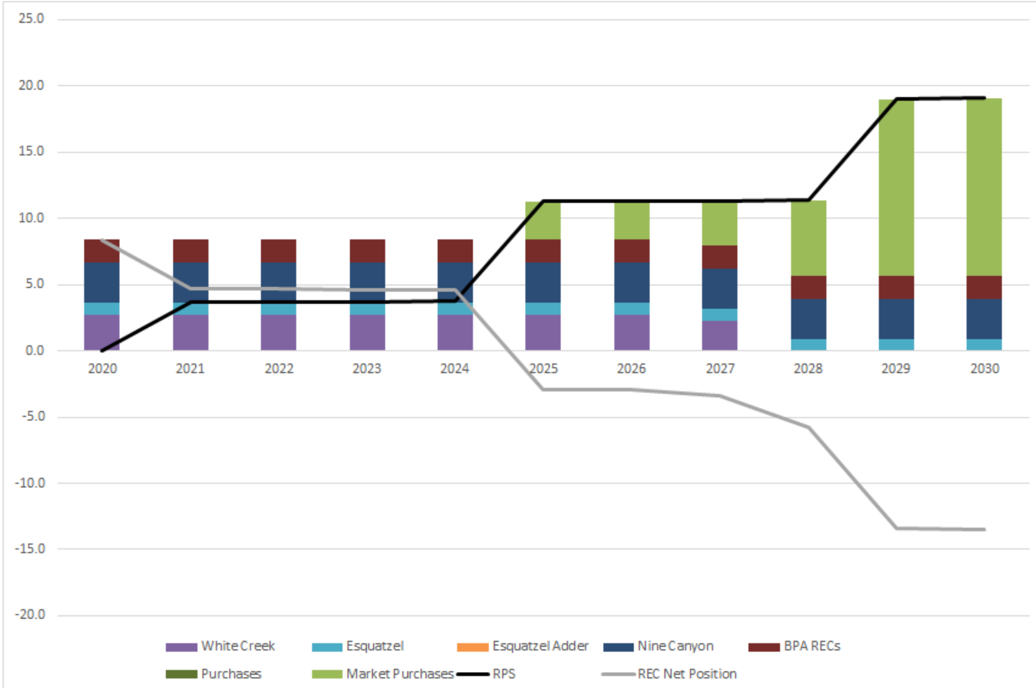
The current analysis concludes that the portfolio that will produce the lowest cost and risk (due to District hedging practice) consists of relying on the market to meet any future energy, capacity and REC deficits (**Error! Reference source not found.**). Energy and RECs in the shorter term are projected to remain below the cost of acquiring a new resource. The energy deficits will be filled with short to medium term market purchases that allow the District to evaluate the relative risk associated with seasonal deficits without the additional burden associated with carrying costs of resources surplus to actual supply needs. Utilizing the market is currently the lowest cost and lowest risk (after applying District hedging practice to mitigate cost volatility) option for the District, but IRP staff will continue to systematically evaluate market conditions, emerging technologies, and resource availability.

Figure 5: Preferred Resource Plan: Energy Position under "Critical Hydro"



Like energy and capacity, supplying RECs from the market is currently the least cost approach to meeting this requirement (Figure 6). The District will actively monitor market and legislative changes to continuously assess this approach.

Figure 6: Preferred Resource Plan REC Position



Chapter 2: Load Forecast

The cornerstone of the IRP is a forecast of future electric power requirements. This forecast is obtained by estimating gross future electric power requirements through the timeframe of the IRP, then subtracting owned and contracted resources amounts to determine the forecasted electric power requirements. These requirements can be met through a myriad of different demand and/or supply-side resource options.

These incremental requirements may be quite different for any hour depending upon time of year, day of week, and time of day. Standard industry practice has been to group the requirements into two distinct categories: average and peak. The annual average energy requirement is the average of all forecasted requirements over a calendar year. The annual peak requirement is the largest forecasted one-hour requirement within the calendar year. This IRP will use an approach that the District has been successfully utilizing, for several years, to determine the requirements and resource forecasting necessary to maintain system reliability at an acceptable economic cost.

This section first examines the forecast of gross electric power requirements for the study period. Assumptions regarding existing resources will then be outlined.

Overview of Customer's Load

Franklin PUD's service territory primarily consists of residential, commercial, industrial, and irrigation load. Residential load accounted for 35% of the energy usage in 2019, commercial loads were 38%, industrial accounted for 15%, and irrigation was 12% of the total load. Though irrigation accounted for the smallest overall share on an annual basis, seasonal irrigation loads peak during the summer and account for about 23% of the District's total energy consumption during that period.

Historical Demand

Electric utilities across the United States, to varying degrees, have shifted from an environment where energy sales increased at a rapid annual rate due to increases in both number of customers and electric usage per customer, to a substantially slower load growth after the 2008 economic recession. Between 2002 and 2008, the District's load grew by about 3.5% annually.

In recent years, annual retail sales have slowed but continue on an upward trajectory. Reasons for this shift in consumption patterns include implementation of energy efficiency measures by consumers such as more efficient lighting, heating and cooling, a shifting from an economy driven by industrial production to a service-based economy, and an increase in demand-side technologies such as rooftop solar panels that reduce metered load and increase consumers' independence from the traditional utility model. Since the 2008 recession, the District's load growth slowed to 1.1% on average per year. Further improvements in energy efficiency measures are expected to lead to further declines in per capital energy consumption, thus further slowing the District's load growth rate in the future.

Demand and Energy Forecast Methodology

Demand forecasts allow Franklin PUD to ensure that sufficient resources are available to meet customer demand. The econometric load forecast in this IRP is from a long-term model which uses historical load data and econometric data to establish the relationship between energy consumption and economic variables. To generate a load forecast for the 10-year period of the study, the model considers:

- Ten years of historical energy data by customer category.
- Woods and Poole county-by-county econometric database.
- Historical locational weather as an input into the weather normalization model.

The econometric forecast model produces a monthly energy usage forecast for each customer class: residential, small general, medium general, large general, industrial, irrigation, and lighting. The forecast also produces a system peak demand. The model weather normalizes historical data using heating degree day and cooling degree day data from the Pasco airport weather station.

The District utilizes Woods & Poole Economic Forecasts, which are updated annually. The Woods & Poole Economics, Inc. database contains more than 900 economic and demographic variables for every county in the United States for every year from 1970 to 2050. This comprehensive database includes:

- Detailed population data by age, sex, and race.
- Employment and earnings by major industry.
- Personal income by source of income
- Retail sales by kind of business.
- Data on the number of households, their size, and their income.

The specific economic projection technique used by Woods & Poole to generate the employment, earnings, and income estimates for each county in the United States generally follows a standard economic "export-base" approach. Because the entire national economy is interconnected in which the actions in one part of the county may likely have upstream or downstream effects, Woods & Poole simultaneously forecasts the data for each county in the United States so that changes in one county will affect growth or decline in other counties. According to Woods & Poole, the long-term outlook for the United States economy is one of steady and modest growth through the year 2050. Although periodic business cycles, such as the 2008-09 recession, will interrupt and change the growth trajectory, the nation's employment and income are expected to rise every year through 2050.

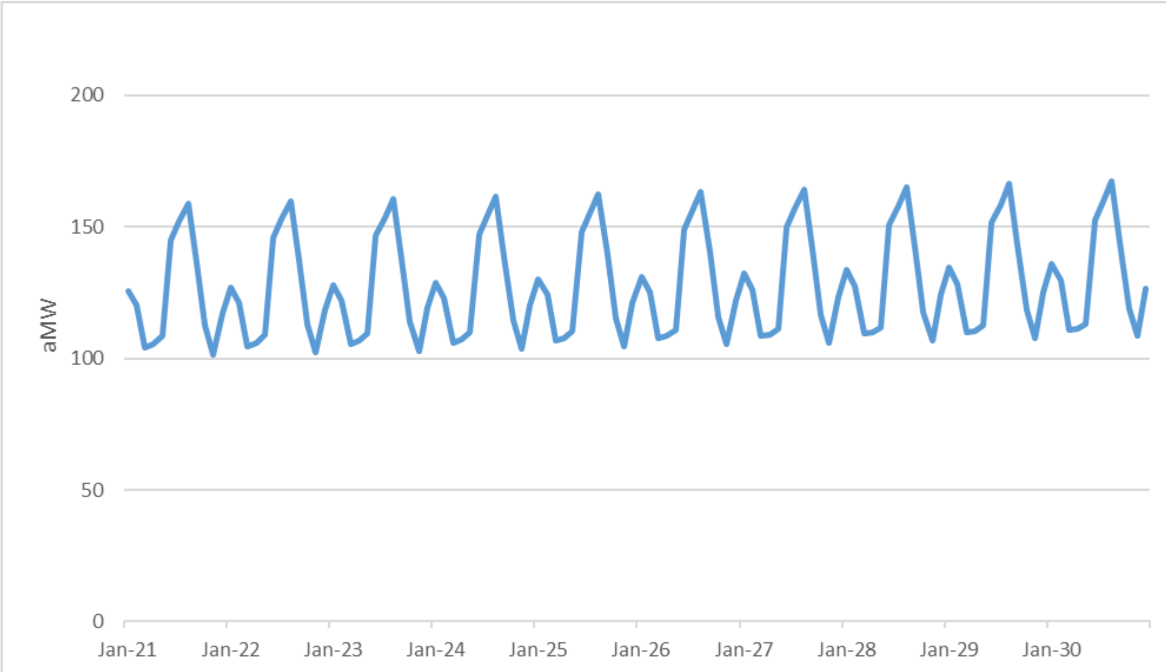
The load forecast model used total population, total employment, and total number of households to forecast total retail sales for the Franklin County region. The relationship between the historical load data and the econometric variables is determined by partial least squares regression. This is a typical approach when constructing predictive models with factors that are highly correlated, as is the case when dealing with econometric factors. Utilizing this methodology based on historical load data and econometric variables from Woods & Poole, the District forecasts a 10-year average energy usage growth rate of 0.54%

Because historical loads include the already achieved impacts of conservation, regression methods also have the benefit of capturing the effects of conservation on District consumption. The methodology carries the effect of that conservation forward. The District also separately forecasts incremental achievable conservation, which is then incorporated to the load forecast.

10-Year Annual Load Forecast

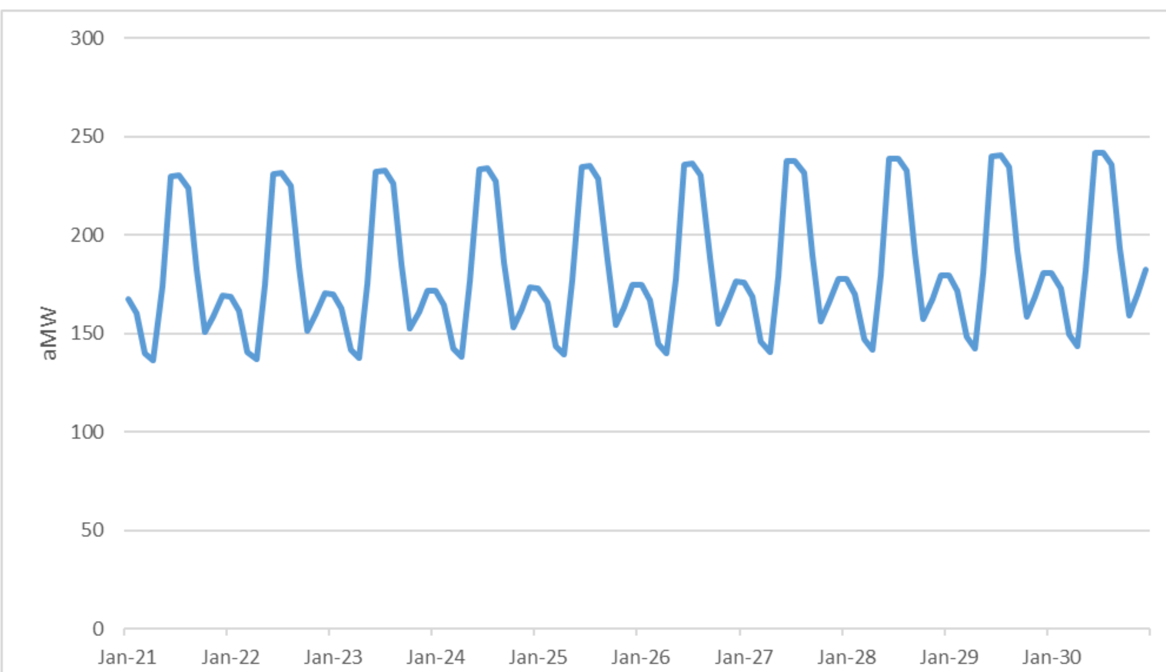
The 2020 ten-year load and customer forecast base case scenario projects an average annual rate of growth (AARG) of 0.54%, a increase from the 2018 forecast which expected a 0.44% AARG. The most recent ten-year load and customer forecast was adopted by the District in May 2020 (Figure 7).

Figure 7: 2021-20230 Monthly Load Forecast



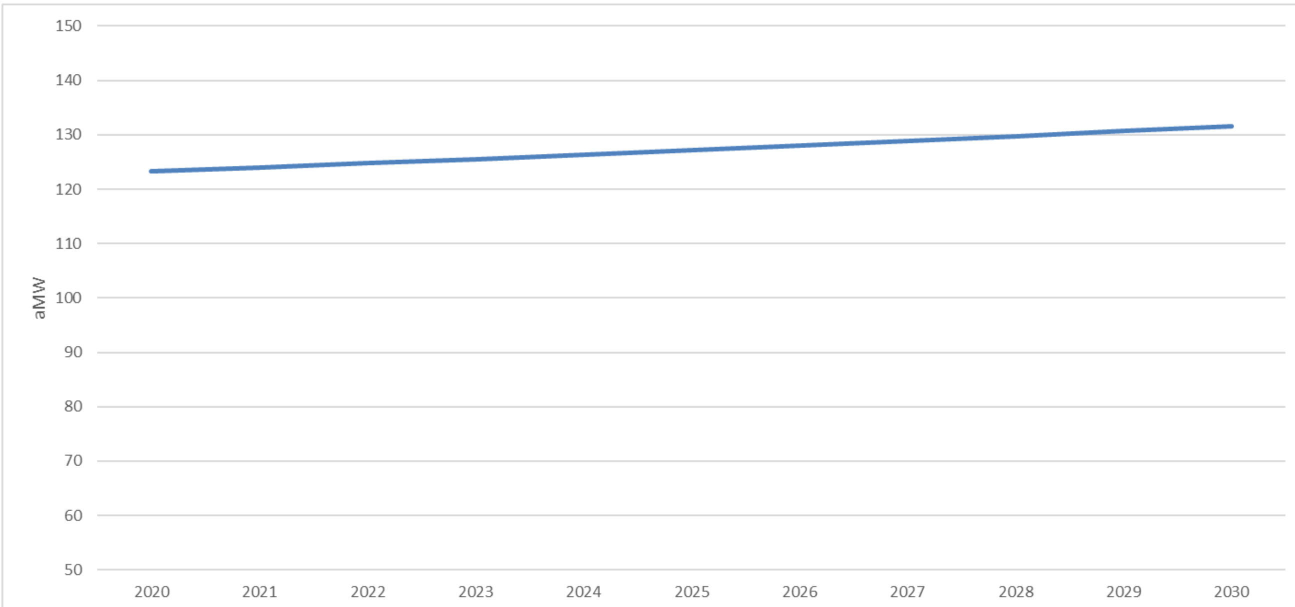
Due to seasonally warm summers and agriculture related irrigation loads, the District's peak energy usage and peak demand period occurs during the summer (Figure 8).

Figure 8: 2021-2030 Monthly Peak Load Forecast



To provide simplified and more relevant reference data, loads are expressed as average power consumption on an annual basis throughout this study. The current forecast anticipates an increase in average energy usage of less than 9 megawatts (aMW) over the 2020 load of 123 aMW (Figure 9).

Figure 9: 2020-2030 Annual Load Forecast



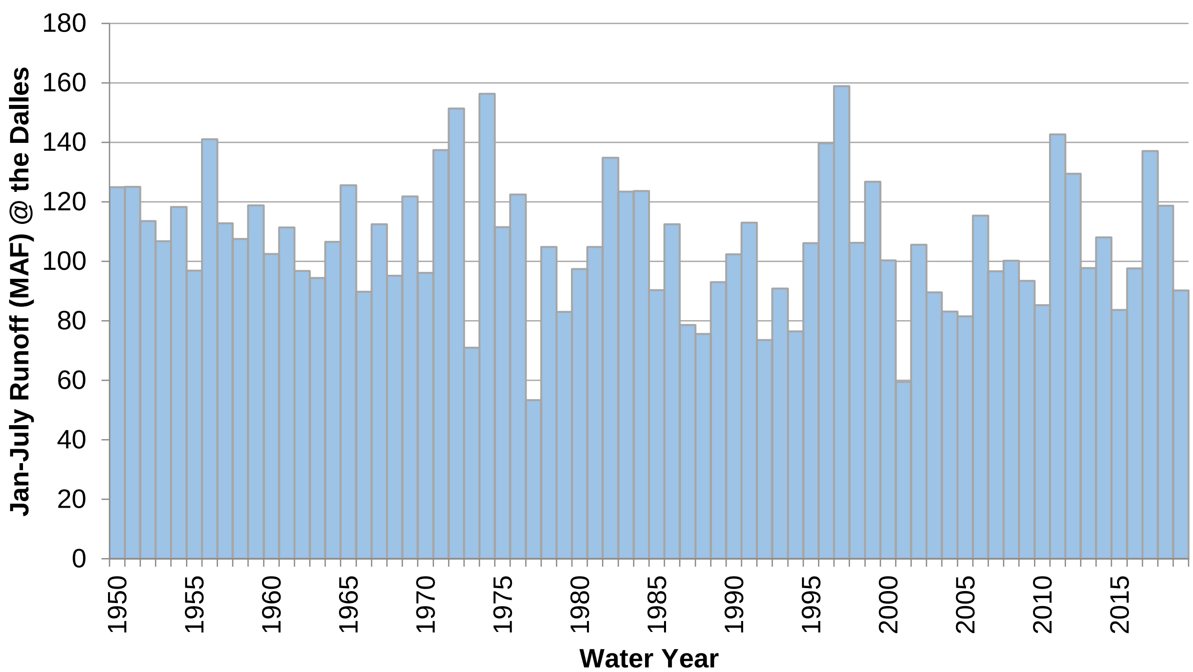
See Appendix A: Ten Year Load & Customer Forecast for more detail.

Chapter 3: Current Resources

Overview of Existing BPA Resources

The Federal Columbia River Power System (FCRPS) is managed and operated by a joint collaboration of three federal agencies: the U.S. Army Corps of Engineers (Corps of Engineers), the Bonneville Power Administration (BPA), and the Bureau of Reclamation. It consists of 31 multipurpose dams which provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate 800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration, n.d.). Due to the size of the system, up to 10,000 MW of generation capacity can be offline for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to overall hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period of time. BPA water years, which begin in October and end in September, are categorized by total water runoff in million acre-feet (MAF) at The Dalles between January and July. Hydrological conditions at The Dalles have been recorded since 1929. In that time period, total runoff has varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1949-2019) is illustrated in Figure 10 below.

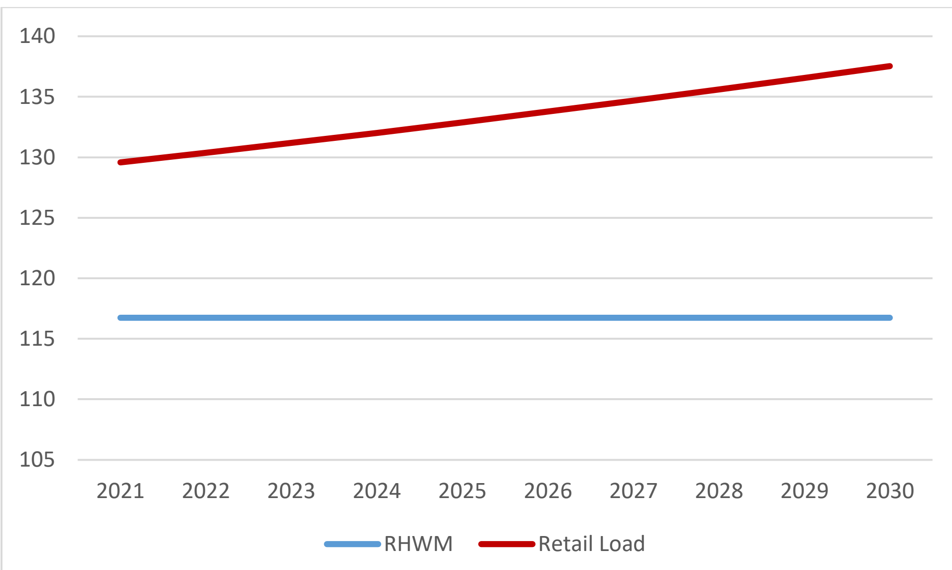
Figure 10: Historical Water Years (1949-2019)



The 1937 water year streamflows represented the worst (lowest) on record and was chosen as the benchmark “critical water” year. The significance of the critical water designation is that it represents baseline system capability – in other words, even in the worst hydrological conditions, the FCRPS will generate at the minimum critical level. BPA conservatively measures the system capability by determining its average annual energy output in critical water conditions. For the 2020 and 2021 water years, the system capability is 7,054 MW and 6,994 MW respectively (slightly lower due to refueling outage at CGS). System generation will exceed 7,054 MW and 6,994 MW in non-critical water years, which should occur the vast majority of the time.

As a Tier 1 Slice/Block customer, Franklin PUD is allocated a certain portion of the system to manage and operate to serve their load. Each customer was initially allocated a certain portion of the system such that on an annual average energy basis, and based on 2010 adjusted loads, the customer is in load/resource balance. In other words, for the first one or two years of the Slice/Block agreement energy supply is equal to energy demand on average for the year without any energy surpluses or deficits. Franklin PUD can receive up to 1.7% of the Slice/Block product. The quantity of power a utility is entitled to be known as its Contract High Water Mark (CHWM). The amount of power a Tier 1 customer is entitled to purchase is its Rate Period High Water Mark (RHWM), which is determined from the CHWM adjusted for any increases or decreases in the system capability.

Figure 11: Retail Load vs. BPA Contract High Water Mark



The system allocation is calculated by dividing a utility's RHWM (or net requirements, whichever is lower) by the sum of all utilities RHWM (which is approximately equal to the Tier 1 system capability under critical hydrological conditions) resulting in a Tier One Cost Allocator (TOCA).

The Tier 1 rate is based on the cost of the existing federal system with very little augmentation. If preference customers choose to buy more power from BPA beyond their HWM, this power is sold at a Tier 2 rate, which fully recovers BPA's incremental costs of securing additional resources to serve this load. Major components of the Tiered Rate Methodology include:

- ✓ Tier 1 priced at cost of existing system
- ✓ Tier 2 priced at marginal cost of new BPA purchases and/or acquisitions (i.e., equal to the cost of market or new resource)

- ✓ Public utilities can buy from BPA at Tier 2 rates, or acquire their own resources, to serve loads in excess of their HWM

The Slice/Block product is divided into two components: fixed and variable. The fixed component, or "Block," is a known and guaranteed quantity of power that Franklin PUD receives from BPA, irrespective of the hydro conditions. Whether it is a critical water year or the highest on record, the quantity of Block power that BPA delivers to Franklin PUD does not change. The power is shaped in advance into monthly blocks, which follows the District's monthly load profile. In other words, more Block power is delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 8,537 MW for the two year rate period, but daily generation will fluctuate from between 4,000 MW to greater than 15,000 MW. The FCRPS is a multipurpose system and power generation achieves only one of system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. Franklin PUD accepts these operational risks as a Slice customer. It accepts fluctuations in actual federal system output and takes responsibility for managing its percentage share of the federal system output to serve its load. There is no guarantee that the amount of Slice output made available, combined with the firm Block power, will be sufficient to meet load obligations, be it hourly, daily, weekly, monthly, or annually. Being a Slice customer requires Franklin PUD to fulfill its load obligations with resources other than what is provided by BPA.

The District currently receives its full RHWM allocation from BPA from October 2019 through September 2020. Franklin PUD's share of output is about 132 aMW in an average water year, but can vary substantially depending on hydrological conditions. Under substantially worse than average water conditions, known as critical water conditions, the District's share of output is 117 aMW. In water conditions greater than critical, total system output will be greater than 7,054 aMW. Based on a 70 year historical mean of hydrological conditions, the expected average system output is 8,920 aMW. Critical water is a rare event, and actual system generation will usually exceed 7,054 aMW.

Columbia Generating Station

The largest non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, WA, with a generation capacity of 1,190MW. It is owned and operated by Energy Northwest (ENW), a joint operating agency that consists of 28 public utilities in Washington State. Franklin PUD's share of output from CGS is equivalent to its Slice system allocation.

BPA Renewable Energy Resources

The Regional Dialogue (RD) Slice contract also includes several resources which generate Western Renewable Energy Generation Information System (WREGIS) registered RECs. Those resources are the Stateline Wind Project, Condon Wind Project, Foote Creek Wind Project and Klondike Wind Project.

- ✓ The Condon Wind project is located in Gilliam County, OR. It came online in December 2001 with a capacity of 49.8 MW.
- ✓ Foote Creek II is located in Carbon County, Wyoming and have a combined generation capacity of 43.2 MW. However, due to its geographic location the District is unable to use these RECs to satisfy state RPS requirements.

- ✓ Klondike I & III are located in Sherman County, Oregon with a combined generation capacity of 261.2 MW. BPA has rights to 63.4 MW of capacity from the project.
- ✓ The Stateline project straddles both Walla Walla County, WA and Umatilla County, OR. It has a nameplate capacity of 300 MW. BPA has rights to 90 MW of its total capacity.

BPA has rights to 231.1 MW of wind generating capacity in the WECC region. The energy and RECs associated with the wind resources are included in the BPA Tier 1 rate. Franklin PUD's entitlement of those resources is approximately 6 MW of capacity. Assuming a capacity factor of 30 percent, the District receives an average of 1.25 Tier 1 RECs per hour or a range of 11,080-12,377 RECs over the last three years.

The new RD Slice contract also includes Incremental Hydro Tier 1 RECs associated with incremental generation from efficiency upgrades such as Grand Coulee Dam, Bonneville Dam, Chief Joseph Dam, and Cougar Dam. The RECS from all hydro efficiency upgrades allocated by BPA are not currently eligible for Washington Renewable Portfolio Standard but are utilized for the Districts Green Power Program. The District receives an average of 1.14 Incremental Hydro Tier 1 RECs per hour or a range of 1,516-16,672 RECs over the last three years.

Overview of Existing Long-Term Purchased Power Agreements

Frederickson 1 Generating Station

Frederickson is a natural gas fueled combined cycle combustion turbine with a capacity of 249 MW. The power plant is located about 18 miles southeast of Tacoma, WA in Pierce County. Through a power purchase agreement that expires in August 2022, Franklin PUD contracts 30 MW of the plant capacity.

Nine Canyon Wind

The Nine Canyon Wind Project is an Energy Northwest-owned wind generation resource situated on dryland wheat farms approximately eight miles southeast of Kennewick in the Horse Heaven Hills. Phase I of the project consists of 37 wind turbines, with a total capacity of 48 MW. Phase II consists of an additional 12 wind turbines, totaling 15.6 MW of capacity. Phase III consists of 14 wind turbines with a total capacity of 32 MW. The aggregate capacity of the Project is 95.6 MW.

Franklin PUD entered into a power purchase agreement with Energy Northwest for 10.5 percent of the generation capacity of the project, including the environmental attributes it produces, that extends through June 2030, and the IRP assumes this contract will extend through the study period. These attributes will help Franklin PUD fulfill its EIA renewable requirements. Nine Canyon has an expected capacity factor of 30 percent, also equating to an average energy output of 3 aMW.

White Creek Wind Generation Project

Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 turbines, each with 2.3 MW of capacity, with a combined capacity of 205 MW. It came online and began generating electricity in November 2007. White Creek provides renewable energy and environmental attributes that will help Franklin PUD meet its Energy independence Act (EIA) renewable requirements. Franklin PUD has contractual rights to a portion of the project's output, including all associated environmental attributes, through 2027.

With a capacity factor of around 30 percent, Franklin PUD receives an average energy output of 3 aMW from the project.

Packwood Lake Hydro Project

The Packwood Lake Hydroelectric Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an average output of approximately 10 aMW. It is owned and operated by Energy Northwest, but 12 Washington PUDs are participants in the project with "ownership-like" rights. It is located 5 miles east of Packwood, Washington in Gifford Pinchot National Forest. Franklin PUD receives a 10.5% share of the output from the project, .7 aMW under critical water conditions, and approximately 1.3 aMW under average water. The project does not qualify as a renewable resource and will not help Franklin PUD meet its obligations under the EIA.

Esquatzel Canal Hydroelectric Project

The Esquatzel Canal, which discharges into the Columbia River, is located about 5 miles north of Pasco, in Franklin County. In 2011, Green Energy Today, LLC installed a hydroelectric generation turbine at the confluence of the canal and the Columbia River to capture the kinetic energy of the flowing water and convert it into electricity. Franklin PUD purchased all of the rights to the power and environmental attributes generated by the .9 MW Esquatzel Canal Hydroelectric Project through 2031, and has an option to extend the contract. The IRP therefore assumes that Esquatzel will remain as a resource through the study period. The project generates power year-round – producing roughly 6,000 MWh of power annually.

Esquatzel is a run of the river project. Its generation cannot be turned on and off since neither Green Energy Today nor Franklin PUD controls the timing or quantity of water flows through the canal. Esquatzel is an EIA eligible renewable resource, and because its generating capacity is less than 5 megawatts, it is also classified as "distributed generation," which allows its environmental attributes (RECs) to count double.

Conservation

Franklin PUD has been actively engaged in conservation/energy efficiency resources for 30 years. Since 2002, the District's programs have resulted in the acquisition of over 10 aMW of conservation resources. More emphasis will be focused on conservation planning and acquisition in the future. Along with a renewable portfolio requirement, the EIA requires that qualifying utilities pursue all cost-effective conservation. For the sake of this IRP, cost effective conservation is assumed to be implicit in the load and is therefore not treated separately as a resource to avoid double counting.

Future Distributed Energy Resource Growth

The IRP team undertook an analysis of potential Distributed Energy Resources (DER), which might be installed in the District's service territory. To arrive at this number, a constant scaling factor was calculated by dividing the current District penetration of DER by the current National Renewable Energy Laboratory (NREL) Mid-Case Rooftop PV Capacity for Washington State. The potential for future buildouts in the District were assumed to remain consistent and proportional to forward NREL modeling. The results can be found in Figure 12 below.

Figure 12: Projected District Distributed Energy Resource Growth

Year	Franklin Scaled Capacity (MW)	NREL Mid-Case Rooftop PV Capacity (MW)
2020	2.683	153.275
2022	2.787	159.198
2024	2.847	162.672
2026	3.098	177.005
2028	3.710	211.954
2030	5.272	301.188
2032	7.263	414.915
2034	8.259	471.835
2036	9.135	521.872
2038	9.759	557.510
2040	10.367	592.276
2042	10.729	612.910
2044	11.315	646.395
2046	11.620	663.826
2048	11.620	663.828
2050	11.649	665.463

Existing Transmission

BPA Transmission Services (BPAT) as the Balancing Authority (BA) is the entity obligated to meet this peak load. A Slice customer sets aside and is not able to access its share of about 900 MW to 1,300 MW of Slice capacity to allow BPAT to meet all its within hour requirements. This includes regulation, imbalance, and contingency reserves (spinning and supplemental). BPAT reimburses BPA Power (BPAP) for any revenues it receives from use of this capacity. Examples of revenues are regulation, imbalance charges (energy and generation imbalance, Variable Energy Resources Balancing Service (VERBS) and Dispatchable Energy Resource Balancing Service (DERBS) charges and Contingency Reserves. The Slice customer receives its share of these revenues as an offset to the Composite Charge.

BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). By virtue purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves) and contractually giving up its share of capacity for within hour services, the District has handed over its obligation for these services to the BA and does not need to include capacity for these services in its capacity planning for the IRP. Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP. It should be noted that the discussions about a regional Energy Imbalance Market (EIM) are focused on this time period. BPA has completed a preliminary cost benefit analysis of joining the EIM that shows small net positive benefits.

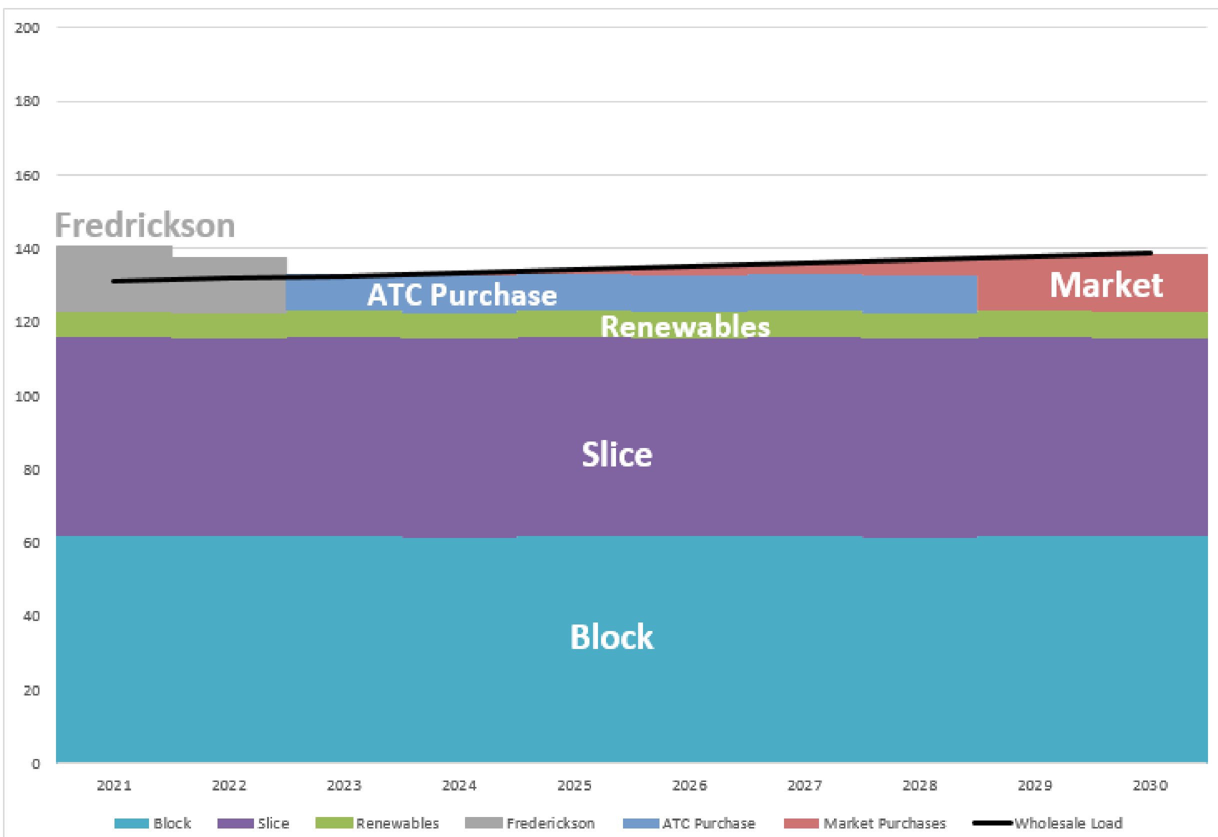
BPA expects the transmission system to serve expected loads and load growth for at least the next ten years based on forecasts. The forecasted peak loads, plus existing long-term firm transmission service obligations, are used to determine the system reinforcement requirements for reliability. BPA plans the system in accordance with the NERC Planning Standards and WECC Regional Criterion to maintain system reliability.

The Western Electricity Coordinating Council (WECC) coordinates a variety of high voltage power links in Western North America. These links, called intertie paths, are aren't always a single transmission line, rather they are interties between various areas. In section 8 we discuss changes to the transmission grid such as the Montana Colstrip units being retired, the Gateway West Project, transmission investments being made to keep up with renewables, and more. As this grid continues to evolve we will monitor all new additions and retirements.

Load/Resource Balance with Existing Resources

Figure 13 compares Franklin's long-term load forecast under the expected load scenario to the District's projected BPA HWM plus already contracted for resources.

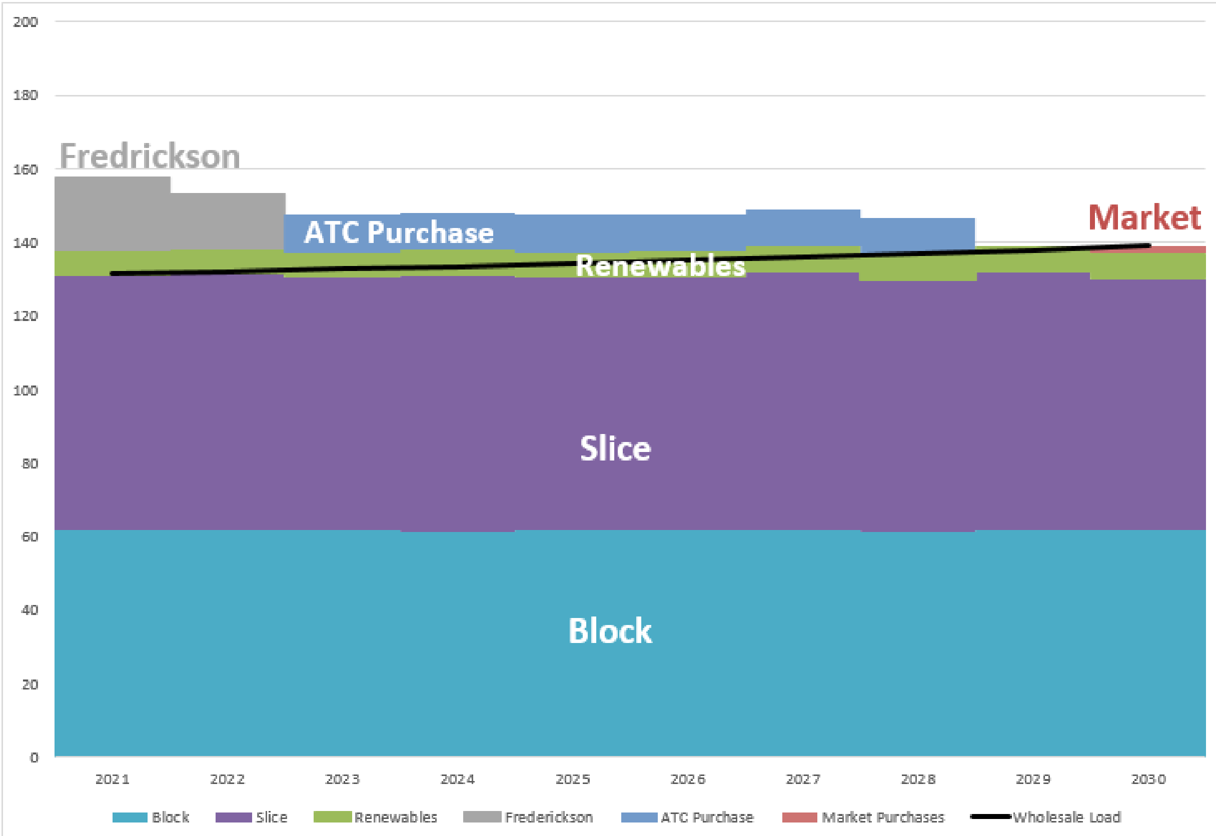
Figure 13: Annual Loads and Existing Resources in Critical Water Conditions



Under critical water conditions the district is short starting in 2024. This deficit will be managed with market purchases. Critical water years are a black swan event and the district is in energy surplus through 2029 during an average water year show in Figure 14**.**

Figure 14 compares Franklin's long-term load forecast under the expected load scenario and average hydro conditions to the District's projected BPA HWM plus already contracted for resources.

Figure 14: Annual Loads and Existing Resources in Average Water Conditions

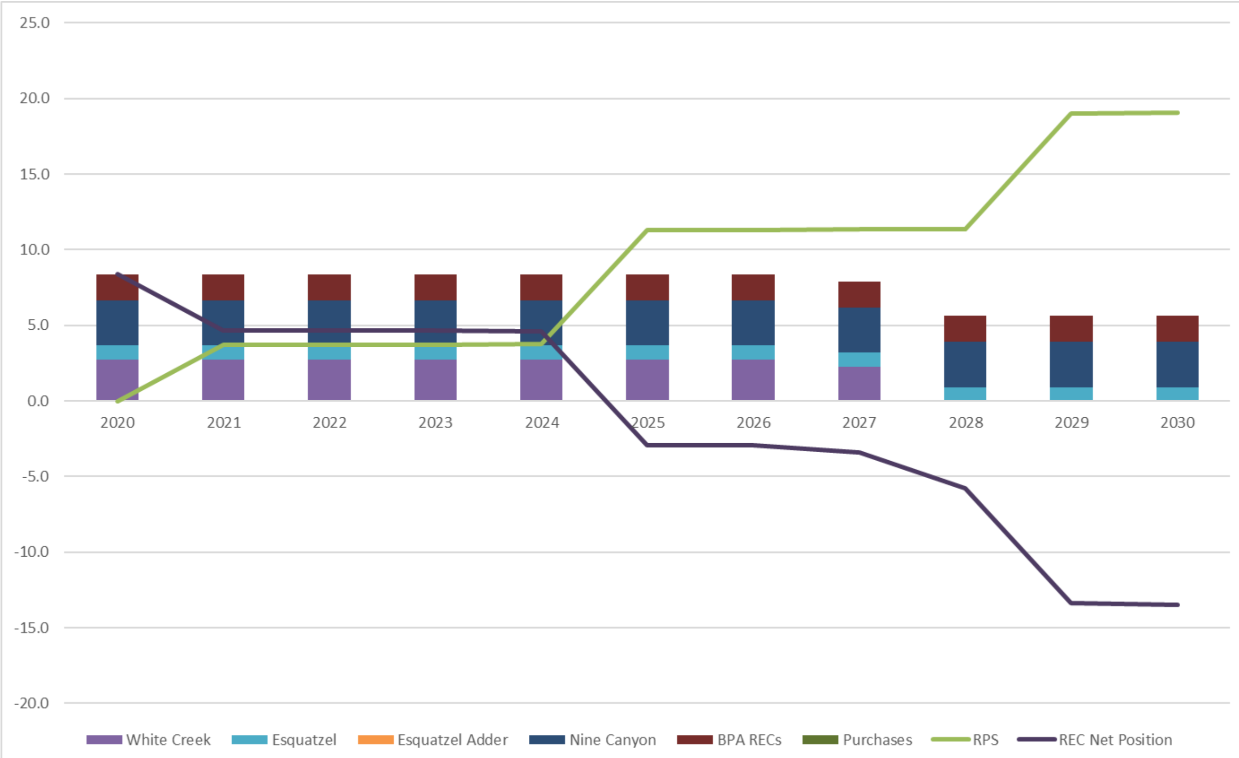


In this scenario, the District is expected to have a deficit in the expected load scenarios in 2029 which will be met with market purchases.

Although the District is surplus energy on an annual load/resource view, the District does have hourly capacity shortages when the demand exceeds the District's supply. This is discussed in further detail in Chapter 7: Capacity, Requirements, Energy Storage, and Demand Response.

The EIA requires the District to supply the following amounts of its load requirements with renewable resources: 3 percent by 2021, 9 percent by 2025, and 15 percent by 2029. The EIA also requires the IRP process to develop a plan for acquiring renewable resources and all cost-effective conservation. The District's RPS requirements and resources to meet those requirements are depicted in Figure 15 below. As discussed in Chapter 9: Risk Analysis and Portfolio Selection, the District will continue to rely on purchases from the market when REC deficits begin, which will occur sometime after 2025 after banked RECs are exhausted.

Figure 15: REC Net Position

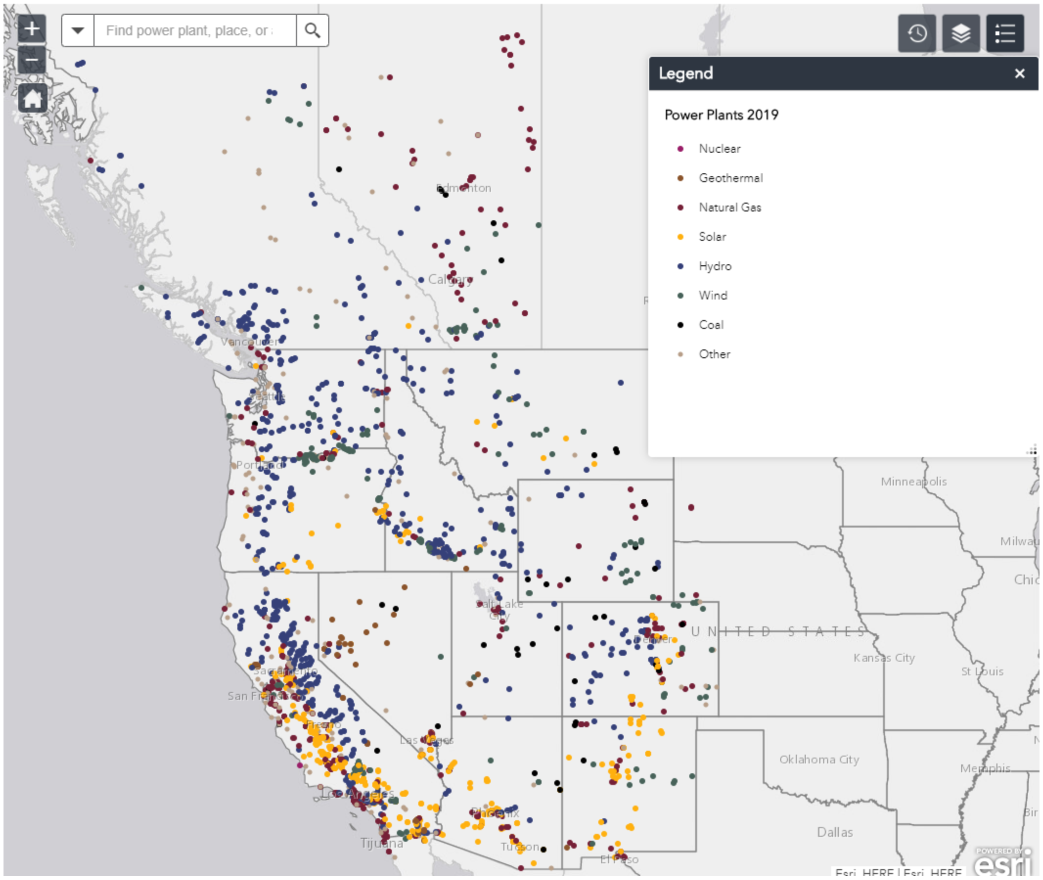


10 Year Generation Assessment

The nature of the grid has changed over the last several decades as fossil fuel units have retired due to a mixture of economics and environmental policy. At the same time, an ever increasing amount is coming from renewable sources. This has left significant uncertainty on the future of the generation stack, particularly in the area of dispatchable capacity leading to concerns the reliability of the grid could be undermined. This issue is especially acute as the nature of the interconnected Alternating Current (AC) and a marketplace for electricity results in a symbiotic relationship between utilities. **Figure 16** below shows power plants operational as shown in WECC's State of the Interconnection visualizations[1].

[1] https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Resource-Portfolio.aspx

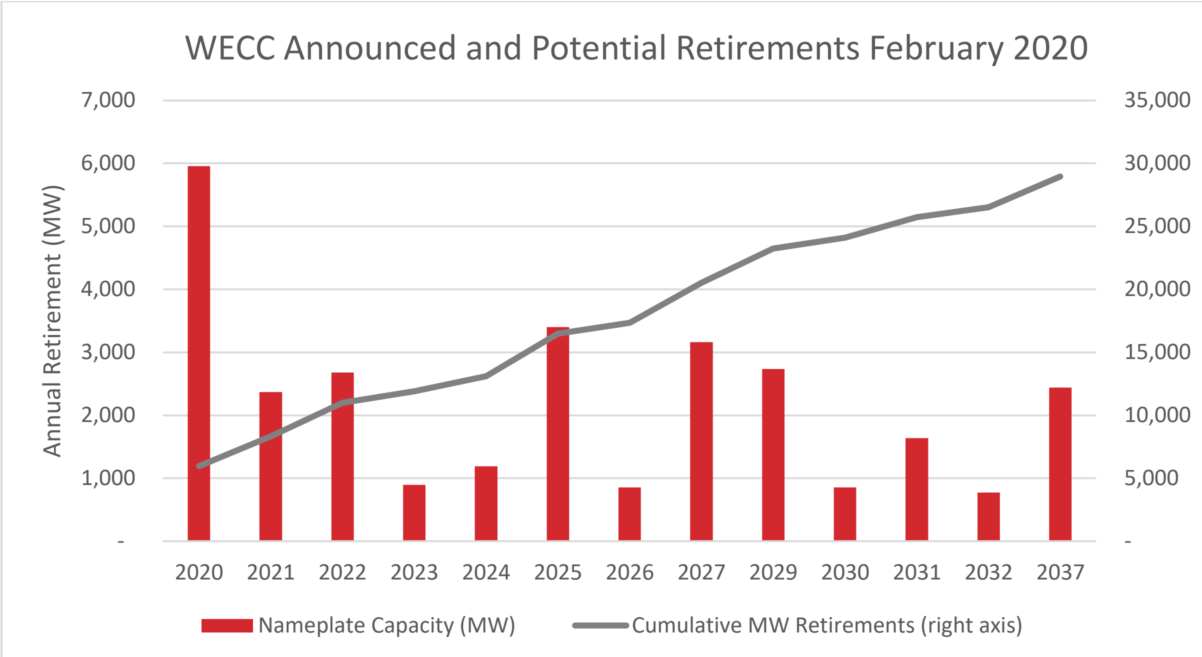
Figure 16: WECC Power Plants 2019



While fossil fueled plants carry emissions concerns, their dispatchable nature makes them more difficult to fully replace by renewable generation absent levels of energy storage which are not currently commercially feasible. WECC published the data in Figure 17 below further detailing known and likely retirement dates for fossil fueled thermal generators[2]. While much of the energy will be replaced by cleaner gas or renewable sources in the future, Resource Adequacy is a major source of concern for reliability in the future.

[2] https://www.wecc.org/Administrative/15_Brown_Resource%20Retirements_February%202020.pdf

Figure 17: WECC announced and potential retirements February 2020



The Public Generating Pool ("PGP") commissioned E3 Consulting ("E3"), a well-respected firm with experience performing regional resource adequacy[3], to analyze different scenarios of resource adequacy into the future. As part of the analysis, the additional generation for growth and replacement for the retiring coal units came primarily from natural gas resources. With the Clean Energy Transformation act significantly truncating the useful lives of new natural gas resources, reliability will continue to be an issue of concern as dispatchable capacity from thermal plants is retired.

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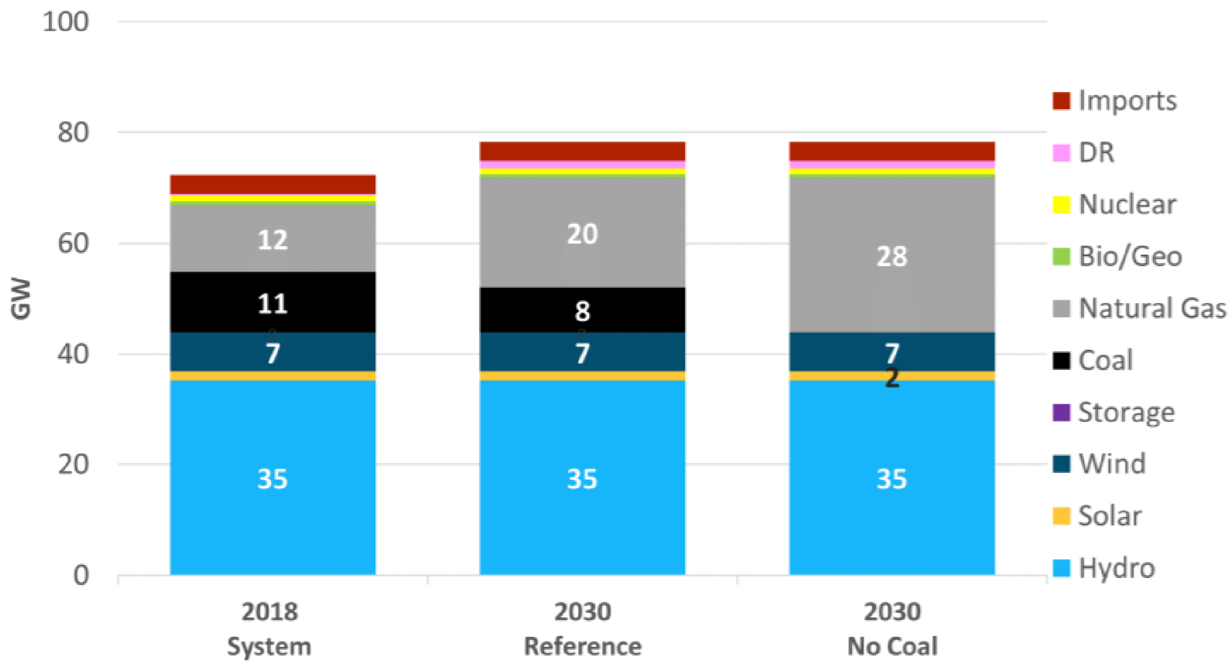
[3] https://www.publicgeneratingpool.com/wp-content/uploads/2019/03/E3_NW-Resource-Adequacy_Final-March-2019.pdf

Figure 18: E3 generation portfolios in 2030



In response, the Northwest Power Pool has formed a collective of utilities working toward a voluntary Resource Adequacy program intended to ensure reliability can be maintained into the future. While much of the plan is in the early phases and design will continue beyond the submission of this IRP, a framework is being constructed in the first half of 2020. The group has sought out a program developer "with proven expertise in design and implementation of multi-state RA programs to assist with areas of technical and operational complexity[4]" and commissioned E3 to perform the supporting analysis surrounding the initiative. **Figure 19** below outlines the expected program design timeline.

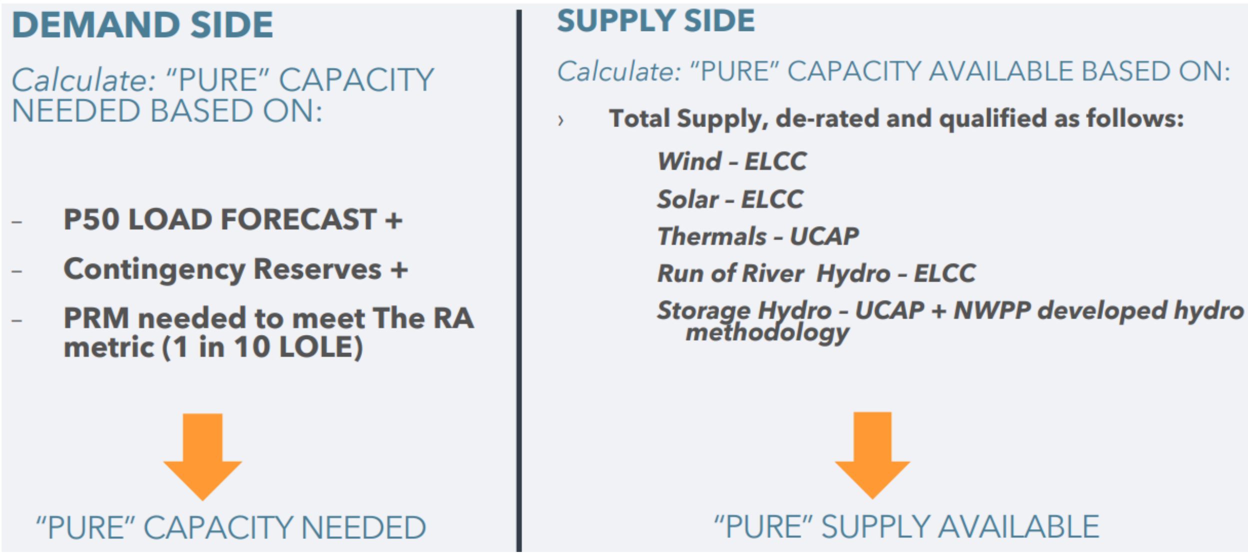
Figure 19: NWPP RA Timeline as of April 24, 2020

The program is expected to be organized into two time horizons. The first will be a forward showing program designed to ensure entities meet regional metrics months in advance. The second will be a shorter term operational horizon intended to share access to pooled resources to better right-size regional metrics for better long term investment savings.

[4] April 2020 Public Webinar

Early designs include advanced metrics to value the contribution of each resource type alongside the demand, reserves, and planning margin to maintain reliability as shown in Figure 20.

Figure 20: NWPP supply and demand summary



While the grid will continue to evolve as technologies become more or less viable over time, a regional Resource Adequacy metric like the one NWPP is developing will be essential to maintaining reliability into the future.

10 Year Transmission Assessment

Like Resource Adequacy, transmission adequacy is also an important issue facing utilities for many of the same reasons. In a time when thermal generators are retiring and making their now-unused transmission available, other generators including renewables will be consuming that capacity to deliver to load often over longer distances. This generation evolution will naturally force a corresponding evolution in the transmission grid as power must be delivered reliably to load.

On an annual basis, Transmission Planning provides a ten-year plan for reinforcements to BPA's transmission system and is provided in accordance with Attachment K of the BPA Open Access Transmission Tariff.[5] The result is a list of proposed projects to meet the forecast requirements over a 10 year planning horizon including provisions for market changes. The latest version of the report containing the proposed reinforcements can be found on BPA's website[6].

[5] https://www.bpa.gov/transmission/CustomerInvolvement/AttachmentK/Documents/2019-bpa-transmission-plan.pdf

[6] https://www.bpa.gov/transmission/CustomerInvolvement/AttachmentK/Documents/2019-bpa-transmission-plan.pdf

Chapter 4: Policy & Regulation

Environmental policy continues to be a significant driver of resource planning processes. State mandated portfolio standards obligate utilities across the WECC to acquire renewable resources and aggressively pursue conservation measures. Some utilities have dramatically altered their long-term strategies based on potential for federal carbon emission laws coming into effect. The District must meet current and prepare for future environmental regulatory requirements while balancing the acquisition of resources that are “least cost” and help mitigate financial volatility. The purpose of this chapter is to provide an overview of the policy issues most relevant to the District. In later chapters, there will be in-depth discussion of the methodologies used to incorporate policy implications in the planning process.

Washington State Related Policies & Regulations

Integrated Resource Planning

The Washington State legislature passed RCW 19.280 in 2006, mandating that electric utilities 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 long-term and the short-term.” The law applies to utilities that have more than 25,000 customers and are not load-following customers of the Bonneville Power Administration. The law stipulates that qualifying utilities produce a full plan every four years and provide an update to the full plan every two years. The plan must include a range of load forecasts over a ten-year time horizon, an assessment of feasible conservation and efficiency resources, an assessment of supply-side generation resources, an economic appraisal of renewable and non-renewable resources, a preferred plan for meeting the utility’s requirements and a short-term action plan.

The District complied with the requirements of this legislation in September of 2008, 2010, 2012, 2014, 2016 using the simplified Coversheet Resource Plan while the District had less than 25,000 customers. In 2016 the District exceeded 25,000 customers and submitted its first comprehensive resource plan in 2018. This IRP is designed to meet the biennial and update requirement.

Energy Independence Act (EIA)

In 2006, Washington State voters approved the Energy Independence Act (EIA), RCW 19.285 (I-937), which requires all utilities with customers exceeding 25,000 to meet 15% of their load from qualifying renewable resources by 2020.

The first phase of the renewable requirement of the EIA required the District to meet 3% of its retail loads with qualified renewable resources. The second phase of the renewable requirement is now in effect and requires the District to meet 9% of retail loads with qualified renewable resources. The third phase of the requirement will increase to 15% in 2020. If the District fails to meet the requirement, it will be assessed a penalty of $50/MWh, in 2007 dollars, equating to approximately $62/MWh in 2020 dollars. The District may comply without meeting the standard discussed in the previous section if it has invested 4% of its total annual retail revenue requirement on the incremental levelized cost of qualifying renewable resources. The intention of this cost-cap provision is to act as a “safety valve” to limit the impacts of the law on ratepayers. The law states:

> “The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that do not qualify as eligible renewable resources.”

A principal driver of resource acquisition for the District is achieving compliance with the EIA. Based on updated analysis and current prices, the District does not believe that this mechanism could be a factor in the future but will continue to analyze the opportunity going forward.
The EIA also requires that the District implement all cost-effective conservation measures, using methodologies consistent with those used by the Pacific Northwest Power and Conservation Council in its most recently published regional power plan. Every two years, the District must identify its achievable cost-effective conservation potential for the next ten years as well as the next two-year target, which the District must meet during the subsequent two-year period.

Washington State Green House Gas Legislation

In 2008, the Washington State Legislature enacted RCW 70.235.020, a law which aims to reduce the State’s anthropogenic greenhouse gas (GHG) emissions in order to mitigate the impacts of climate change and was amended effective June 11, 2020 to increase the emissions reductions. The goal of the law is to lower GHG emissions to 1990 levels by 2020, 55% of 1990 levels by 2030, 30% of 1990 levels by 2040, and 5% of 1990 levels by 2050 (Figure 21). In addition, RCW 80.80 established a performance standard for all baseload electric generation, modeled on California’s Senate Bill 1368, which would apply to all generation used to serve load in Washington, whether that generation is located within the state. The statute defines baseload generation as generation that is “designed and intended to provide electricity” at an annualized plant capacity factor of at least 60 percent.

Figure 21: Target GHG Emissions

The law established an emissions performance standard (EPS) which limits CO2 emissions from any baseload electric resource to 1,100 lbs./MWh. Starting in 2013, the law could be amended to lower the emission limit to the emission rate of the most efficient commercially available combined cycle combustion turbine. In March 2013, the Department of Commerce (DOC) lowered the EPS to 970 lbs./MWh. In March 2018, the DOC filed a proposed rulemaking change to lower the EPS to 930 lbs./MWh. The CO_2 emissions from a coal-fired power plant are close to 2000 lbs./MWh, well in excess of the new standard. The law also prevents Washington utilities from entering into any long-term (over 5 year) power purchase agreement sourced from any resource that does not comply with the emissions standard. Without the ability to sequester a large portion of its CO_2 emissions or find other means of emissions reductions, the law in effect bans new coal fired generation. While CO_2 emissions reductions or sequestration are possible, these are both unproven processes and are likely to make coal economically less competitive.

Clean Energy Transformation Act

On May 7, 2019 Washington Governor Jay Inslee signed the Clean Energy Transformation Act (CETA) (E2SSB 5116, 2019) into law committing to zero carbon emissions from the power sector by 2045.

The Clean Energy Transformation Act (CETA) applies to all electric utilities serving retail customers in Washington and sets specific milestones to reach the required 100% clean electricity supply. The first milestone is in 2022, when each utility must prepare and publish a clean energy implementation plan with its own targets for energy efficiency and renewable energy.

By 2025, utilities must eliminate coal-fired electricity from their state portfolios. The first 100% clean standard applies in 2030. The 2030 standard is greenhouse gas neutral, which means utilities have flexibility to use limited amounts of electricity from natural gas if it is offset by other actions. By 2045, utilities must supply Washington customers with electricity that is 100% renewable or non-emitting, with no provision for offsets.

CETA includes safeguards to protect consumers from excessive rates or unreliable service. Utilities may adopt a slower transition path if necessary to avoid rate shock, and they must improve assistance programs for low-income households. The law provides for short-term waivers of the standards if needed to protect reliability.[7]

CETA further requires utilities to include sections for a 10-year generation and transmission availability assessment as well as an assessment of equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities.

Oregon Cap and Trade

The Oregon state legislature introduced a cap and trade bill in this year's legislative session which would require the state's largest polluters to purchase carbon offsets to their emissions, with the intention of ultimately joining the Quebec-California-Ontario carbon market. The bill failed, in the short legislative session, but continues to be a topic of debate.

Oregon Clean Energy Program

The effects of this law are two-fold. First, it will result in the retirement of all coal and coal-by-wire into Oregon by 2030, with the exception of Portland General Electric's 20% share of Colstrip units 3 and 4, which will be allowed to operate through no later than 2035. It also creates a higher RPS mandate for IOUs of 27% renewables by 2025, 35% by 2030, 35% by 2035 and 50% by 2040.

Outside of Oregon, this law may set a precedent for other states like Washington to follow suit. California and Oregon both have 50% RPS mandates; more renewable buildout is expected, particularly

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[7] https://www.commerce.wa.gov/growing-the-economy/energy/ceta/

in Oregon because of how the bill is structured. It limits the amount of unbundled out-of-state RECs a utility can purchase to meet its RPS obligation to 20 percent.

Oregon Clean Fuels Program

The Oregon Clean Fuels Program was authorized in 2009 with the passage of HB 2186. Subsequent legislation (SB 324) was passed in 2015 allowing the Oregon Department of Environmental Quality (DEQ) to support the 2016 implementation of the Program. The Program has a stated goal of reducing the carbon intensity of transportation fuels by 10 percent in 10 years. Starting with a 2015 baseline, regulated parties must demonstrate that they have met the annual benchmarks set by the DEQ.

Credits are generated when the carbon intensity of a fuel is lower than the annual benchmark and generates deficits when the carbon intensity of a fuel is greater than the annual benchmark. The number of credits and deficits generated proportional to carbon intensity of the fuel relative to its benchmark. Credits and deficits are reported in metric tons. The current value of a credit is in the range of $50/metric ton.

Electricity utilized for transportation is regulated by the Program. Gasoline has a 2018 benchmark carbon intensity score of about 100.14 gCO2e/MJ in 2020[8]. The carbon intensity of electricity can vary significantly depending on a utility's specific resource mix. Those that are heavily reliant on coal will have a higher carbon intensity than gasoline, whereas those that are more dependent on hydro and renewables will likely have low carbon intensity scores. BPA customers in Oregon have an average carbon intensity score of 7, over 12 times less polluting than gasoline, translating to a large credit earning potential.

The low carbon intensity of grid power from BPA customers incentivizes electric vehicle adoption, which consequently incentivizes additional electricity consumption.

Net Metering of Electricity

The District will comply with RCW 80.60.020, 80.60.030, and 80.60.040, which requires utilities to offer Net Metering of Electricity (Net Metering) programs to customers who have installed small generating systems, limited to water, solar, wind, biogas from animal waste as a fuel, fuel cells, or produces electricity and used and useful thermal energy from common fuel source. To be eligible for Net Metering, each installation must be 100 kW or less in size. Total Net Metering capacity for each utility is set at the 4% of the utility's 1996 peak demand. Excess generation at the end of each bill period will be carried over to the next billing period as credit. Any excess generation accumulated during the previous year will be granted to utilities without any compensation to the customer-generator on April 30 of the following year.

Voluntary Green Power

Legislation passed in 2001 requires large electric utilities to provide their retail customers voluntary option to purchase qualified alternative energy resources. This is often referred to as green power. Franklin PUD offers "Generation Green", a green power program. It is voluntary and retail customers can contribute any amount above the existing retail rate for their rate class. The PUD retires RECs in

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[8] https://www.oregon.gov/deq/aq/programs/Pages/Clean-Fuel-Pathways.aspx

WREGIS that equate to the annual amount contributed by customers. There is no state mandated reporting requirements associated with RCW 19.29A.090.

Federal Policies & Regulations

PURPA

The Public Utility Regulatory Policies Act of 1978 (PURPA) directs state regulatory authorities and non-FERC jurisdictional utilities (including the District) to consider certain standards for rate design and other utility procedures. The District is operating in compliance with these PURPA ratemaking requirements. The FERC could potentially assert jurisdiction over rates of licensees of hydroelectric projects and customers of such licensees under the Federal Power Act. The FERC has adopted maximum prices that may be charged for certain wholesale power. The District may be subject to certain provisions of the Energy Policy Act of 2005, relating to transmission reliability and non-discrimination. Under the Enabling Act, the District is required to establish, maintain and collect rates or charges that shall be fair and nondiscriminatory and adequate to provide revenues sufficient for the payment of the principal of the interest on revenue obligations for which the payment has not otherwise been provided and for other purposes set forth in the Enabling Act.

PURPA established a new class of generating facilities known as qualifying facilities (QFs) which would receive special rate and regulatory treatment, including qualifying small power production facilities "of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources."

The FERC defers to the states to determine the implementation of PURPA-based contracts, and this has had a significant impact on how many QFs have been built in a given state. Idaho had a short-lived solar surge until the state PUC shortened the length of negotiated QF contracts from 20 years to 2 years. In June 2016, the Montana Public Service Commission (PSC) issued an emergency order suspending guaranteed PURPA contracts to small solar farms in response to a large number of applications from solar developers (as many as 130 solar projects). Oregon, however, has many PURPA facilities in the pipeline. In March 2016, the Oregon PUC decided to keep its 20-year guaranteed contracts in place with 15 years of fixed prices, which pleased renewable developers. Washington, on the other hand, doesn't have a required standard contract length for QFs. In addition, the depressed wholesale market prices (when compared to other markets) due to low-cost hydro makes the avoided cost of power too low for PURPA projects in Washington to be economically viable to developers. The District is currently a purchaser of RECs from an Idaho PURPA facility, Yahoo Creek Wind, LLC., which contributes to satisfying the EIA renewable requirement.

The FERC announced its intention to review PURPA citing reports from utilities that developers may be unfairly applying PURPA rules to maximize economic returns. The FERC applies a test, known as the "one mile rule," to determine whether adjacent facilities should be counted as one or multiple facilities. PURPA limits each facility's generation capacity to 80MW; thus breaking a single large facility into multiple, smaller facilities increases the generation capacity allowance. The one mile rule states that facilities located within one mile of each other are considered a single facility, whereas those greater than one mile apart are separate facilities. With wind plants stretched out over an extremely wide geographic footprint relative to other generation technologies, the FERC decided to review and clarify its one-mile rule. The rule is still under review as of the publication of this IRP.

Renewable Electricity Production Tax Credit (PTC)

In December 2015, the Consolidated Appropriations Act 2016 extended the expiration date for this tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. The Act extended the tax credit for other eligible renewable energy technologies commencing construction through December 31, 2016. The Act applies retroactively to January 1, 2015.

The federal renewable electricity production tax credit (PTC) is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities placed in service after August 8, 2005. The PTC for generators with a construction commencement vintage of 2017 was $19/MWh. That rate will be reduced to approximately $14.25/MWh for generators with a 2018 vintage and $9.50/MWh for those with a 2019 vintage. The PTC for new wind construction was sunset entirely by the end of 2019 before being extended until the end of 2020 and restored to $9.50/MWh for facilities that start construction during the 2020 calendar year.

Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by the Taxpayer Certainty and Disaster Tax Relief Act of 2019 that passed in December 2019. Previously it had been extended by the American Recovery and Reinvestment Act of 2009 (H.R. 1 Div. B, Section 1101 & 1102) in February 2009 (often referred to as "ARRA"), the American Taxpayer Relief Act of 2012 (H.R. 8, Sec. 407) in January 2013, the Tax Increase Prevention Act of 2014 (H.R. 5771, Sec. 155) in December 2014, and the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015.

Renewable Energy Investment Tax Credit (ITC)

The Consolidated Appropriations Act, signed in December 2015, extended the expiration date for PV and solar thermal technologies, and introduced a gradual step down in the credit value for these technologies. The credit for all other technologies expired at the end of 2016.

A taxpayer may claim a credit of 26% of qualified expenditures for a system that serves a dwelling unit located in the United States that is owned and used as a residence by the taxpayer. This value is set to decrease to 22% in 2021 and 10% in 2022. Expenditures with respect to the equipment are treated as made when the installation is completed. If the installation is at a new home, the "placed in service" date is the date of occupancy by the homeowner. Expenditures include labor costs for on-site preparation, assembly or original system installation, and for piping or wiring to interconnect a system to the home. If the federal ITC exceeds tax liability, the excess amount may be carried forward to the succeeding taxable year. The maximum allowable credit, equipment requirements and other details vary by technology, as outlined in Figure 22**.**

Figure 22: ITC Eligibility by Resource Type

Resource Type	Eligible Expditures	Maximum Allowable Expenditures
Solar Technologies	Equipment that uses solar energy to generate electricity, to heat or cool a structure, to provide process heat, to heat water, or to provide fiber-optic distributed sunlight	100% eligible
Fuel Cells	Minimum fuel cell capacity of 0.5kW required	30% of expenditures or $1500 per 0.5kW of capacity
Small Wind Turbines	Up to 100kW in capacity	30% of expenditures
Geothermal	Geothermal heat pumps	10% of expenditures
Microturbines	Up to 2MW of capacity with an electricity generation efficiency of at least 26%	10% of expenditures, $200 per kW of capacity
Combined Heat and Power	Generally systems up to 50MW in capacity that have generation efficiencies of at least 60%	10% of expenditures
Source: DSIRE USA, Business Energy Investment Tax Credit Program Overview, Updated March 1, 2018		

The increase in wind and solar capacity from the PTC and the ITC has caused wholesale market prices to decrease, negatively impacting the District's sales for resale which in turn increases the District's Net Power Costs.

Chapter 5: Supply Side Resource Costs

The District analyzed a broad array of supply-side resource options in the IRP. Each technology has its own unique set of advantages and limitations, and therefore, a unique impact on the District's power supply costs.

The Governor's signature of Washington's Clean Energy Transformation Act into law will eliminate carbon emitting electricity generation assets over a period from 2030 to 2045. The law does not preclude the District from considering carbon emitting assets to meet its energy needs until then, however, utilities are required to include incorporate the societal cost of carbon when considering such resources. The economic life of the assets that the District considered in this report generally have a life of 20 to 30 years, meaning that carbon emitting resources are not precluded from consideration. Such assets would likely be nearing the end of their economic life before the law requires their full decommissioning.

The District gathered resource cost data from a variety of sources. In general, the plan attempts to base its analysis on "regional consensus" data. This was accomplished by surveying the assumptions used by research institutions, developers, and resource planners from other utilities in the region for their IRPs. In circumstances where the District had access to more specific resource cost data, that information was used instead.

A project economics model was developed to evaluate the different variables across the various generation resource options. The model considered both resource specific data such as capital, operating, and fuel expenses, as well as non-technical expenses such as the cost of carbon and environmental compliance. The model was developed to compare the effect of the different variables across the generation technologies through a simplistic levelized cost of energy ($/MWh) metric (LCOE).

Resource Alternatives

Future resource requirements can be satisfied through the purchase or construction of capacity, the reduction in demand and energy consumption by end-users, or a combination of the two.

The following sections provide descriptions of each type of resource which may be used to meet the District's future capacity and energy resource options.

Conventional Thermal Generation

Steam Units

Simple thermodynamic cycle steam turbine-generators were once the stalwart of electric generating units for many decades, with coal and nuclear units anchoring the group. Until the last two decades, steam units have been the primary choice for base load operation due to their reliability and long economic lives. Steam units typically have relatively long start-up times (8-24 hours) and are usually restricted in the number of starts and minimum run-time to reduce thermal fatigue, wear and tear on large expensive components.

Over the last two decades, steam generators have become less cost competitive and practical than other alternatives, as technology, commodity markets, and consumer behavior evolved. Natural gas fired combined cycle (CCGT) units now represent the marginal unit due to increasing thermal efficiencies, lower realized costs due to persistently low natural gas prices, and flexibility to match the changing hour-by-hour consumer demand profiles. For over 30 years, the Boardman, Centralia, and Colstrip coal units contributed about 2500 MW to the regions generation supply. With cost, environmental, and regulatory pressures, however, the region is winding down its coal fleet. Washington State's Clean Energy Transformation Act requires utilities within the state to eliminate coal generation resources by 2025. A result of the headwinds faced by coal generation units, Colstrip decommissioned 2 of its 4 units at the end of 2019. Boardman will retire, or at least stop burning coal, at the end of 2020. And Centralia is scheduled to shut down by 2025.

Nuclear generation assets were considered in this report, but in the form of new small modular reactors instead of the more traditional steam units.

Simple Cycle Gas Turbines (CT)

Simple cycle assets generally have relatively low capital costs and high operational costs due to their inefficient nature and smaller scale. Because of their lower thermal efficiencies, these are generally limited to serving load only during peak load conditions.

Over the last three decades, technological advances have resulted in substantial improvements in CTs, resulting in larger and significantly more efficient electric generation when compared with earlier vintage CTs. Today, there are a variety of sizes, types (aero-derivative vs. industrial or "frame" types) and manufacturers to choose from.

Combined Cycle Gas Turbine (CCGT)

Combined cycle gas turbine units utilize the waste heat from gas turbines to increase efficiency and produce additional electricity. The hot exhaust gas from the CTs are recovered with a heat recovery steam generator (HRSG) to produce steam which powers a conventional steam turbine. As a result, the most efficient units have a thermal conversion rate exceeding 60 percent, as compared to the 40% or less conversion rate of traditional steam turbines

Reciprocating Internal Combustion Engine (RICE)

Reciprocating internal combustion engines (RICE) are becoming an increasingly popular choice for utilities over CTs. These units are generally retain a more favorable economic operating profile which does not vary significantly over the operating range of a single unit. These are also modular in nature, offer quicker start-up and ramp times, are capable of frequent starts and stops, and reduce operating and maintenance costs while providing dual fuel (natural gas and fuel oil) capability. This type of flexibility is becoming more valuable given the intermittent nature of wind and solar generation. As the region's wind and solar generation capacity continues to increase, these type of quick start units are able to quickly respond and balance the sometimes-rapid fluctuations in wind and solar generation.

Small Modular Reactor (SMR)

Several companies are in the process of developing a commercially available small modular reactor (SMR), which are a new class of nuclear power plants that will be smaller in size and capacity than traditional nuclear plants. As the name implies, the units will be modular and offer more flexibility to utility capacity needs. Each module is a self-contained 50 MW reactor. SMRs bring several key benefits. Unlike the first-generation large scale nuclear plants in operation today, a SMR will not require active cooling during emergency conditions for the plant to remain in a safe condition, significantly lowering the risk of accidents. Another key concern is the risk of proliferation. SMRs are expected to increase the security and safety of the nuclear industry as the plants are designed to be located underground. These are also expected to run for longer periods without refueling, thus limiting the risks associated with transportation and other fuel handling concerns. Other benefits include the ability to ramp generation up and down to better follow the load shape – unlike traditional nuclear plants that have more limited ramping capabilities.

A 12-module, first of its kind plant built by NuScale at the Idaho National Laboratory for the Utah Associated Municipal Power Systems is currently in the planning stages. Energy Northwest, the current operator of the Columbia Generating Station, will also be the operator of this plant. It is expected to achieve commercial operation by 2026.

Renewable Generation

State and federal lawmakers and regulatory authorities have placed considerable emphasis on increasing the amount of electricity produced by renewable energy resources through regulatory requirements and financial incentives on both the state and federal level.

Biomass

In the context of this report, biomass is sourced from combustion of by-product from the forestry industry. While the combustion releases carbon emissions, biomass qualifies as a renewable, carbon-free resource as the fuel itself is itself renewable. The characteristics and costs of biomass plants vary widely and are dependent on the quality of the fuel itself. Transport is a significant driver of fuel costs, and is proportional to proximity to the plant itself and inversely proportional to the energy density of the fuel.

Wind and Solar

The cost of wind and solar generation plummeted in the preceding decade. In 2010, the average cost of solar energy across its lifetime was just about the highest of all commercially available resources. Today, in low cost environments with favorable solar conditions, new solar plants can generate electricity for less than the marginal cost of already existing thermal units. Most observers believe that this trend will continue. To a lesser extent, the same is true of wind energy as well. In favorable geographical environments, wind energy is the lowest cost resource available. Of course, these technologies are intermittent by nature and thus cannot be relied upon for serving load, particularly during periods of highest demand.

Laws such as CETA imply that by the time the law fully takes effect, a technical solution to managing the intermittent nature of these variable resources will be technically and economically viable. Development is accelerating on the energy storage front as a greater number of new wind and solar project proposals are paired with on-site battery storage.

Energy Storage

Successfully converting the grid to be supplied solely using carbon-free energy, as mandated by CETA, likely depends on the ability to develop and deploy energy storage at a large scale. For the forseeable future, intermittent resource such as wind and solar will remain the lowest cost carbon-free resources for energy. Managing the power grid around the variability of these renewable resources has become more challenging. The complexity of grid management will continue to increase as intermittent resources continue to gain market share.

Distributed and grid-scale energy storage resources have gained significant interest in the industry. Storage devices collect electricity produced from such resources when supply exceeds demand and discharge during periods when demand increases and/or the primary energy is not available. In addition to acting as a resource when the grid needs additional power, energy storage can also modulate the production from wind and solar by storing excess generation.

The most prominent distributed energy storage resource is a battery bank, which depending on its size, can supply an average household from several hours to several days of energy. Batteries are available on the utility scale as well, with several battery storage projects installed in California.

Other storage technologies have been commercially available for decades. Pumped storage moves water from a lower reservoir to a higher reservoir, and that potential energy is converted to electricity when the water is discharged through a turbine. While they are the most commercially mature storage technology and feature long economic lives, pumped storage units require very specific siting conditions which have limited their penetration. There is however a 1,200 MW facility near Goldendale, WA currently in the permitting phases underscoring the desire for this technology to persist into the future.

Distributed Energy Resources (DER)

Instead of traditional, one-way delivery of electricity from large, central station power plants located far from demand, technologies are now available that allow customers to generate their own electricity. Due to a combination of maturing technology and financial incentives, many of these technologies, such as rooftop solar, are currently affordable to many customers. Costs are expected to continue to trend down and more technologies are expected in the near future as research progresses allowing more customers to move in that direction. Understanding how DERs impact the grid itself, including reliability, is an important factor to be considered. Alternatively, understanding where, when, and how DER can benefit the grid is of equal value. While the economic signals may not yet be fully developed, technology has advanced to the point where consumers can respond to price changes, reduce (or increase) demand when useful to the system, or store electricity for later use.

DER are typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DER are being adopted at increasing rates due to favorable policies from both state and federal governments, improvements in technology, reduction in costs, and identifiable customer benefits, both at the individual and grid levels.

Once DER adoption passes certain levels, DER can begin to cause significant issues for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of ratepayers. It is important for electric utilities to identify potential economic and grid issues and benefits from DER. DER are becoming more widespread with increasing commercial availability, decreasing costs, and evolving consumer preferences. The District is proactively investigating and exploring different rate strategies that will lead to greater benefits for the public, customers, developers, and utilities alike. The DER space is evolving at a pace as rapid as any industry – it is imperative to develop a plan flexible enough to adapt to increased levels of DER.

Federal Tax Credits and Incentives

As referenced in Chapter 4, there are two federal incentives available to renewable resources: the Production Tax Credit (PTC) and the Investment Tax Credit (ITC).[9,10] The ITC provides a tax credit of 30% for the capital expenditures of solar projects. It was initially established in the Energy Policy Act of 2005. Since their initial inceptions, federal renewable tax credits have expired, been extended, modified, and renewed numerous times. Changes in federal tax policies were historically highly correlated with year-to-year variations in the construction of renewable capacity, particularly for wind energy, where the U.S. wind industry has experienced multiple boom-and-bust cycles that coincided with PTC expirations and renewals. The PTC provides a tax credit to eligible renewable generators for each kilowatt-hour of electricity produced for the first 10 years of operation. While the PTC began its sunset in 2016 and expired at the end of 2019, developers were able to secure more generous PTC benefits by procuring land and equipment and beginning construction on projects in advance of the various deadlines in an act known as "safe harboring," extending the PTC window by several years. Wind, geothermal, and biomass technologies receive $23/MWh. All other eligible technologies (i.e. tidal or small hydro) receive $12/MWh. The PTC received a four-year extension beginning 2016 that gradually reduces the subsidy by 20 percent each year to wind generators until it was to be phased out on December 31, 2019. On December 20, 2019, however, the Taxpayer Certainty and Disaster Tax Relief Act of 2019 extended the PTC for an additional year, valid for facilities that begin construction during 2020 for 60% of the original PTC amount.

- Wind generators that begin construction in 2016 receive the full amount of the PTC
- Wind generators that begin construction in 2017 receive 80% of the PTC
- Wind generators that begin construction in 2018 receive 60% of the PTC
- Wind generators that begin construction in 2019 receive 40% of the PTC
- Wind generators that begin construction in 2020 receive 60% of the PTC

There are several differences between the PTC and ITC. The subsidy amount provided by the ITC is a percentage of the installed capital costs instead of a fixed rate per unit of energy provided. It is also applied based on the in-service date, rather than the construction start date.

The subsidy schedule for the ITC varies significantly by generation resource gradually ramping down until its expiration. **Figure 23** below displays the credit provided by the ITC as a percent of capital expenditures.

Figure 23: Investment Tax Credit as a Percentage of Capital Expenditures

In-Service Date	End of 2016	End of 2017	End of 2018	End of 2019	End of 2020	End of 2021	End of 2022	Beyond
Solar	30%	30%	30%	30%	26%	22%	10%	10%
Wind	30%	24%	18%	12%	-	-	-	-

[9] Renewable Energy Production Tax Credit. *US Energy Information Administration*. US Energy Information Administration. Web. May 24, 2016

[10] Business Energy Investment Tax Credit. *US Energy Information Administration*. US Energy Information Administration. Web. May 24, 2016

The continued production and investment tax credit programs for wind and solar energy, along with technology development, will likely result in the continued growth of renewable capacity. It will be important during any potential procurement process to evaluate multiple renewable options as the tax credits associated with safe harbor status can make a material impact to pricing terms.

New Supply Side Resources

A variety of options for new supply side resources could be used to meet the District's future needs. The choices of new resources considered for this IRP were limited to those which are generally size-compatible with regional sizing over the study period, but many of the larger thermal facilities would require other entities or Districts to reach the economies of scale necessary for a larger project. Coal power was not considered as there is a de-facto prohibition on building new coal fired generators without expensive carbon capture and storage capabilities. Large scale nuclear facilities were also excluded for budgetary, fiscal, and political considerations. Small modular reactors, however, were examined in this study.

Figure 24 and Figure 25 below includes the supply-side resource options evaluated for this IRP. All costs are expressed in nominal dollars.

Figure 24: Potential district owned resources

District Owned Resources						
Resource Type	Capital Cost ($/KW)	Fixed O&M ($/kW - Year)	Variable O&M ($/MWh)	Full Load Heat Rate (BTU/kWh)	Capacity Factor	Fuel Type
Combustion Turbine - Aeroderivative	$1,212	$16.30	$4.70	9.12	10%	Natural Gas
Combined Cycle	$1,135	$14.10	$2.55	6.43	28%	Natural Gas
Reciprocating Internal Combustion Engine	$1,207	$35.16	$5.69	8.30	11%	Natural Gas
Geothermal	$2,734	$128.54	$1.16	0	73%	Geothermal
Small Modular Reactor - EIA Cost	$6,191	$95.00	$3.00	10.45	90%	Uranium
Pumped Storage	$2,390	$24.80	$0.37	0	30%	Various

Figure 25: Potential resources modeled per unit

Resources Modeled Per Unit			
Resource Type	**PPA Cost**	**Capacity Factor**	**Fuel Type**
Eastern Montana Wind †	$29.00	37%	Wind
Columbia Gorge Wind †	$35.00	32%	Wind
Single Axis Tracking Solar Photovoltaic‡	$38.00	20%	Solar
Solar + Storage	$60.00		Solar
Small Modular Reactor - Aggressive Target	$55.00	90%	Uranium

†Capacity factor derived from the National Renewable Energy Laboratory – System Advisor Module v.2017.9.5, location of Roosevelt, WA for Columbia Gorge and Colstrip, MT for Eastern Montana

‡ Capacity factor derived from the National Renewable Energy Laboratory – System Advisor Module v.2017.9.5, location of Kennewick, WA

Fuel and Cost Assumptions

The fuel cost assumptions are equivalent to those described in the Market simulation chapter. Renewables costs are reported in both subsidized and unsubsidized figures to cover the range of possible outcomes as the subsidy decreases over time. The costs of thermal generators are calculated both with and without a carbon price. The carbon price regime was adapted from the Societal Cost of Carbon, as outlined in CETA beginning at $74 per metric ton in 2020, escalating to $87 per ton by the end of the study period.

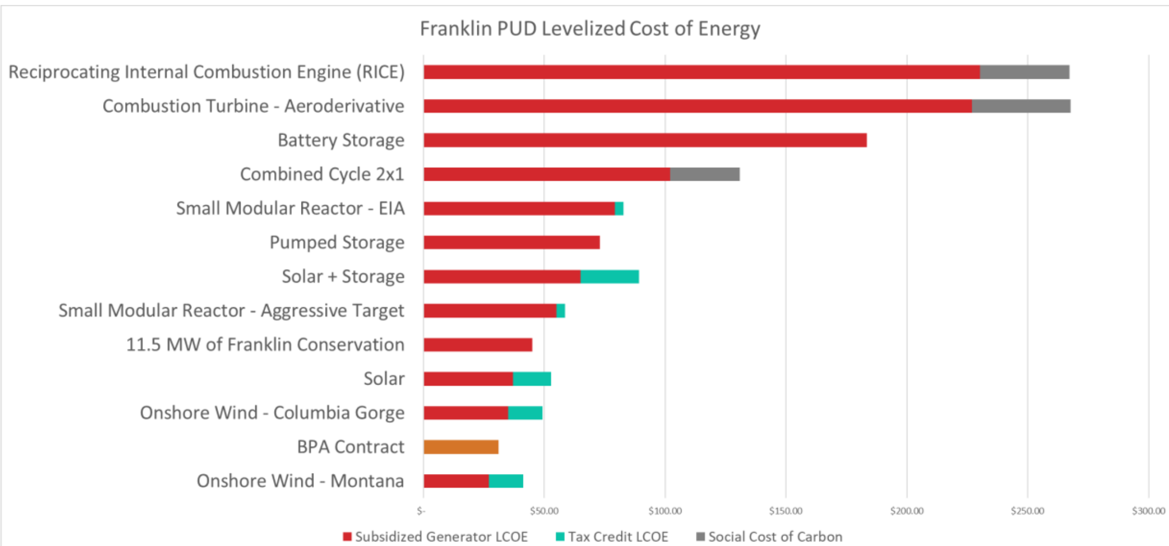
Renewable Integration Costs

The intermittent nature of renewable resources requires additional integration services to ensure a steady supply of energy. Based on the experience of the IRP team in the wholesale markets, the integration costs were estimated to be an incremental $8/MWh for wind generators and $2/MWh for solar generators.

Levelized Cost and Energy

A project economics model was developed to evaluate the different variables across the various generation resource options under a single metric. The model considered both resource specific data such as capital, operating, and fuel expenses, as well as non-technical expenses such as the cost of carbon and environmental compliance. While industry standard, this metric does not fully assess the capacity value of resources necessary to maintain reliability particularly in periods or low wind, solar, or hydro output. The model was developed to compare the effect of the different variables across the generation technologies through a levelized cost of energy ($/MWh) metric. Below is the cost of each resource examined in this IRP.

Figure 26: Levelized Cost of Energy



Levelized Cost of Energy for Resources Analyzed

Outside of hydroelectricity, the Northwest possesses uniquely inferior renewable resource potential, which is reflected in the levelized cost analysis. There are other areas in the country, particularly in the interior Midwest and Mountain West regions, where wind energy has levelized costs in the low-teens. Capacity factors in this region approach 60%, almost double what is estimated to be achievable in Washington. A similar narrative can be constructed about solar energy; the Northwest is not known for its solar resources. Capacity factors in West Texas and the Desert Southwest more than double of those achievable in Washington. With costs entirely loaded into capital expenditures and fixed costs, the economics will favor generators located in places that can attain higher capacity factors.

The IRP team recognizes that LCOE is an imperfect metric. It does not incorporate or value resource specific attributes, nor does it differentiate between energy, capacity, and flexibility. Assets such as CCCTs that possess both dispatchability and flexibility are inherently more valuable to the grid as these can be dispatched to follow the fluctuations in demand. Intermittent resources cannot provide those benefits. However imperfect of a metric LCOE is, at the moment all energy is valued equally in the region. Chapter 3 provides a more comprehensive discussion of the forthcoming regional resource adequacy requirement, which will require capacity and flexibility to be valued differently than energy.

Resources Selected for Additional Analysis

Based on both quantitative and qualitative factors, the following resources were considered by the District's IRP team to warrant further study:

Renewable resources:

- Wind
- Solar
- Geothermal

Other resources:

- Small Modular Reactors
- Battery Storage

Coal was excluded from further analysis it would violate the legal requirements mandated under RCW 80.80.

Chapter 6: Macro Utility Environment – The New Status Quo and Utility Industry Disruptions

The energy landscape is evolving as rapidly as any other sector of the economy. This industry has observed changes on all fronts since the 2018 IRP from expanding markets, to additional regulatory pressures, and ever-advancing technologies. There are several such technologies in development that have the potential to fundamentally alter the way that society generates and consumes electricity. On top of these forces looms the unknown effects of the COVID-19 pandemic that have drastic implications for a number of industry initiatives ranging from the future of wind tax credits to the feasibility of energy storage. This section delves into the trends shaping the energy industry and the effect of technology, politics, science, and the resulting impacts of COVID-19.

In many state legislatures across the US, energy bills poised to require utilities to use carbon-free generation, adhere to renewable portfolio standards (RPS), and allow the formation of Community Choice Aggregators (CCAs) have been superseded by addressing the public health and economic consequences resulting from COVID-19 as the top priority. A handful of these energy related bills are summarized below:

- In Illinois, a bill that would set carbon free standards by 2030 and 100% renewable goals by 2050 has lost momentum as the legislature is suspended
- A Similar bill in Maryland that would limit emissions and allow CCAs is at a similar standstill
- In Colorado, bills that are designed to support a 100% RPS law are stalled
- A bill in Michigan that would bring it into compliance with the Paris Climate accords is facing delays
- Minnesota's legislature has looked to scale back a plan to make the state's utilities move to carbon free generation, and instead is likely to pass an energy efficiency bill.

The slowed legislative activity driven by the pandemic will have less of an effect in Washington State, which adopted clean energy legislation in 2019; the same cannot be said for adoption of similar bills nationwide.

Federally, the COVID-19 pandemic has prompted regulators to relax reporting requirements and reduce restrictions on emissions. However, the impact and duration of these changes is unclear.[11] More significantly, the Safer Affordable Fuel Efficient (SAFE) Vehicles Rule lowered the annual increase in vehicle fuel efficiencies from 5% to 1.5%. This move is likely to slow the adoption of electric vehicles (EVs) as manufacturers find it more difficult to compete against internal combustion engine models. The retail prices of traditional vehicles are also expected to decline by about $1,000. This action was intended to aid automakers struggling during the COVID-19 crisis, however it will likely disadvantage American EV manufacturers.

The COVID-19 pandemic is unfortunately expected to continue beyond the publish date of this report, and will continue to shape the economy in new and unpredictable ways. The District will continue to assess the impacts and adjust accordingly.

[11] https://www.utilitydive.com/news/epa-gives-power-plants-regulated-entities-pollution-compliance-flexibility/575103/

COVID-19's Effects on Load

In the short term, load has both decreased overall as well as changed in shape. So far, load is about 3-5% lower than what would be expected at this time of year given the weather. The shape of the load curve has adjusted so that there is a slower ramp to peak levels in the morning, and then a pattern of higher than normal level of energy usage in the afternoon. The curve shape is similar to what could be expected of a snow day. This is mostly caused by patterns in business closures and the effects of an increase in employees working from home, and as a result is more pronounced in areas of cities with high concentrations of offices and small businesses. Areas with high industrial concentrations, however, are not seeing the same effect.

Some portion of those who begin to work from home as a result of this crisis will never return to the office. Obviously, it remains to be seen the degree to which the load curve will remain shifted after America recovers from the COVID pandemic. In addition to office work, the COVID pandemic has caused a massive shift to homeschooling and remote medical treatment, and as the population becomes more comfortable with performing these activities remotely, it is increasingly likely that the shift in load will be sticky.

Fracking and Natural Gas

Prior to Coronavirus, gross production of Natural Gas in the US had continued to grow steadily since 2018, driven primarily by increases in production of shale gas. However, the COVID-19 pandemic poses a serious threat to the stability of the industry. Global demand for gas, while not impacted as severely as oil, is projected to drop by about 5% in 2020. This figure is still uncertain however, as each month spent in lockdown at April levels worldwide is projected to increase the drop by about 1.5 percentage points. On the whole, the debt-laden industry is expected to see a culling of firms in the shale industry that are unable to produce efficiently enough to remain in business.

Prices are projected to rebound by the fall, and even as oil prices reach all-time lows, many plant operators are avoiding the switch to burning oil instead of natural gas for generation. Many projects have seen delays in development as a result of the pandemic, but if the renewable sector is an indicator, these projects are only delayed temporarily rather than permanently.

The use of fracking has not been without its controversies. There is increasing evidence that the widespread use of fracking has adverse impacts on air, water, and the health of those living near fracking developments. Despite this, the current administration has extensively collaborated with the shale industry, and applications for permits to drill on public land have increased 300% due in part to regulatory rollbacks. This will continue to be a political issue for further observation in the future.

Electric Vehicles (EVs)

Around the world, automakers are ramping up their EV output and moving up their goals for electrified fleets. Many of the biggest names in the auto industry have raised their targets for electrified or fully electric vehicles. For example:

- Toyota plans to generate half its sales from EVs by 2025, moving up the target date from a previous goal of 2030.
- Volkswagen has said that it will meet its goal of 1 million EVs produced, two years ahead of the initially scheduled date.

- All of the cars sold by Honda in Europe will be at least partially electrified by 2022, beating earlier estimates of achieving this goal by 2025.
- BMW projects that EV sales will double from 2019 levels by 2021 and grow 30% annually until 2025.

Overall, Automakers are speeding their adoptions of EVs. Sales of EVs are projecting to grow in the coming years, and manufacturers are ramping up their ability to produce more electrified cars.

On the regulatory side, the EV industry has seen setbacks at a federal level, while seeing some states adopt laws that are favorable to the further proliferation of EVs. Federally, recent rollbacks of regulations have dealt a blow to the ability of EVs to compete with traditional vehicles on cost. Last month, the Trump Administration slashed the required increase in fuel efficiency from 5% annually to 1.5%. This move is forecast to reduce the price of traditional vehicles by up to 1000$. Not only will the adoption of EVs in the US be stunted, but the lack of domestic demand will set back American manufacturing of EVs in the years to come, placing them at a competitive disadvantage compared to foreign automakers that have faced stricter regulation for years.

Aside from the federal level, laws have been passed in some states that are much friendlier to the expansion of the market for EVs. For example, in New Jersey, legislation has passed this year putting forth an ambitious plan to spur the demand for and adoption of EVs in the state. Broadly, New Jersey has set a goal of 2 million EVs on its roads by 2035. The cost of EVs had dropped by 13% in the last year alone, however over the next decade New Jersey is offering additional rebates of up to $5,000 on new EVs. The state also plans to build infrastructure to support the anticipated surge in demand, planning to build 1,500 chargers across the state. The plan even includes a goal to electrify fleets of state-owned light duty vehicles and aims to extend this to heavy-duty vehicles given any advances in R&D for large vehicles. This has the additional benefit of saving taxpayer money on gasoline costs for state vehicles. The initiative undertaken by New Jersey is the most ambitious seen so far, but an early moving state can cause others to follow.

Corporate Procurement

The rate of adoption of corporate procurement has only accelerated since 2018. Relative to 2017 levels, the amount of onsite generation, corporate PPAs, and utility purchasing have all increased by about a factor of four. Previously, corporate procurement was concentrated in states with deregulated energy markets, however in recent years it has proliferated to states with regulated markets as more utilities offer green tariffs to their customers. The most growth in procurement has occurred in the northeast of the country.

A greater number of types of businesses are participating in procurement as well. In 2018, this trend was mostly limited to tech giants such as Facebook using procurement to meet aggressive sustainability targets. However, recently mid-size companies are looking to use procurement to meet renewable energy goals that are increasingly ambitious. As these practices become more widespread, more tools to ease the transaction costs associated with procurement become available, which serves to only increase the adoption of corporate procurement. Additionally, advancements in storage technology can boost the viability of onsite generation and procurement more broadly.

COVID-19 is expected to have little long-term impact on the adoption of corporate procurement. The main concern regarding procurement is disruption of supply chains and development as the pandemic runs its course. However, supply chains for renewable resources are resilient as a result of regulatory uncertainty surrounding tariffs in recent years, so it is unlikely progress will grind to a total halt. As business returns to usual, it is expected that development will resume smoothly, as the driving factor behind the adoption of procurement is its economics, which will remain solid after the pandemic fades. Storage is discussed in further detail below.

Coal

In 2018, coal had been recently surpassed by natural gas as the largest resource for power generation in the US. This trend has only continued, as the use of coal continues to decline, with some projections forecasting coal to make up less than 20% of the generation mix by 2020, and potentially below 10% by 2025 as wind and solar continue to increase their market share. As evidence, February 2020 marks the first time that renewable generation has surpassed coal generation in a calendar month.

In many states, there is still support for the coal industry from lawmakers. For example, Ohio residents are seeing their rates increase in order to keep the doors of two older plants open in the near future. IOUs, however, are shifting increasingly away from coal in the long term, both for economic and environmental reasons.

Many aging coal plants are being retired in the upcoming years, and this trend is only set to accelerate in the near future as Coronavirus depresses the prices of energy. Some plants are reaching their physical limits of coal storage and may need to stay operational over summer 2020, even at a loss, in order to decrease the excess stock. All of these factors point to a quickening of the pace of coal retirements in this year and the coming years.

Renewable Resources

Wind

Wind's rapid growth in past years may slow soon. Much of the geographic area which is viable for wind generation has already been saturated, and the high cost of transmission is a barrier for development in more isolated areas with conditions suitable for wind projects. As states push for higher amounts of renewable energy in the generation mix, it is likely that solar will outcompete wind as the renewable resource of choice. Supporting this is the fact that many of the most obvious technological advances that lower wind costs have already been achieved, such as improvements in design of wind blades and turbines.

Wind developers are also facing challenges posed by the ending of the production tax credit safe harbor window at the end of 2020. Delays caused by COVID-19 are causing many projects to be in danger of failing to qualify for tax credits, despite pushes by lobbyists to extend the deadline for credits in response to the pandemic. COVID also poses challenges to turbine maintenance, which generally must be done in teams which are being disrupted due to social distancing guidelines.

Prior to the outbreak of COVID-19, offshore wind had been expected to see an increase in demand in 2020 and beyond. While the pandemic introduces plenty of uncertainty to this prediction, some states have set ambitious offshore wind targets, such as New Jersey's goal of developing 7.5 GW of offshore wind by 2035, enough to power half of the state's homes. While the offshore wind industry is still relatively in its infancy, costs are dropping rapidly supporting the forecasted future development.

Solar

The proliferation of solar energy generation must be considered separately at the utility scale and at the residential scale. Residentially, the adoption of rooftop PV is quickening, and the technology, when paired with improvements to home energy efficiency and distributed storage, is making it increasingly easy for homes to achieve zero net energy. The expansion in use of rooftop PV is the major driver of projected stabilization of energy intensity of buildings, both commercial and residential. This combination of widespread proliferation of rooftop PV and improved energy efficiency is forecast to cause a 17% drop in total energy delivered to homes by 2050. This poses challenges to utilities that must recoup infrastructure related costs to customers practicing net metering, an issue that is covered in greater depth below.

It is worth noting the effect the Coronavirus will have on the demand for rooftop systems. In the short term, it is likely that there will be delays and cancellations of projects as it becomes difficult for installers to work together on jobs, supply chains are disrupted, and customers prioritize more essential purchases. However, in the long term it is expected that there will be an uptick in demand for distributed generation and storage. Analysts predict that in the aftermath of the COVID-19 pandemic, households will seek greater independence from the grid to provide security in the event of future crises, a pattern that is supported by consumer behavior following wildfires in California and widespread blackouts across the country. There is evidence already that storage firms may be more resilient than the rest of the industry – COVID related job cuts among these companies are far less severe than in clean energy more broadly.

At the utility scale, improvements in the economics of storage technology are resulting in the replacement of aging coal plants most frequently with solar and storage installations. Currently, there are about 40 solar plus storage developments across the country, offering about 1,200 MW of solar generation with 533 MW of storage capability. However, more than 80 projects are currently in development, which will add nearly 9,000 MW of solar generation and over 4,100 MW of storage.

Solar is expected to be at the forefront of growth in renewable energy jobs. Already, solar installation technicians had been one of the fastest-growing sources of employment in the US. However, the COIVD-19 pandemic is threatening the job gains that the sector has made over the last years. In March 2020 alone, the number of overall clean energy jobs lost is greater than the total gains across all of 2019. However, there is potential that future stimulus passed by the federal government will contain relief to the solar sector. Despite earlier packages failing to include support for the clean energy industry, there is optimism throughout the industry that stimulus for the clean energy sector will be a crucial part of recovery efforts in the coming months and years.

Net Metering

Utilities are still struggling to determine the best way to cover fixed costs associated with distribution to customers that utilize distributed generation resources. One proposed course of action has been to charge customers with solar installations a higher rate, however a rate plan similar to this was recently been struck down by the Kansas State Supreme Court. It is unclear whether a stance similar to this ruling will be applicable in other states, but the decision is indicative of the continued need to find a way to effectively balance incentives for consumers to adopt distributed generation and the need for utilities to cover their infrastructure costs.

Two plans to help find this balance are worth noting. First, as mentioned in the previously linked source, utilities are considering imposing a flat fee for all customers to cover distribution and other infrastructure related costs. This would solve some of the cost shift issues associated with solar installations. Alternatively, some states have instituted rules in which energy generated by distributed resources and sold back to the grid is compensated at the wholesale price rather than the retail price. While this has the effect of decreasing the financial strain on utilities, it has the side effect of decreasing the incentives to adopt distributed resources in the future. Again, this poses the challenge of balancing the adoption of distributed resources and the environmental benefits they bring with utilities' finances and the need to recover costs.

Energy Storage

In January of this year, the DOE launched an initiative to ensure that the United States is a leader in developing and manufacturing energy storage by 2030. Included in these efforts are measures to ensure that the US has access to domestic supply and manufacturing chains. This program is heavily reliant on the continued development of lithium-ion batteries, and a growth in domestic demand for these storage systems is a crucial component of the success of this program. Some states have passed initiatives of their own, such as Massachusetts, where legislation calls for 1 GW of additional storage to be built, leading to an increased proliferation of utility-scale solar projects.

Regulation and legislation, however, have not always benefitted storage technology in this way. For example, despite the efforts of the industry, there was no funding granted to battery development as part of the COVID-19 relief packages. In states like Texas, utilities are prohibited from owned large-scale battery projects. And even in more traditionally democratic states like New York, there have been difficulties installing batteries in compliance with safety regulations, especially when extra precautions are being taken following an explosion of a utility-scale battery in Arizona.

Regardless of regulation, however, the market for storage is forecast to grow up to 700% over the next 4 years. This is partially due to storage becoming part of transmission infrastructure, and partially due to the use of solar + storage to fill the gap left by the retiring of old, inefficient coal plants. Furthermore, storage can serve as a resilience measure in the events of wildfires in California or blackouts in New York. Following the COVID-19 pandemic, it is likely that there will be an uptick in demand for residential solar + storage systems as homeowners look to have backup energy in the event of another event such as this one.

Carbon Offsets

Carbon Offsets remain a nascent industry, however they are worth touching on due to the rapid projected growth in the sphere and potential role they could play in helping states reach carbon reduction targets. California, for example, has already begun to use offsets generated by Vermont forests in order to help the state reach its decarbonization goals. This extends to the private sector as well. Microsoft has invested in offsets to help the company become carbon neutral and intends to only act more aggressively in the coming years. The airline industry is also a large buyer of offsets, and the UN has recently released a set of rules guiding the purchase of Carbon Offsets by airlines. The fact that these guidelines have been released even in the midst of the COVID-19 pandemic demonstrate the UN's commitment to ensuring airlines have access to these products. All of these sources of demand for lead to projections that the market for Carbon Offsets could eclipse $200B by 2050, from a current value of just under $1b. This has potential to impact utility costs as the non-energy renewable attributes increase in value.

In terms of developing offset projects, the lion's share of the work so far has come from nonprofit organizations, with wildlife conservation being an issue equal in weight to decarbonization for some developers. For example, Nature Conservancy, a nonprofit, has recently acquired over 100,000 hectares of land in Tennessee, Virginia, and Kentucky that it intends to convert into a development for conservation and the creation of carbon offsets. The quality, scale, and variety of offsets are likely to improve as the industry grows and new participants emerge however, and potential future products could include the planting of trees, prevention of deforestation, and even subsidizing energy efficient appliances for consumers.

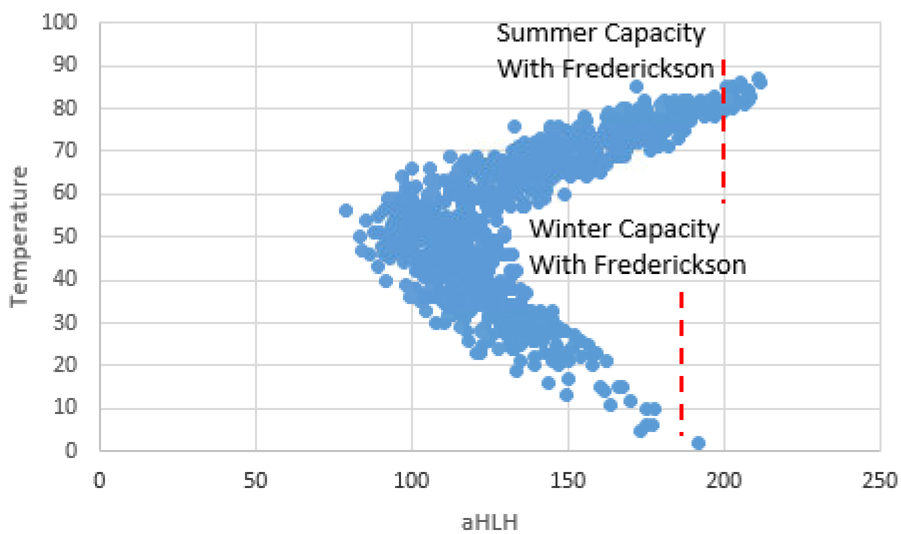
Chapter 7: Capacity, Requirements, Energy Storage, and Demand Response

An important aspect of an IRP is an accurate forecast of peak load and a resource plan to meet this load. Energy storage and demand response will be reviewed in this chapter in the context of meeting peak load. These resources can be used to make a variable resource firm, either within an hour or across multiple hours. Since the District is not a Balancing Authority, firming within an hour will not be addressed; however, the following will attempt to examine firming across several hours.

Peak Load and Capacity Position

As discussed in Chapter 3: Current Resources, the District is surplus energy from an annual load/resource basis; however, the District does have hourly capacity shortages when the demand exceeds the District's supply. Figure 27 charts the daily average temperature vs. the daily average HLH between 2017 and 2019. The red lines indicate expected summer and winter resources in 2021 with Fredrickson gas plant. Loads are generally the lowest during periods when the temperature is between roughly 50°F and 60°F. While periods of extreme heat or cold are both accompanied by higher loads, higher load periods come more frequently during the summer rather than the winter Figure 27.

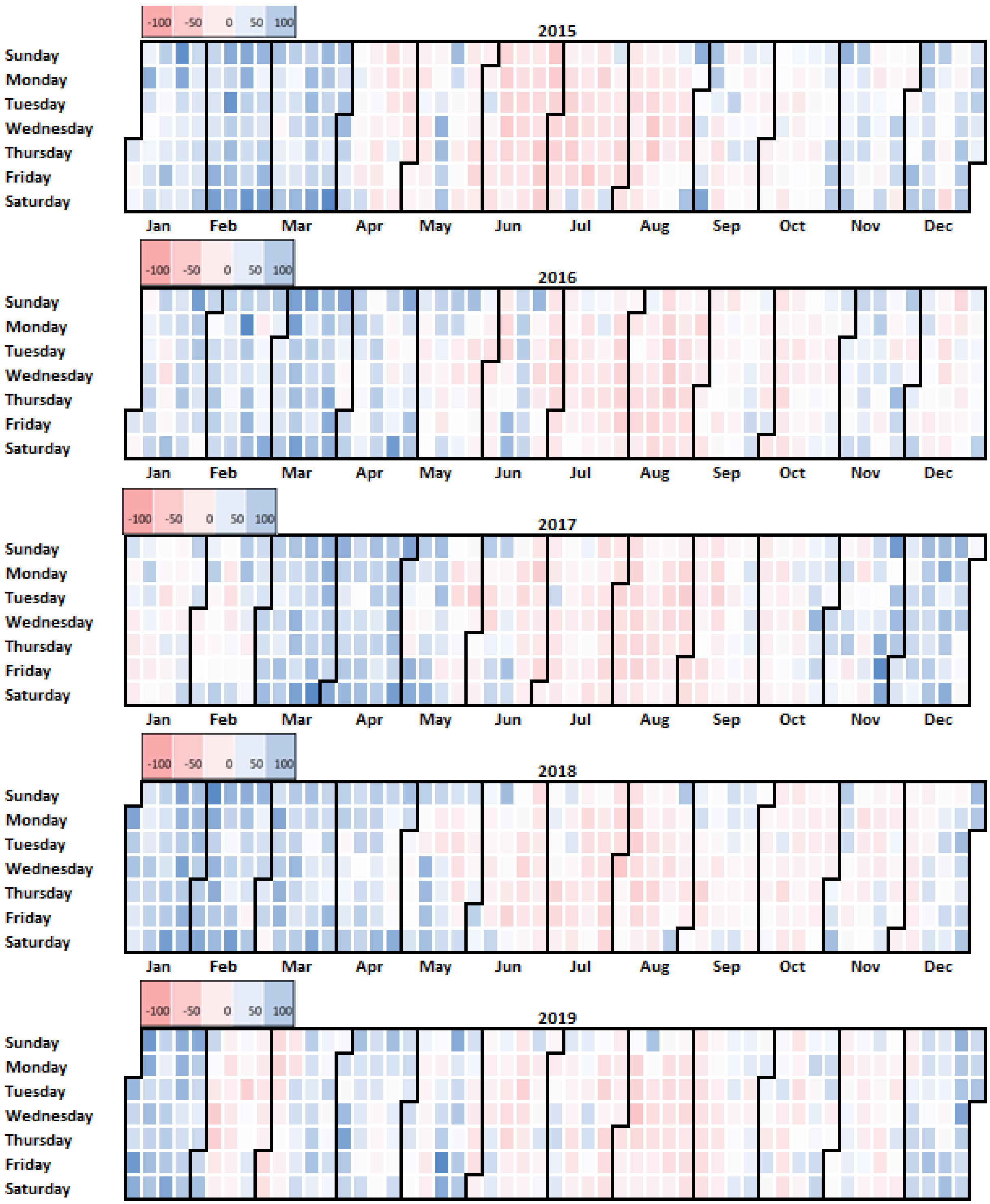
Figure 27: Daily Average Temperature vs. Daily HLH Average Load from 2017-2019



The highest load periods typically appear in June through August, though there are short periods of high loads during the winter months as well. The District currently has a summer peak generation capacity of 195 MW and 178 MW of peak winter generating capacity. This assumes a typical BPA system peak slice generation level of 10,500 MW (83 MW for the District) which can vary year by year and across seasons. Consistent with the BPA White Book analysis, this estimate excludes wind resources, which cannot be relied upon to generate electricity on demand due to their intermittent "fuel" supply. Compared to the highest peak demand and average heavy load hour (aHLH) loads observed in the last 5 years of 212 MW and 192 MW, respectively, the District's demand will exceed its supply during certain periods.

Figure 28 displays a theoretical net position of the daily peak demand hour that was calculated by applying the District's estimated peak generation capability to the actual loads observed between 2015 and 2019. Estimated peak generation capability is defined as the average peak generation available, by month, over the past five years.

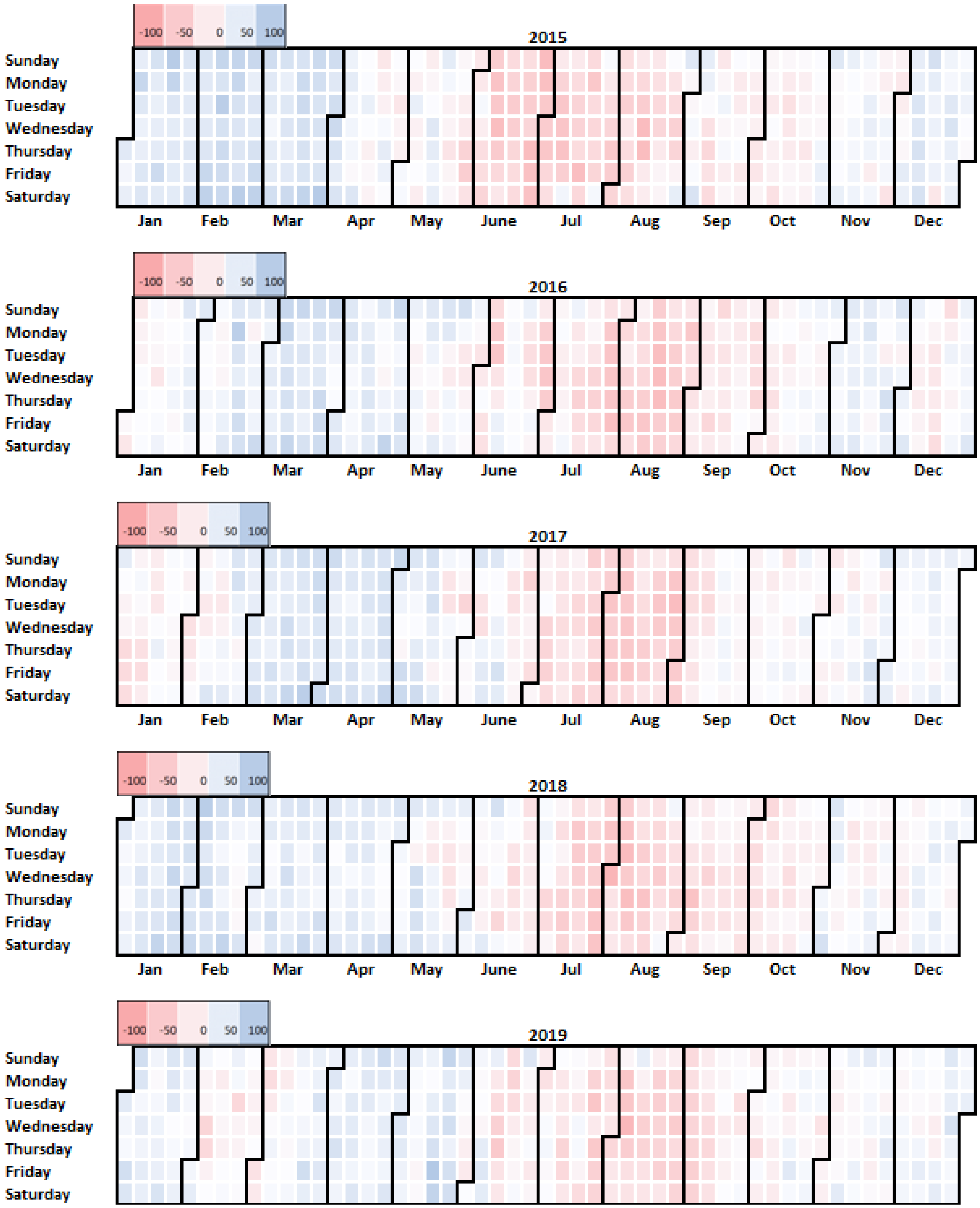
Figure 28: Daily Peak Demand Net Position by month with Frederickson



A majority of the capacity deficits occurred during the summer, with minimal deficit periods appearing in the winter. Most of the deficits were less than 30 MW. The largest deficit occurred in August 2019 when the peak hourly deficit was 65 MW. Summer capacity shortages are currently filled through fixed price power purchases from the market. Procurement of a physical asset to protect against capacity deficits will be evaluated in this IRP. When the 30 MW Frederickson PPA expires after the summer of 2022, the District can expect more frequent capacity deficits of a higher magnitude, though this has been temporarily offset through the summer of 2028 with the purchase of an outright 40 MW ATC (around the clock) Q3 physical firm purchase planned to expire in September 2028.

Figure 29 replicates Figure 28, but does not count Frederickson or any physical call option as a resource.

Figure 29: Daily Peak Demand Net Position by month without Frederickson or Physical ATC Purchase



Peak Load Analysis

Peak load definitions: Peak load and the capacity products and resources to meet peak load in the context of a resource plan can be defined in many ways and it is important to agree on definitions. The following will describe the different definitions and will recommend a definition to use in this plan.

Within hour peak load: This is the highest instantaneous and 5/15/30 minute integrated peak load that occurs within the month or year. BPA Transmission Services (BPAT) as the Balancing Authority (BA) is the entity obligated to meet this peak load. A Slice customer sets aside and is not able to access its share of about 900 MW to 1,300 MW of Slice capacity to allow BPAT to meet all its within hour requirements. This includes regulation, imbalance, and contingency reserves (spinning and supplemental). BPAT reimburses BPA Power (BPAP) for any revenues it receives from use of this capacity. Examples of revenues are regulation, imbalance charges (energy and generation imbalance, Variable Energy Resources Balancing Service (VERBS) and Dispatchable Energy Resource Balancing Service (DERBS) charges and Contingency Reserves. The Slice customer receives its share of these revenues as an offset to the Composite Charge.

BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). By virtue of purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves) and contractually giving up its share of capacity for within hour services, the District has handed over its obligation for these services to the BA and does not need to include capacity for these services in its capacity planning for the IRP. Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP. It should be noted that the discussions about a regional Energy Imbalance Market (EIM) are focused on this time period. BPA has completed a preliminary cost benefit analysis of joining the EIM that shows small net positive benefits.

Hourly peak load: This is the largest 60 minute load that historically occurs or is forecast to occur during a year, season, or month. It can be defined as the largest actual hourly load, the largest actual load that has occurred during a historical period, a forecast of the hourly load under extreme conditions, or the expected hourly load (i.e. hourly load expected to occur less than a given percentage of the time, for instance, less than 95% of the time). It is typical to identify the largest expected winter and summer hourly load for resource planning purposes (usually by choosing from actuals from a recent year, or a series of years or an extreme forecast). Figure 30 displays the hourly load for the summer and winter peak days from October 2011 through February 2020. The highest hourly winter peak has been 202 MW and highest summer peak has been 236MW.

Heavy load hour (HLH) peak load: This is the largest daily average load during the hours from 6 am to 10 pm on a NERC defined peak day that historically occurs or is forecast to occur during a time period. The time periods are the same as hourly peak load as is the discussion of largest and expected. The highest HLH winter peak has been 192 aMW and highest HLH summer peak has been 212 aMW.

Figure 30 displays the hourly load for the summer and winter peak days from October 2011 through February 2020. The highest hourly winter peak has been 202 MW and highest summer peak has been 236MW.

Figure 30: Winter and Summer Loads

Season	Hourly Peak	aHLH Peak
Winter11/12	169	155
Summer 12	215	189
Winter 12/13/	157	146
Summer 13	222	198
Winter 13/14	183	169
Summer 14	230	205
Winter 14/15	163	153
Summer 15	226	200
Winter 15/16	158	152
Summer 16	222	194
Winter 16/17	202	192
Summer 17	226	199
Winter 17/18	160	142
Summer 18	236	211
Winter 18/19	195	161
Summer 19	236	212
Winter 19/20	178	160
All Data	236	212
All Winters	202	192
All Summers	236	212

Determination of Peak Load for Resource Planning

There are several standard practices to determine which peak load to use in resource planning. First, one must determine whether to plan to serve the one-hour peak load or the HLH peak load. There are reliability issues and financial issues to consider. For a utility embedded within the BPAT BA, there is currently no requirement to demonstrate Resource Adequacy (RA) on a forecasted basis. The only requirement is to enter the hour of delivery with scheduled resources sufficient to meet the forecasted load. A required methodology to forecast the hourly load is also not required. This will likely change in the near future when the larger Resource Adequacy initiative discussed in Chapter 3 is finalized.

Since there is no local reliability issue associated with not having resources available to meet an hourly peak load and there has not been a cost effective resource option to meet that one-hour peak load, utilities often procure resources (or forward market products) to meet the HLH peak load and depend on the market and the BA for the one-hour peak load. Demand Response (DR) and Energy Storage (ES) are potential products for meeting some of the peak load and will be analyzed for their cost effectiveness as compared to the market along with conventional peaking resources.

Hourly peak load determination utilized by Organized Markets/Regional Reliability Organizations (RRO): Organized markets/RROs typically employ a Resource Adequacy (RA) requirement on Load Serving Entities (LSEs) within its footprint. The RA metric usually contains rules for determining peak hourly load and resource outputs. A survey of markets found the following requirements for determining peak load:

- Western Electric Coordinating Council (WECC): Forecast peak hour load increased by 18% to cover; contingency reserves 6%, regulation 5%, 4% for additional outages, and 3% for temperature variation.
- Northwest Power Pool (NWPP): Forecast peak hour load increased by 7-8% for Contingency and Regulation, by 3-10% for additional or prolonged outages, and by 1-10% to cover temperature (assume about 5% for this portion), economics, and new plant delays; this results in an 11-28% requirement.
- California Independent System Operator (CAISO): Forecasted hourly peak loads are increased by 15% to account for outages and contingencies . CAISO does not break out the load variation portion.
- Midcontinent Independent System Operator (MISO): Forecasted coincidental hourly peak loads are increased by about 8% for load variation and 7% for outages (contingencies).

Energy+Environmental Economics (E3) presented a report back in 2015 to the Public Power Council (PPC) summarizing Resource Adequacy (RA) and Planning Reserve Margin (PRM) (Figure 31):

Figure 31: E3 Summary of Approaches to RA

	Peak Demand in 2021 (MW)	Planning Criterion	PRM	Peak Season
Puget Sound Energy	7,000 MW	LOLP: 5%*	16% (2023 - 2024)	Winter
Avista	Summer: 1,700 MW; Winter: 1,900 MW	LOLP: 5%*	22% (14% + operating reserves)	Both
PacifiCorp	10,876 MW	LOLE: 2.4 hrs/ year	13%	Summer
Arizona Public Service	9,071 MW	One Event in 10 Years	15%	Summer
Tuscon Electric Power	2,696 MW	PRM	15%	Summer
Public Service Co. of New Mexico	2,100 MW	LOLE: 2.4 hrs/ year	Greater of 13% or 250 MW	Summer
El Paso Electric	2,000 MW	PRM	15%	Summer
Cleco	3,000 MW	LOLE = 1-day-in-10 yrs.	14.8%	Summer
Kansas City Power & Light	483 MW	Share of SPP**	12%**	Summer
Oklahoma Gas & Electric	5,500 MW	Share of SPP**	12%**	Summer
South Carolina Electric & Gas	5,400 MW	24 to 2.4 days/10 yrs	14-20%	Both
Tampa Electric	4,200 MW	PRM	20%	Both
Interstate Power & Light	3,300 MW	PRM	7.3%	Summer
Florida Power and Light	24,000 MW	PRM	20%	Both
California ISO	52,000 MW	LOLE: 0.6 hours/year	15-17%	Summer

* PSE and Avista use NWPCC criterion of 5% probability of shortfall occurring any time in a given year
** SPP uses 1-day-in-10 years or 12% PRM system-wide

There does not appear to be a single standard used in planning for load variations. However, it does appear that a general planning criteria for variation in load is in the 3-8% range. The other components of the standards are for contingencies, which as discussed above is not the requirement of the LSE.

E3 also provided recommendations for planning criteria:

+ **Each participant would demonstrate that it is resource adequate on a season-ahead basis**
  - Each participant is obligated to procure sufficient Certified Capacity to meet its regional obligation: share of regional 1-in-2 peak load plus PRM
    - Season-ahead showing to identify resources designated to meet assigned share of regional requirement
  - Participants could use their own resources or purchases of Certified Capacity from IPPs or other utilities
  - Participants that have excess capacity can sell Certified Capacity product based on Regional Entity rating to other participants
+ **Regional Entity role ends with season-ahead resource sufficiency demonstration**
  - BA operations unchanged

Approach used for peak load determination:

1. Examine the winter (December-February) and summer (June-August) actual single-hour daily peak load and daily HLH average load for December 2015 through Dec 2019 and determine the load associated with the given percentile.
2. Establish this value as expected winter and summer hourly and HLH peak load for the 1st year of the IRP (2021).
3. Use the annual growth in energy load as the annual growth rate for future years.
4. As shown below in Figure 33, using a P95 historical load results in higher peak planning loads than the approach suggested by E3.

Determination of peak load/resource balance, Slice and Frederickson treatment

Figure 32 displays the Peak Load scenarios studied to assess the District's peak load/resource balance. The 2030 values were derived by escalating the 2021 values by 0.54% per year, which is the District's 10-year forecasted annual energy growth rate. The "winter" scenario includes the months of December, January, and February. The "summer" scenario includes the months of June, July and August.

Figure 32: Peak Load Scenarios

	Peak Load (aMW)		
	Load 50th	Load 50th * 1.12	Load 95th
Winter Average HLH	123	138	154
Winter Peak	134	150	166
Summer Average HLH	169	189	199
Summer Peak	189	212	224
2030 Peak Load (aMW)			
10 Year AARG	0.54%	0.54%	0.54%
Winter Average HLH	130	146	162
Winter Peak	141	158	175
Summer Average HLH	178	200	210
Summer Peak	199	223	236

Figure 33 represents the expected resource output during peak events for both summer and winter, across the HLH period and the hourly peak. These are the forecasted peak resources that the District is expected to generate. The Slice values were determined by internal hydro planning and operations staff.

Figure 33: Forecasted Peaking Resources

	Expected Resources			
	Slice	Block	Fredrickson	Total Resource
Winter Peak 2021	83	65	30	178
Summer Peak 2021	83	82	30	195
Winter HLH Average 2021	71	65	30	166
Summer HLH Average 2021	71	82	30	183
	Slice	Block	ATC Purchase	Total Resource
Winter Peak 2025	83	65	0	148
Summer Peak 2025	83	82	40	205
Winter HLH Average 2025	71	65	0	136
Summer HLH Average 2025	71	82	40	193

Figure 34 shows the one-hour peak resource generation over the winter and summer months. Peak slice generation is assumed to be 10,500 MW at the system level, which equals 83 MW of generation for the District.

Figure 34: Peak Resources

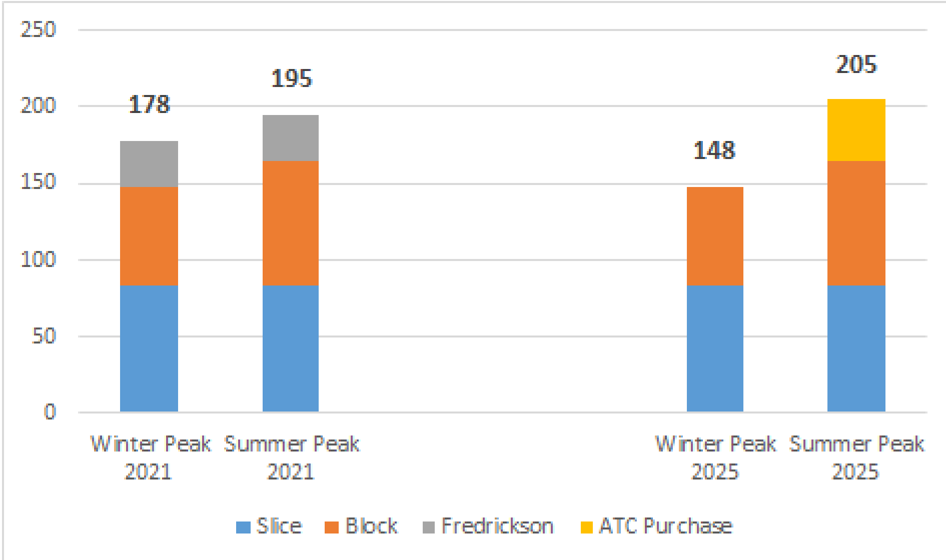


Figure 35 shows the monthly average HLH planning net position when using the P95 HLH average load using current resources with Frederickson, without Frederickson, and without Frederickson but including an outright 40 MW ATC Q3 purchase. Actual loads from January 2015 – December 2019 were used to assess the P95 load scenario. For winter months, the P95 value was based on December, January, and February. For summer months, the P95 value was based on July and August. A small capacity shortfall remains after the energy purchase in the summer months, but a larger shortfall exists in the winter without Frederickson as a resource.

Figure 35: Monthly HLH Average Planning Net Position Using Historical P95 HLH Load

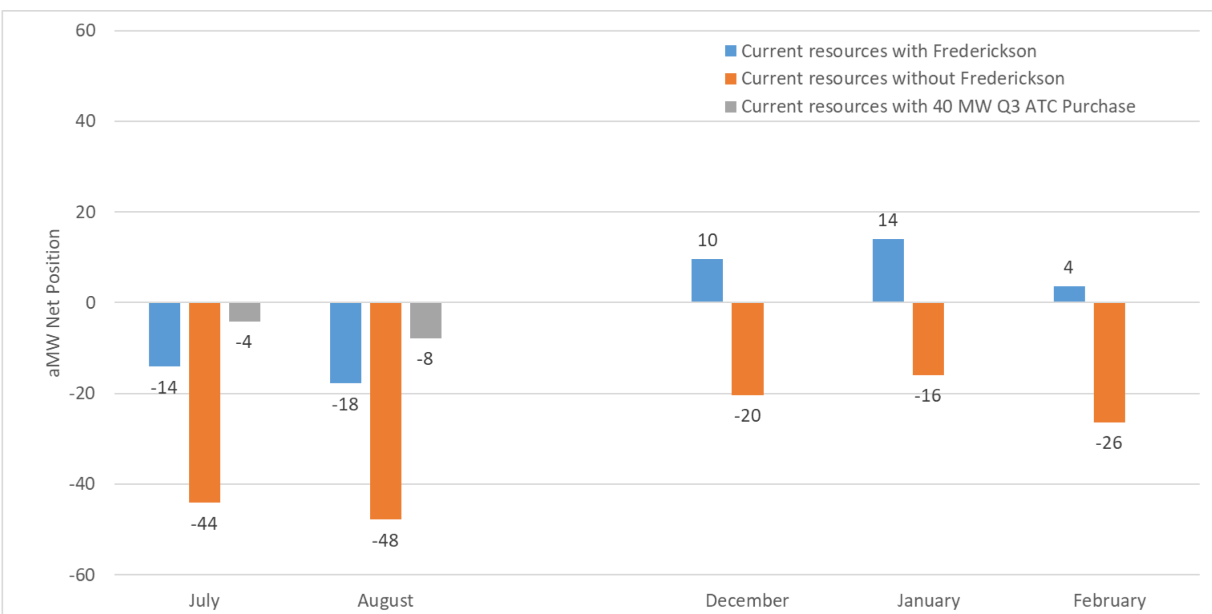


Figure 36 shows the monthly single-hour peak planning net position using a 12% planning reserve margin based on P50 loads. Using this approach, a similar small capacity shortfall remains in the summer months with a 40MW ATC contract, but only a small winter shortfall exists.

Figure 36: Monthly Single-Hour Peak Planning Net Position Using a 12% PRM with Historical P50 loads

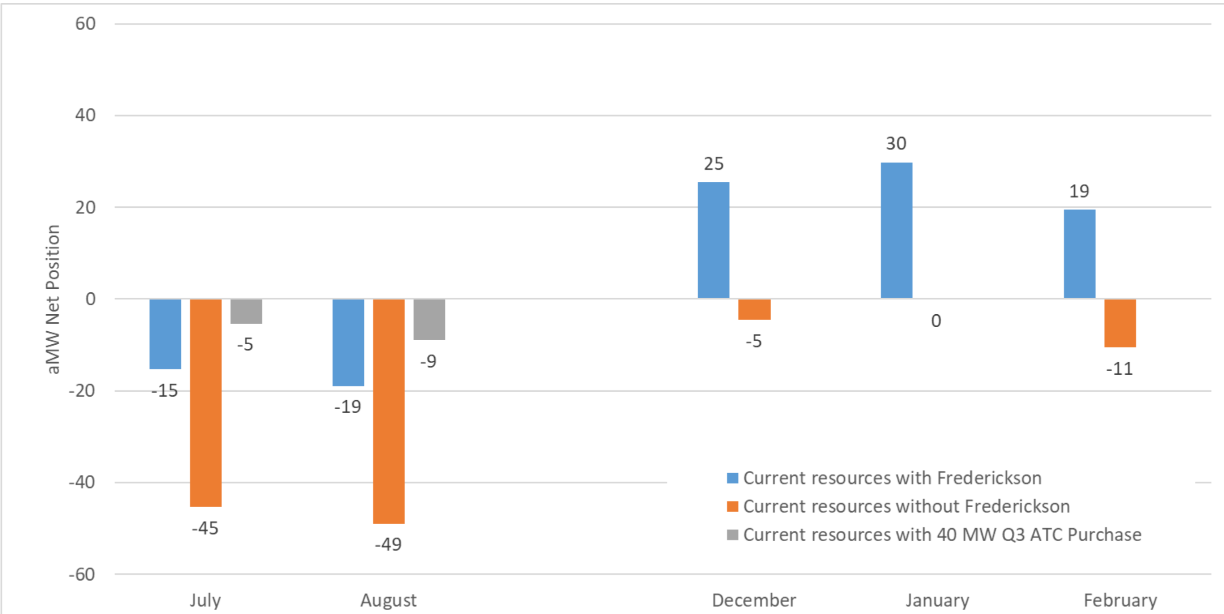


Figure 37 shows the annual summer load-resource balance using P50 summer hourly peak and a 12% Planning Reserve Margin (PRM). This P50 value was calculated using the peak hour of every summer period from 2015-2019 as opposed to the average HLH value shown above. Note that capacity shortfalls is minimal in the years covered by the 40 MW ATC purchase (2023-2028), but are almost 50 MW when adding on the PRM starting in 2029. Figure 39 tells a similar story when looking at P95 HLH average loads.

Figure 37: Annual Summer Single-Hour Peak Load-Resource Balance Using a 12% PRM with Historical P50 Summer Loads

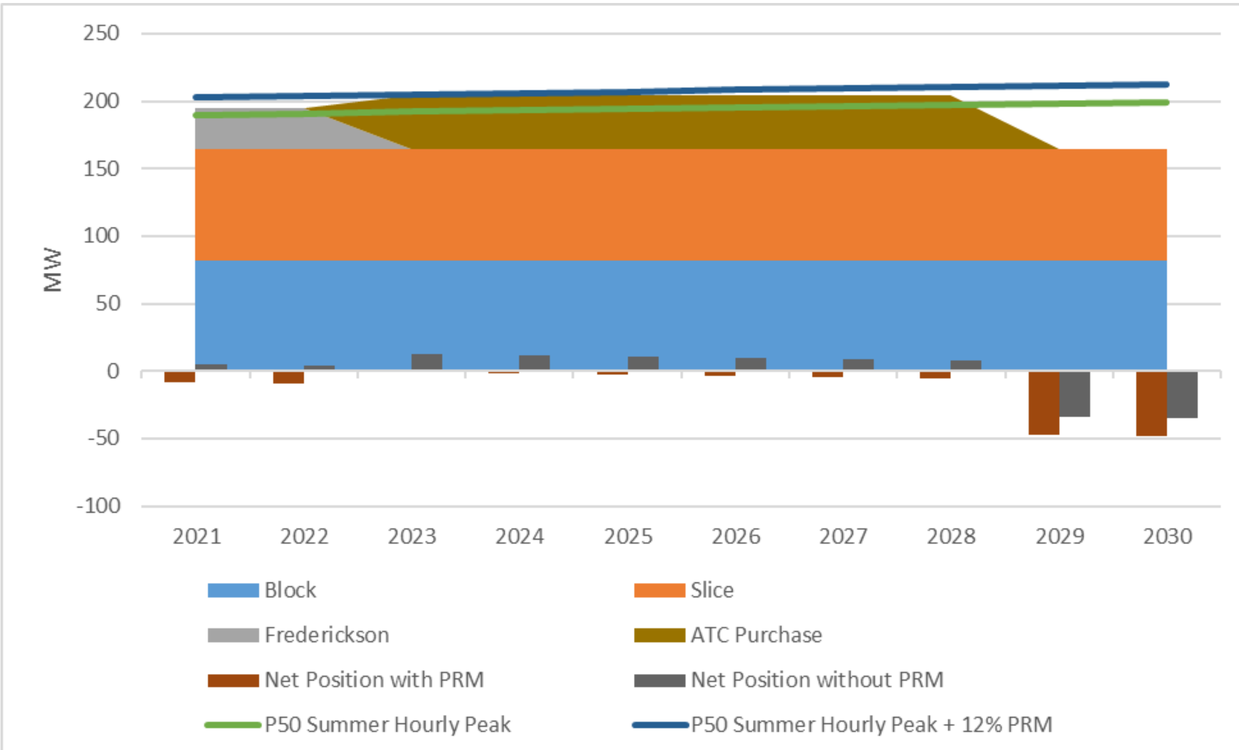


Figure 38: Annual Summer Peak HLH Average Load-Resource Balance Using Historical P95 Summer HLH Load

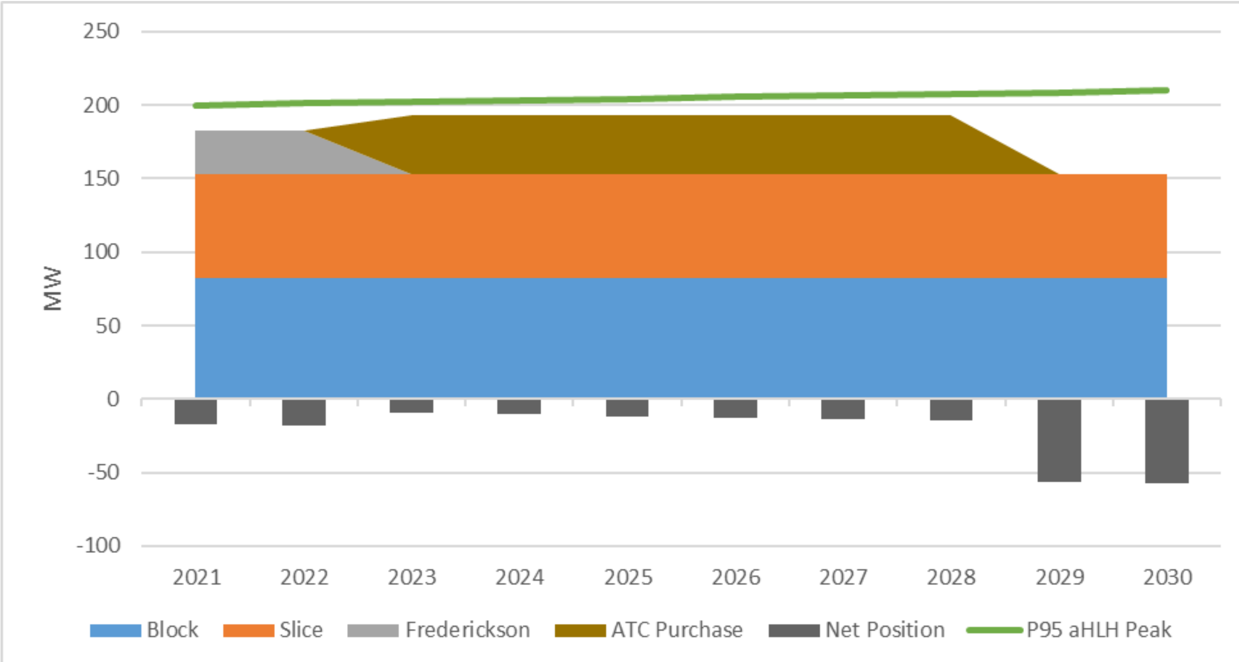


Figure 39 shows a historical view of the districts daily heavy load hour profile from 2015-2019, showing the frequency of days in which average HLH load reached certain levels.

Figure 39: Daily Peaks sorted annually

Events	Daily aHLH Load (MW)				
		171-180	181-190	191-200	200+
Annual	2015	22	15	13	3
	2016	13	10	7	0
	2017	29	21	8	2
	2018	15	8	7	12
	2019	27	20	4	4

Figure 40 shows the Summer and Winter Peak events that have occurred over the last seven years. The District's biggest concern is around Summer since the peak can often be 50 aMW higher than the Winter peaks.

Figure 40: Summer Hourly Peak and HLH Average

Events	Month			
		June	July	Aug
Daily aHLH Load (MW)	140-150	24	9	10
	151-160	26	21	15
	161-170	35	19	39
	171-180	16	38	39
	181-190	14	31	29
	191-200	7	20	11
	200+	2	13	6

Events	Month			
		June	July	Aug
Daily Peak Load	170-180	17	15	18
	181-190	28	23	26
	191-200	16	30	37
	201-210	10	30	18
	211-220	13	19	25
	221-230	2	15	7
	230+	1	6	4

Figure 41 shows a similar look for winter. Note that there are much fewer dates with extreme loads in the winter compared to the summer.

Figure 41: Winter Hourly Peak and HLH Average

Events		Month		
		Dec	Jan	Feb
Daily aHLH Load (MW)	140-150	17	10	11
	151-160	5	4	9
	161-170	2	4	2
	171-180	1	6	0
	181-190	0	0	0
	191-200	0	1	0
	200+	0	0	0

Events		Month		
		Dec	Jan	Feb
Daily Peak Load	170-180	4	4	1
	181-190	1	4	1
	191-200	0	1	1
	201-210	0	2	0
	211-220	0	0	0
	221-230	0	0	0
	230+	0	0	0

Resources to Serve Peak Load

There are several approaches to the determination of a resource mix to serve peak load. Each of these will be analyzed with its pros and cons.

1. Market purchases above what is needed for energy in the IRP, including physical options with 1-5 year terms
2. Demand response and energy storage
3. Build a NG peaking resource (based on BPA's generic peaker resource in the BP-20 rate case)

Market Purchases

Buy what is required above the IRP preferred resource mix: The IRP will determine resources needed to meet annual energy load over multiple years. Rather than procuring additional resources to meet the peak load value, one option is to continue current practice to buy from the market as needed. This has the advantage of only buying what is needed, without a resource sitting idle much of the year. This approach includes the use of buying daily physical HLH call options in advance of the start of a winter or summer month. Hourly peak load needs would be bought in the real time market.

With both forward natural gas and power market prices very low, this option is likely to be found to be the least cost in the screening process because it assumes that market power will always be available. There are regional indicators on whether this is a good assumption. The Council performs a Resource Adequacy Assessment (RAA) which determines a Loss of Load Probability (LOLP). The 2018 analysis indicated a regional annual expected LOLP of below 5% through 2020, increasing to 6.9% in 2023 as displayed in Figure 42, when several large coal plants are scheduled to shut down (Figure 44). This increased to 8.2% by 2024 in the 2019 study displayed in Figure 43.

Figure 42: NWPCC 2023 LOLP Assessment

Table 2: 2023 Loss of Load Probability (LOLP in %)

Import (MW)	1500	2000	2500	3000
High Load +2%	14.3	12.1	10.1	7.8
Medium Load	11.0	8.6	6.9	5.1
Low Load -2%	8.0	6.4	4.9	3.5

Figure 43: NWPCC 2024 LOLP assessment

Table 1: 2024 Loss of Load Probability (LOLP in %)

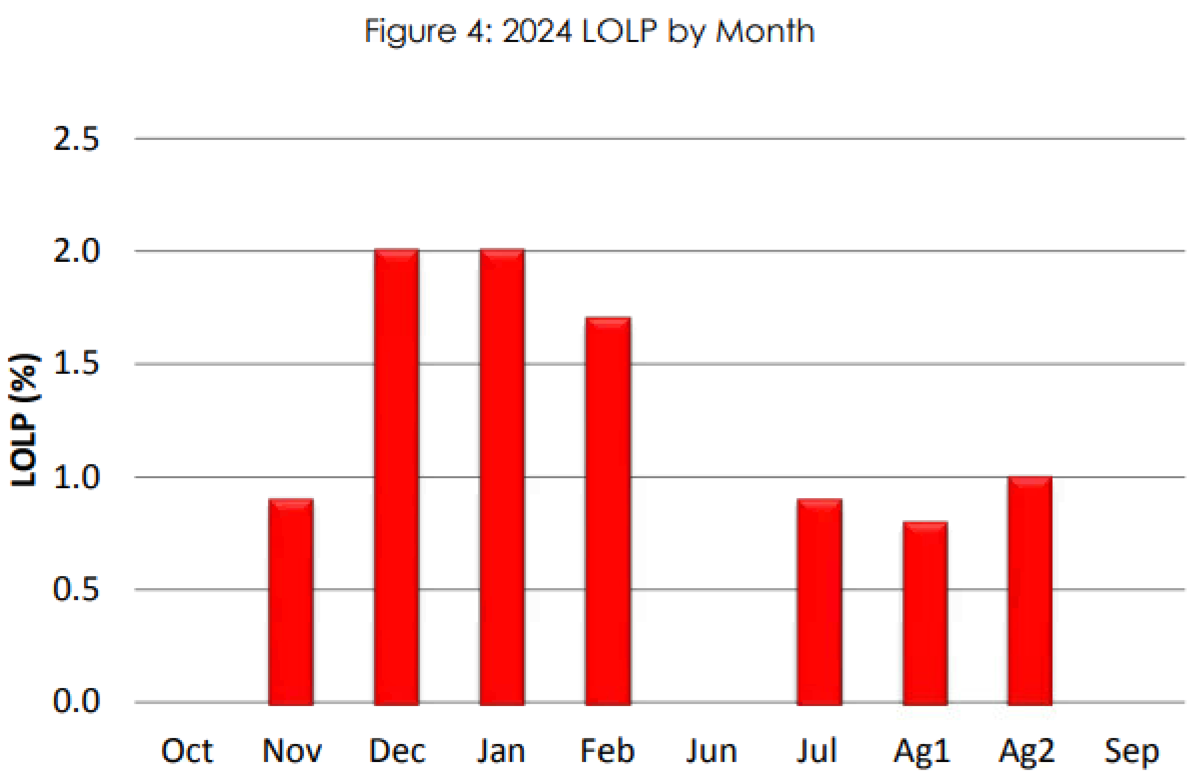
Import (MW)	1500	2000	2500	3000	3500
High Load (3% higher)	21.1	18.0	16.0	14.4	12.0
Medium Load	12.5	10.2	8.2	6.9	5.2
Low Load (3% lower)	7.0	5.2	4.0	3.1	2.0

Figure 44: Major coal plant projected retirement dates

Major Coal Plants Serving the PNW	Nameplate Capacity (MW) Serving PNW	Reference Case Retirement Dates (EOY)	Updated Retirement Dates (EOY)
Hardin	119	2018	
Colstrip 1	154	2019	
Colstrip 2	154	2019	
Boardman	522	2020	
Centralia 1	670	2020	
N Valmy 1	127	2021	
N Valmy 2	134	2025	
Centralia 2	670	2025	
Bridger 1	530	2028	2023
Bridger 2	530	2032	2028
Colstrip 3	518	TBD	2027
Colstrip 4	681	TBD	2027
Total	**4,809**		

The analysis provides LOLP for both summer and winter and assumes no imports from outside the region from April through September. As seen below, the monthly assessment is less than 2.0% in all months through 2024. The updated analysis shows a low LOLP for the summer (Figure 45).

Figure 45: NWPPC Monthly LOLP Summary



Buy forward (5 year +) physical daily fixed-price call options or daily heat rate (HR) call options: The Frederickson contract is essentially a physical HR call option. It provides a fixed HR, but still leaves exposure to natural gas price and supply risk. (These risks are currently managed by the District's Risk Management Committee using approved hedging products over a three year time horizon). After this contract expires, similar products, with shorter terms and fixed charges, could be examined. Electricity call options do not leave exposure to natural gas prices but cost more on a per unit basis. Both of these options can be procured as physical or financial products. The LOLP should provide some insight into whether a physical option is desired. These options could be for the entire HLH deficit or some portion, with the balance left in the short term markets.

There is likely an interesting dynamic at play here. In the short term the LOLP is likely to be 5% or less, with studies showing a future state when it begins to increase. Major Northwest IOU's will likely monitor this dynamic and begin to plan new resources for the future periods when LOLP is higher. The District may find that the LOLP is never greater than 5% in the prompt year or prompt year plus one to five. Therefore, the District could plan to purchase a forward call option for 3-5 forward years, but never need to actually purchase the product if it finds the LOLP moves back to 5% in this medium term.

Staff Concerns about Market Purchases for Peak Load

During regional meetings, staff has heard from a number of other electric utilities that they all are currently relying on the market for energy and capacity needs. Since that is the preferred portfolio from previous IRPs and likely the least cost, least risk portfolio and so many other utilities are relying on the market, concerns related to the availability of the market during worse than average scenarios are increasing. Staff asked TEA to explore a number of regional documents and analysis to determine if any or all would indicate a high risk of using market purchases to meet peak load. TEA explored the following:

1. PNUCC Northwest Regional Forecast
2. BPA White Book
3. CA ramping needs to meet the solar ramp (duck curve)
4. NW IOU dispatchable resource build out plans from most recent IRP

Pacific Northwest Utilities Conference Committee (PNUCC) Northwest Regional Forecast (NRF)

The NRF[12] indicates in Figure 46 a greater need for capacity in the winter months, starting with a 2,000 MW shortfall in 2021 that grows to over 7,100 MW over the 10-year period. If average hydro conditions are included, the region has no capacity constraints for many years after 2021 due to the additional 4,000+ MW of above critical water generation. Figure 46 also indicates a potential summer capacity constraint starting in 2022 if average hydro conditions are not observed.

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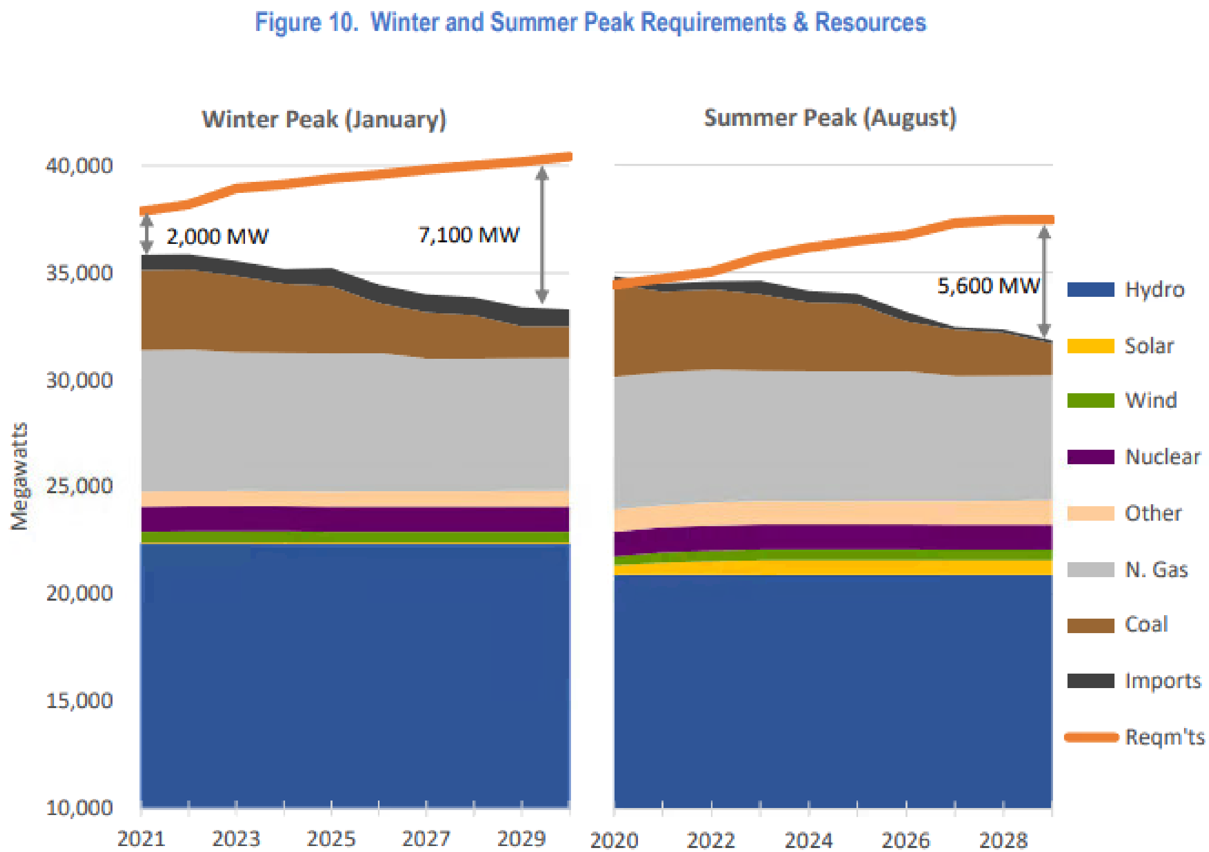
12 https://pnucc.org/sites/default/files/Xdak24C14w3677n7KsL43OEL4J25MW0b3d5cmx3FGD4d9OQ3B189OF/2020%20PNUCC%20NRF_0.pdf

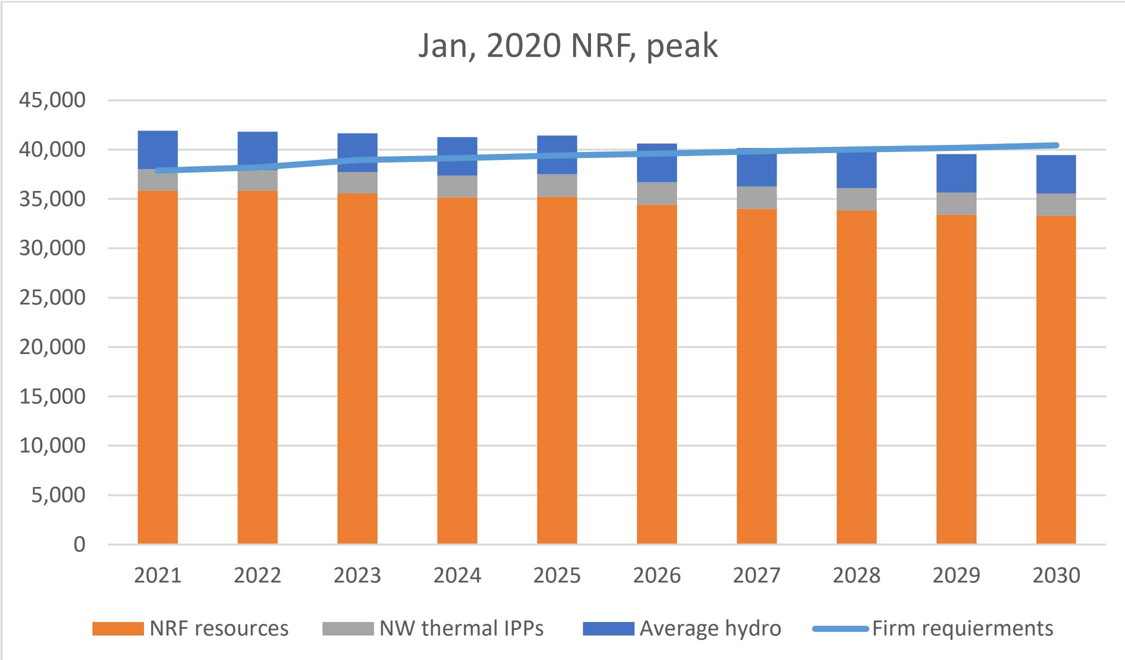
Figure 46: PNUCC Region-wide Winter and Summer Peak Capacity



Analysis of Regional Studies of Winter Loads and Resources

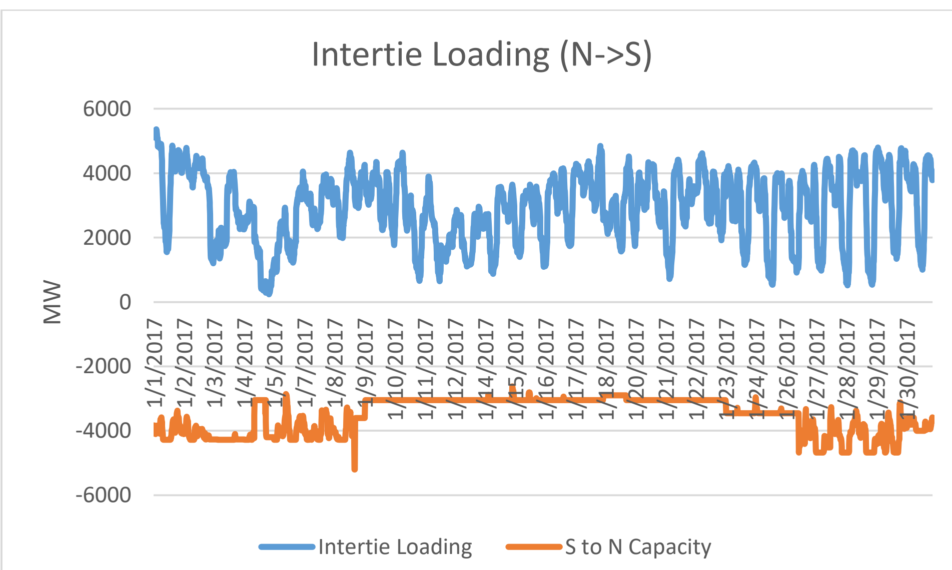
Since the NRF shows large deficits during winter peak events, additional analysis was performed to better understand the regional picture. IPP resources and average hydro are added to the NRF resources in Figure 47. As stated previously, the District is near Load/Resource (L/R) balance during a winter peaking event so the results of the NRF are less concerning.

Figure 47: PNUCC NRF January Peak L/R Balance



The NRF also omits imports (which the NWPPC does include in its LOLP analysis). As can be observed in Figure 48, significant import capability is available in the winter, even when regional load is peaking.

Figure 48: Pacific NW/SW Intertie Loading in Winter

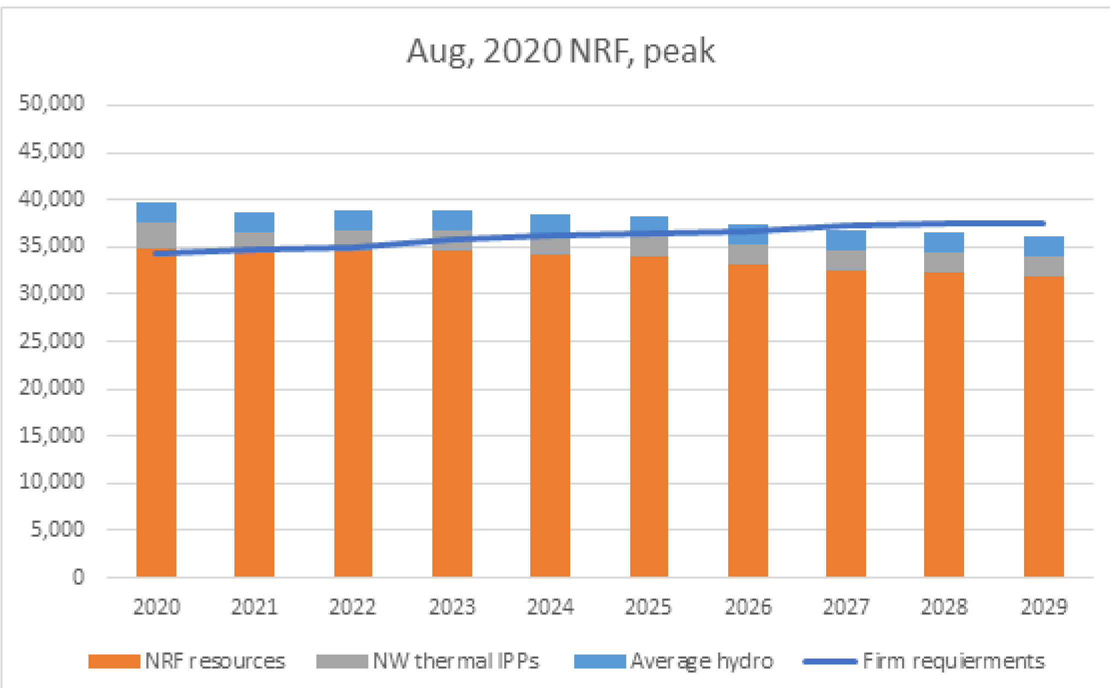


CAISO's winter peak is typically 30 GW, with 40 GW of thermal capacity (plus renewables). However, while the thermal capacity units are currently available, they are becoming uneconomical to operate due to regulatory policy. Retirement of thermal units in CAISO could remove valuable import related resources from the resource stack.

Analysis of Regional Studies of Summer Loads and Resources

PNUCC and BPA suggest the region may be short during a winter or summer peaking event. The Pacific Northwest Utilities Conference Committee (PNUCC) Northwest Regional Forecast (NRF) summer load resource chart excludes regional IPP's not contracted by NW utilities, hydro generation above critical, and imports from CA. When IPP resources are added to the analysis, the region shows a surplus during the summer peak through 2025 as can be observed in Figure 49. In addition, if average hydro generation is taken into account, the region shows a surplus through 2026.

Figure 49: PNUCC NRF Summer Peak L/R Balance



As mentioned above, the NRF analysis does not include imports from California. The Council's LOLP analysis includes small amounts of imports, as California loads are also peaking in the summer. As can be seen in the following chart, even during summer peak days regionally, large amounts of power are still flowing to California from the northwest region. Although the District could be competing with California entities on the price of power during peak summer days, Figure 50 indicates that power is available from an adequacy perspective.

- Though power will not physically simultaneously flow in both directions, bidirectional flows can be and are often scheduled concurrently

- TEA believes that the long-term power delivery commitments to California will not materially affect regional capacity
    - Almost exclusively renewable/carbon-free power deals which in TEA's experience have flexible delivery arrangements

Figure 50: Pacific NW/SW Intertie Loading in Summer

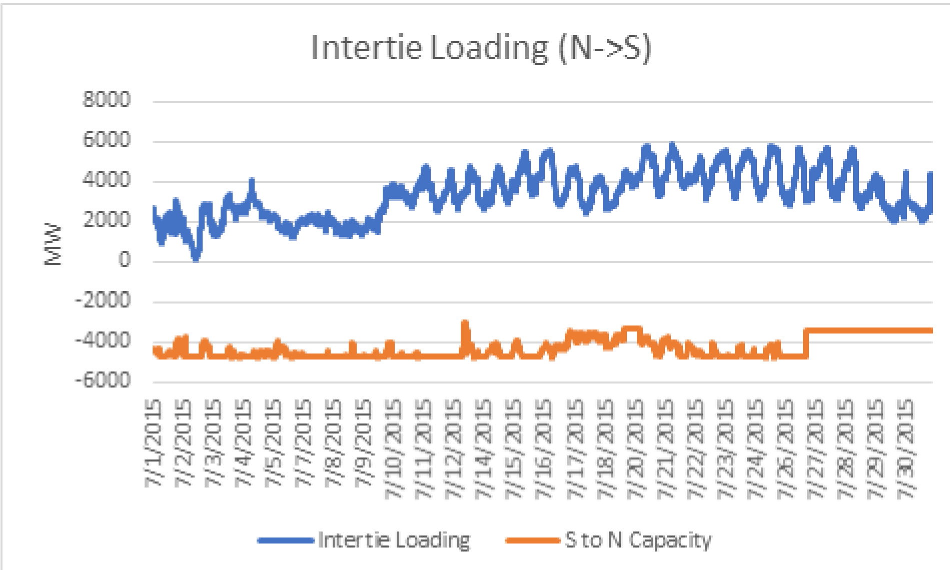
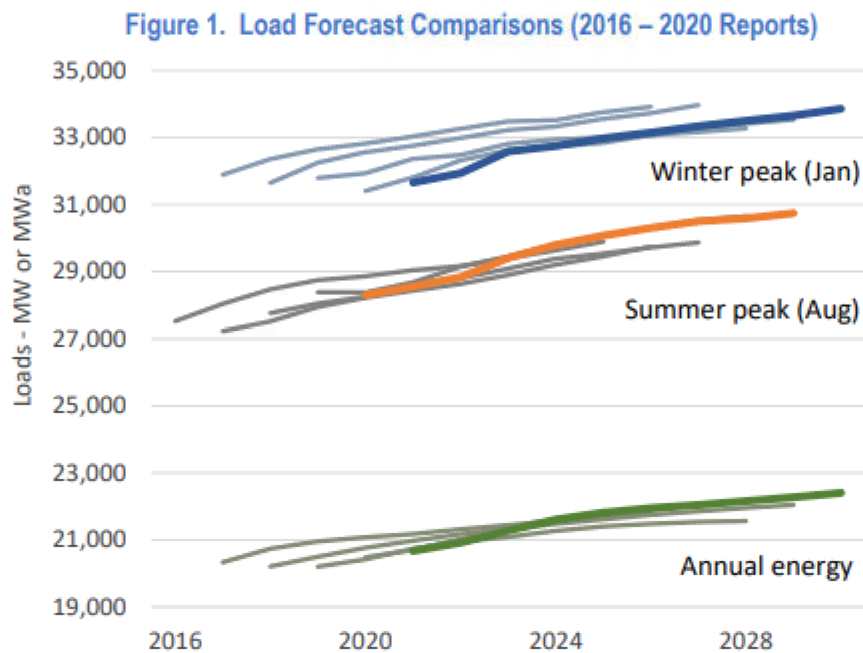


Figure 51 also notes that looking at past reports, firm annual energy and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply. This trend is not found in the summer peak forecasts which continue to trend as expected.

Figure 51: PNUCC 2020 NRF Region-wide Annual Energy Forecasts (Gray indicates previous forecasts)



BPA White Book

The "BPA 2018 Pacific NW Loads and Resources Study" also known as the White Book had the following key assumption changes from the 2017 version (Figure 52):

- Continue to have average energy surplus each year
  Larger winter capacity deficits exist across the study period, with no imports assumed; under average water conditions, however, the PNW region has capacity surpluses throughout the study period

Figure 52: BPA White Book Energy and Capacity Surplus/Deficit

Table 3-9

PNW Region
Annual Energy Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2020 through 2029
1937-Critical Water Conditions

Energy (aMW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2018 White Book	4,058	3,141	2,303	1,637	1,750	1,416	965	614	579	403
2017 White Book	4,032	3,017	2,372	1,721	1,779	1,347	918	505	465	n/a
Difference *(2018 WBK – 2017 WBK)*	*26*	*124*	*-69*	*-85*	*-28*	*69*	*47*	*109*	*114*	n/a

Table 3-12

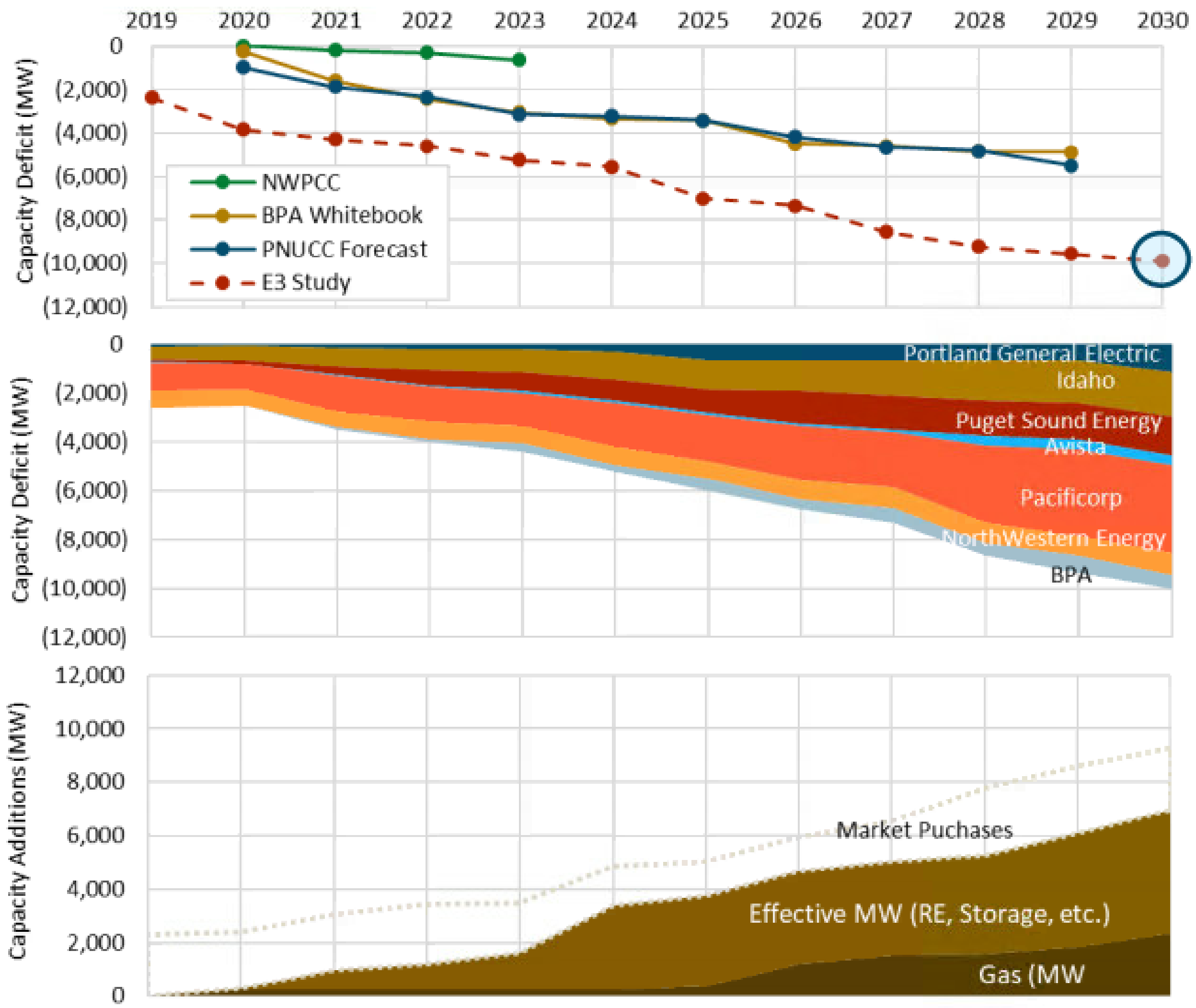
PNW Region
January 120-Hour Capacity Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2020 through 2029
1937-Critical Water Conditions

January 120-Hour Capacity (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
2018 White Book	-246	-1,588	-2,456	-3,056	-3,337	-3,436	-4,482	-4,589	-4,866	-4,891
2017 White Book	308	-1,185	-1,666	-2,331	-2,599	-2,840	-3,765	-4,019	-4,175	n/a
Difference *(2018 WBK – 2076 WBK)*	*-553*	*-404*	*-791*	*-725*	*-738*	*-597*	*-717*	*-570*	*-692*	n/a

Summary of NW IOU Resource Procurement Plans in most Recent IRPs

Figure 53 below shows a summary of projected annual capacity deficits and additions for BPA and Investor-Owned Utilities (IOUs) based on their most recent IRPs. As one can see, the region is facing potentially serious capacity shortfalls that will need to be addressed in the near future, as the planned capacity additions are not equal to the expected deficits.

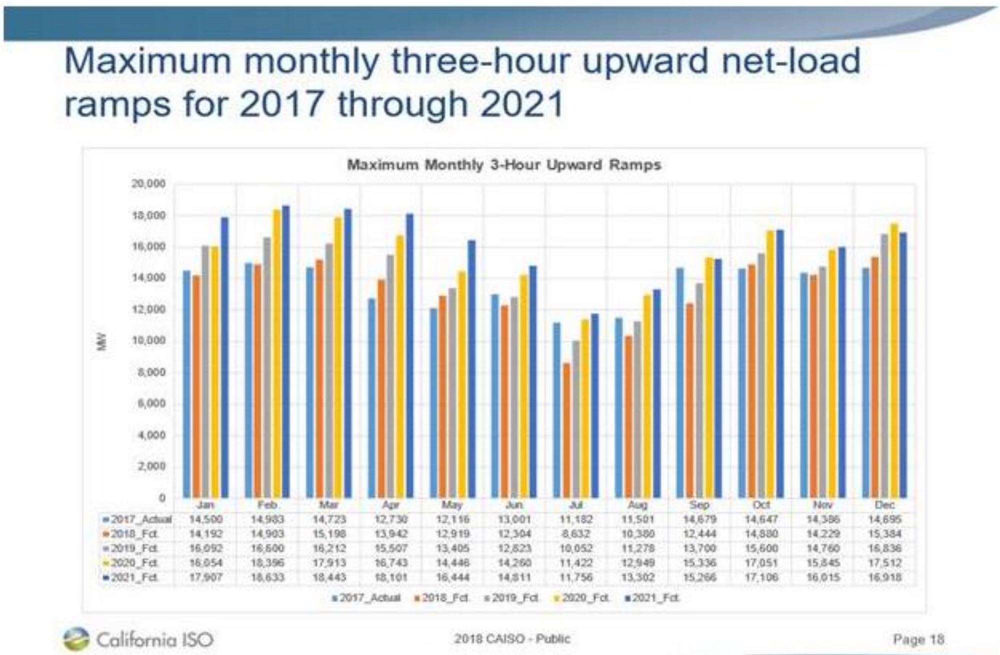
Figure 53: E3 Summary of Regional IOU IRP Capacity Deficits and Additions

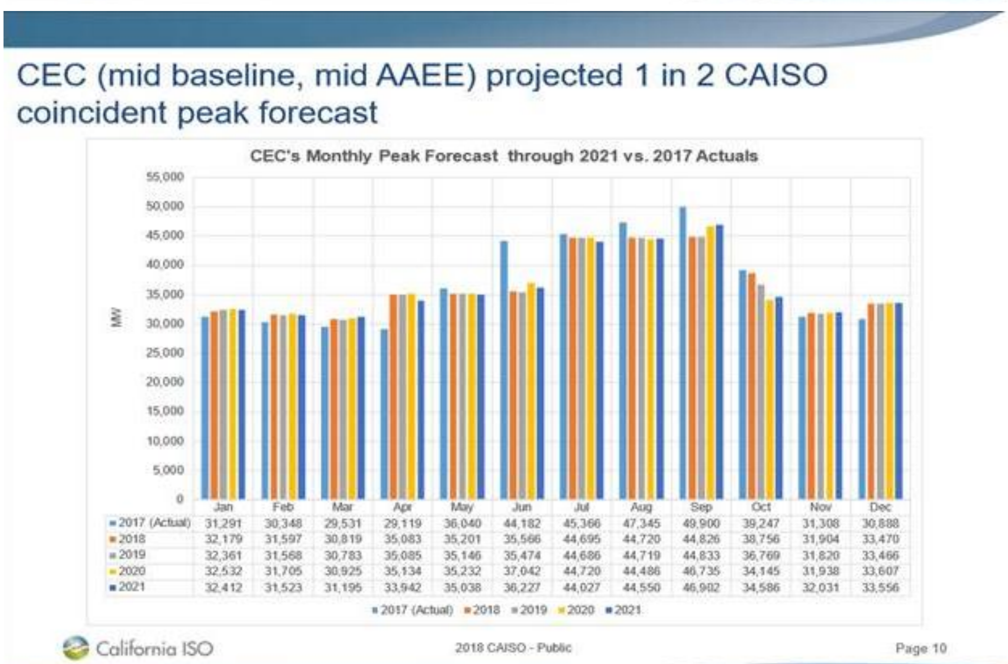


Summary of Impacts of CA need for Ramping due to Solar

Could the need in CA for ramping resources due to the solar "Duck Curve" impact the ability to access market resources to meet the District's summer peak load? CAISO has recently analyzed the monthly ramping need. As noted in the following charts, CAISO's summer peak is decreasing and their need for ramping resources are at their minimums in the summer months (Figure 54).

Figure 54: CAISO Net Load Ramps and Peak Forecast





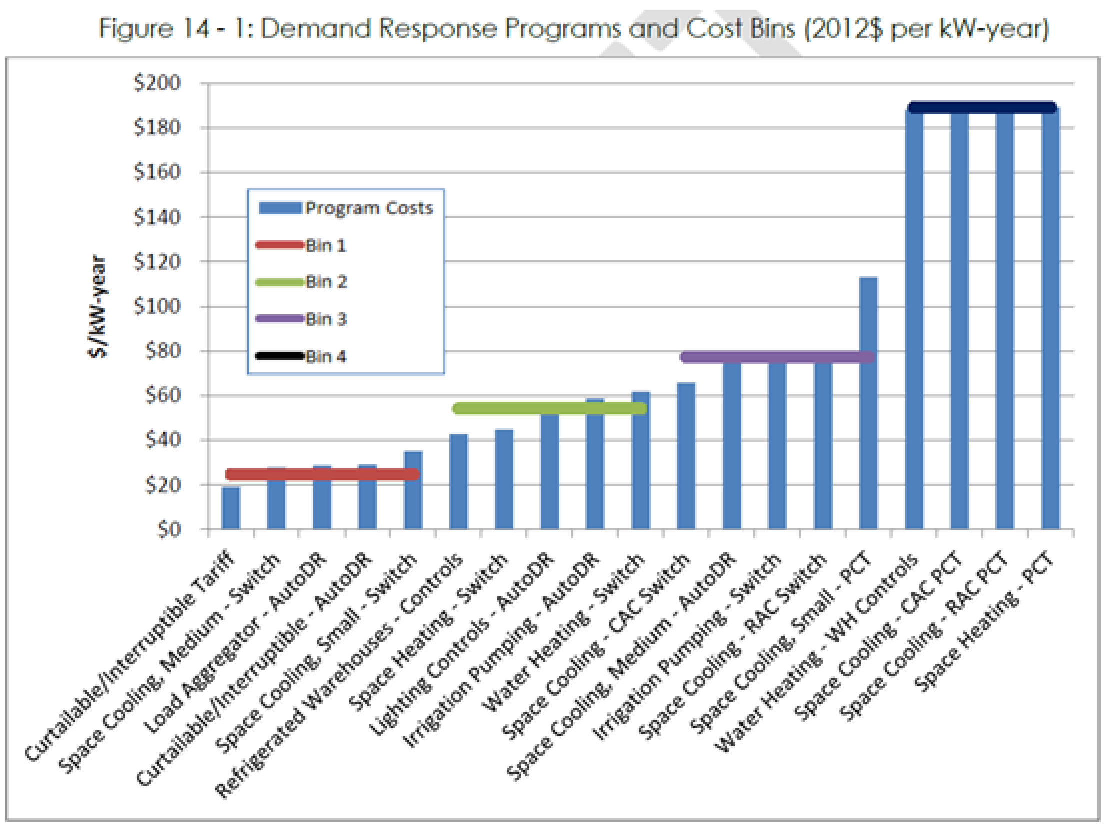
Summary of Above Discussion of Staff Concerns with Market Purchases for Peak Load Service

The depth of the market when loads are peaking on both the District and regional levels is thought to be diminishing as the region continues to grow and peak loads increase due to electrification. However, given both the District's current expected capacity position, and the timing of its expected peak loads, the IRP team believes with high confidence that it will be able to serve its load during peak periods until a region-wide RA standard is adopted in the near future. The discussion surrounding RA and LOLP, along with overall situational awareness of market availability, will continue to be monitored closely. The District will consider taking further action and pursue physical resources (including front-office transactions linked to physical resources) to meet its needs if LOLP projections rise above 5% in the one to two-year time horizon.

Demand Response (DR)

DR is best suited for meeting the hourly peak load deficit. In the Northwest Power and Conservation Council's 7th Power Plan, Demand Response (DR) was thoroughly reviewed and determined to be a cost-effective resource to meet peak load. The Power Council's 7th Plan determined the results for various DR programs as outlined in Figure 55. Since actual program implementation costs are unknown, it is assumed that DR could be implemented at the District for costs as displayed in Figure 55.

Figure 55: Seventh Northwest Power Plan's Estimated Cost of Demand Response



DR will continue to be evaluated and is addressed as an action item in Chapter 10: Action Plan Summary.

Energy Storage

Advancing energy storage technology to the point where it can be economically used as the backup resource to renewable energy could solve the current paradoxical situation. The storage system would be charged using surplus renewable energy, or during periods of low demand and released when demand increases, supply decreases, or both. Current research is diversified among many different technologies which explore storing potential energy in flywheels, compressed air, pumped storage, and even in trains parked at the top of a hill. The technology poised to dominate the market, at least in the near term, is battery storage.

Battery storage systems are not a one size fits all solution and the system design varies significantly depending on its desired function, whether it's for renewable integration, peaking, frequency regulation, or transmission congestion.[13] Building a battery storage system to absorb excess renewable generation for later use requires more infrastructure than a battery system used for short-term frequency response. Imagine an island grid powered only by solar and batteries. The battery bank will require a capacity that can store enough energy when the sun is shining to meet its demands at night. If that island grid also had backup generators on standby as a part of its generation mix, those could increase production when a cloud unexpectedly blocked the sun. The battery storage system then would be relied on for a much shorter burst of energy to maintain grid stability until the generators take over. The costs for the first option are greater, perhaps even significantly more than the second option. Battery technology, however, is evolving at a rapid pace. The development of battery packs in recent years can be attributed primarily due to investments into research and development from the automotive industry. The solar industry utilized technology from the semiconductor industry in its evolution earlier in the century and the energy storage sector is expected to leverage battery technology from other industries such as automotive development of electric vehicles.

The cost of battery packs declined from $1,000/kWh in 2010 to $350/kWh by 2015.[14] Battery capacity for the upcoming generation of electric vehicles dropped to $145/kWh as displayed in Figure 56, arriving at that price point 15 years ahead of current forecasts.[15][16] Energy storage will continue to be evaluated and is addressed as an action item in Chapter 10: Action Plan Summary.

13 "Lazard's Levelized Cost of Storage Analysis Version 1.0." Lazard. Web. 11 June 2016

14 Bandyk, Matthew. "Battery Storage Mandates Could Become Policy Norm, Report Says." SNL. N.p., 10 June 2016. Web. 14 June 2016.

15 Cole, Jay. "LG Chem "Ticked Off" With GM For Disclosing $145/kWh Battery Cell Pricing." Inside EVs. 23 Oct. 2015. Web. 30 May 2016.

16 "BNEF: Wind, Solar to Grab Majority of Power-sector Investments." SNL. N.p., 15 June 2016. Web. 15 June 2016.

Figure 56: Cost of EV Batteries

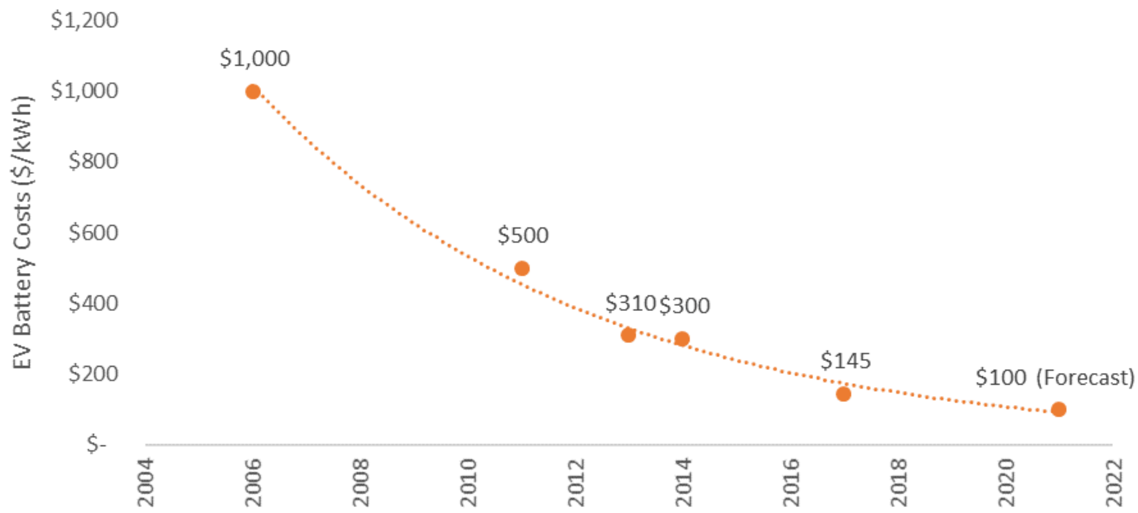


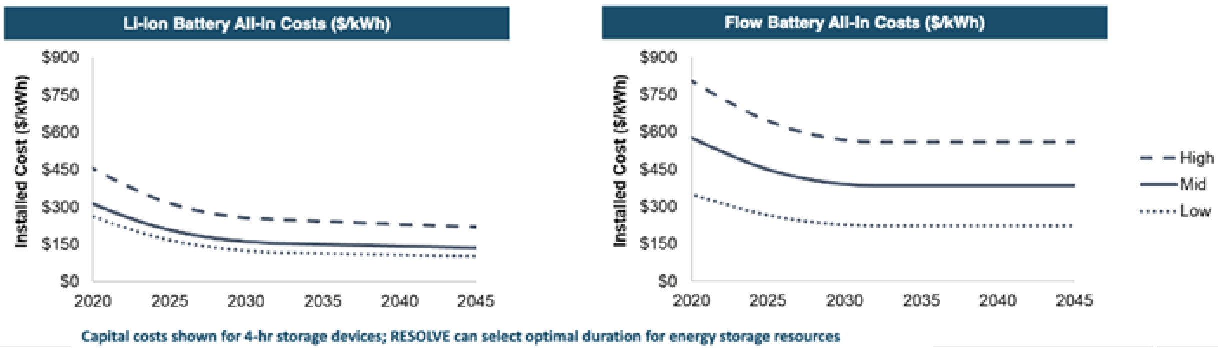
Figure 56 is a forecast of electric vehicle battery cost, which are forecasted to decline by 85 percent in six years, and seemingly follows a similar cost trajectory as wind and solar. Exponential cost declines continuously exceed the pace of forecasts along with higher than forecasted rates of adoption. Whether and how long this trend will keep its pace is unknown. However, it is relatively certain that technology will continue to advance and costs will continue to decline.

Tesla is one company that is leveraging their experience in the EV market to enter into the residential market. Most notable for manufacturing EVs, Tesla is also offering lithium-ion battery home and utility-scale energy storage systems at a cost between $350 and $600/kWh, excluding installation.[17] Energy storage systems are costlier than the batteries alone due to balance of system costs that include bi-directional inverters that allow the two way flow of batteries, software, and other integration costs to ensure seamless operation regardless of energy source, whether it's from the grid, solar panels, or battery packs. There are few case studies available to determine the actual cost of battery storage systems. Puget Sound Energy's Glacier battery storage pilot project tied several thousand lithium ion batteries together and created a 4.4MWh system with a 2MW instantaneous power delivery rating. The total costs of the system are unclear, with at least $3.8 million funded through a grant from the Washington State Clean Energy Fund plus additional investments from PSE.

E3 provided estimates of battery storage system costs in their Carbon Markets analysis (Figure 57)

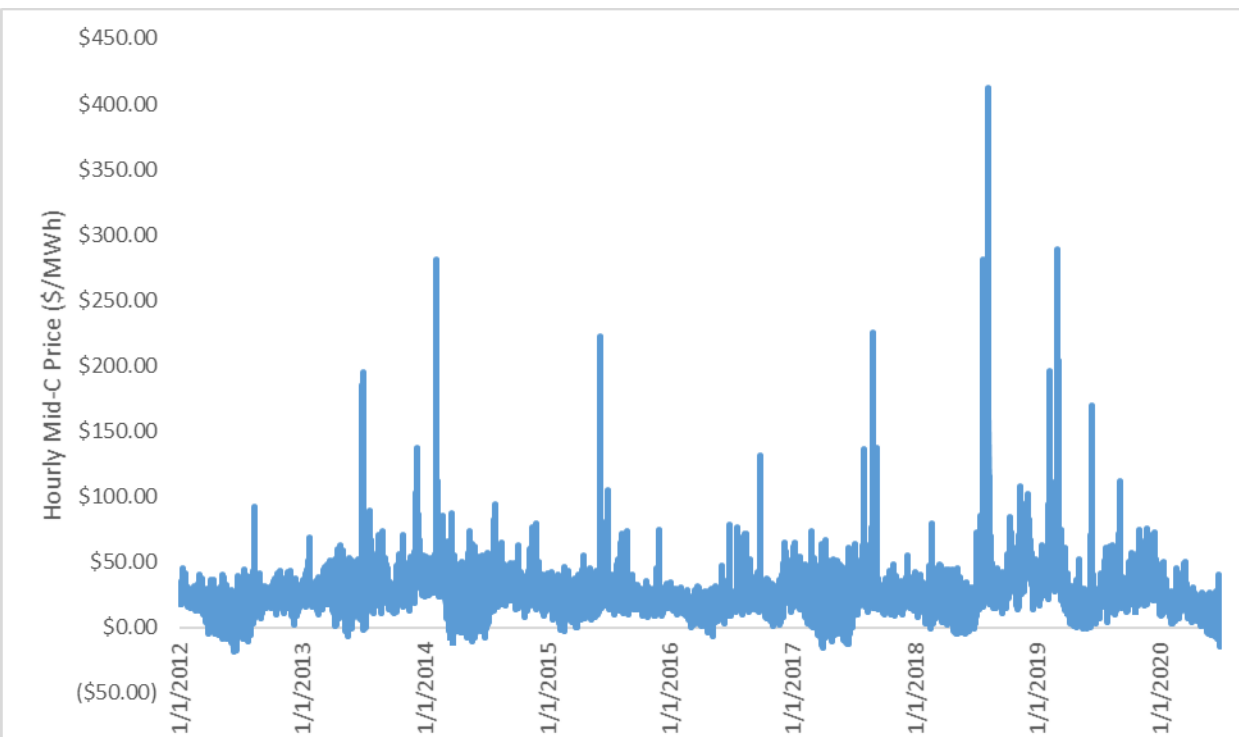
[17] Lambert, Fred. "Tesla Opens Direct Orders of up to 54 Powerpacks and Reveals Pricing." Electrek. N.p., 22 Apr. 2016. Web. 16 July 2016.

Figure 57: E3 Assumptions on Battery Costs



Storage is estimated to cost a minimum of $200/MWh on a levelized basis, reaching as high as $1,000/MWh.[18] An analysis of five year historical wholesale market data (Figure 58) reveals that there are very few hours and even fewer days where batteries are cost competitive.

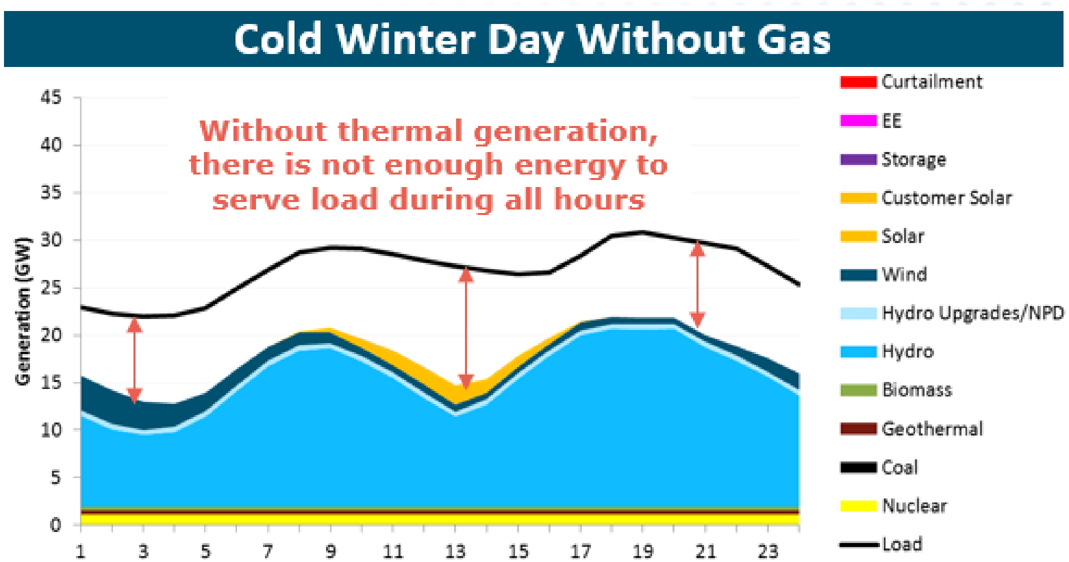
Figure 58: Hourly Mid-C Power Prices Through Time



[18] ibid

E3, in a presentation at the NW Power Markets Conference, performed analysis of using renewables plus battery storage to meet load in the Northwest. E3 concluded that renewables plus batteries alone is not sufficient to meet load on a cold winter day (Figure 59).

Figure 59: E3 Analysis of Meeting NW Load with Renewables plus Battery Storage



Wholesale market prices would need to sustain levels of $200/MWh or enter periods of extreme volatility in order to make an economic argument for the inclusion of battery storage with costs at this time.

The IRP team conducted a stochastic analysis of market prices under various gas price, carbon price, load growth, and carbon restricted scenarios. The results indicated that energy storage, in its current form, would not be economically viable within the current study period. The caveat, though, is that energy storage technology is still immature; the technology will not remain static, it will only improve, and costs will inevitably decline. At this moment though, there are few data points available to extrapolate out a forecast of when energy storage will become viable. Costs will need to decline significantly if they are to compete on the wholesale energy markets.

Simple Cycle Combustion Turbine

Another resource for meeting peak load needs is a simple cycle combustion turbine (CT). A CT can typically start on shorter notice than a combined cycle turbine and has less required up and down time. Given this flexibility, the CT can be used to meet peak energy needs. The analysis in the BPA rate case will be used as a proxy for the cost of a CT (Figure 60). Note the capacity cost is $123.42/kW/year. If 50 MW were desired from this resource, the annual cost would be about $6M/year.

Figure 60: BPA Demand Rates

Table 4.1
Demand Rates

	A	B	C	D	E	F	G	H	I	J
1				**Calendar Year**	**Chained GDP IPD**		**Month**	**Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2020		2013	101.76		Oct	23.84	9.25%	$ 11.42
3	Cost of Debt	3.94%	/1	2014	103.68		Nov	25.19	9.78%	$ 12.07
4				2015	104.79		Dec	28.09	10.90%	$ 13.45
5	Inflation Rate	1.64%		2016	105.94		Jan	25.24	9.80%	$ 12.10
6	Insurance Rate	0.25%	/2	2017	107.95		Feb	24.36	9.45%	$ 11.66
7				2018	110.38		Mar	19.19	7.45%	$ 9.19
8	Debt Finance Period (years)	30	/2				Apr	17.98	6.98%	$ 8.61
9	Plant Lifecycle (years)	30	/2		101.64%	5-year Ave.	May	11.71	4.54%	$ 5.60
10							Jun	10.52	4.08%	$ 5.04
11	Plant in service 2020 Vintaged Heat Rate Btu/kWh	8,541	/3				Jul	21.45	8.32%	$ 10.27
12				Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 26, 2019			Aug	25.24	9.80%	$ 12.10
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.17	/3				Sep	24.86	9.65%	$ 11.91
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 45.76	/3						**Average $/kW/mo**	**$ 10.29**
15	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2020$	$ 46.90								
16	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2020$	$ 52.12								
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2020$	$ 49.51								
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2020$	$ 42.29								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,139.06	/4	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
21	Fixed O&M $/kW/yr 2020$	12.53	/5	2020	$ 1,120.08	$65.39	$ 12.53	$ 2.80	$ 42.29	$ 123.01
22	Fixed Fuel $/kW/yr	$ 42.29		2021	$ 1,082.11	$65.39	$ 12.74	$ 2.71	$ 42.98	$ 123.82
23									**Rate Period Average Expense $/kW/year**	**$ 123.42**
24										
25	[/1] Source BPA FY 2019 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
26	[/2] Source NWPCC 7th Power Plan Appendix H.									
27	[/3] Source NWPCC Microfin Model, Version 15.0.5									
28	[/4] Source NWPCC Microfin Model assumption of $1000/kW in 2012$, with 100% PUD ownership at 3.94% with plant in service 2020.									
29	[/5] Source NWPCC Microfin Model assumption of $11/kW/yr in 2012$.									

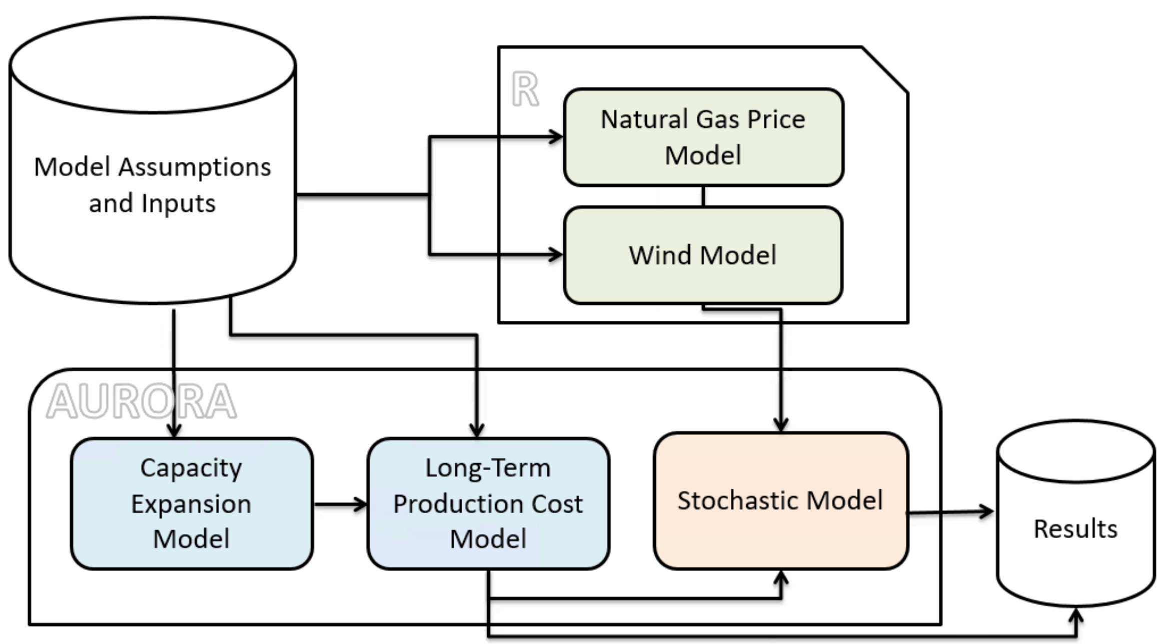
Chapter 8: Market Simulation

Methodology Overview

Approach

The electricity price simulation is created by several fundamental models working in concert. Figure 61 provides an overview of the process used to create the price simulation. The progression can be broken down into four principal phases. In the first phase, fundamental and legislative factors were modeled and integrated, including carbon penalty assumptions, load forecasts, and regional renewable portfolio standards. The second phase of the study uses the inputs from the first step to run a capacity expansion analysis. The capacity expansion model optimally adds hypothetical resources the existing supply stack over a 10-year time horizon. In the third phase, long term runs are performed using the modified supply stack to simulate market prices for all of the Western Interconnect utilizing a production cost methodology. In the final phase, the same modified supply stack is used to create a stochastic simulation of price, fuel and hydro generation variables. This section will describe the price simulation in further detail.

Figure 61: Modeling Approach



Model Structure

The main tool used to determine the long-term market environment is Aurora. Originally developed by EPIS, Inc. and now offered by Energy Exemplar LLC, Aurora simulates the supply and demand fundamentals of the physical power market, and ultimately produces a long-term power price forecast. Using factors such as the economic and performance characteristics of supply resources, regional demand, and zonal transmission constraints, Aurora simulates the WECC system to determine an adequate generation portfolio, constrained by the limitations of the transmission network, that work together to serve load. The model simulates resource dispatch which is used to create long-term price and capacity expansion forecasts. The software includes a database containing information on over 13,600 generating units, fuel prices, and demand forecasts for 115 market areas in the United States.

The District utilized Aurora for four main purposes:

1. To determine a long-term deterministic view of resource additions and retirements
2. Establish an expected long-term forecast price
3. To analyze corresponding stochastic results of market behavior around the expected price forecast
4. Perform scenario analysis on the expected price forecast by changing key inputs and assumptions

The District created or utilized reputable third-party forecasts of key variables, such as regional load growth rates and planning reserve margins, natural gas prices, hydro generation, and carbon prices. Renewable resource additions were set to correspond to the regional load growth and renewable portfolio standard set by each state. Using a recursive-optimization process, Aurora determines an economically optimal resource expansion path within the given constraints. Once long-term capacity expansion results were created, they were input into a model that utilizes various stochastic inputs: natural gas prices, hydro generation, and renewables generation profiles to stochastically generate a long-term price forecast for the Mid-Columbia (Mid-C) region.

WECC-Wide Forecast

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which encompasses the 14 western-most states in the U.S., parts of Northern Mexico and Baja California, as well as Alberta and British Columbia. The WECC region is the most geographically diverse of the eight Regional Entities that have delegation agreements with the North American Electric Reliability Corporation (NERC). Aurora was used to model numerous zones within the Western Interconnect based on geographic, load and transmission constraints. The analysis focuses mainly on the Northwest region, specifically Oregon, Washington and Idaho. Even though the study forecast focuses on the Mid-C electricity market, it is important to model the entire region because fundamentals in other parts of the WECC exert a strong influence on the Pacific Northwest market. Because of the ability to import electricity from or export to other regions, the generation and load profiles of another region can have a significant impact on Mid-C power prices. As such, to create a credible Mid-C forecast, it is imperative that the economics of the entire Western Interconnect are captured.

Long-Term Fundamental Simulation

A vital part of the long-term market simulation is the capacity expansion analysis. The study utilized Aurora to determine what types of generation resources will likely be added in the WECC over the next 10 years, given our current expectations of future load growth, natural gas prices, and regulatory environment. To arrive at an answer requires an iterative process. In the first step, Aurora was programmed to run a 10-year dispatch study assuming that no new resources are built in the WECC. In the second step, Aurora progressively adds resources to meet expected load growth and renewable portfolio standards. The resources that are chosen are the best economic performers – i.e. the resources which provide the most regional benefit for the lowest price.

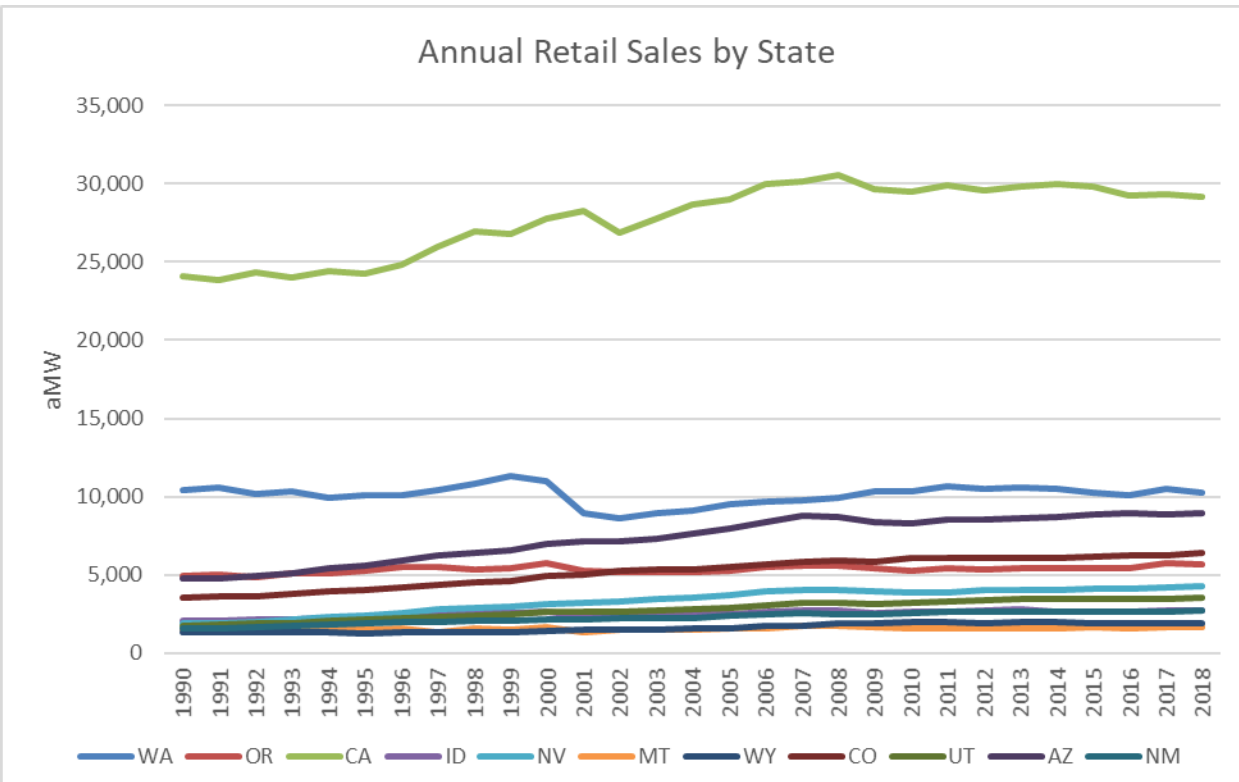
Principal Assumptions

This section reviews the key assumptions that were used in the capacity expansion.

WECC Load

Aurora's default demand escalation forecasts for zones in the WECC region are based on WECC's Transmission Expansion Policy and Procedure Study Report[19] and are provided in the Aurora database. However, based on recent observed retail load in the WECC and using the Northwest Power and Conservation Council's Seventh Power Plan and its updated Midterm Assessment, load is expected to increase negligibly in the Pacific Northwest region over the study horizon.[20] Increases in energy efficiency, behind the meter generation, slower economic growth, and decreased population growth have contributed to a relatively flat growth when compared to the historical average. Figure 62 below shows the clear flattening/declining trend to retail loads in nearly every state in the WECC over the past two decades.[21]

Figure 62: Historical WECC Retail Loads



[19] https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_StudyReport_draft.pdf

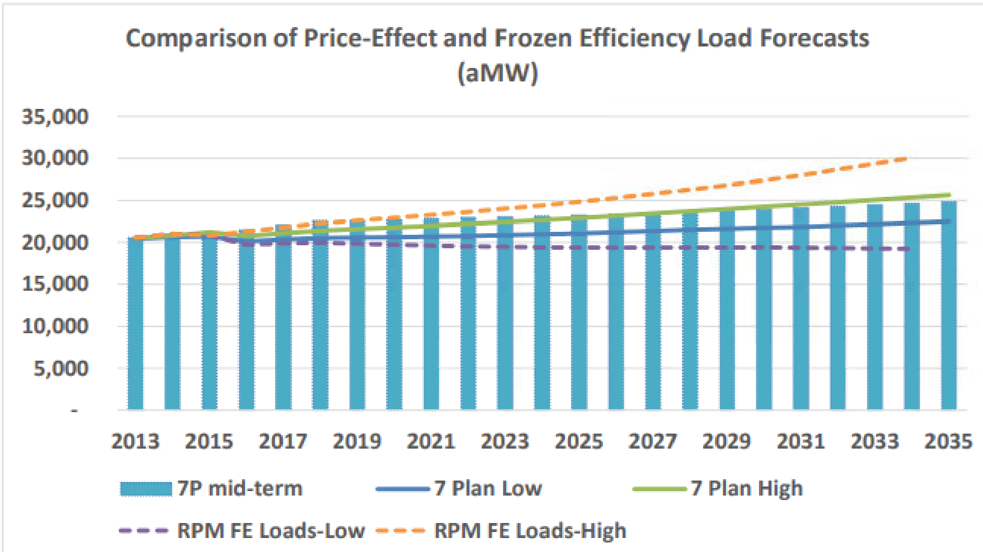
[20] https://www.nwcouncil.org/sites/default/files/7th%20Plan%20Midterm%20Assessment%20Final%20Cncl%20Doc%20%232019-3.pdf

[21] https://www.eia.gov/electricity/data/state/sales_annual.xlsx

Because of this trend, the District made use of the NWPCC's regional mid-term load growth assumptions for this study, summarized in Figure 63 below. The average annual load growth for the Pacific Northwest for the Base Case the District used was approximately 0.4%.

Figure 63: NWPCC Load Projections

Figure 3 - 1: Load Forecast



Regional Planning Reserve Margins

In order to ensure there will be sufficient generating capacity to meet demand in case of generator outages or demand spikes, a certain amount of generating reserve capacity is built into the market. These operating reserves are often extra generating capacity at existing operating plants, or fast-start generators, usually natural gas-fired, which can start-up and reach capacity within a short amount of time.

Planning reserve margins are a long-term measurement of the operating reserve capacity within a region, used to ensure there will be sufficient capacity to meet operating reserve requirements. The planning reserve margin is an important metric used to determine the amount of new generation capacity that will need to be built in the near future. For the capacity expansion analysis, the District used the Aurora default planning reserve margins with slight modifications provided by the Northwest Power and Conservation Council (13% for US states in the NWPP, starting in 2026).

WECC Renewable Portfolio Standards

Renewable portfolio standards (RPS) are state-level requirements that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. There are currently no federally mandated RPS requirements; states have set their own based on their particular environmental, economic, and political needs.

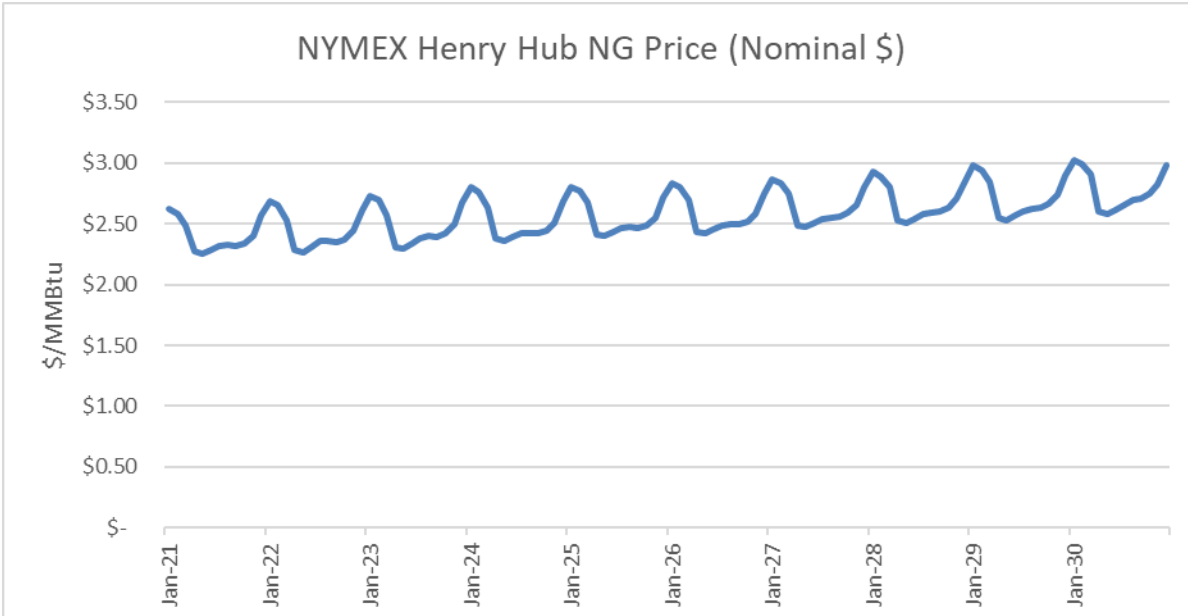
Among states in the WECC, California has the highest RPS requirement at 60% by 2030, with Oregon following shortly behind it with a 50% requirement for its IOUs by 2040. In Washington, there is a 15% RPS requirement, but with the 2019 enactment of the Clean Energy Transformation Act (CETA), there is now also an 80% carbon-free requirement by 2030. A wide variability in the requirements exists between states in the region, which could have a sizeable effect on electricity pricing within the region. To prevent an unreasonable resource buildout, the District decided to make use of blended WECC-wide annual MWh RPS targets supplied by the Northwest Power and Conservation Council. The justification for this method is that resources from out-of-state whose energy is imported into another state can usually contribute to satisfying that state's RPS and carbon-free requirements.

Natural Gas Price

Natural gas prices are a key factor in the market simulation. It is challenging to forecast natural gas prices in the future, as the prices are inherently volatile and market dynamics are constantly changing. The price curve shown in Figure 64 uses Henry Hub forward pricing data from the New York Mercantile Exchange (NYMEX) through the year 2030 at a certain snapshot in time (as of January 21st, 2020). Past IRPs have used a blend of NYMEX futures contract pricing for the near term and gradually transitioning to a long-term price forecast sourced from a reputable energy research firm. The rationale behind blending the two forecasts was that near-term NYMEX pricing reflects actual trading activity and should encompass all the collective information of the market. In short, it represents the most well-informed, consensus gauge of the value of the commodity. Outside of the short-term, though, trading activity is limited and the pricing ceases to exist beyond a 10-year outlook. The long-term forecast incorporates the fundamental factors of supply, demand, and variables that can cause those to change to develop a forecast.

The District decided to use only the NYMEX forecast for this year's study for two reasons. First, NYMEX prices are available through the entire shortened study period of 10 years. Second, while research firms rigorously analyze the market to determine their forecast, it reflects a proprietary methodology which is necessarily opaque. It is impossible to reverse engineer a third-party forecast based on limited data to validate inputs. The same can be said for market prices; however, NYMEX pricing reflects the opinions of not just a single firm, but of all market participants. Short of developing a separate natural gas price forecast, the District believes that for this IRP, the NYMEX prices are the best representation of the expected future price of natural gas.

Figure 64: Natural Gas Price Assumptions



Carbon Pricing

There is a high level of uncertainty regarding the regulation of Carbon Dioxide (CO2) emissions, as well as the structure and creation of carbon trading markets. Currently in the Western United States, the only state that has a carbon emissions trading market is California, as part of the Western Climate Initiative in partnership with the provinces of British Columbia, Manitoba, Quebec and Ontario.

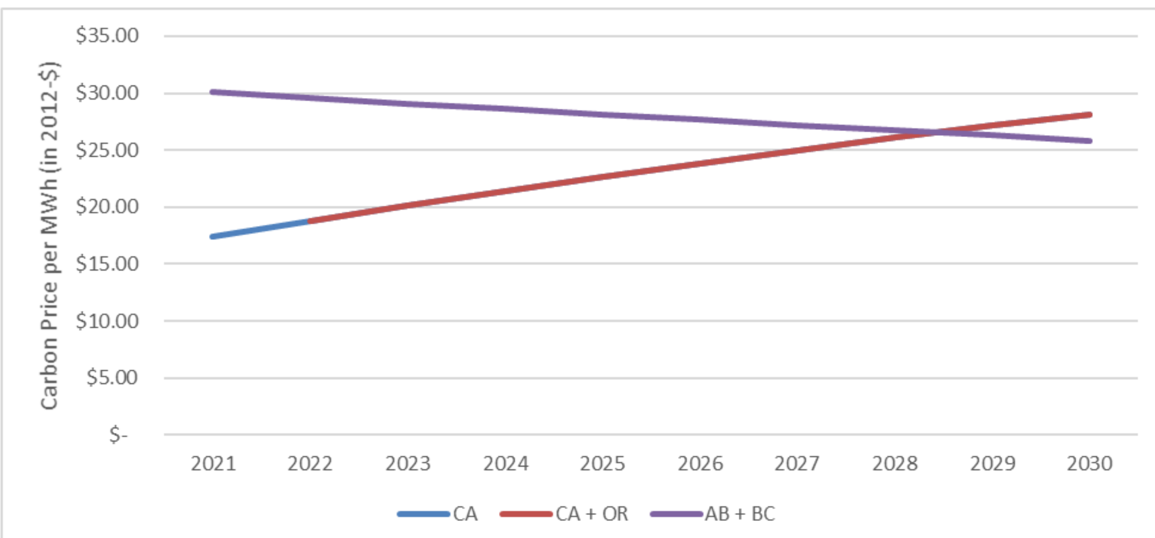
Although Washington State does not have a carbon trading market, there has been a push in recent years to set one up. For example, the Clean Air Rule ("CAR") went into effect in 2016; this rule, however, was challenged in court and eventually ruled unconstitutional. In addition, carbon tax initiatives failed in both 2016 and 2018. However, in 2019, the state legislature passed the Clean Energy Transformation Act (CETA). One provision of this new law requires utilities to consider the social cost of carbon in resource planning, evaluation, and selection. The values provided by the Washington State Department of Commerce for the social cost of carbon are summarized in Figure 65 below. These values are applied like a carbon tax to carbon-emitting resources in Washington State in the Capacity Expansion run. The new resource stack from this run is then fed into a Long-Term Production Cost Model run with the social cost of carbon removed, since the social cost of carbon will not affect dispatch decisions in real life.

Figure 65: Social Cost of Carbon

Year in Which Emissions Occur or Are Avoided	Social Cost of Carbon Dioxide (in 2007 dollars per metric ton)	Social Cost of Carbon Dioxide (in 2018 dollars per metric ton)
2020	$62	$74
2025	$68	$81
2030	$73	$87
2035	$78	$93
2040	$84	$100
2045	$89	$106
2050	$95	$113

There has also been a significant push in Oregon to introduce carbon legislation, including a cap-and-trade proposal that would link its program to California's. As such, Oregon was modeled as having a carbon penalty equal to California's, starting in 2022. North of the border, British Columbia and Alberta already have carbon taxes in place, which are included in the market simulation and summarized below in Figure 66.

Figure 66: Carbon Penalty Assumptions in CA, OR, BC, and AB



Simulations

Capacity Expansion & Retirement

The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, storage, hydro, geothermal, and biomass. The District input economic assumptions for each of these resources such as capital cost, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal efficiency), and capacity factor. Announced retirements for existing resources are input into the model with their scheduled retirement dates, which include a large number of coal resources set to retire throughout the decade. A large number of once-through-cooling natural gas resources in California are scheduled to retire in 2020, and the Diablo Canyon Nuclear facility, the last nuclear plant in California, will retire by 2025.

New for this IRP cycle, the District made use of the CAISO Interconnect Queue (as of April 20th, 2020) and assumed that half of the resources in the queue are built.[22] This added a total of 6140 MW of Solar, 1868 MW of Wind, and 9892 MW of Storage across the study period as an input into the model. Similarly, half of the projects listed in the Province of Alberta's Major Projects website were also assumed to be built, resulting in an addition of 950 MW of Wind and 305 MW of Solar across the study period.[23] Lastly, based on the most recent AESO 2019 Long-term Outlook, 5171 MW of Alberta coal resources are converted to gas-fired resources during the study period.[24]

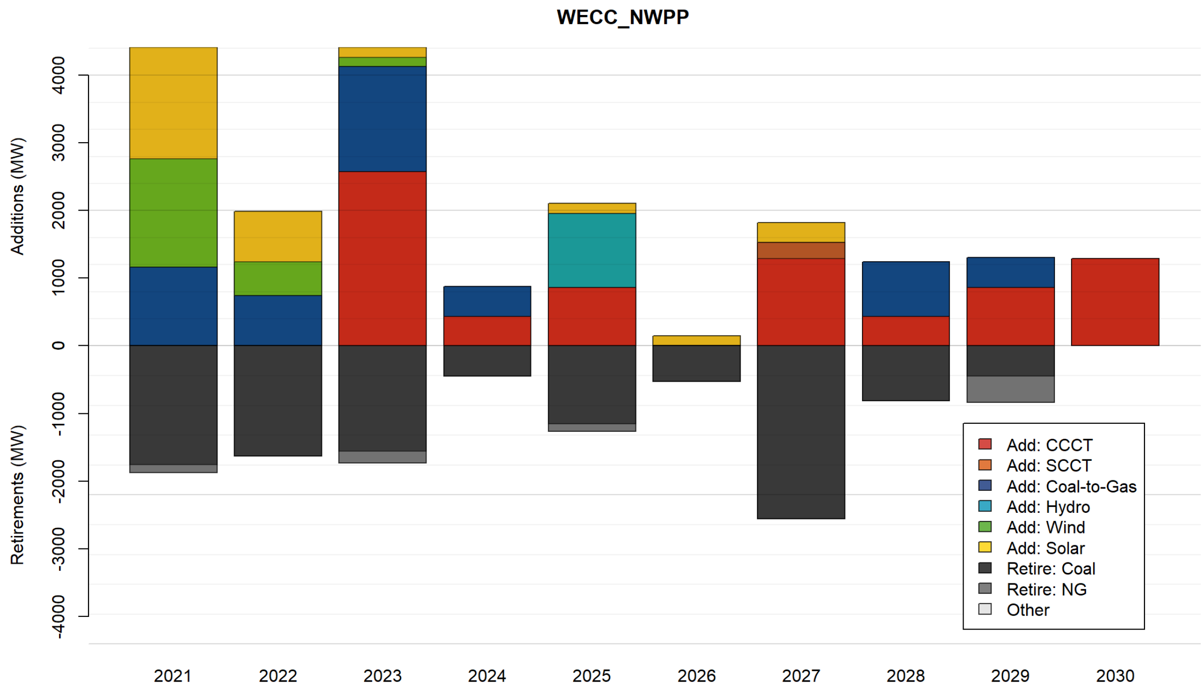
Based on the parameters outlined above, Aurora then determines the ideal mixture of new resource additions and further retirements to meet the inputs constraints in the most economical way. Figure 67 and Figure 68 illustrate the expected new resource expansion and retirements through 2030 in the Pacific Northwest and California/Mexico regions.

RPS requirements are one of the main drivers of new resource expansion over the next decade. These resources, particularly solar, make up the majority of capacity additions over the study period. A significant contributor to solar economics is the recent extension of the Investment Tax Credit (ITC). Solar generation expansion is highest in 2021, the first year of the study period, after which the ITC drops to 10 percent for commercial and utility projects and zero for residential projects. In addition, more wind resources are built and come online in the first few years of the study period in order to take advantage of the Production Tax Credit (PTC), which has been extended for projects that commence by the end of 2020 and come online by 2024.

Throughout the WECC region coal output is forecasted to decline substantially, with new coal plants not being developed due to tighter emissions regulations and economics. By 2030, nearly 13,000 MW of coal capacity will be retired or converted into natural gas resources. Nuclear output will decline as aging resources are taken off-line, and hydro output will increase slightly with the addition of BC Hydro's 1100 MW Site C Project, scheduled to come fully online in 2025.

[22] http://www.caiso.com/PublishedDocuments/PublicQueueReport.pdf
[23] https://majorprojects.alberta.ca
[24] https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf

Figure 67: Forecasted Pacific Northwest Generation Capacity Additions through 2030

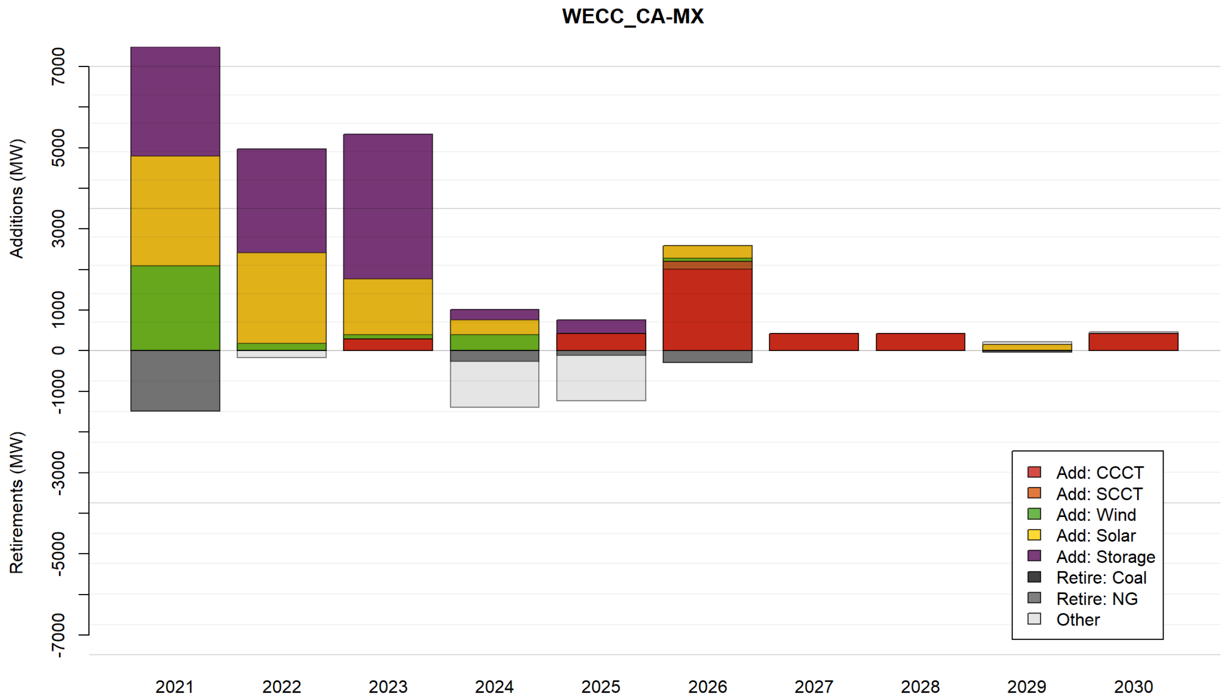


Within the Northwest Power Pool region, which includes the Canadian providences of British Columbia and Alberta, and the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, Utah, and a small portion of northern California, hydro will remain the largest single generating resource through the study period. All coal plants in the region are projected to retire (or be converted into natural gas units) by the end of 2030.

Solar is the renewable choice for fulfilling RPS requirements in the first years of the study. A few years ago, this increase in renewable generation would have been largely wind, making this shift a significant development in the last three years. The cumulative renewables expansion in the Pacific Northwest over the study period is 14,500 MW, of which 5,800 MW are wind resources and 8,700 MW are solar.

In addition to a significant build out of solar in the region, just under 8,000 MW of Combined Cycle Gas Turbine (CCGT) generation is added. This addition over the study period largely offsets some of the lost capacity from retiring coal generation. Due to the assumption of slightly increasing loads across the WECC, more capacity will be required to serve load, and this build-out of natural gas resources supports the need for capacity in the region. The additional cost of carbon, however, puts thermal resources at a disadvantage for meeting overall energy needs, preventing a higher buildout of this resource type.

Figure 68: Forecasted California Generation Capacity Additions through 2030

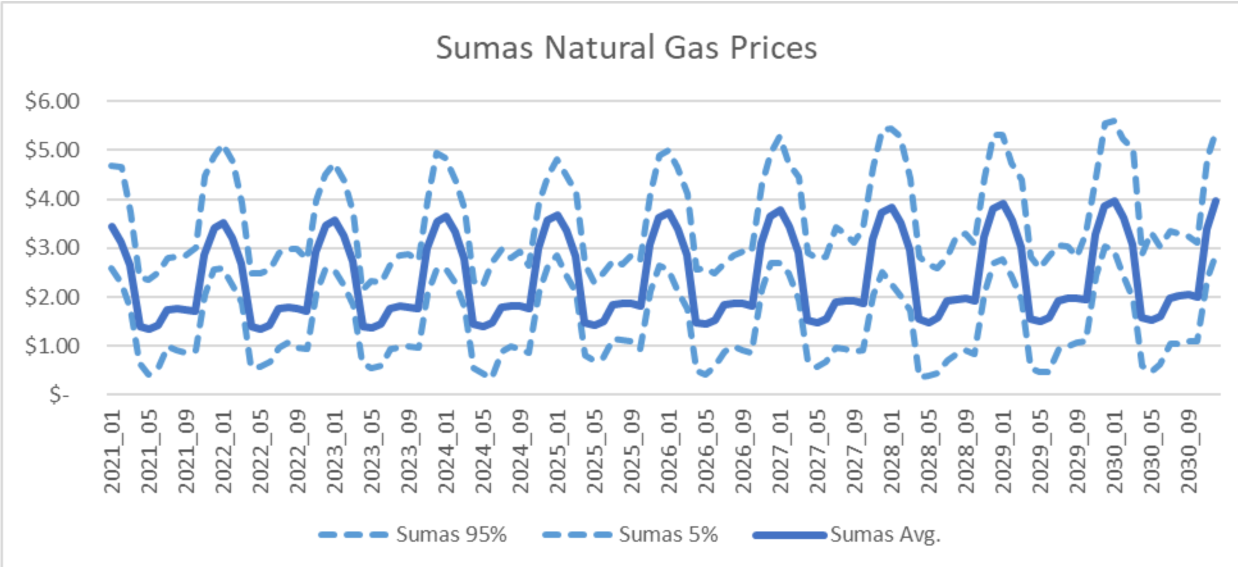


In California, although there are substantial natural gas resource retirements through 2021 (almost entirely made up of previously announced retirements of once-through-cooling units) and the retirement by 2025 of Diablo Canyon, the final nuclear facility in CAISO, the story is similar. With the large amount of storage in the CAISO Interconnect Queue, the need for additional natural gas resources for capacity needs are less in the front half of the study period, though nearly 4,000 MW are built-out in the late 2020s to meet increasing demand. Like in the Northwest, the majority of generation expansion is from solar. However, there is a significant amount of wind generation that is also built in the first year of the study period, largely to take advantage of the expiring Production Tax Credit.

Natural Gas Price Simulation

The District used a proprietary model to develop natural gas distributions for use in stochastically modeling electricity prices. The model is a statistical model which uses historical Henry Hub prices to generate an overall distribution of gas prices. A monthly basis factor is then applied to give the price of gas at the Sumas Hub in Washington at the US-Canada border, which are shown below in Figure 69.

Figure 69: Sumas Natural Gas Price Simulation

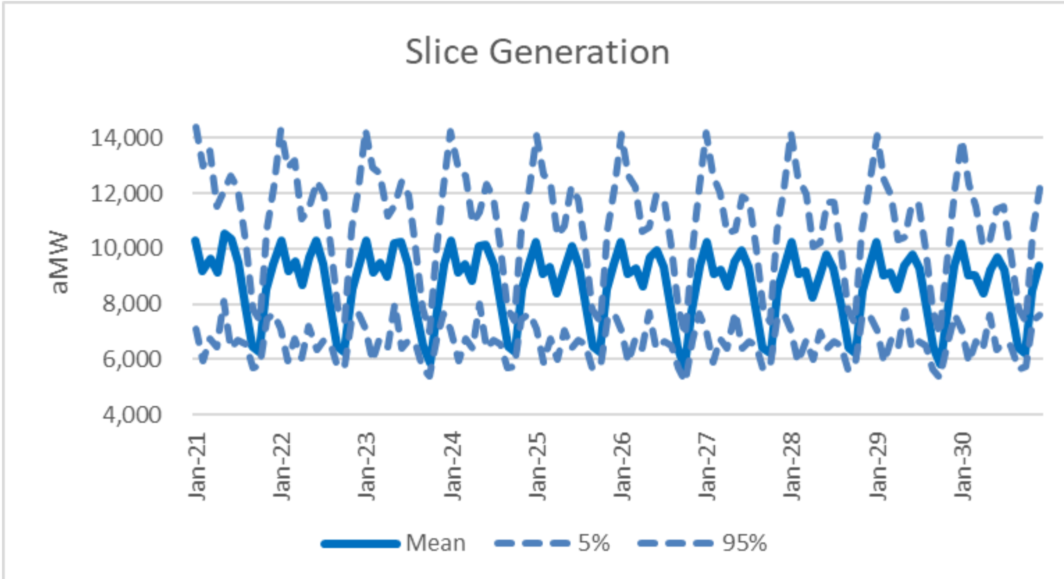


The middle line represents the average of all the iterations, and the dashed lines represent the 5th and 95th percentiles. A multi-factor mean-reverting Monte Carlo process was used to simulate the volatility of daily spot gas prices, which is then used in a Heston Model to generate prices. The model is seasonally adjusted to reflect historic seasonal trends in price and volatility. Seventy-nine iterations of this model were run, each generating daily spot gas prices through 2030, which were then input into Aurora.

Hydroelectric Generation Simulation

Hydro power currently accounts for approximately two-thirds of electricity generated in the Pacific Northwest, and one-quarter of generation in the WECC. One of the challenges of hydro generation is its seasonal variability and uncertainty. Yearly hydroelectric output depends on a number of variables, including snowpack and environmental regulations. To capture this uncertainty in the market simulation modeling, the District used historical hydro generating data as an input for the stochastic model. Figure 85 illustrates the hydro generation assumption used in the price simulation. The solid blue line represents the expected generation level and the light-blue dashed lines represents the 5th and 95th percentiles.

Figure 70: Slice System Hydro Simulation



Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained over multiple iterations of Monte Carlo analysis. Figure 71 shows the expected Mid-C power prices from the long-term capacity expansion run, while Figure 72 and Figure 73 show the stochastic distributions for the range of potential outcomes. The solid dark blue lines represent the average of all the iterations, while the dashed lines represent the 5th and 95th percentiles. The high HLH price excursions for the 95th percentiles in January of 2024, 2029, and 2030 correspond to poor hydro generation draws, combined with high natural gas price scenarios.

Figure 71: Mid-Columbia Prices

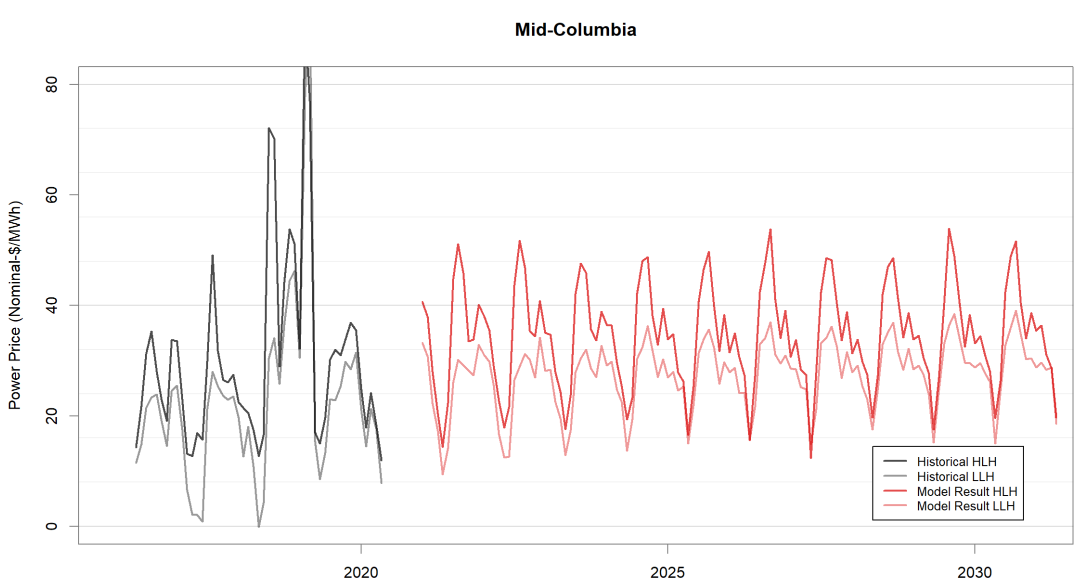


Figure 72: Mid-Columbia HLH Price Simulation

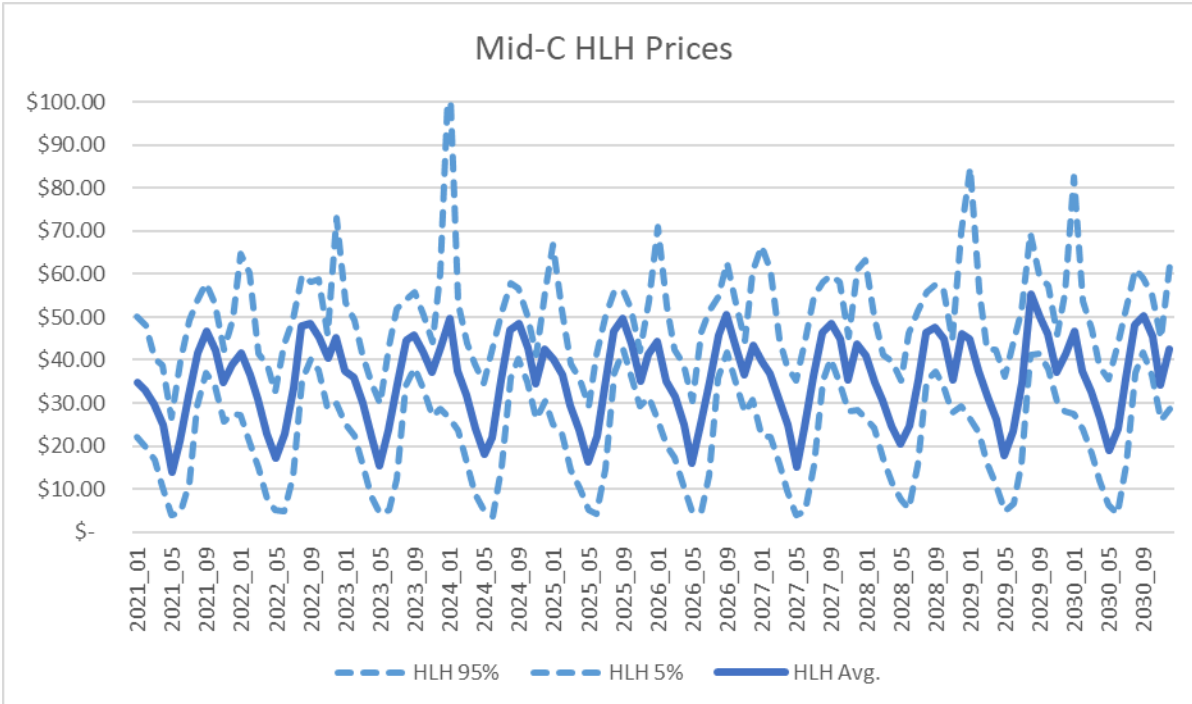
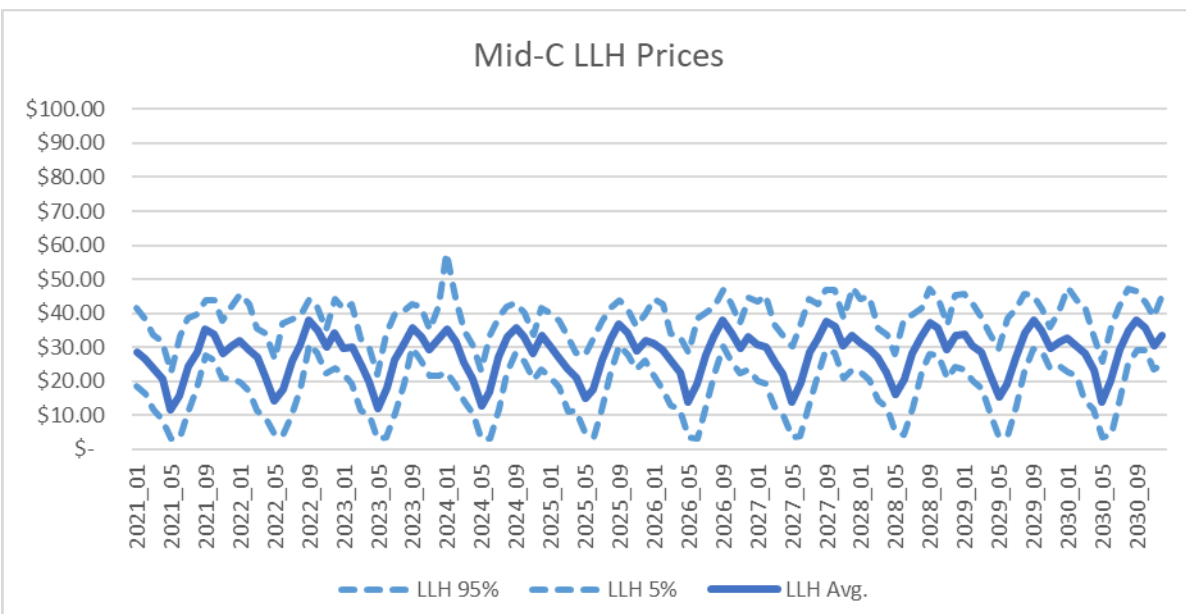


Figure 73: Mid-Columbia LLH Price Simulation



Within the past couple of years, there has been a dramatic shift in the relationship between HLH and LLH Mid-Columbia heat rates and power prices. Starting as early as 2021 for lower demand periods, LLH heat rates and power prices are higher than HLH heat rates and power prices, as shown in Figure 74. During the spring runoff period, low loads and low natural gas prices, when combined with an increase in renewable generation, lead to the collapse of the HLH/LLH spread.

Figure 74: Mid-C HLH/LLH Spread

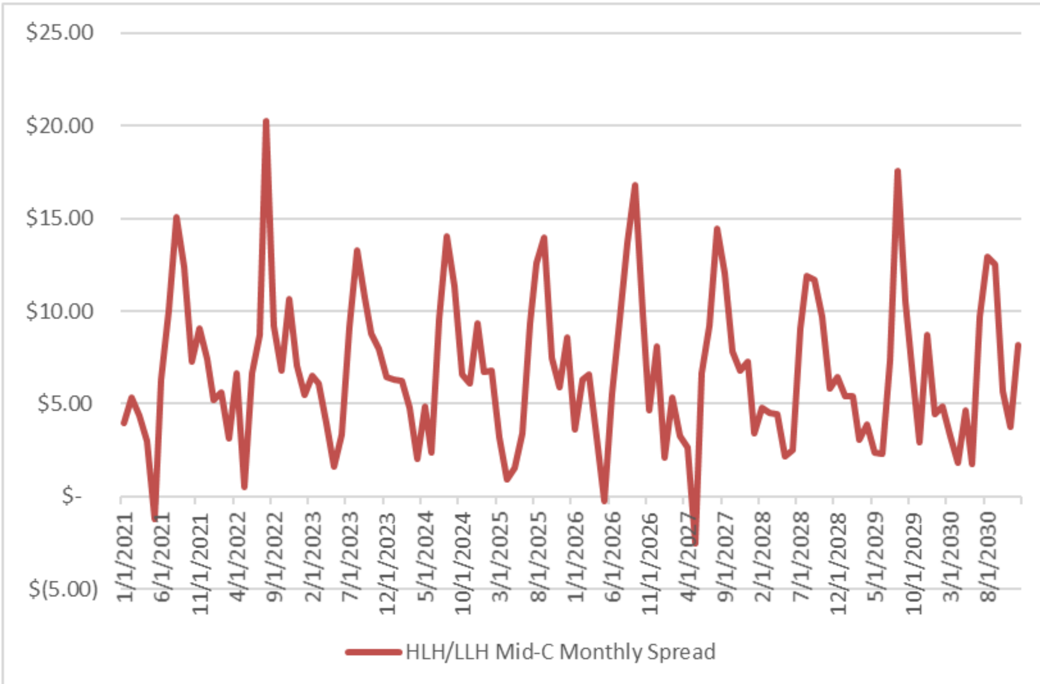


Figure 75, Figure 76, and Figure 77 below show the average hourly profile of Mid-Columbia power prices for the months of April, August, and December in the years 2021, 2024, 2027, and 2030. As can be seen, there is a clear increase in prices for the evening peak, as thermal generation must come online to make up for the decreased solar generation in the evening.

Figure 75: Mid-C Average Hourly Price Profile for April 2021, 2024, 2027 and 2030

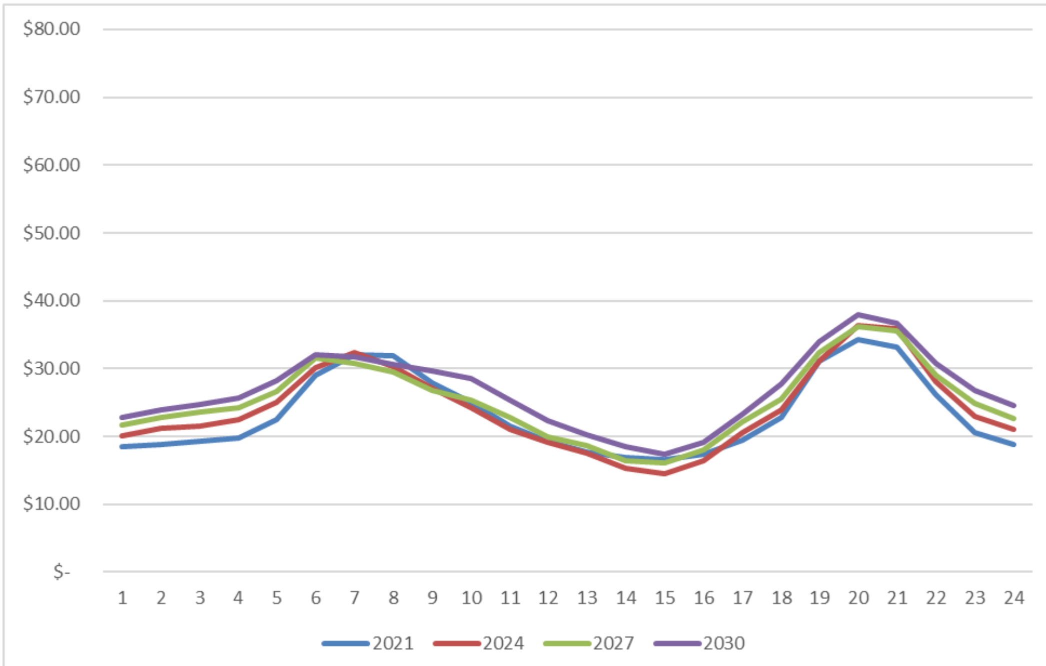


Figure 76: Mid-C Average Hourly Price Profile for August 2021, 2024, 2027 and 2030

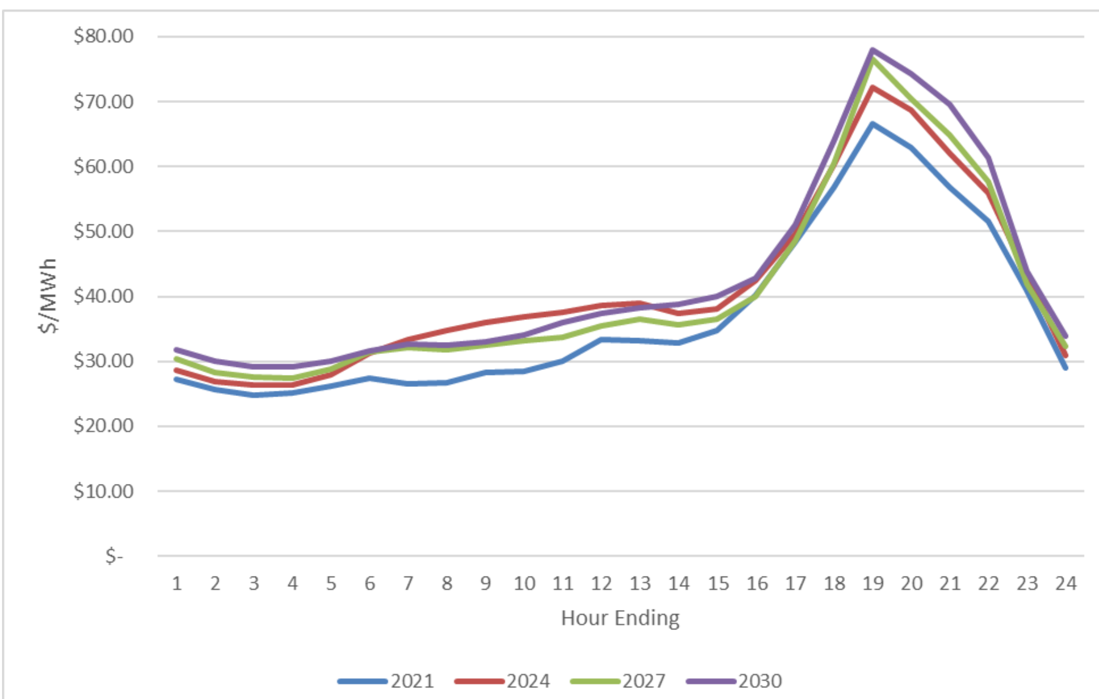
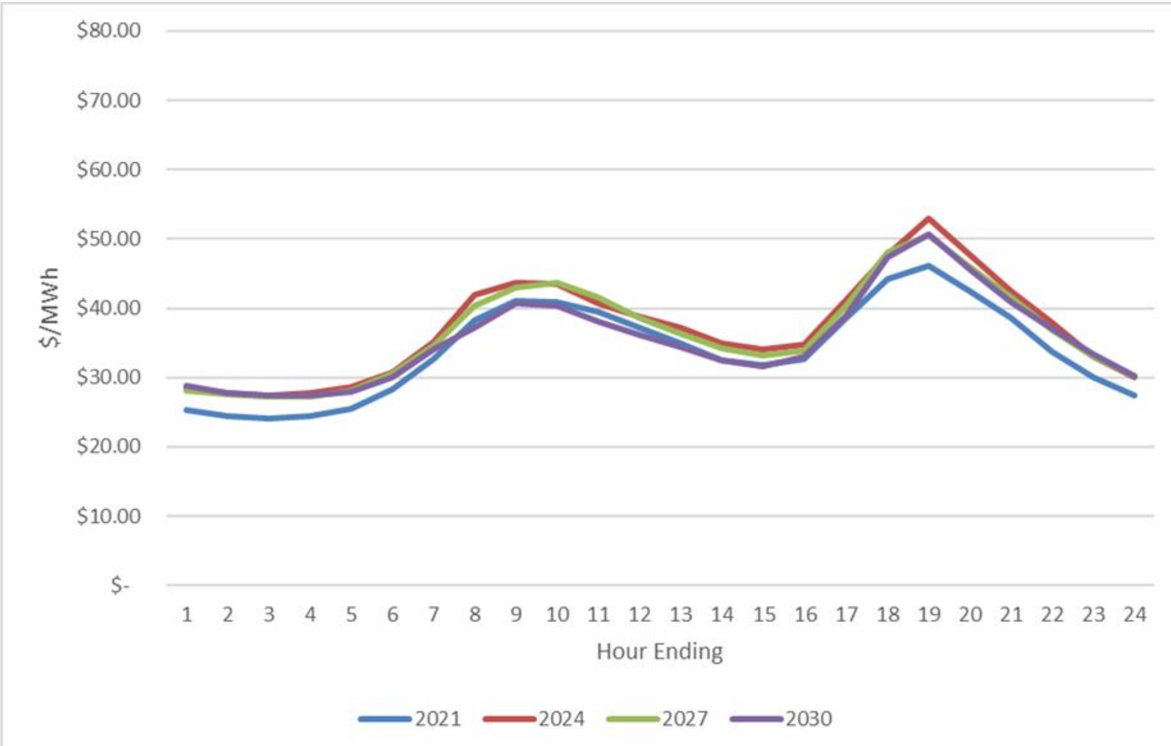


Figure 77: Mid-C Average Hourly Price Profile for December 2021, 2024, 2027 and 2030



Scenario Analysis

In addition to the above Base Case scenario, two other alternative hypothetical scenarios were considered. These were separate model runs intended to stress one of the key assumptions that went into the market simulation, and based on the IRP team's judgment, could potentially change in the near future. These changes reflect differences in key underlying assumptions in the market simulation model that directly affect the expected case, whereas the stochastic simulations provide a distribution around the expected case. The goal of the scenario analysis is to project a range of outcomes contingent upon changes in key underlying assumptions that are included in the market simulation. These two alternative scenarios include:

1) *Low Load Growth Scenario*: A high reduction in the load growth assumption for the entire WECC region. This scenario assumes a negative growth rate of -2% year-over-year on average across the entire study. This is intended to analyze the potential impacts of a prolonged decrease in load growth due to such factors as energy efficiency and distributed generation. Historically, both of these have contributed to a reduction in demand and a continued revision downward in load forecast.

2) *High Load Growth Scenario*: An increase in the load growth assumption for the entire WECC region. In this scenario, load is assumed to increase on average by 2% year-over-year across the study. This is intended to look at the impacts of increased population growth, manufacturing, and electrification of the transportation industry across the WECC.

Figure 78 below is the projected resource additions in the Northwest through time under the Low Load Growth scenario. Interestingly, under the Low Load Growth scenario, about 3,700 MW less natural gas generation is built out in the region over the entire study period. However, nearly the same amount of renewables (wind and solar) are built to meet state RPS requirements. This suggests that the renewables build out in the region will likely continue regardless of load growth to meet increasing RPS mandates.

Figure 78: Forecasted Resource Additions under the Low Load Growth Scenario

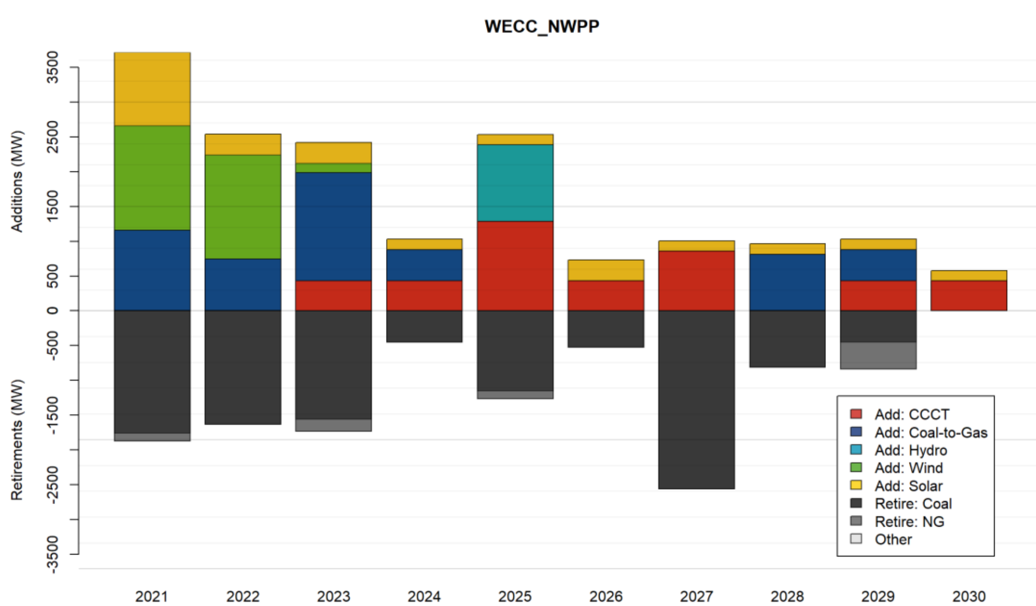
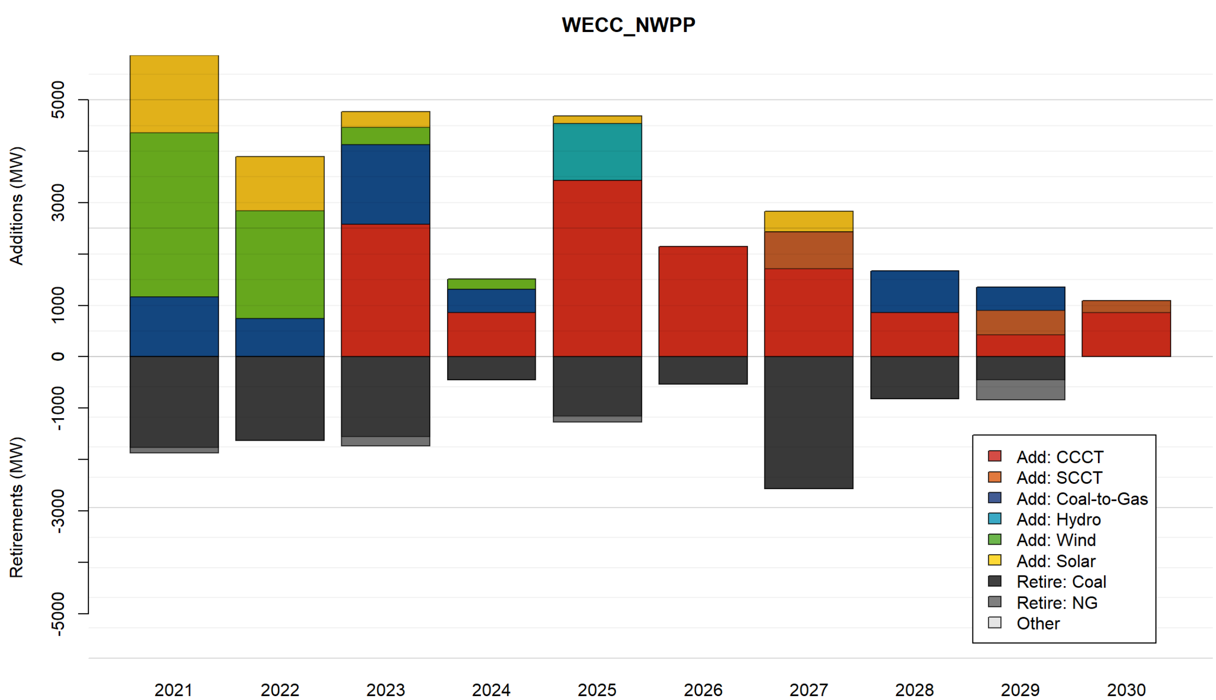


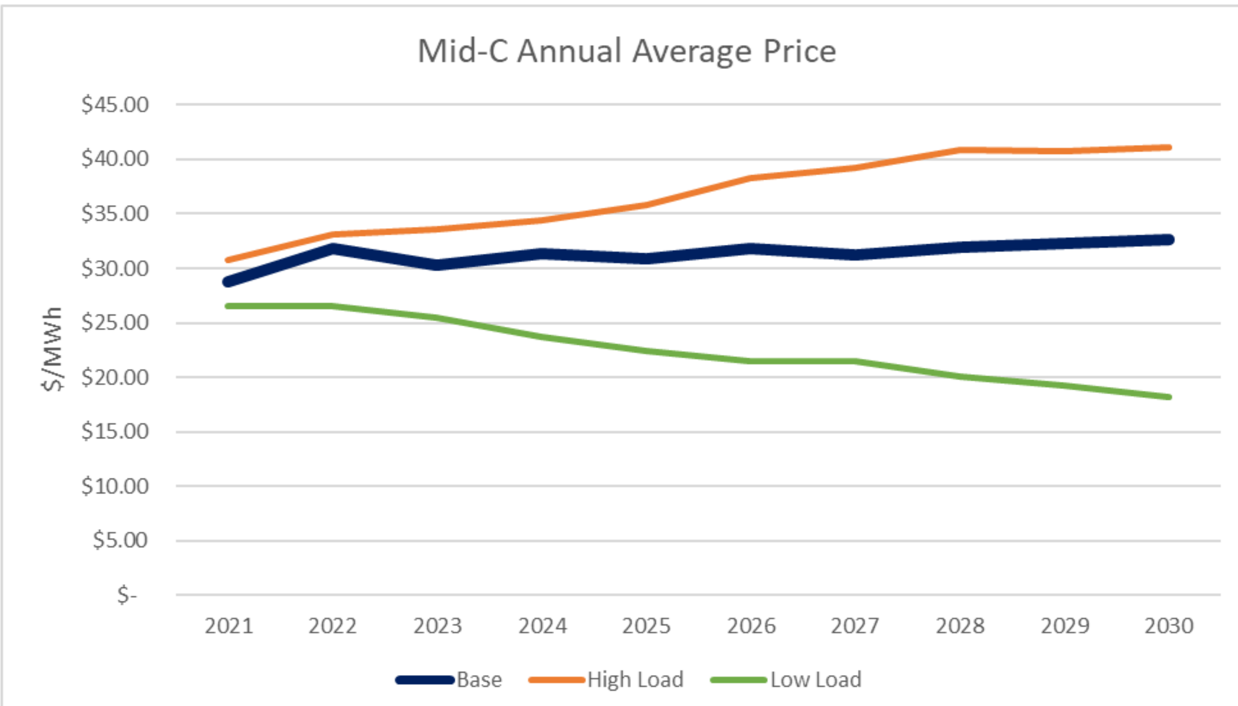
Figure 79 below is the projected resource additions in the Northwest through time for the High Load Growth scenario. Note that there are significant CCGT additions in the back half of the study period to meet the higher load, and a total of 6,000 MW more natural gas generation in the region compared to the Base Case. Across all of WECC, approximately 14,500 MW of solar and 16,500 MW of wind is built in the High Load Growth scenario, compared to approximately 13,000 MW of solar and 8,000 MW of wind in the Base Case.

Figure 79: Forecasted Resource Additions under the High Load Growth Scenario



The effects on power prices are illustrated below in Figure 80. As expected, the High Load Growth scenario sees an increase in the forecasted Mid-C market price throughout the study period, whereas the Low Load Growth scenario sees prices deteriorate over time. Annual average prices remain within a few dollars of one another in the first couple of years of the study, but grow to as much as $8.50 higher in the High Load Growth scenario compared to the Base Case in 2030, and $14.50 lower in the Low Load Growth scenario compared to the Base Case in 2030. Across the whole study period, the average power price for the High Load Growth scenario is about $5.50/MWh higher than the Base Case, and the Low Load Growth scenario is about $8.75/MWh lower than the Base Case. The higher price in the High Load Growth scenario can be attributed to natural gas generation as the marginal unit in the Pacific Northwest to meet the higher load requirements, whereas the Low Load Growth scenario sees hydro as the marginal unit.

Figure 80: Projected Mid-C Power Prices Through Time



It should be emphasized that the scenario analyses provide insight into the impacts of potential changes to key underlying assumptions in the market simulation model, rather than a statistical distribution around model results with static underlying assumptions. That is, the market simulation model assumes a given load growth assumption, and by changing the load growth, we can observe the impact of changing such key assumptions.

Chapter 9: Risk Analysis and Portfolio Selection

The IRP team created a long-term integrated financial and energy position model, which forecasted the District's net power cost for the duration of the study period. The financial model used the results from previous sections, including forecasted loads, simulated hydro generation scenarios, forecasted output from generation resources, simulated market price scenarios, and forecasted generation resources. The output from the model measured the impact of these different scenarios in a single metric: the net present value of net power costs for the 10-year study period.

Energy Net Position

Under the medium load forecast and critical hydro scenario, the District has sufficient resources to meet average annual energy needs until 2024 (Figure 81**)**. The deficits will continue to increase commensurate with the District's load growth until the end of 2028 when the ATC purchase expires at which point the deficit will jump to 15 aMW. In average water conditions (Figure 82), the District has sufficient resource on an average annual basis to meet energy needs until 2029.

Figure 81: Energy Net Position – Medium Load Forecast and Critical Hydro

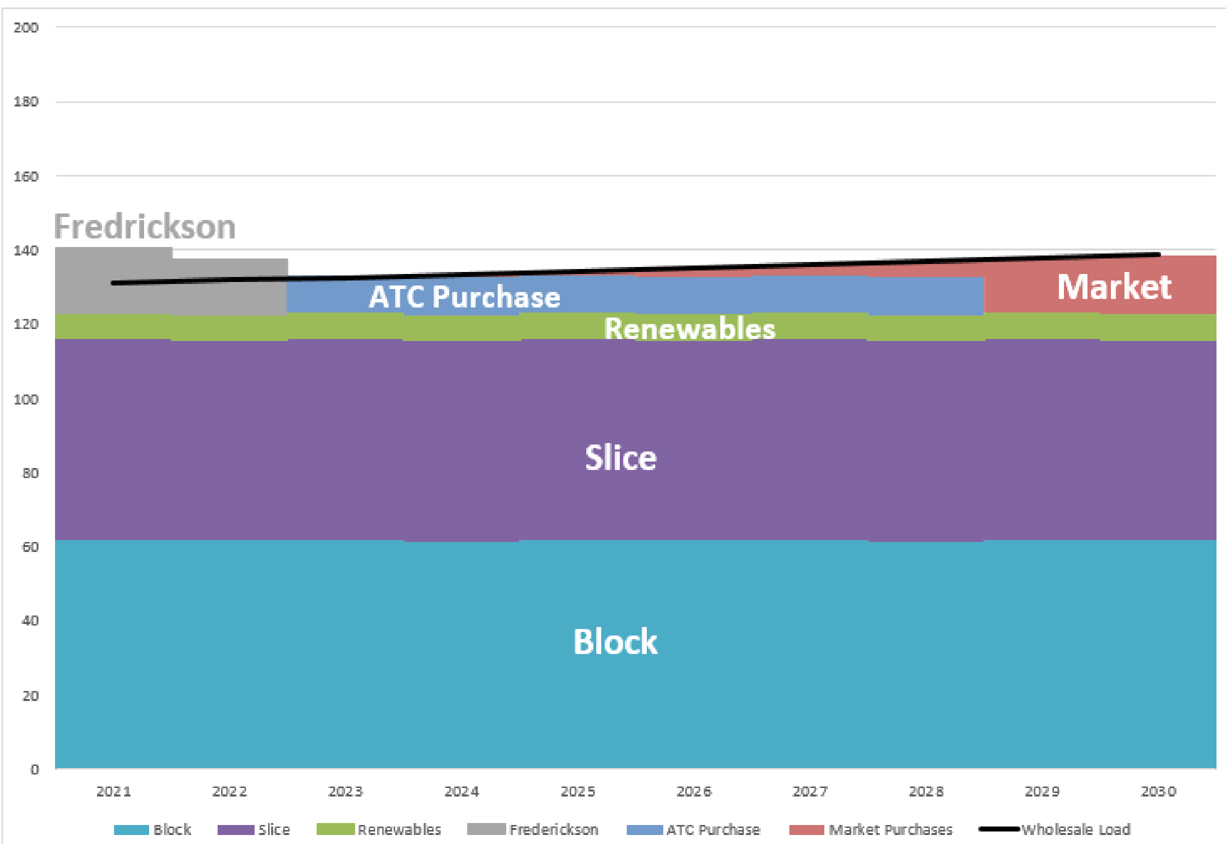
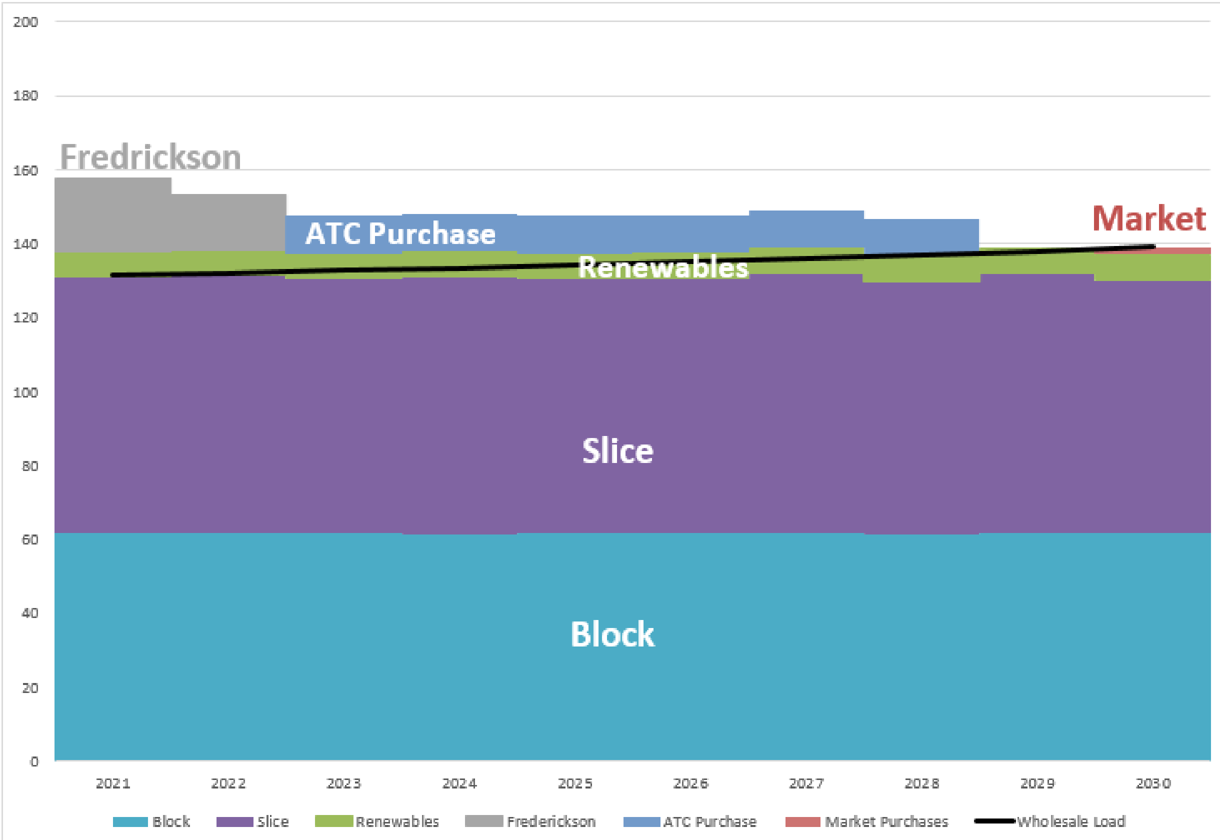


Figure 82: Energy Net Position - Medium Load Forecast and Average Hydro

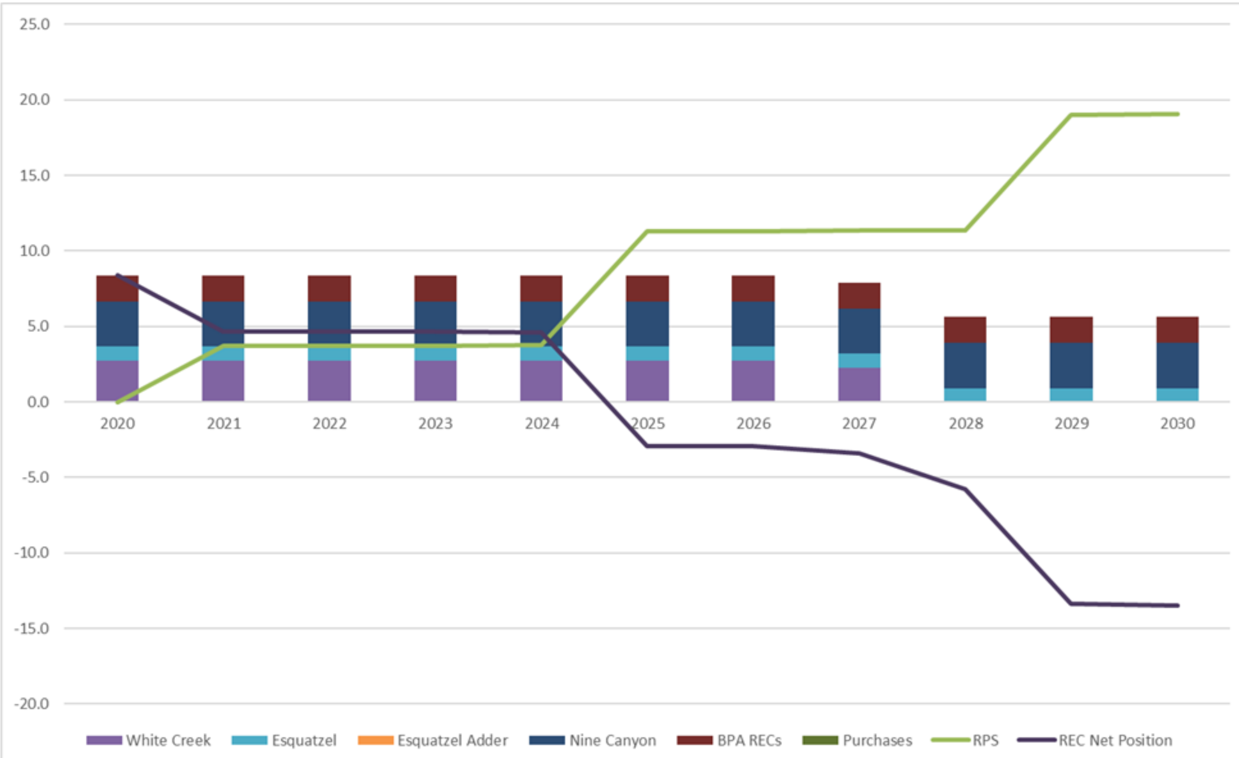


Renewable Portfolio Standard (RPS) / REC Net Position

The District may fulfill RPS requirements with a renewable resource acquisition or by purchasing only the renewable attributes (RECs). With its current renewable assets, the District has sufficient resources to meet its forecasted RPS requirement through the end of 2024. That surplus turns into a deficit beginning in 2020 when the RPS increases from 9% to 15%. The REC deficit is projected to begin at 15 MW, and is expected to grow to almost 30 MW by the end of the study period (Figure 83). The growth of the deficit can be attributed primarily to the increasing demands of meeting I-937 requirements, as the RPS obligation increases from 0% today, 3% starting 2021, 9% starting 2025, and 15% starting 2029. The expiration of the REC generating wind resources and load growth also contributes to the expansion of the REC deficit expected to start in 2025.

Acquiring additional renewable resources to meet the RPS requirements has both benefits and drawbacks. Procuring a resource ensures that the District receives a steady supply of RECs at a known price and reduces exposure to the REC market. A generation resource also augments the District's energy supply, which is helpful during the summer months when the District has to manage its seasonal energy deficit. However, the most economical renewable resources, wind and solar, are not dispatchable and will not necessarily generate electricity when it is needed most, during peak demand periods on the hottest or coldest days of the year. Furthermore, the cost of owning a REC generating resource is forecasted to be costlier than buying RECs from the market. The intrinsic value of a REC is residual of the levelized cost of a new resource less the value of the brown power component. With the rising green energy requirements demand on RECs are expected to increase. This increase in demand will cause the price of RECs to increase through time.

Figure 83: District RPS Obligation and REC Supply



Portfolio Strategies

Five portfolios were analyzed, each comprised of a different resource mix, to determine the optimal portfolio. The portfolios were constructed based on meeting the needs of Strategies 1 through 6 listed below. The colors and portfolio numbers (P1, P2, etc.) match the colors and numbers as described below.

1. Keep the status quo
    - Rely on the market to cover energy, capacity, and REC deficits
2. Acquire a 25 MW Solar + Storage in 2023 to help meet capacity needs and fulfill RPS requirements for the remainder of the study period
    - Solar meshes well with the district summer peaking tendency
    - Wil help backfill some retired resources while contributing to the RPS requirements
3. Acquire a 30 MW combined cycle gas turbine beginning 2023 to meet summer energy needs
    - Sized to meet average energy deficits in critical water conditions as the Frederickson contract expires
    - Will help to fill summer season energy deficits
    - RPS deficits would be purchased from the market
4. Acquire 10 MW solar and 6 MW wind beginning 2025, increasing to 18 MW solar and 10 MW wind in 2027

- This all renewables portfolio would purchase enough physical renewable generation to cover REC deficits throughout the study period
- Energy produced from the renewable assets would partially offset some of the energy deficits in summer months
- The solar generation profile coincides well with the District's peak load periods. Solar will also contribute RECs towards meeting the District's RPS requirements.
- Wind energy will be used to meet the balance of RPS requirements as it is a more economically efficient resource in the Pacific Northwest.

5. Acquire 30 MW natural gas fueled reciprocating engines beginning 2023 plus 21 MW solar in 2025 increasing to 36 MW solar by 2027
    - REC plus capacity portfolio will cover significant capacity deficits in addition to all renewable requirements
6. Acquire a 30 MW Small modular reactor beginning 2023 or as soon as possible
    - Adds a baseline resource to load
    - Provides capacity and energy benefits that can be turned down during market lows
    - Rely on market to meet RPS requirements

The portfolio construction process chose the resources that the IRP team determined to be technically and economically viable within the timeframe of the study period.

Figure 84 lists the key drivers and variables associated with risk in the simulation performed. Of these hydro generation, loads, heat rate, and gas price were treated as stochastic inputs which, derived a distribution of power prices. Each is an important driver of the final results represented in the financial and risk modeling.

Figure 84: Risk Drivers

Asset

- Capital Costs
- Variable Fixed Costs

Fundamental & Market

- Hydro Generation
- Loads
- Heat Rate
- Gas Price
- Power Price

Regulatory

- Renewable Portfolio Standards
- Carbon Reduction Targets
- Tax Credits

The portfolios examined in this IRP are outlined in Figure 85. Each group of portfolios was structured to accomplish different goals. Portfolio 1 was established as the baseline portfolio in which the District does not acquire any resources and relies on the market to fill all energy, capacity, and renewable deficits. Portfolios 2 fills a significant portion of the district's energy and capacity shorts on an hourly and daily basis and makes the District long on an annual average energy basis. Portfolios 3 fills a significant portion of the District's seasonal energy deficits, but the District may still need to cover capacity shortages with market purchases. It will replace half of Frederickson's generation capability. Portfolio 4 is used to meet REC deficits; however, the District is still short capacity during the summer months. Portfolio 5 combines Portfolio 3 and Portfolio 4 to meet all requirements and meet the large majority of daily and hourly deficits in energy and capacity. The reciprocating engine should meet the District's energy and most capacity needs on an average annual basis under critical hydro conditions after the Frederickson PPA expires, while the wind and solar will help fill REC deficits. Portfolio 6 was reviewed and included but will not be commercially viable until 2024 at the earliest.

Other resources were considered on a qualitative basis but were not considered as part of this analysis as the impact of each could be predetermined. One example, is entering into a long-term hedge with an entity that already has a physical asset but does not need the energy or capacity. This could be a slice of hydro generation from a non-federal asset or a physical heat rate call option from a CCCT or CT/reciprocating engine. The advantage of these hedges are they are priced closer to market, which is a lower cost than acquiring a new asset, and have physical attributes such as physical supply and hourly shaping. The IRP team did not include any market-based hedges as it was assumed the results would be similar to Portfolio 1, which is based on market prices.

Figure 85: Resources Considered in Portfolio Construction

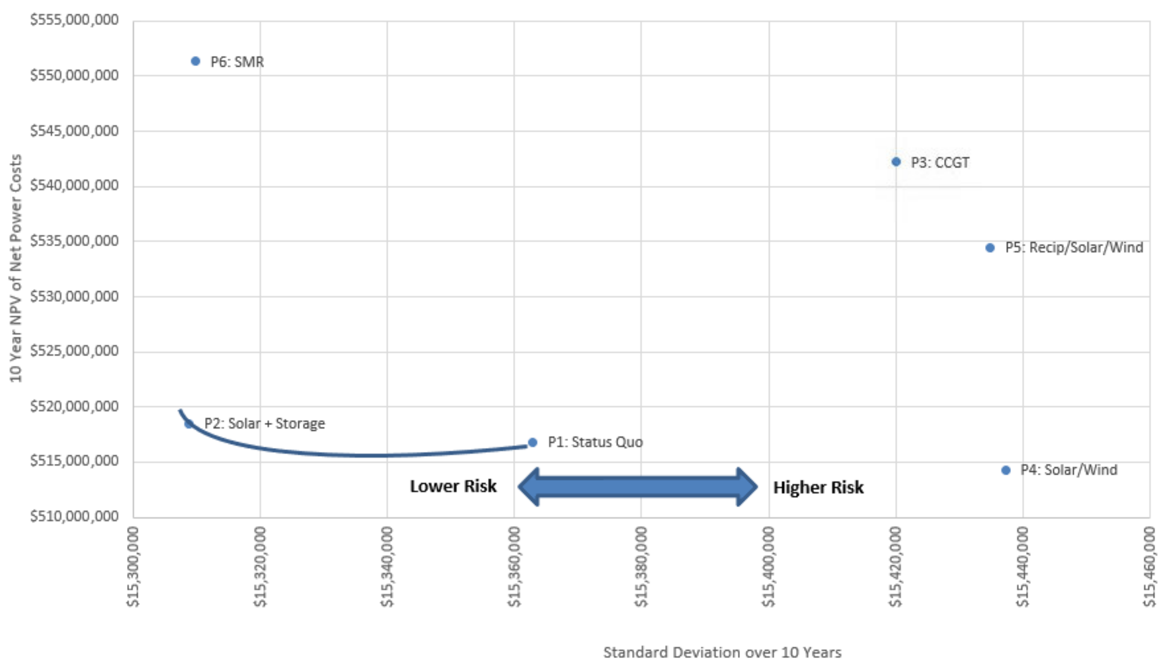
		P1	P2	P3	P4	P5	P6
Portfolio	>	P1	P2	P3	P4	P5	P6
Energy Source	>	Market	Solar + Storage	CCGT	Solar + Wind	Recip	SMR
REC Source	>	Market		Market		Solar + Wind	Market
Strategy	>	Utilize wholsale market purchases for all energy REC deficits	Acquire solar + Storage to meet RPS requirements and help with summer capacity needs	Acquire a CCGT to replace a portion of the capacity and energy provided by Fredrickson; market purchases for RPS	Acquire solar + Wind to meet RPS requirements and help with summer capacity needs	Acquire wind, solar, and a reciprocating engine to meet capacity and RPS needs.	Acquire SMR to help replace fredrickson and add a baseline load resource

			New Generation Capacity Installed											
			P1		P2		P3		P4		P5		P6	
Year	Energy net Position (aMW)	REC Net Position (aMW)	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource
2021	22	5	0	0	0	0	0	0	0	0	0	0	0	0
2022	8	5	0	0	0	0	0	0	0	0	0	0	0	0
2023	1	5	0	0	25	25	30	0	0	0	30	30	30	0
2024	-1	5	0	0	25	25	30	0	0	0	30	30	30	0
2025	-1	-3	0	0	25	25	30	0	16	16	51	51	30	0
2026	-2	-3	0	0	25	25	30	0	16	16	51	51	30	0
2027	-3	-3	0	0	25	25	30	0	28	28	66	66	30	0
2028	-7	-6	0	0	25	25	30	0	28	28	66	66	30	0
2029	-18	-13	0	0	25	25	30	0	28	28	66	66	30	0
2030	-19	-13	0	0	25	25	30	0	28	28	66	66	30	0

The portfolios were input into the long-term financial model and then all the stochastic variables discussed in chapter 8 were simulated in the financial model to produce a range of outcomes in financial metrics. The simulation subjected each portfolio to the 80 scenarios of power prices, which are dependent on the 80 scenarios of natural gas prices, regional hydro, and regional renewable generation.

Figure 86 is a plot of each portfolio's 10-year NPV net power cost on the y-axis vs. the standard deviation on the x-axis. Portfolio evaluation involves assessing cost vs. risk. The ideal portfolios can be isolated by fitting a hyperbola, known as the efficient frontier, through the points, as shown in Figure 86. Portfolios situated below the vertex, but still on the efficient frontier, have the least risk for a particular cost bucket. Portfolios that are high cost and high risk, such as Portfolio 5 (acquire a reciprocating engine, wind, and solar resources), have undesirable characteristics and can be quickly eliminated. The ideal portfolio would have a low cost and low risk, but that is generally not achieved as there is usually a tradeoff between cost and risk. It is up to the District to determine the best fit for the utility: lower expected cost with more risk or higher expected cost with less risk (e.g. Portfolio 1 vs. Portfolio 6).

Figure 86: Efficient Frontier and Preferred Portfolios



Preferred Portfolio

The results of the analysis suggest that the least cost versus least risk optimal portfolio is Portfolio 1 (market only portfolio). The cumulative 10-year costs are expected to be over $500,000 less expensive when compared to solar + storage and requires no investment in new technology. During times of uncertainty surrounding Covid-19 and potential impacts to the economy this portfolio was seen as the best option for the district. For these reasons, Portfolio 1 continues to be the preferred portfolio at this point, as it has been for the last several IRPs for several reasons:

1. Gas prices remain in a persistent low price, low volatility scenario. Additionally, regional load growth is in a flat to declining pattern, thus inflation-adjusted power prices are expected to continue to remain as the lowest cost resource for the foreseeable future.
2. There are certain risks that the model is unable to capture which include site risks, regulatory risks, and construction risks, among others. With market purchases, the District maintains a high level of flexibility and can also reduce some of the risk it faces through purchases from other entities ahead of time and locking in a price for the energy.
3. The variability of Portfolio 1, which relies on the market for energy and REC purchases, can be significantly reduced with forward hedging. The District currently has a regimented hedging policy in place that it plans to continue indefinitely. By forward hedging, the District effectively reduces the standard deviation and thus narrows the range of cost variability.
4. In addition to using the market for standard forward, daily, and hourly market purchases the District could consider long-term off-take agreements with existing assets in the market. One example is entering into an agreement to take a slice of generation from non-Federal hydro projects in the region. Another example is entering into a physical heat rate call option with an owner of an existing natural gas fired asset. These alternative choices offer the same physical attributes such as providing capacity and flexibility as developing or acquiring a new resource, but without the development cost and long-term commitment.
5. Washington REC prices remained low through the first and second compliance periods from 2012-2020 despite RPS requirements increasing from 3% to 9%. The continued build out of renewable generation should, and although it is difficult to forecast, warrant that REC prices will remain low for the foreseeable future.
6. The District will continue to monitor market conditions; any dramatic shift in the market may compel the District to revisit its preferred portfolio.

Figure 87 below is the impact of Portfolio 1 on the District's net energy position. The District will continue its practice of utilizing shorter-term power purchases and other instruments to provide additional capacity and financial protection. The benefit of this approach is that the District can target the parts of the year that present the most challenges (summer and winter) while avoiding the carrying costs of a physical asset during "lower risk" parts of the year (spring and fall), when loads are significantly lower. The District will regularly reevaluate this strategy. If there is a fundamental shift in the natural gas or power markets, the preferred portfolio could change.

Figure 87: Energy Net Position of the Preferred Portfolio

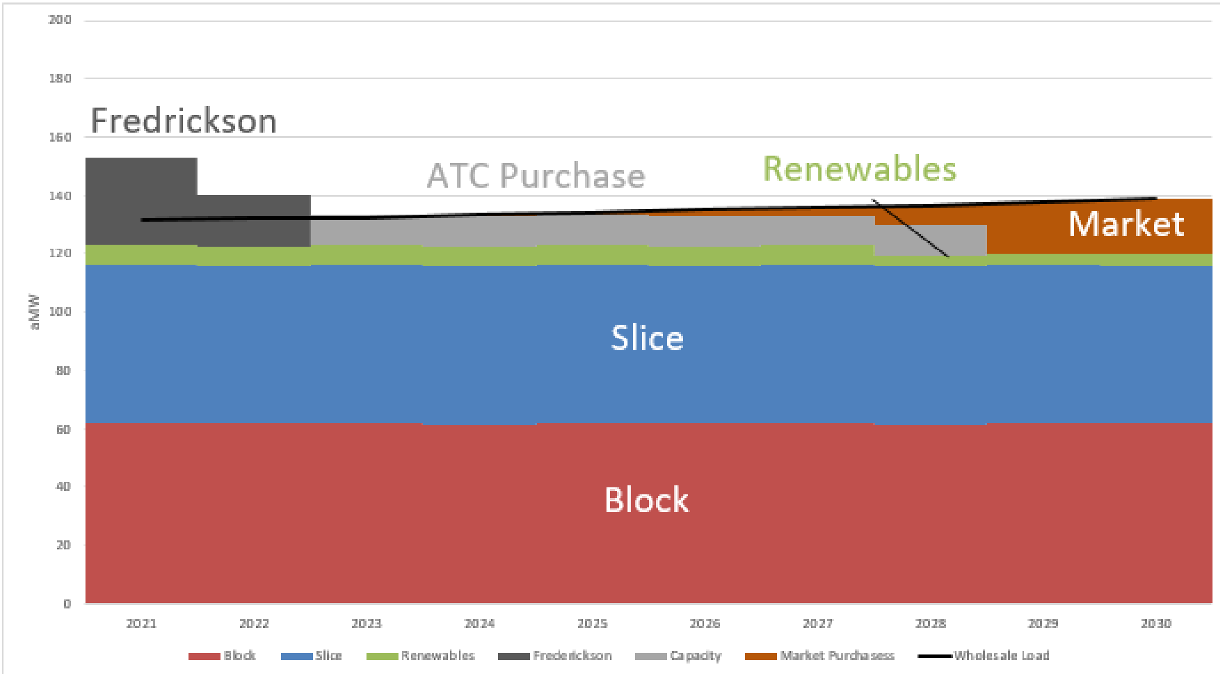
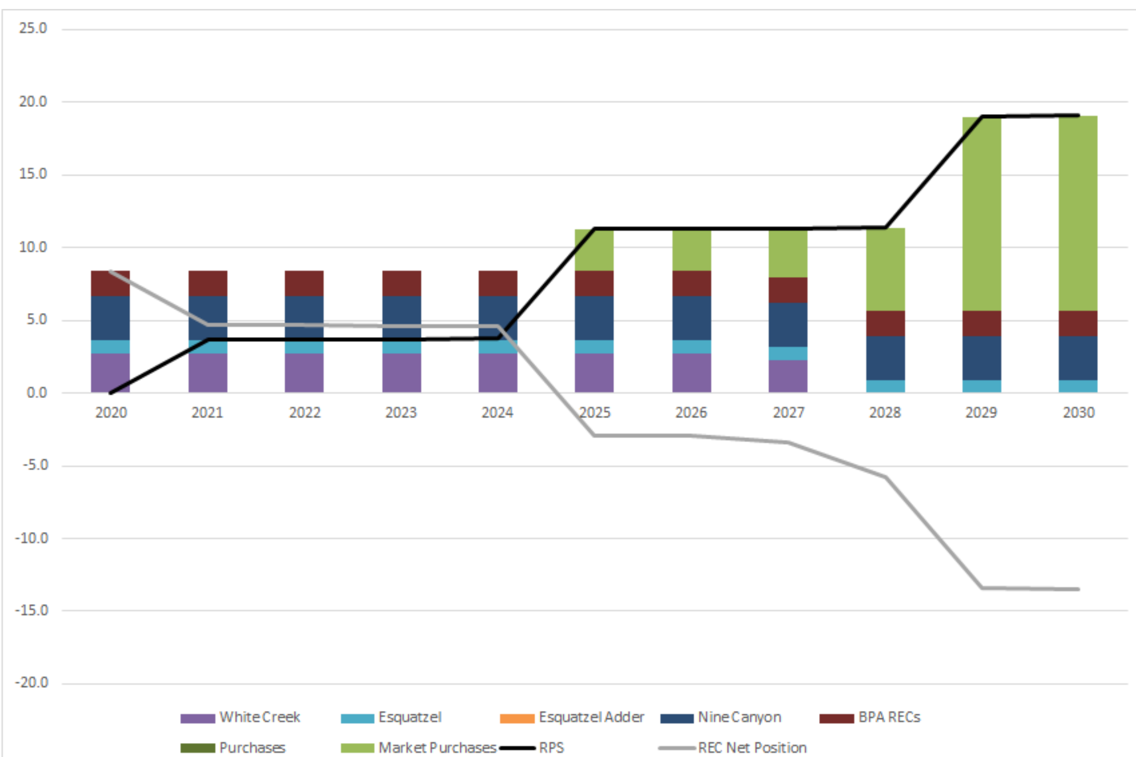


Figure 88: RPS Position - Preferred Portfolio



Chapter 10: Action Plan Summary

The District's IRP defines the District's need for new resources and investigates different generic resource types with an objective of presenting both quantitative and qualitative analysis of the benefits of pursuing different resource technologies to fulfill the District's load and RPS requirements. The District's action plan addresses both resource acquisitions and power supply related issues that will require additional investigation outside of the IRP process.

1. The preferred portfolio to meet energy and REC requirements is to continue to make purchases from the market in the short-to-intermediate term. The District will continue to monitor market conditions to track any significant changes in regional resource sufficiency.
    a. Energy requirements should continue to be met using the 3-year purchase/sale window used by the RMC.
    b. RPS requirements will be met by executing new Renewable Energy Credit (REC) purchase contracts once deficits begin to appear. The District can bank RECs for future use, however, this study does not forecast when the REC bank will be exhausted.
    c. The District will investigate alternative approaches for risk simulation analysis to account for peak loads and capacity needs consistent with the requirements of the NWPP regional RA initiative. This approach should be identified by 9/1/2021.
    d. The District will analyze the impacts of the CAISO's proposed Enhanced Day Ahead Market (EDAM) on the recommendation to use the market as the preferred portfolio to meet energy needs.
    e. If significant new industrial load (greater than 10 MW) commits to the District's service territory, prepare a report that analyzes the impacts on energy purchases and transmission infrastructure.
2. Assuming more will be known about the post 2028 BPA product offering, budget for and prepare a study in 2021 that examines:
    a. Scenarios of BPA supply of energy, capacity, and non-emitting attributes.
    b. Include various changes in the BPA resource, BPA augmentation, and regional loads placing Net Requirements on BPA.
3. The District will continue to monitor the regulatory environment and modify its resource strategy as necessary.
    a. The District will closely monitor CETA rulemaking for impacts to this action plan.
4. The IRP continues to identify the District's summer/winter capacity deficits as an item to closely monitor as the region's coal plants are retired.
    a. Actively monitor the NWPP RA program development.
    b. Develop a white paper that describes a process for determining a Levelized Cost of Capacity for use in the 2022 IRP process. Complete by Aug-2021.
    c. Monitor the Council's LOLP studies and consider longer term resource acquisition for future periods:
        i. Monitor the cost and availability of regional developments of pumped hydro storage, solar plus storage, and standalone battery storage.

    ii. Explore how to and consider developing a demand response potential assessment and supply curves that could be implemented in synergy with the District's smart meters as a potential resource for meeting hourly peak loads.

5. Implement all cost-effective conservation consistent with the requirements and any future amendments of the EIA. This number was 11.49 aMW over 10 years in the November 2019 Conservation Potential Assessment but will continue to evolve as better information becomes available.
6. The District will continue to monitor energy economic fundamentals to ensure that its resource strategy provides rate payers with low cost energy with a low level of risk. Major changes to price and volatility of wholesale electricity, natural gas, and RECs may require changes to the District's plan.
7. The District will continue to take steps to ensure compliance in the 2030-2044 period as well as the 2045 period consistent with prudent utility planning practices. This will include procuring reliable and environmentally compliant assets as the future need arises evaluated in light of the District's relationship with BPA.

Appendix A: Ten Year Load & Customer Forecast

I. LOAD FORECAST UNCERTAINTIES

While every effort is made to have the most accurate forecast possible, the unknown is always a factor when looking five years and ten years into the future. In an effort to mitigate the unknown, three forecasts are studied with the Medium Base Case forecast being adopted as the most expected for current economic conditions and average weather.

Table 1– Load Forecast Summary (including Conservation) shows summarizes the monthly forecasted values for 2021. The base case is the expected, the "high" scenario is 3% higher load than the base case, and the "low" case scenario is 3% lower than the base case.

Date	Base	High	Low
Jan-20	94,079	98,242	89,915
Feb-20	84,029	87,747	80,310
Mar-20	77,817	81,261	74,374
Apr-20	76,426	79,809	73,044
May-20	81,440	85,044	77,836
Jun-20	105,386	110,050	100,722
Jul-20	114,255	119,311	109,198
Aug-20	119,190	124,465	113,915
Sep-20	98,947	103,326	94,569
Oct-20	84,444	88,181	80,707
Nov-20	73,516	76,769	70,262
Dec-20	87,769	91,654	83,885
Jan-21	97,788	102,116	93,461
Feb-21	84,314	88,045	80,582
Mar-21	80,771	84,345	77,196
Apr-21	79,207	82,713	75,702
May-21	84,300	88,031	80,569
Jun-21	109,193	114,025	104,361
Jul-21	118,338	123,575	113,101
Aug-21	123,521	128,987	118,054
Sep-21	102,592	107,133	98,052
Oct-21	87,563	91,438	83,688
Nov-21	76,325	79,703	72,947
Dec-21	91,202	95,238	87,166
Jan-22	98,599	102,962	94,235
Feb-22	84,995	88,757	81,234
Mar-22	81,328	84,928	77,729
Apr-22	79,631	83,155	76,107
May-22	84,648	88,394	80,901
Jun-22	109,748	114,605	104,891
Jul-22	118,895	124,157	113,634

Aug-22	124,173	129,668	118,678
Sep-22	103,185	107,752	98,619
Oct-22	88,079	91,977	84,181
Nov-22	76,866	80,268	73,465
Dec-22	91,930	95,998	87,861
Jan-23	99,425	103,825	95,025
Feb-23	85,693	89,485	81,900
Mar-23	81,897	85,521	78,273
Apr-23	80,070	83,613	76,526
May-23	85,009	88,771	81,247
Jun-23	110,320	115,202	105,438
Jul-23	119,471	124,758	114,183
Aug-23	124,844	130,369	119,319
Sep-23	103,794	108,387	99,201
Oct-23	88,609	92,531	84,688
Nov-23	77,421	80,847	73,995
Dec-23	92,674	96,776	88,573
Jan-24	100,272	104,709	95,834
Feb-24	89,490	93,451	85,530
Mar-24	82,482	86,132	78,831
Apr-24	80,521	84,085	76,958
May-24	85,384	89,163	81,606
Jun-24	110,910	115,818	106,002
Jul-24	120,068	125,381	114,754
Aug-24	125,537	131,093	119,981
Sep-24	104,422	109,043	99,800
Oct-24	89,154	93,100	85,209
Nov-24	77,989	81,440	74,537
Dec-24	93,435	97,570	89,300
Jan-25	101,135	105,610	96,659
Feb-25	87,133	90,989	83,277
Mar-25	83,082	86,759	79,405
Apr-25	80,985	84,569	77,401
May-25	85,774	89,570	81,978
Jun-25	111,519	116,454	106,583
Jul-25	120,680	126,021	115,339
Aug-25	126,248	131,835	120,661
Sep-25	105,063	109,713	100,414
Oct-25	89,712	93,683	85,742
Nov-25	78,571	82,048	75,094
Dec-25	94,213	98,383	90,044
Jan-26	102,017	106,532	97,502
Feb-26	87,877	91,766	83,988
Mar-26	83,696	87,400	79,992
Apr-26	81,466	85,071	77,861
May-26	86,178	89,991	82,364

Jun-26	112,144	117,107	107,181
Jul-26	121,314	126,683	115,946
Aug-26	126,981	132,600	121,361
Sep-26	105,724	110,403	101,045
Oct-26	90,286	94,282	86,291
Nov-26	79,167	82,671	75,664
Dec-26	95,006	99,211	90,802
Jan-27	102,916	107,470	98,361
Feb-27	88,636	92,559	84,714
Mar-27	84,325	88,056	80,593
Apr-27	81,959	85,586	78,332
May-27	86,597	90,429	82,764
Jun-27	112,786	117,778	107,795
Jul-27	121,969	127,367	116,571
Aug-27	127,733	133,386	122,080
Sep-27	106,402	111,111	101,693
Oct-27	90,875	94,896	86,853
Nov-27	79,776	83,306	76,245
Dec-27	95,818	100,058	91,578
Jan-28	103,835	108,430	99,240
Feb-28	92,605	96,703	88,507
Mar-28	84,970	88,730	81,210
Apr-28	82,468	86,118	78,819
May-28	87,031	90,882	83,179
Jun-28	113,448	118,468	108,427
Jul-28	122,642	128,070	117,215
Aug-28	128,505	134,192	122,818
Sep-28	107,096	111,836	102,357
Oct-28	91,478	95,526	87,430
Nov-28	80,401	83,959	76,843
Dec-28	96,647	100,924	92,370
Jan-29	104,774	109,411	100,137
Feb-29	90,204	94,196	86,212
Mar-29	85,630	89,419	81,840
Apr-29	82,991	86,664	79,319
May-29	87,481	91,353	83,610
Jun-29	114,129	119,180	109,079
Jul-29	123,336	128,795	117,878
Aug-29	129,300	135,022	123,578
Sep-29	107,810	112,582	103,039
Oct-29	92,097	96,173	88,021
Nov-29	81,040	84,627	77,454
Dec-29	97,495	101,809	93,180
Jan-30	105,730	110,409	101,051
Feb-30	91,013	95,041	86,985
Mar-30	86,305	90,125	82,486

Apr-30	83,531	87,228	79,834
May-30	87,945	91,837	84,053
Jun-30	114,828	119,910	109,747
Jul-30	124,052	129,542	118,562
Aug-30	130,115	135,873	124,357
Sep-30	108,540	113,344	103,737
Oct-30	92,732	96,836	88,628
Nov-30	81,693	85,308	78,077
Dec-30	98,358	102,711	94,005

Appendix B: 2019 Conservation Potential Assessment

Conservation Potential Assessment

Final Report

November 12, 2019

Prepared by:

EES Consulting

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Kirkland, Washington 98033

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November 12, 2019

Mr. Richard Sargent
Franklin County Public Utility District
P.O. Box 2407
Pasco, WA 99302

SUBJECT: 2019 Conservation Potential Assessment

Dear Mr. Sargent:

Please find attached the final report summarizing the 2019 Franklin County Public Utility District Conservation Potential Assessment (CPA). This report covers the time period from 2020 through 2039. The measures and information used to develop Franklin PUD's preliminary conservation potential incorporate the most current information available for Energy Independence Act (EIA) reporting.

The potential has increased from the 2015 CPA. While the amount of potential decreased in several sectors, these decreases were outweighed by increases in the commercial and industrial sectors, driven by updated data.

We would like to acknowledge and thank you and your staff for the excellent support in developing and providing the baseline data for this project.

Best Regards,

Ted Light

Ted Light
Senior Project Manager

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Kirkland, Washington 98033

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A registered professional engineering corporation with offices in Kirkland, WA and Portland, OR

Contents

Executive Summary

This report describes the methodology and results of the 2019 Conservation Potential Assessment (CPA) for Franklin Public Utility District (Franklin PUD). This assessment provides estimates of energy savings by sector for the period 2020 to 2039. The assessment considers a wide range of conservation resources that are reliable, available and cost-effective within the 20year planning period.

Background

Franklin PUD provides electricity service to approximately 27,180 customers in Franklin County Washington; a service territory that covers approximately 435 square miles and includes 1,041 miles of transmission and distribution lines. The utility has offered conservation programs for over 30 years and continues to include demand-side management resources as priority resources in its resource planning.

Washington's Energy Independence Act (EIA), effective January 1, 2010 and modified October 4, 2016, requires that utilities with more than 25,000 customers (known as qualifying utilities) pursue all cost-effective conservation resources and meet conservation targets set using a utilityspecific conservation potential assessment methodology.

The EIA sets forth specific requirements for setting, pursuing and reporting on conservation targets. The methodology used in this assessment complies with RCW 19.285.040 and WAC 19437-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Seventh Power Plan. Thus, this Conservation Potential Assessment will support Franklin PUD's compliance with EIA requirements.

This assessment was built on a model which was based on the completed Seventh Power Plan. The model was subsequently updated, to reflect changes since the completion of the Seventh Plan. The primary model updates included the following:

- New Avoided Costs
  - Recent forecast of power market prices
  - Updated values for avoided generation capacity
  - New transmission and distribution capacity costs based on new values from the Council
- Updated Customer Characteristics Data
  - New residential home counts
  - Updated commercial floor area
  - Updated industrial sector consumption
- Measure Updates
  - Measure savings, costs, and lifetimes were updated based on the latest updates available from the Regional Technical Forum (RTF)
  - New measures not included in the Seventh Plan but subsequently reviewed by the RTF were added
- Accounting for Recent Achievements
  - Internal programs

- NEEA programs

The first step of this assessment was to carefully define and update the planning assumptions using the current data and forecasts. The Base Case conditions were defined as the most likely market conditions over the planning horizon, and the conservation potential was estimated based on these assumptions. Additional scenarios were also developed to test a range of conditions and evaluate risk.

Results

Table ES-1 shows the high-level results of this assessment. The economically achievable potential by sector in 2, 6, 10, and 20-year increments is included. The total 20-year energy efficiency potential is 17.88 aMW. The most important numbers per the EIA are the 10-year potential of 11.49 aMW, and the two-year potential of 1.67 aMW.

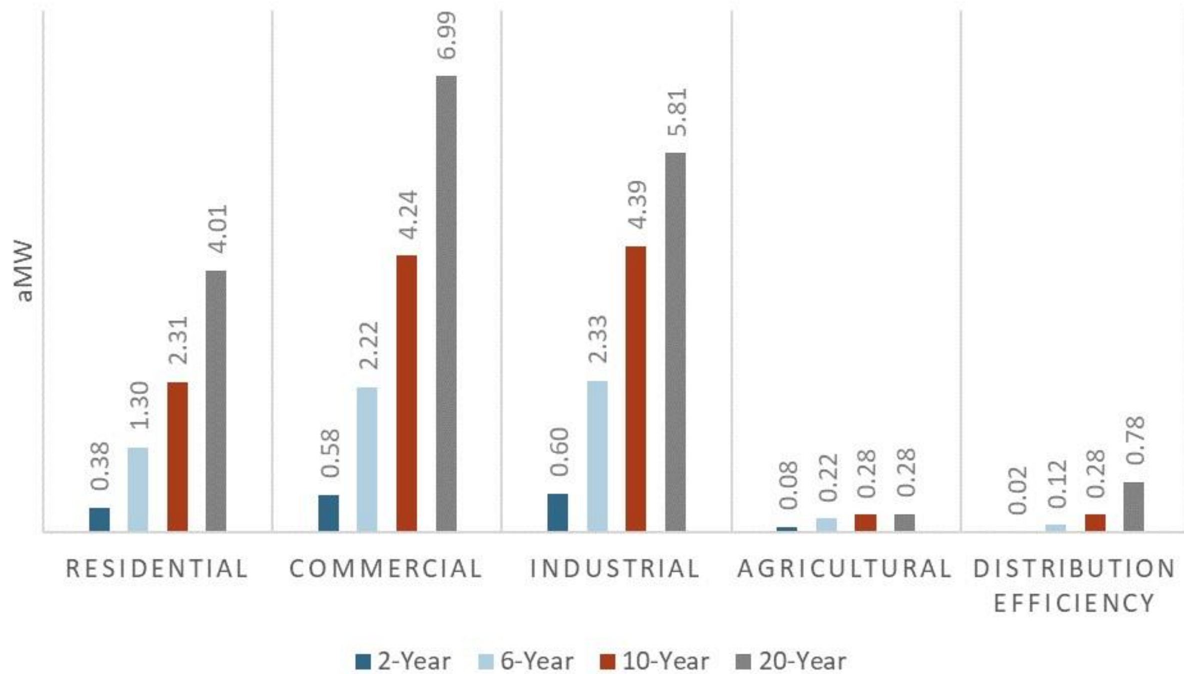
These estimates include energy efficiency that could be achieved through Franklin PUD's utility programs and also through Franklin PUD's share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. Some code and standard changes may also account for part of the potential, especially in the later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA's Momentum Savings work.

Table ES-1
Cost Effective Potential (aMW)

	2-Year*	6-Year	10-Year	20-Year
Residential	0.38	1.30	2.31	4.01
Commercial	0.58	2.22	4.24	6.99
Industrial	0.60	2.33	4.39	5.81
Agricultural	0.08	0.22	0.28	0.28
Distribution Efficiency	0.02	0.12	0.28	0.78
Total	**1.67**	**6.19**	**11.49**	**17.88**

**2020 and 2021*
Note: Numbers in this table and others throughout the report may not add to total due to rounding.

Figure ES-1
Cost-Effective Potential



Energy efficiency also has the potential to reduce peak demands. Based upon hourly load profiles developed for the Seventh Power Plan and load data provided by Franklin PUD, the reductions in peak demand provided by energy efficiency are summarized in Table ES-2 below. Franklin PUD's annual peak occurs in the summer evenings. In addition to these peak demand savings, demand savings would occur throughout the year.

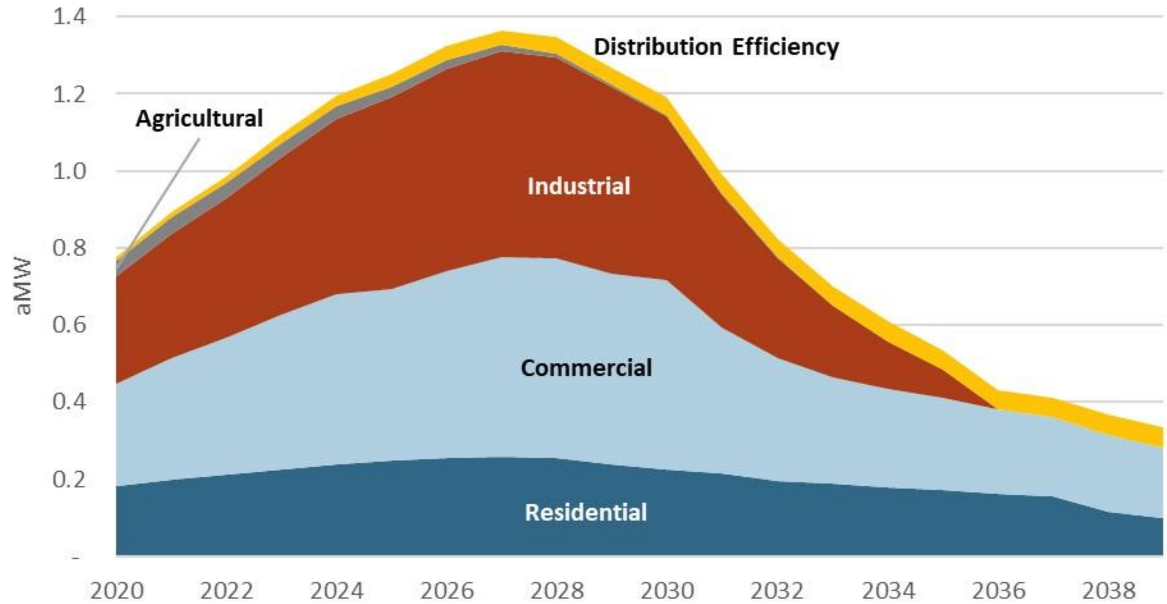
Table ES-2
Cost Effective Demand Savings - Base Case (MW)

	2-Year	6-Year	10-Year	20-Year
Residential	1.14	3.49	5.66	9.00
Commercial	0.91	3.37	6.26	10.25
Industrial	0.66	2.50	4.63	6.08
Agricultural	0.02	0.05	0.07	0.07
Distribution Efficiency	0.02	0.15	0.34	0.97
Total	**2.75**	**9.56**	**16.96**	**26.37**

The 20-year energy efficiency potential is shown on an annual basis in Figure ES-2. This assessment shows annual potential starting at 0.77 aMW in 2020 and ramping up to 1.37 aMW in 2025. Ramp rates from the Northwest Power and Conservation Council's (Council) Seventh Power Plan technical documentation were used to develop the annual savings potential estimates over the 20-year study. In some instances, alternate ramp rates were assigned to measures to better fit Franklin PUD's recent program history.

Figure ES-2

Annual Cost-Effective Energy Efficiency Potential Estimates



Relative to the 2015 CPA, the amount of cost-effective potential in the residential sector has decreased. Much of the change is due to lighting standards scheduled to take effect in 2020. These standards require efficiency levels only found in CFLs and LEDs; and with CFLs losing market share to LEDs, energy efficiency programs may not be necessary for residential lighting. While there is some uncertainty about whether the federal standard will be implemented, Washington state recently enacted identical standards, also scheduled to take effect in 2020. Accordingly, residential lighting measures have not been included in this CPA. The remaining conservation potential in the residential sector is among the water heating and HVAC end uses. Notable areas for achievement in the residential sector include:

- HVAC-related measures, including weatherization and duct sealing
- Water heating measures like heat pump water heaters and clothes washers

Significant conservation is also available in Franklin PUD's commercial sector. Notable areas for commercial sector savings potential include:

- Lighting – including exterior, street and roadway and LPDs
- Commercial HVAC measures like rooftop unit controllers
- Refrigeration – including grocery refrigeration measures

Industrial potential contributes to Franklin PUD's conservation potential as well and consists largely of energy management and refrigeration end uses.

Comparison to Previous Assessment

Table ES-3 shows a comparison of the 10 and 20-year Base Case conservation potential by customer sector for this assessment and the results of Franklin PUD's 2015 CPA.

Table ES-3 Comparison of 2015 CPA and 2019 CPA Cost-Effective Potential						
	10-Year			**20-Year**		
	2015	**2019**	**% Change**	**2015**	**2019**	**% Change**
Residential	2.29	2.31	1%	4.64	4.01	-13%
Commercial	1.33	4.24	219%	2.50	6.99	180%
Industrial	1.91	4.39	130%	2.49	5.81	133%
Agricultural	1.97	0.28	-86%	4.30	0.28	-93%
Distribution Efficiency	0.24	0.28	15%	0.67	0.78	16%
Total	**7.74**	**11.49**	**48%**	**14.60**	**17.88**	**22%**

**Note that the 2015 columns refer to the CPA completed in 2015 for the time period of 2016 through 2035. The 2018 assessment is for the timeframe: 2020 through 2039.*

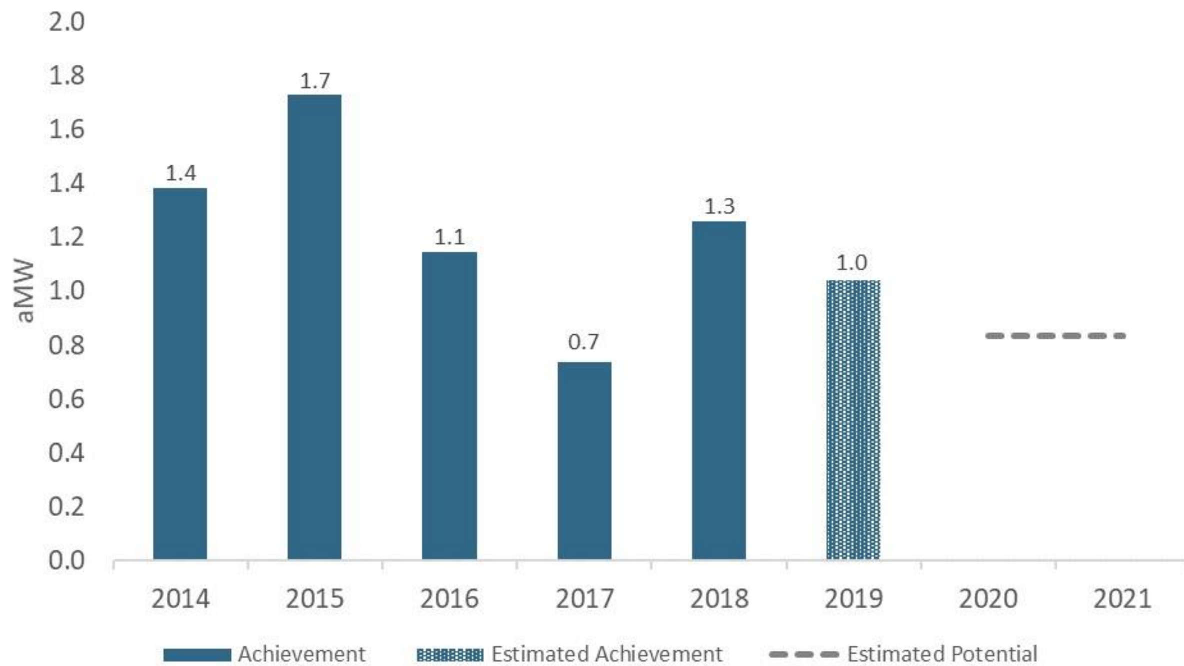
The overall results of this 2019 assessment are higher than the 2015 results. Residential potential has decreased due to the above-mentioned changes to lighting standards. The commercial sector has grown in potential from the 2015 CPA, driven in part by updated tax assessor data producing a higher estimate of commercial floor space. The industrial potential has also grown, largely as a result of changes in the saturation assumptions from the draft Seventh Plan materials (used in the 2015 CPA) to the final draft used in this assessment. Industrial sector forecasted load growth has also increased modestly from the previous assessment. Potential in the agriculture sector has decreased, largely due to the exclusion of scientific irrigation scheduling savings after recent evaluations did not identify savings associated with this measure.

Additionally, the Council updated its assumptions on the value of deferred transmission and distribution capital expenditures, with the new values being significantly lower. The extent to which each measure realizes these values depends on its contribution to reducing peak demands, so measures in the residential and commercial sectors, which tend to contribute more to reducing system peaks, were more impacted. Savings in the industrial sector tend to be more evenly distributed across time, so the changes in assumptions had less of an impact to the industrial sector.

Targets and Achievement

Figure ES-3 compares Franklin PUD's historic conservation achievement with the estimated potential for 2020 and 2021. The figure shows that Franklin PUD has consistently achieved conservation levels in line with the estimated potential for the coming biennium and that the potential estimates presented in this report are achievable through Franklin PUD's utility conservation programs and the utility's share of NEEA savings.

Figure ES-3
Historic Achievement and Estimated Potential



Conclusion

This report summarizes the CPA conducted for Franklin PUD for the 2020 to 2039 timeframe. Based on the results of the Base Case scenario, the total 10-year cost effective potential is 11.49 aMW and the 2-year potential is 1.67 aMW. This assessment results in slightly higher potential than the previous assessment, largely due to updated commercial floor space and model updates from the 2015 CPA. The exclusion of many residential lighting measures as well as the change in the valuation of transmission and distribution capacity costs has impacted the potential estimate as well. The avoided cost assumptions are discussed further in Appendix IV.

Introduction

Objectives

The objective of this report is to describe the results of the Franklin Public Utility District (Franklin PUD) 2019 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2020 to 2039, with the primary focus on 2020 to 2029 (10 years). This analysis has been conducted in a manner consistent with requirements set forth in 19.285 RCW (EIA) and 194-37 WAC (EIA implementation) and is part of Franklin PUD's compliance documentation. The results and guidance presented in this report will also assist Franklin PUD in strategic planning for its conservation programs in the near future.

The conservation measures used in this analysis are based on the measures included in the Northwest Power and Conservation Council's Seventh Power Plan and updated where appropriate with subsequent changes approved by the Regional Technical Forum (RTF). The assessment considered a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

Energy Independence Act

Chapter 19.285 RCW, the Energy Independence Act, requires that, "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." The timeline for requirements of the Energy Independence Act are detailed below:

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the Pacific Northwest Power and Conservation Council's (Council) latest power planning document.
- By January 1 of each even-numbered year, 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 ten years.
- By June 1 of each year, each utility shall submit an annual conservation report to the department (the department of commerce or its successor). The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.
- Beginning on January 1, 2014, cost-effective conservation achieved by a qualifying utility in excess of its biennial acquisition target may be used to help meet the immediately subsequent two biennial acquisition targets, such that no more than twenty percent of any biennial target may be met with excess conservation savings.

Other Legislative Considerations

Washington state recently enacted several laws that impact conservation planning. Washington's Clean Energy Transformation Act (CETA) has several components that impact conservation planning. First it requires the use of a specific social cost of carbon in utility planning. It also sets several requirements for the retail sales of electricity to be from greenhouse gas free or renewable sources. Franklin PUD assumes the current social cost of carbon in the EIA to be unaffected by the new law but will incorporate any changes adopted in the rulemaking process in the next biennium.

Washington HB 1444 enacts efficiency standards for a variety of appliances, some of which are included as measures in this CPA. This law takes effect on July 28, 2019 and applies to products manufactured after January 1, 2021. As the law applies to the manufacturing date, products not meeting the efficiency levels set forth in the law could continue to be sold in 2021 and a reasonable time of six months or more may be necessary for product inventories to turn over. As such, the standards contained in this law will be addressed in the 2021 CPA.

This report summarizes the preliminary results of a comprehensive CPA conducted following the steps provided for a Utility Analysis. A checklist of how this analysis meets EIA requirements is included in Appendix III.

Study Uncertainties

The savings estimates presented in this study are subject to the uncertainties associated with the input data. This study utilized the best available data at the time of its development; however, the results of future studies will change as the planning environment evolves. Specific areas of uncertainty include the following:

- Customer characteristic data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that Franklin PUD's service area is similar to that of the region, or that the regional survey data represents the population.
- Measure data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Council and RTF, will vary across the region. In some cases, measure applicability or other attributes have been estimated by the Council or the RTF based on professional judgment or limited market research.
- Market price forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, risk credits are included in the analysis to mitigate the market price risk over the study period.
- Utility system assumptions – Credits have been included in this analysis to account for the avoided costs of transmission and distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits to be representative estimates of these avoided costs.
- Discount rate –This CPA uses a discount rate that is specific to Franklin PUD. The rate reflects the current borrowing market although changes in borrowing rates will likely vary over the study period.

- Forecasted load and customer growth – The CPA bases the 20-year potential estimates on forecasted loads and customer growth. Each of these forecasts includes a level of uncertainty.
- Load shape data – The Council provides conservation load shapes for evaluating the timing of energy savings. In practice, load shapes will vary by utility based on weather, customer types, and other factors. This assessment uses the hourly load shapes used in the Seventh Plan to estimate peak demand savings over the planning period, based on shaped energy savings. Since the load shapes are a mix of older Northwest and California data, peak demand savings presented in this report may vary from actual peak demand savings.
- Frozen Efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

Due to these uncertainties and the changing environment, under the EIA, qualifying utilities must update their CPAs every two years to reflect the best available information.

Report Organization

The main report is organized with the following main sections:

- Methodology – CPA methodology along with some of the overarching assumptions
- Recent Conservation Achievement – Franklin PUD's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions

- Results – Energy Savings and Costs – Primary base case results
- Scenario Results – Results of all scenarios
- Summary
- References & Appendices

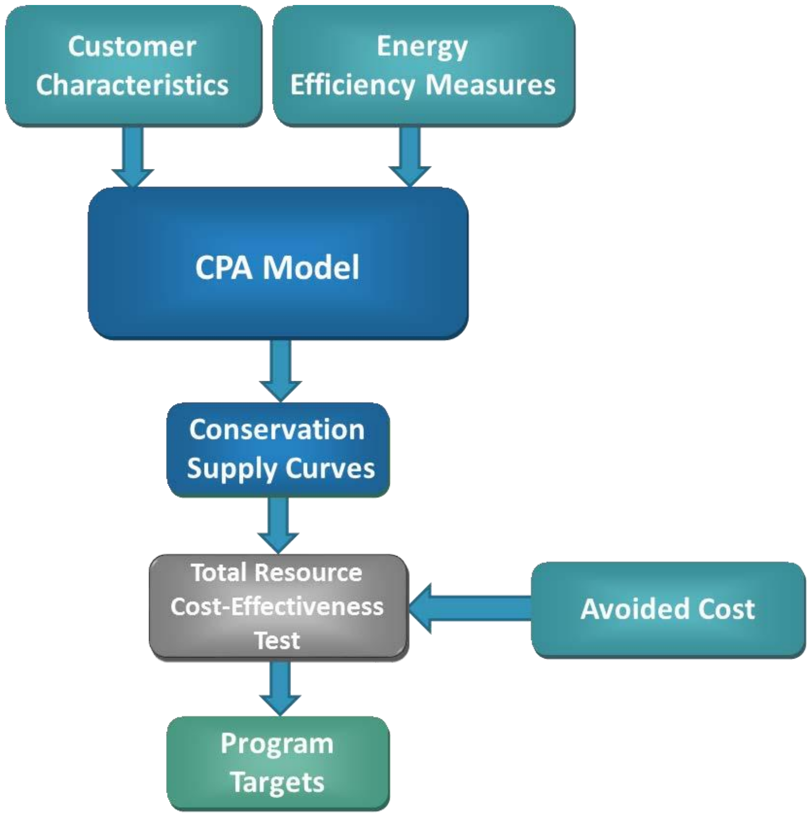
Methodology

This study is a comprehensive assessment of the energy efficiency potential in Franklin PUD's service area. The methodology complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Seventh Power Plan. This section provides a broad overview of the methodology used to develop Franklin PUD's conservation potential target. Specific assumptions and details of methodology as it pertains to compliance with the EIA are provided in Appendix III of this report.

Basic Modeling Methodology

The basic methodology used for this assessment is illustrated in Figure 1. A key factor is the kilowatt hours saved annually from the installation of an individual energy efficiency measure. The savings from each measure is multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure are then aggregated to produce the total potential.

Figure 1
Conservation Potential Assessment Process



Customer Characteristic Data

Assessment of customer characteristics includes estimating both the number of locations where a measure could feasibly be installed, as well as the share—or saturation—of measures that have already been installed. For this analysis, the characterization of Franklin PUD's service territory was determined using data from the Northwest Energy Efficiency Alliance (NEEA) commercial and residential building stock assessments. Details of data sources and assumptions are discussed for each sector later in the report.

This assessment also sourced baseline measure saturation data from the Council's Seventh Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources. This data was updated with NEEA's 2016 Residential Building Stock Assessment and Franklin PUD's historic conservation achievement data, where applicable. Franklin PUD's historic achievement is discussed in detail in the next section.

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings, demand savings, measure costs, and measure life. Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The Council's Seventh Power Plan is the primary source for conservation measure data. Where appropriate, the Council's Seventh Plan supply curve workbooks have been updated to include any subsequent updates from the RTF. New measures reviewed by the RTF were also added to the model.

The measure data include adjustments from raw savings data for several factors. The effects of space-heating interaction, for example, are included for all lighting and appliance measures, where appropriate. For example, if an electrically-heated house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the electric heating system. These interaction factors are included in measure savings data to produce net energy savings.

Other financial-related data needed for defining measure costs and benefits include: discount rate, avoided costs, line losses, and deferred capacity expansion benefits.

A list of measures by end-use used in this CPA is included in Appendix VI.

Types of Potential

Once the customer characteristics and energy efficiency measures are fully described, energy efficiency potential can be quantified. Three types of potential are used in this study: technical, achievable, and economic or cost-effective potential. Technical potential is the theoretical maximum efficiency in the service territory if cost and market barriers are not considered. Market barriers and other consumer acceptance constraints reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 2 illustrates the three types of potential followed by more detailed explanations.

Figure 2
Types of Energy Efficiency Potential[25]

Technical – Technical potential is the amount of energy efficiency potential that is available, regardless of cost or other technological or market constraints, such as customer willingness to adopt a given measure. It represents the theoretical maximum amount of energy efficiency that is possible in a utility's service territory absent these constraints.

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Additionally, the number of applicable units must be estimated. Applicable units are the units across a service territory where the measure could feasibly be installed. This includes accounting for units that may have already be installed the measure. The value is highly dependent on the measure

[25] Reproduced from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency.* Figure 2-1, November 2007

and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. A saturation factor accounts for measures that have already been completed.

In addition, technical potential considers the interaction and stacking effects of measures. For example, interaction occurs when a home installs energy efficient lighting and the demands on the heating system rise due to a reduction in heat emitted by the lights. If a home installs both insulation and a high-efficiency heat pump, the total savings of these stacked measures is less than if each measure were installed individually because the demands on the heating system are lower in a well-insulated home. Interaction is addressed by accounting for impacts on other energy uses. Stacked measures within the same end use are often addressed by considering the savings of each measure as if it were installed after other measures that impact the same end use.

The total technical potential is often significantly more than the amount of achievable and economic potential. The difference between technical potential and achievable potential is a result of the number of measures assumed to be unaffected by market barriers. Economic potential is further limited due to the number of measures in the achievable potential that are not cost-effective.

Achievable Technical – Achievable technical potential, also referred to as achievable potential, is the amount of potential that can be achieved with a given set of market conditions. Achievable potential considers many of the realistic barriers to adopting energy efficiency measures. These barriers include market availability of technology, consumer acceptance, non-measure costs, and the practical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure. The Council assumes a maximum achievability of 85% for all measures over the 20-year study period. This is a consequence of a pilot program offered in Hood River, Oregon where home weatherization measures were offered at no cost. The pilot was able to reach over 90% of homes. The Council also uses a variety of ramp rates to estimate the rate of achievement over time. This CPA follows the Council's methodology, including the both the achievability and ramp rate assumptions.

Economic – Economic potential is the amount of potential that passes an economic benefit-cost test. In Washington State, EIA requirements stipulate that the total resource cost test (TRC) be used to determine economic potential. The TRC includes all costs and benefits of the measure regardless of who pays a cost or receives the benefit. Costs and benefits include the following: capital cost, O&M cost over the life of the measure, disposal costs, program administration costs, environmental benefits, distribution and transmission benefits, energy savings benefits, economic effects, and non-energy savings benefits. Non-energy costs and benefits can be difficult to enumerate, yet non-energy costs are quantified where feasible and realistic. Examples of nonquantifiable benefits might include: added comfort and reduced road noise from better insulation or increased real estate value from new windows. A quantifiable non-energy benefit might include reduced detergent costs or reduced water and sewer charges from energy efficient clothes washers.

For this potential assessment, the Council's ProCost model was used to determine cost effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2019 CPA evaluates measure savings on an hourly basis, but ultimately values the energy savings during two segments covering high and low load hour time periods.

Avoided Cost

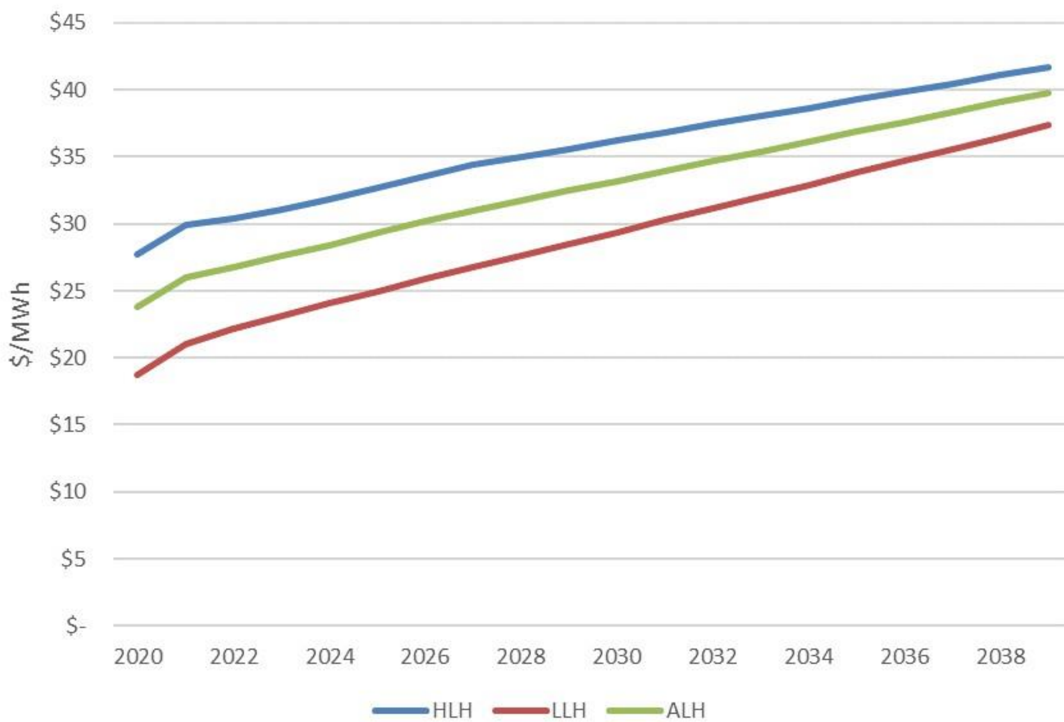
The avoided cost of energy is the cost that is avoided through the acquisition of energy efficiency in lieu of other resources. Avoided costs are used to value energy savings benefits when conducting cost effectiveness tests and are included in the numerator in a benefit-cost test. The avoided costs typically include energy-based values ($/aMW) and values associated with the demand savings ($/kW) provided by energy efficiency. These energy benefits are often based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the resource planning process.

Energy

Figure 3 shows the market price forecast that was used as the primary avoided cost component for the planning period. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (ALH).

Figure 3

20-Year Market Price Forecast (Mid-Columbia)



The EIA requires that utilities "…set avoided costs equal to a forecast of market prices." As discussed in Appendix IV, Franklin PUD currently meets peak demands through market purchases; therefore the market price forecast shown in Figure 3 is appropriate for modeling the value of avoided energy.

Social Cost of Carbon & Renewable Energy Credits

In addition to the avoided cost of energy, energy efficiency provides the benefit of reducing carbon emissions. The EIA rules require the inclusion of the social cost of carbon. California's capand-trade carbon market prices were used in the base case, as these represent the closest analogue to a carbon market. Prices in the California market are currently near $15 per metric ton and are expected to rise to near $16 in 2020. The price floor in California's market is stipulated to rise at 5% plus inflation, so that escalation rate was used. These prices are similar to those included in carbon policies that have been recently considered in Washington state. These values were used in the development of the results discussed in this report. Additional scenarios considered other values.

Related to the social cost of carbon is the value of renewable energy credits. Washington's Energy Independence Act established a Renewable Portfolio Standard (RPS) for utilities with 25,000 or more customers. In 2020, utilities are required to source 15% of all electricity sold to retail customers from renewable energy resources. Conservation can reduce the cost of this requirement by reducing Franklin PUD's load. Further details are discussed in Appendix IV.

Transmission and Distribution System Benefits

The EIA requires that deferred capacity expansion benefits for transmission and distribution systems be included in the cost-effectiveness analysis. To account for the value of deferred transmission and distribution system expansion, Council staff developed a distribution system credit value of $6.33/kW-year and a transmission system credit of $2.85/kw-year applied to peak savings from conservation measures, at the time of the regional transmission and local distribution system peaks. These values were developed in preparation for the 2021 Power Plan. ***Generation Capacity***

New to the Seventh Plan was the explicit calculation of a value for avoided generation capacity costs. The Council reasoned that in pursuing energy efficiency, in each year it was deferring the cost of a generation unit to meet the region's capacity needs. Based upon the cost savings of deferring this cost for 30 years, the Council estimated a generation capacity value of $115/kWyear.

As a slice block customer of BPA, Franklin PUD can purchase capacity when needed and sell excess capacity when it is not. Thus, saved capacity represents either an avoided cost of purchased capacity or an opportunity cost of capacity that could potentially be sold.

To represent the value of capacity, EES used BPA's monthly demand charges as a proxy value for the monthly value of generation capacity, as those charges are based upon the cost of a gas generating unit. EES also applied a monthly shape to approximate Franklin PUD's peak demand reductions due to conservation.

With these two factors, the value of generation capacity was calculated to be $85/kW-year. For the base case, it was assumed the demand charges would increase in real terms by 3% annually. Over the 20-year analysis period, the resulting cost of avoided capacity is $109/kW-year (2012$) in levelized terms. Additional scenarios considered other values.

Risk Analysis

In Franklin PUD's 2015 CPA included risk mitigation credits in the scenario analysis to account for risks that were not quantified. Rather than including an explicit risk credit in each of the scenarios, this CPA addresses the uncertainty of the inputs by varying the avoided cost values. The avoided cost components that were varied included the energy prices, generation capacity value, and the social cost of carbon. Through the variance of these components, implied risk credits of up to $32/MWh and $109/kW-year were included in the avoided cost. For reference, in the past, the Council has calculated risk credits using stochastic portfolio modeling resulting in risk mitigation credits of up to $55/MWh ($2016) depending on the value of the avoided cost inputs.

Additional information regarding the avoided cost forecast and risk mitigation credit values is included in Appendix IV.

Pacific Northwest Electric Power Planning and Conservation Act Credit

Finally, a 10% benefit was added to all avoided cost components as required by the Pacific Northwest Electric Power Planning and Conservation Act.

Discount and Finance Rate

The Council develops real discount rate assumptions for each of its Power Plans. The most recent real discount rate assumption developed by the Council is 3.75%, which has been proposed for the 2021 Power Plan. Franklin PUD has used this discount rate to model conservation potential for this assessment. The discount rate is used to convert future cost and benefit streams into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives.

In addition, the Council uses a finance rate that is developed from two sets of assumptions. The first set of assumptions describes the relative shares of the cost of conservation distributed to various sponsors. Conservation is funded by the Bonneville Power Administration, utilities, and customers. The second set of assumptions looks at the financing parameters for each of these entities to establish the after-tax average cost of capital for each group. These figures are then weighted, based on each group's assumed share of project cost to arrive at a composite finance rate.

Recent Conservation Achievement

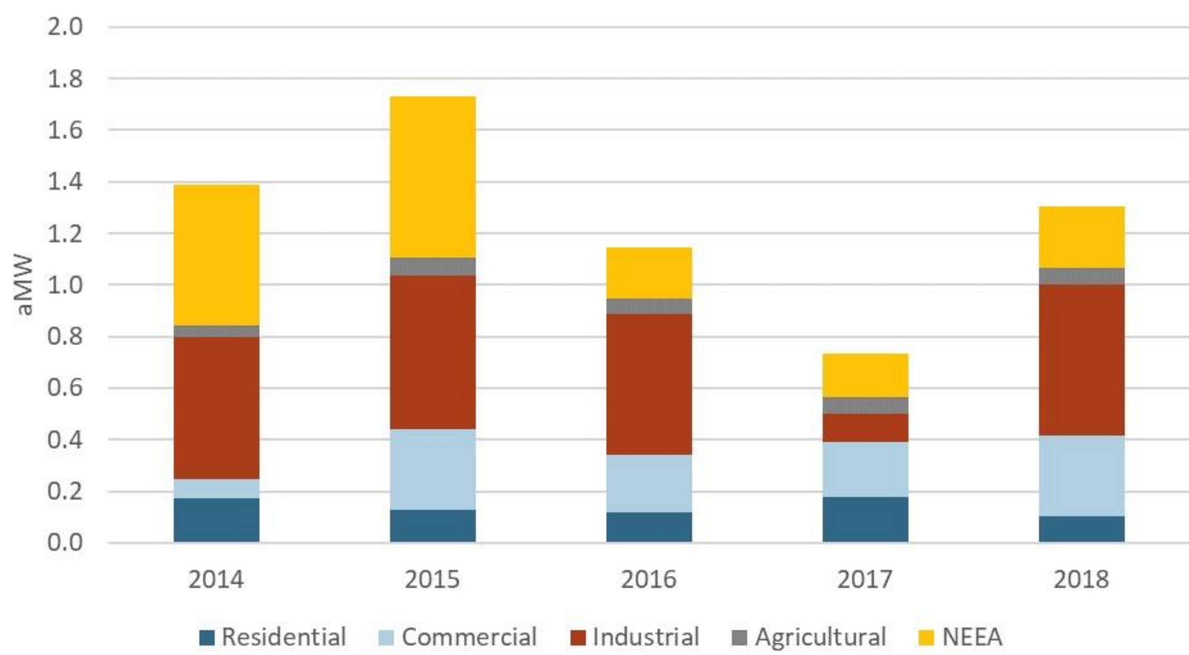
Franklin PUD has pursued conservation and energy efficiency resources since the early 1980s. The utility currently offers several rebate and incentive programs for both residential and nonresidential customers. Residential customers can participate in weatherization, HVAC and appliance rebate programs and non-residential customers can take part in rebate programs for irrigation management, building lighting, refrigeration and other measures targeted at commercial and industrial customers.

Figure 4 details the distribution of conservation among the utility's customer sectors and through Northwest Energy Efficiency Alliance (NEEA) efforts over the past five years. In this time period roughly one third of savings came from the industrial sector. Franklin PUD's conservation achievement has averaged 1.26 aMW per year since 2014. More detail for these savings is provided below for each sector.

Savings from NEEA declined significantly in 2016. The decline was caused by the adoption of the Seventh Power Plan, which resets the baseline against which NEEA's market transformation savings are claimed. As NEEA's work to transform markets continues and its initiatives continue to build market share of efficient products, the savings will continue to grow, as is apparent below. NEEA's work helps bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters to the Northwest markets.

Figure 4

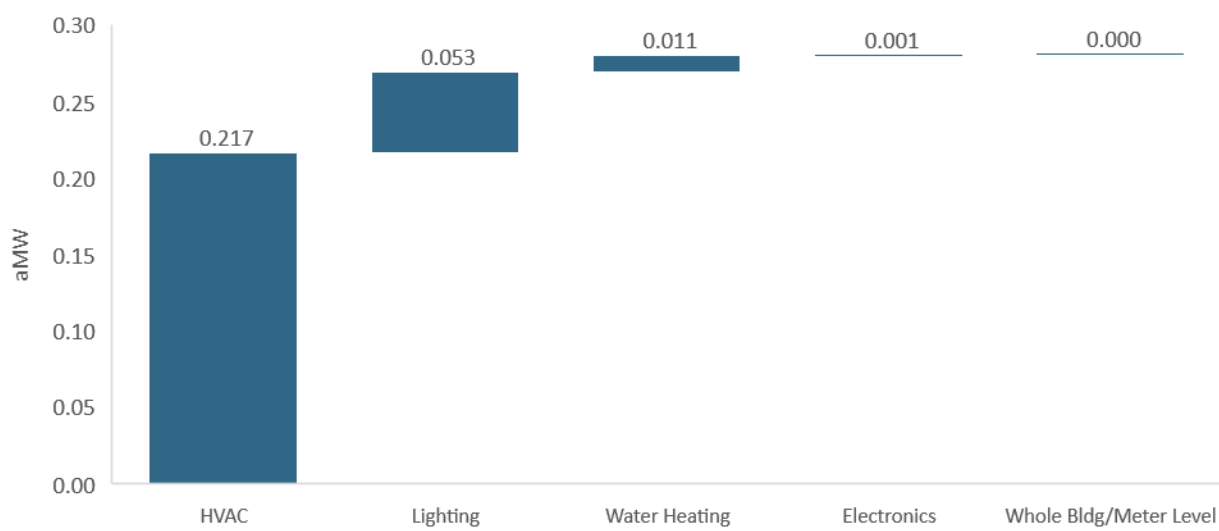
Franklin PUD's Recent Conservation History by Sector



Residential

Figure 5 shows conservation achievement by end use in the residential sector, from 2017 and 2018 savings. Due to the large share of electric heat in Franklin PUD's service area, the HVAC category, which includes measures like heat pumps and weatherization measures, make up a significant share of savings. Whole Building measures include NEEM manufactured homes.

Figure 5
2017-2018 Residential Savings



Commercial & Industrial

Historic achievement in the commercial sector is primarily due to lighting. Figure 6 shows the breakdown of 2017 and 2018 commercial savings.

Figure 6
2017-2018 Commercial Savings

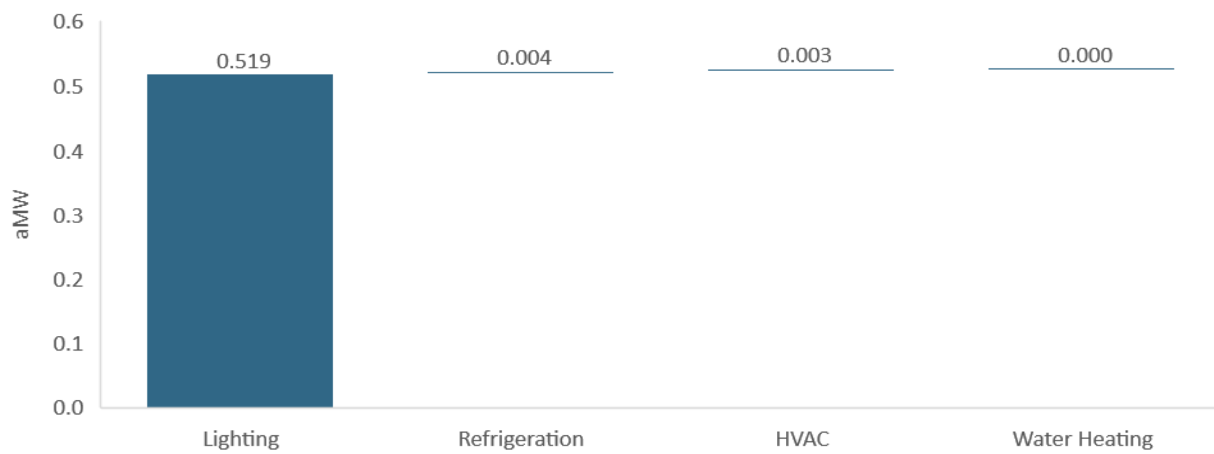
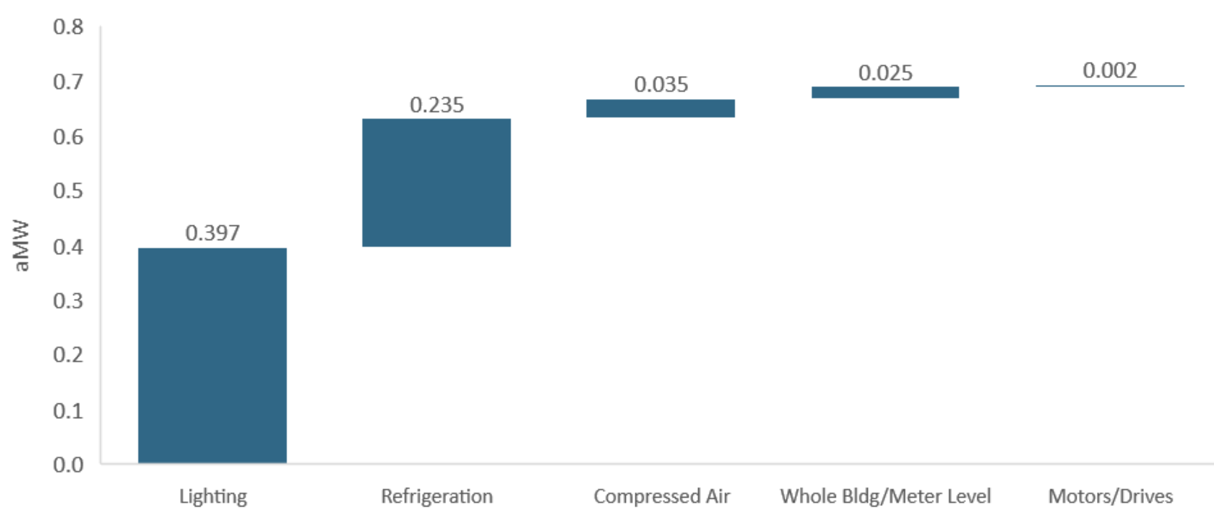


Figure 7 shows the breakdown of 2017 and 2018 industrial savings.

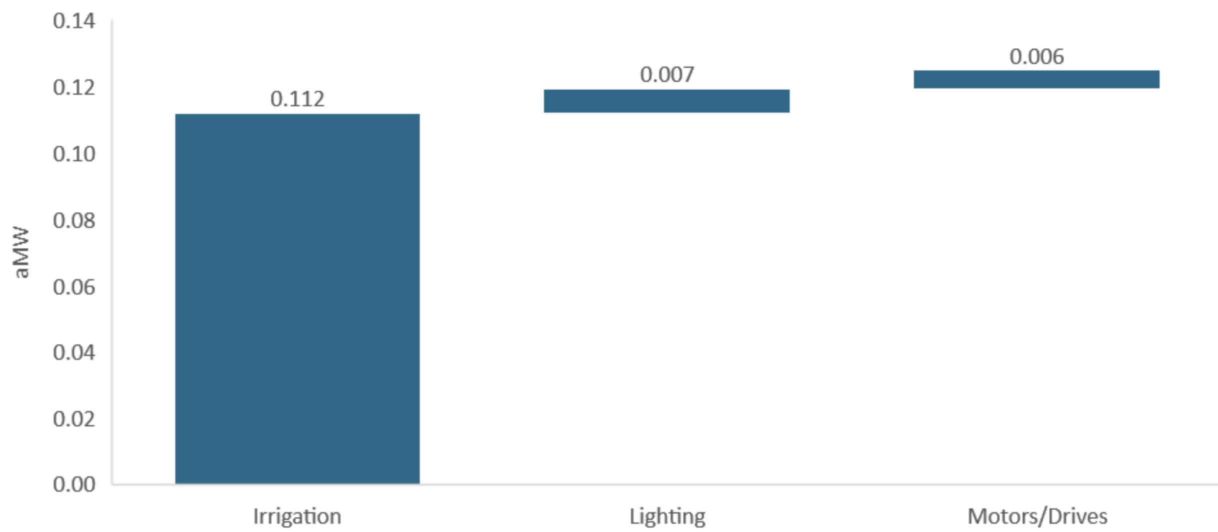
Figure 7
2017-2018 Industrial Savings



Agriculture

Figure 8 shows the 2017 and 2018 agriculture savings, the majority of which are in the irrigation end use.

Figure 8
2017-2018 Agriculture Savings



Current Conservation Programs

Franklin PUD offers several conservation programs for residential customers. Franklin PUD's current conservation program offerings are detailed below. Agriculture, commercial and industrial rebates are offered on a case-by-case basis .

Residential Programs

- *Energy Star Rebates* – Franklin PUD offers a $25 rebate for Energy Star clothes washers and a $50 rebate for clothes dryers.
- *Weatherization* – Franklin PUD offers rebates for insulation and holds a winter weatherization workshop, at which one weatherization kit is given per household.
- *Education* – In addition to the incentives described above, Franklin PUD offers detailed educational materials on its website to inform customers about how to conserve energy.

Summary

Franklin PUD plans to continue offering incentives for energy efficiency investments. The results of this study will help Franklin PUD program managers in strategic planning for energy efficiency program offerings, incentive levels, and program review.

Customer Characteristics Data

Franklin PUD serves approximately 27,180 electric customers in Franklin County, Washington, with a service area population of nearly 81,600. A key component of an energy efficiency assessment is to understand the characteristics of these customers – primarily the building and end-use characteristics. These characteristics are described below for each customer sector.

Residential

For the residential sector, the key characteristics include house type, space heating fuel, and water heating fuel. Table 1 shows relevant residential data for single family, multi-family and manufactured homes in Franklin PUD's service territory. The data is based on the Northwest Energy Efficiency Alliance's (NEEA) 2016 Residential Building Stock Assessment (RBSA) as well as data from the US Census. The data shown in Table 1 provides estimates of the current residential characteristics in Franklin PUD's service territory and are utilized as the baseline in this study. The number of homes using electric heat has increased from the 2015 CPA, while estimates of homes using electric forced air furnaces has decreased.

This assessment assumes an average annual residential growth rate of 2 percent.

Table 1
Residential Building Characteristics

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	24,740	81,599

	Single Family	Multifamily Low Rise	Multifamily High Rise	Manufactured
Heating / Cooling System Saturations				
Electric Forced Air Furnace (FAF)	7%	16%	16%	56%
Heat Pump (HP)	50%	0%	0%	19%
Ductless HP (DHP)	2%	0%	0%	0%
Electric Zonal (Baseboard)	7%	67%	67%	0%
Central AC	63%	12%	12%	45%
Room AC	30%	63%	63%	49%
Appliance Saturations				
Electric Water Heat	70%	77%	77%	94%
Refrigerator	136%	105%	105%	119%
Freezer	45%	16%	16%	50%
Clothes Washer	96%	53%	53%	100%
Clothes Dryer	91%	49%	49%	100%
Dishwasher	87%	67%	67%	88%
Electric Oven	96%	105%	105%	106%
Desktop	49%	40%	40%	56%
Laptop	53%	35%	35%	38%
Monitor	51%	44%	44%	56%

Commercial

Building square footage is the key parameter in determining conservation potential for the commercial sector, as many of the measures are based on savings as a function of building area (kWh per square foot). The 2020 commercial square footage was estimated with 2018 tax assessor data provided by Franklin PUD.

Table 2 shows 2018 commercial floor area in each of the 18 building categories. Estimates of commercial floor area by building type are higher than 2015 CPA estimates (15.8 million square feet). The growth rate assumed for commercial buildings is 0.6%.

Table 2
Commercial Building Square Footage by Segment

Segment	Area (Square Feet)	Growth Rate
Large Office	-	
Medium Office	728,820	
Small Office	1,420,666	
Extra Large Retail	620,206	
Large Retail	1,732,125	
Medium Retail	-	
Small Retail	170,120	
School (K-12)	445,925	
University	8,176	
Warehouse	12,229,816	
Supermarket	291,686	
Mini Mart	104,156	
Restaurant	293,454	
Lodging	863,980	
Hospital	189,672	
Residential Care	72,314	
Assembly	1,125,740	
Other Commercial	4,977,746	
Total	**25,274,602**	**0.6%**

Industrial

The methodology for estimating industrial potential is different than approaches used for the residential and commercial sectors primarily because industrial energy efficiency opportunities are based on the distribution of electricity use among processes at industrial facilities. Industrial potential for this assessment was estimated 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 are applied to each sector's process shares.

Franklin PUD provided 2018 energy use for its industrial customers. Individual industrial customer usage is shown by industrial segment in Table 3. While there have been some changes in the loads in each segment, the overall industrial load has changed little since the 2015 CPA. Load growth was calculated from Franklin PUD's econometric forecast of industrial load growth between 2020 and 2039 and is slightly higher from the value assumed in the 2015 CPA.

Table 3 Industrial Sector Load by Segment		
Segment	**Annual Base Load (2018 MWh)**	**Annual Growth Rate**
Frozen Food	220,487	
Other Food	8,873	
Cold Storage	7,585	
Fruit Storage	7,564	
Miscellaneous Manufacturing	7,551	
Potato and Onion Storage	10,255	
Total	**262,316**	**0.71%**

Franklin PUD has potato and onion storage facilities in its service area, which are categorized as industrial customers. However, the Council does not evaluate energy efficiency measures specifically for potato and onion storage facilities. Therefore, a custom analysis was completed for MWh consumption for potato and onion storage facilities.

Distribution Efficiency (DEI)

For this analysis, EES developed an estimate of distribution system conservation potential using the Council's Seventh Plan approach. The Seventh Plan estimates distribution potential for five measures as a fraction of end system sales ranging from 0.1 to 3.9 kWh per aMW, depending on the measure.

Franklin PUD provided a total system load for 2018. The forecast was then adjusted to account for transmission system losses only, since the savings happen at the distribution level. Distribution system potential is discussed in detail in the next section.

Results – Energy Savings and Costs

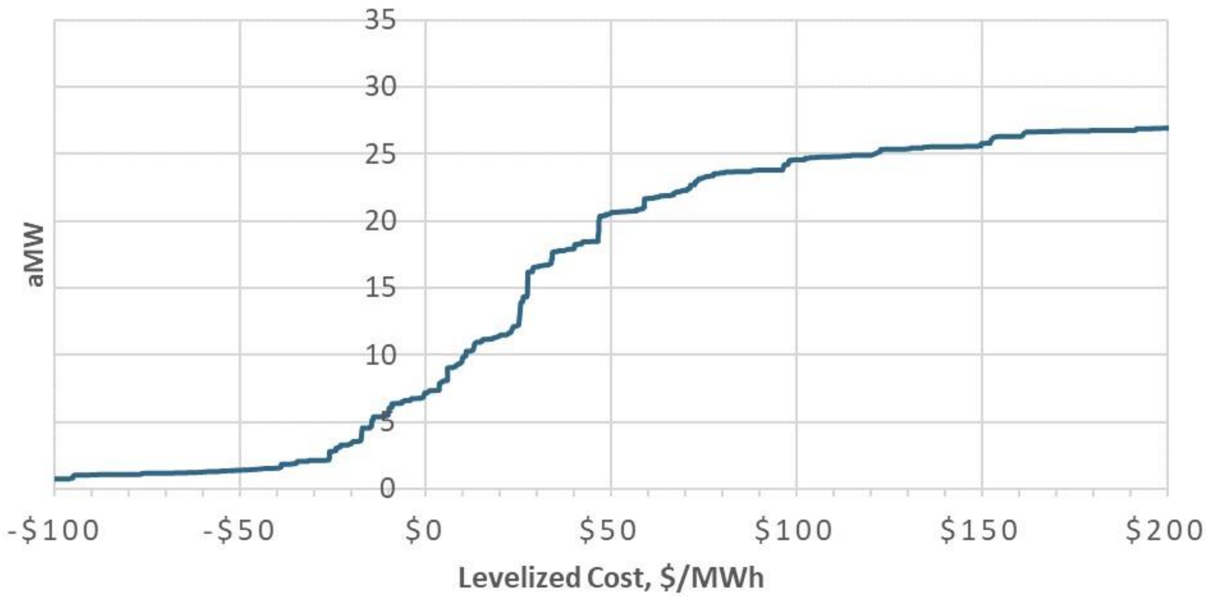
Achievable Conservation Potential

Achievable potential is the amount of energy efficiency potential that is available regardless of cost. It represents the theoretical maximum amount of achievable energy efficiency savings.

Figure 7, below, shows a supply curve of 20-year achievable potential. A supply curve is developed by plotting energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the conservation. The technical potential has not been screened for cost effectiveness. Costs are levelized, allowing for the comparison of measures with different lives. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with resource plans. Figure 7 shows that 16.5 aMW of saving potential are available for less than $30/MWh and over 23.6 aMW are available for under $80/MWh. Total achievable potential for Franklin PUD is approximately 29.7 aMW over the 20year study period.

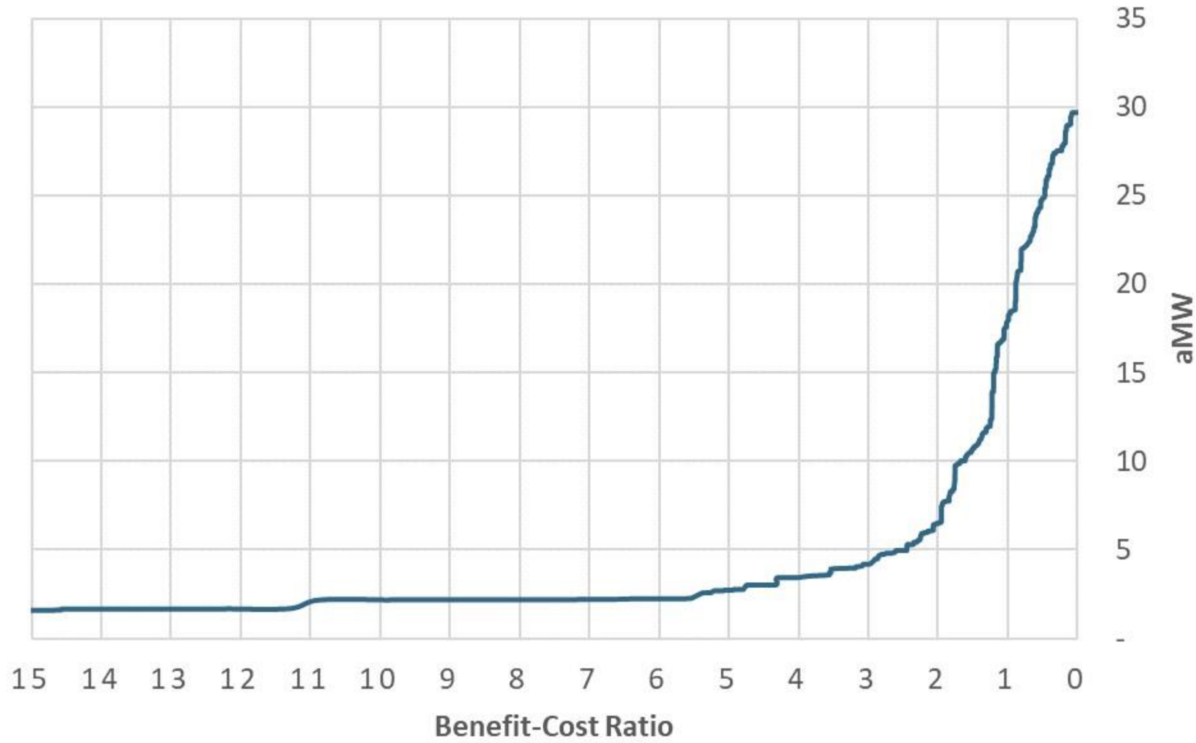
Figure 7

20-Year Technical-Achievable Potential Supply Curve



While useful for considering the costs of conservation measures, supply curves based on levelized cost are limited in that not all energy savings are equally valued. Another way to depict a supply curve is based on the benefit-cost ratio, as shown in Figure 8 below. This figure repeats the overall finding that 17.88 aMW of potential is cost-effective with a benefit-cost ratio greater than or equal to 1.0. The line is steep near the point where the benefit-cost ratio is 1.0, suggesting significant changes in economic potential if avoided cost parameters are changed.

Figure 8
Benefit-Cost Ratio Supply Curve



Economic Achievable Conservation Potential

Economic achievable, also referred to as economic potential or cost-effective potential is the amount of potential that passes the Total Resource Cost (TRC) test. This means that the present value of the benefits exceeds the present value of the measure costs over its lifetime.

Table 6 shows aMW of economically achievable potential by sector in 2, 6, 10 and 20-year increments. Annual potential estimates by sector are included in Appendix VII. Compared with the achievable potential, it shows that 17.88 aMW of the total 29.7 aMW is cost effective for Franklin PUD. The last section of this report discusses how these values could be used for setting targets.

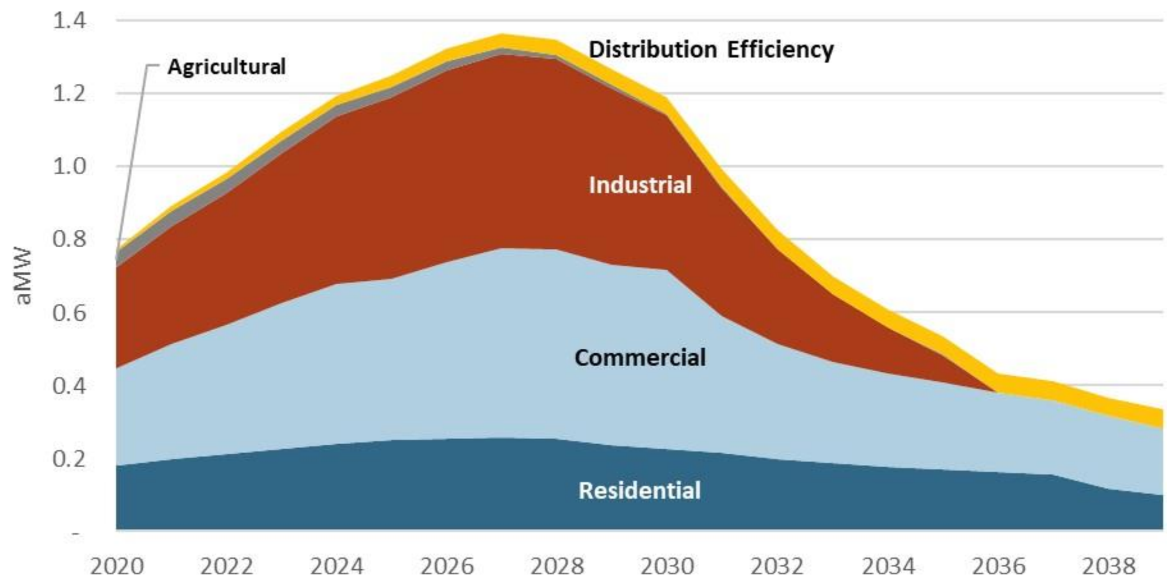
Table 4
Cost-Effective Achievable Potential - Base Case (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.38	1.30	2.31	4.01
Commercial	0.58	2.22	4.24	6.99
Industrial	0.60	2.33	4.39	5.81
Agricultural	0.08	0.22	0.28	0.28
Distribution Efficiency	0.02	0.12	0.28	0.78
Total	**1.67**	**6.19**	**11.49**	**17.88**

Sector Summary

Figure 9 shows economic achievable potential by sector on an annual basis.

Figure 9
Annual Achievable Potential by Sector



The largest share of the potential is in the commercial sector followed by substantial savings potential in the industrial and residential sectors. Ramp rates are used to establish reasonable conservation achievement levels. Adjustments to these ramp rates were made to reflect the timeline of this CPA. Additionally, alternate ramp rates were assigned to reflect Franklin PUD's current rate of program achievement. These changes decelerated the acquisition of potential in all sectors except distribution efficiency (unchanged) and agriculture (accelerated slightly). Achievement levels are affected by factors including timing and availability of measure installation (lost opportunity), program maturity, and current utility staffing and funding. Ramp rates are further discussed in Appendix V.

Table 7 below shows how recent program history compares to the near-term program potential. Residential achievements exclude lighting savings, as these measures were excluded from the program potential. Savings from NEEA have been allocated to the appropriate sectors.

Table 7
Comparison of Program Achievement and Potential

	Program History			Potential		
	2017	**2018**	**Average**	**2020**	**2021**	**2022**
Residential	0.26	0.29	0.28	0.18	0.20	0.21
Commercial	0.25	0.36	0.30	0.27	0.32	0.36
Industrial	0.11	0.59	0.35	0.28	0.32	0.36
Agricultural	0.06	0.06	0.06	0.04	0.04	0.04
Distribution Efficiency	-	-	-	0.01	0.01	0.02
Total	**0.68**	**1.30**	**0.99**	**0.77**	**0.89**	**0.98**

Residential

Residential conservation potential is lower compared with the 2015 assessment. Savings potential has been impacted by the expected impact of lighting standards scheduled to take effect in 2020 as well as changes to the value of capacity savings in the avoided cost.

Figure 10 shows the distribution of annual residential potential across measure end uses for the first ten years of the planning period. As can be seen, the cost-effective potential is primarily comprised of measures in the HVAC and water heating end uses. Measures in other end uses, such as refrigeration, did not pass the economic screening.

The HVAC end use includes both heating equipment and weatherization measures such as attic insulation, ductless heat pumps, and Wi-Fi-enabled thermostats.

Water heating is a growing area of potential, with heat pump water heaters providing the majority of cost-effective savings. Showerheads are also a significant contributor. Other measures included in the water heating end use include aerators, behavior programs, clothes washers, and thermostatic shutoff valves.

Electronics contribute slightly to Franklin PUD's potential with both computer and monitor measures.

Figure 10
Annual Residential Potential by End Use

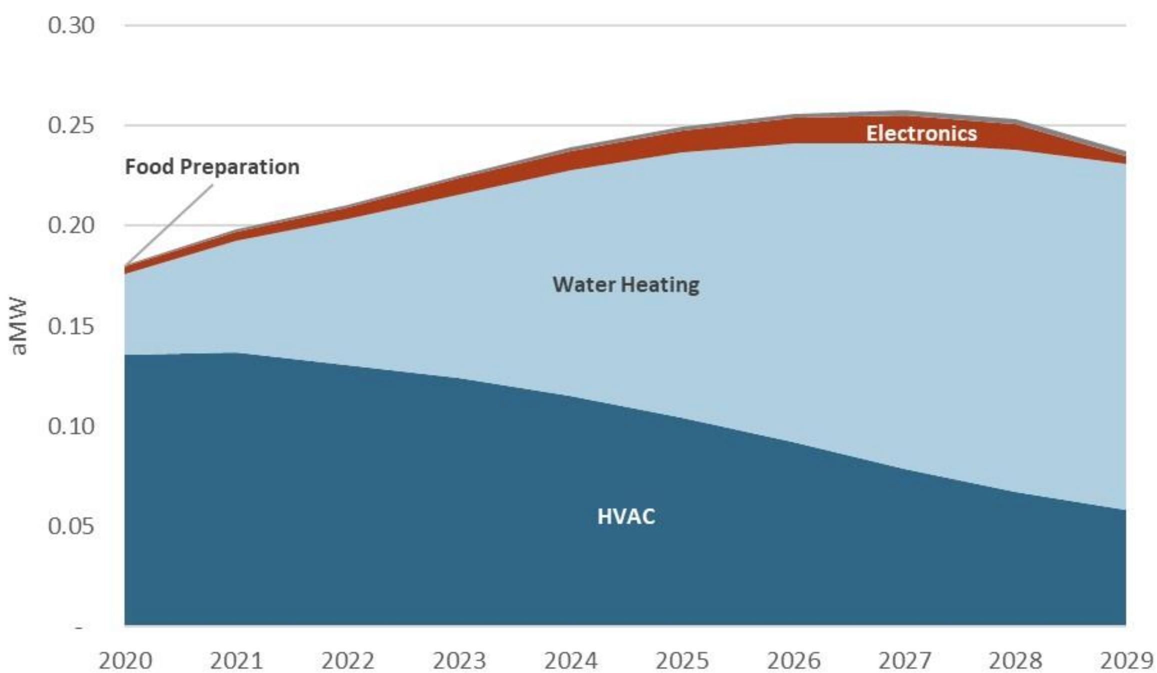
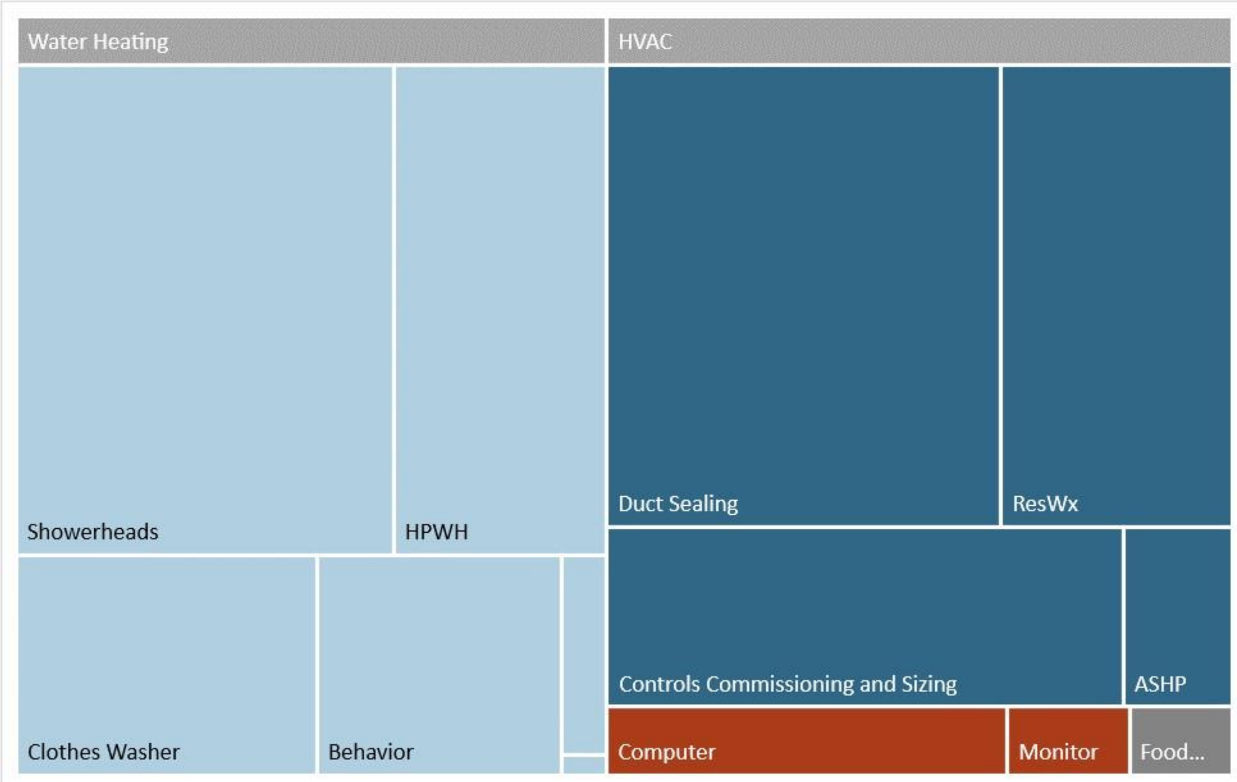


Figure 11 shows how the 10-year residential potential breaks down into end uses and key measure categories. The area of each block represents its share of the total 10-year residential potential.

Figure 11
Annual Residential Potential by End-Use



Commercial

Commercial lighting measures remain the largest share of commercial conservation potential for the 2019 CPA planning period (Figure 12). Lighting savings are lower in this assessment after accounting for the lighting standards mentioned above and program achievement, which impacts several commercial measures.

HVAC control measures continue make up a substantial part of the balance of commercial conservation potential for this assessment period. Significant measures in this category include advanced rooftop controls, ductless heat pumps and variable refrigerant flow technology.

Commercial HVAC measures are often more complicated and disruptive to install compared to lighting measures and are, therefore, more slowly acquired.

Figure 12
Annual Commercial Potential by End Use

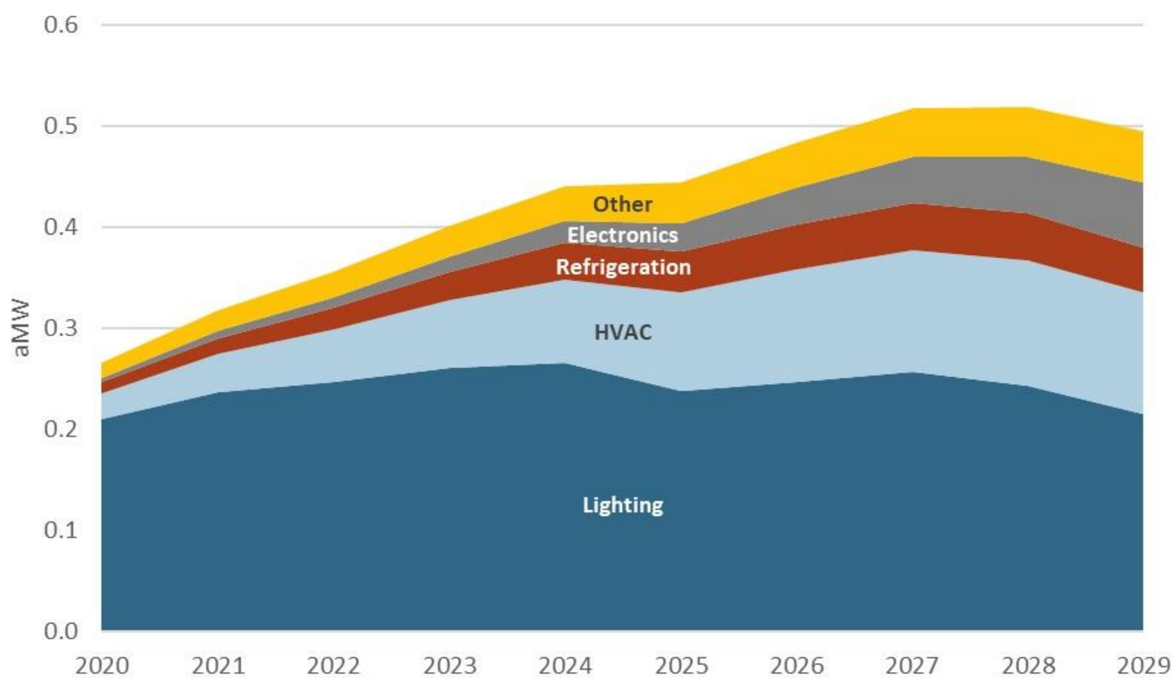
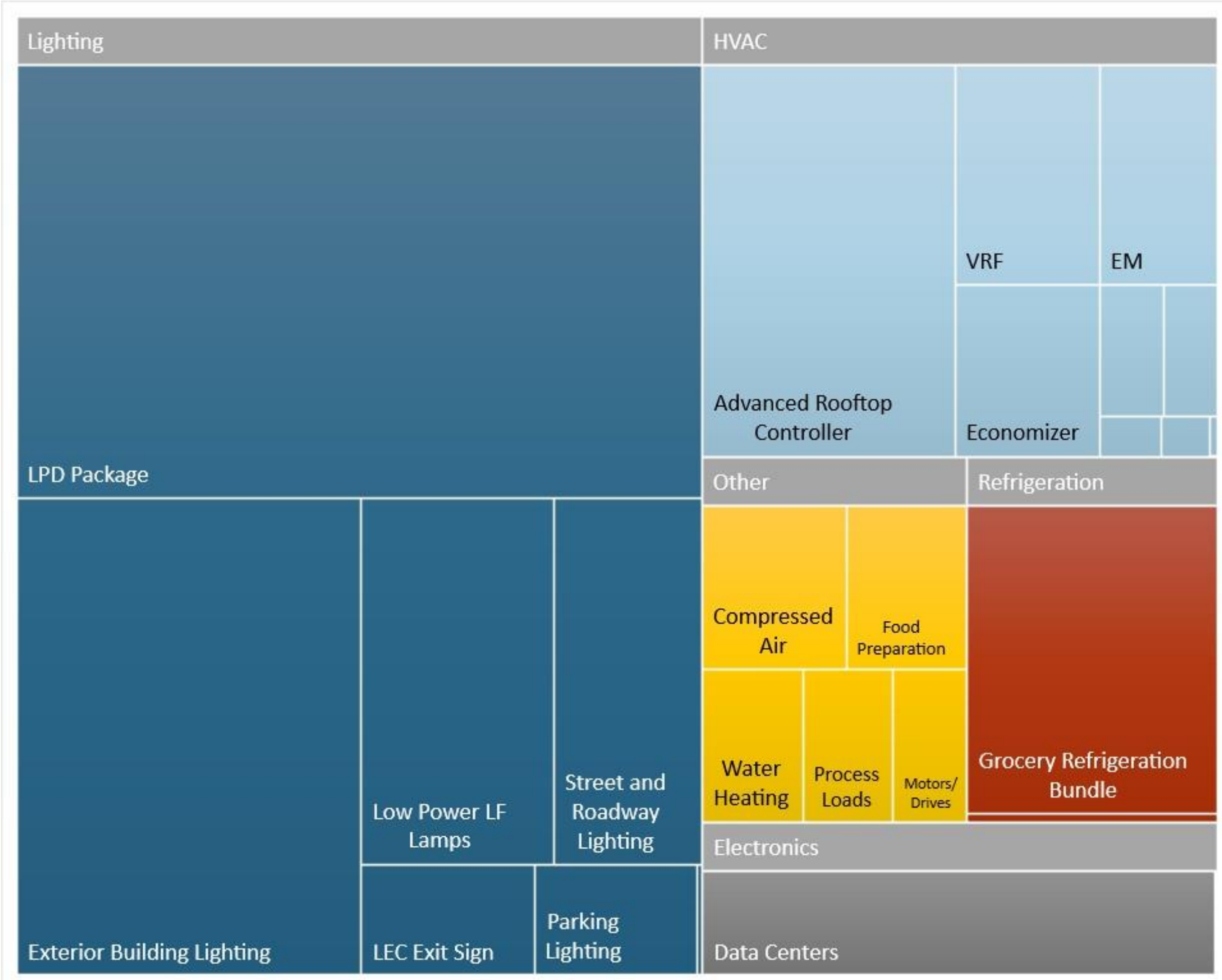


Figure 12 shows that, unlike residential potential, the commercial potential is characterized by a diverse set of measures and end uses due to the more varied nature of commercial buildings. The Other category is made up of measures in the compressed air, motors/drives, process loads, food preparation and water heating end uses. Detail of the savings by these end uses can be found in Appendix V.

The key end uses and measures within the commercial sector are shown in Figure 14. The area of each block represents its share of the 10-year commercial potential.

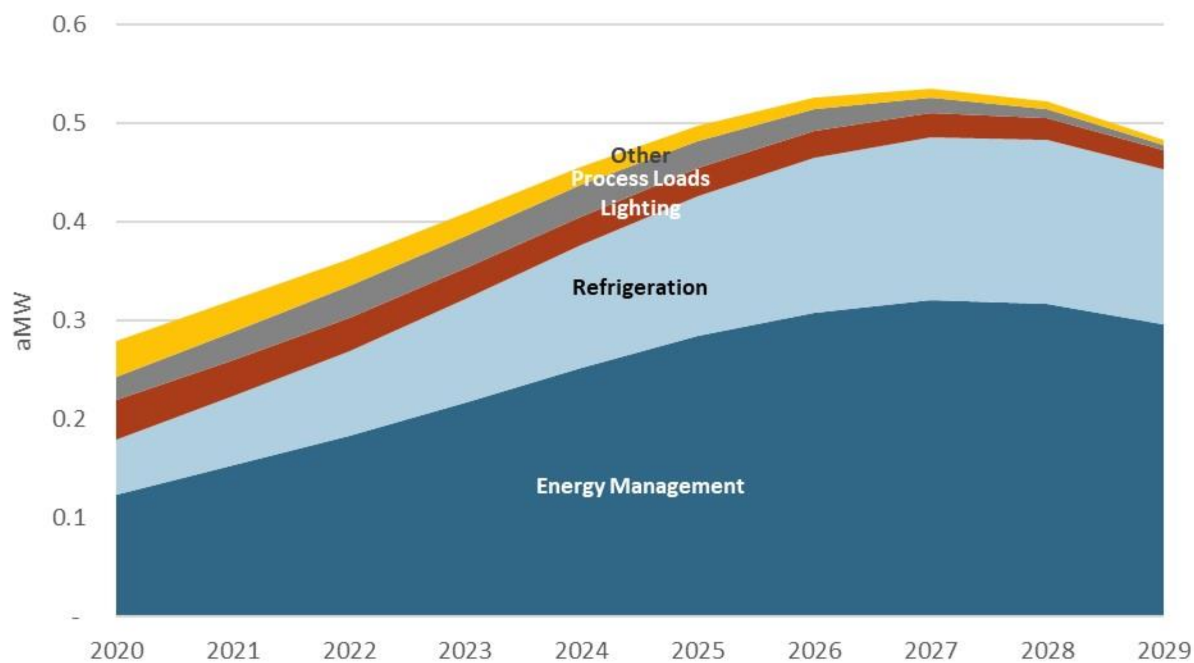
Figure 13
Commercial Potential by End Use and Measure Category



Industrial

Industrial sector potential by end-use category is shown in Figure 14. The largest industrial segment in Franklin PUD's service area is frozen food processing, which contributes to the energy management end use. The 2, 6, 10 and 20-year industrial sector potential estimates by measure end-use category are provided in Appendix VI.

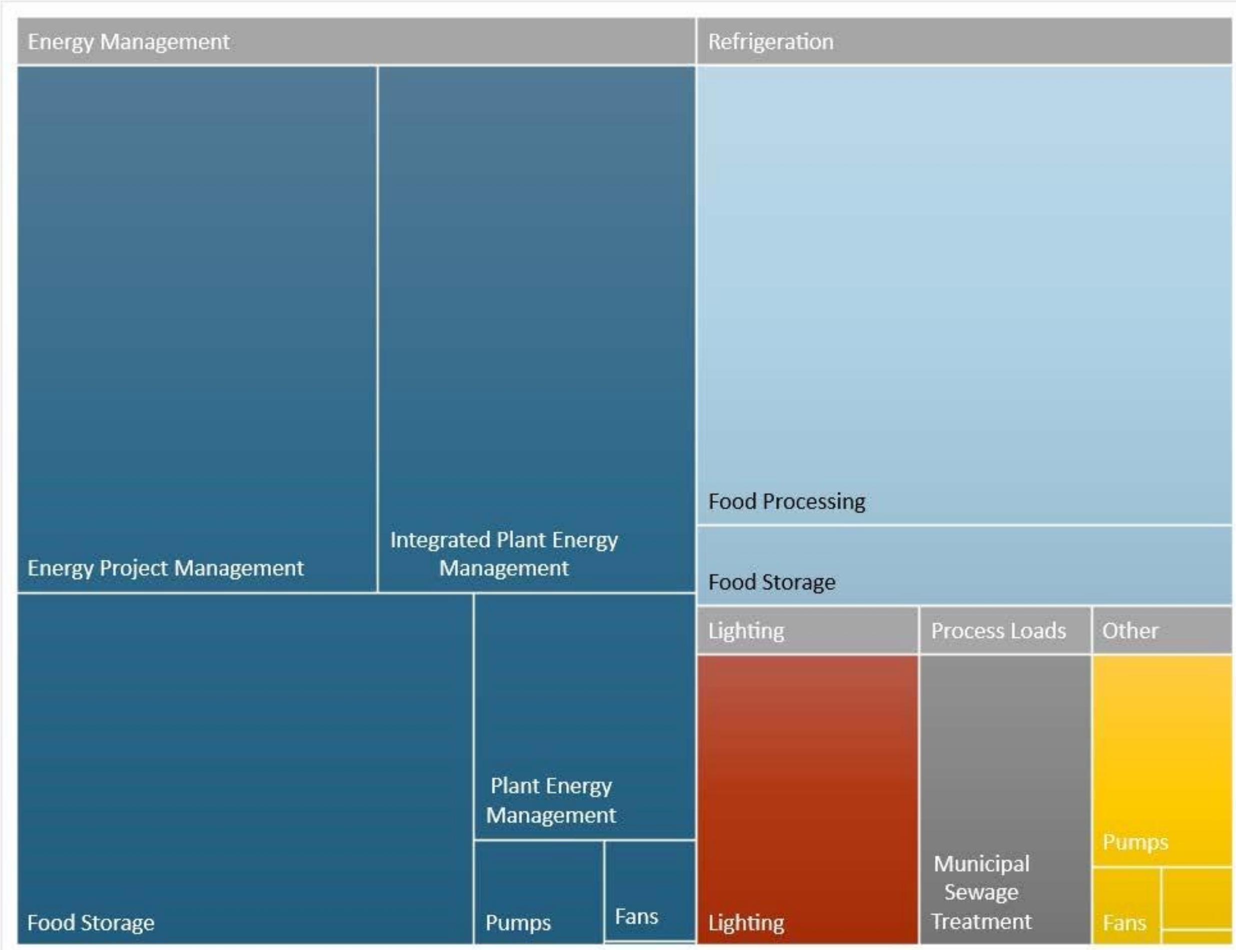
Figure 14
Annual Industrial Potential by End Use



In Figure 14, the Other category is comprised of measures in the fans, compressed air, pumps, and high-tech end uses.

Figure 15 shows how the 10-year industrial potential breaks down by end use and measure categories.

Figure 15
Industrial Potential by End Use and Measure Category



Agriculture

Potential in agriculture is a product of total irrigated acres in Franklin PUD's service territory, number of pumps, amount of dairy production, and number of farms. Figure 16 summarizes the first ten years of potential by end use.

Figure 16
Annual Agricultural Potential by End Use

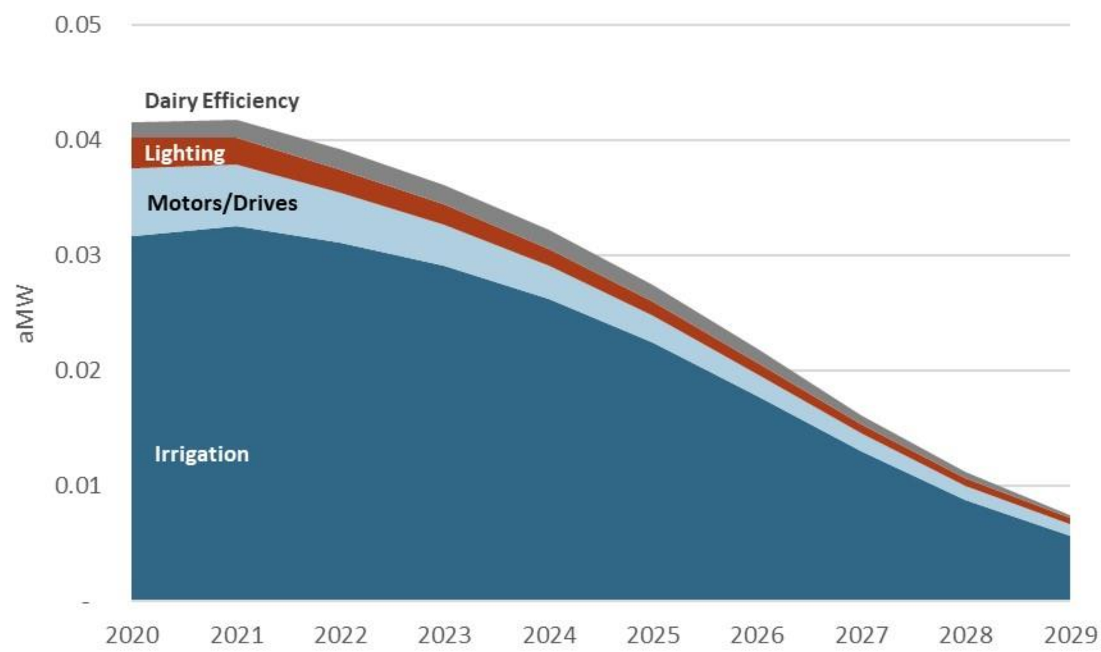


Figure 17 shows how the 10-year industrial potential breaks down by end use and measure categories.

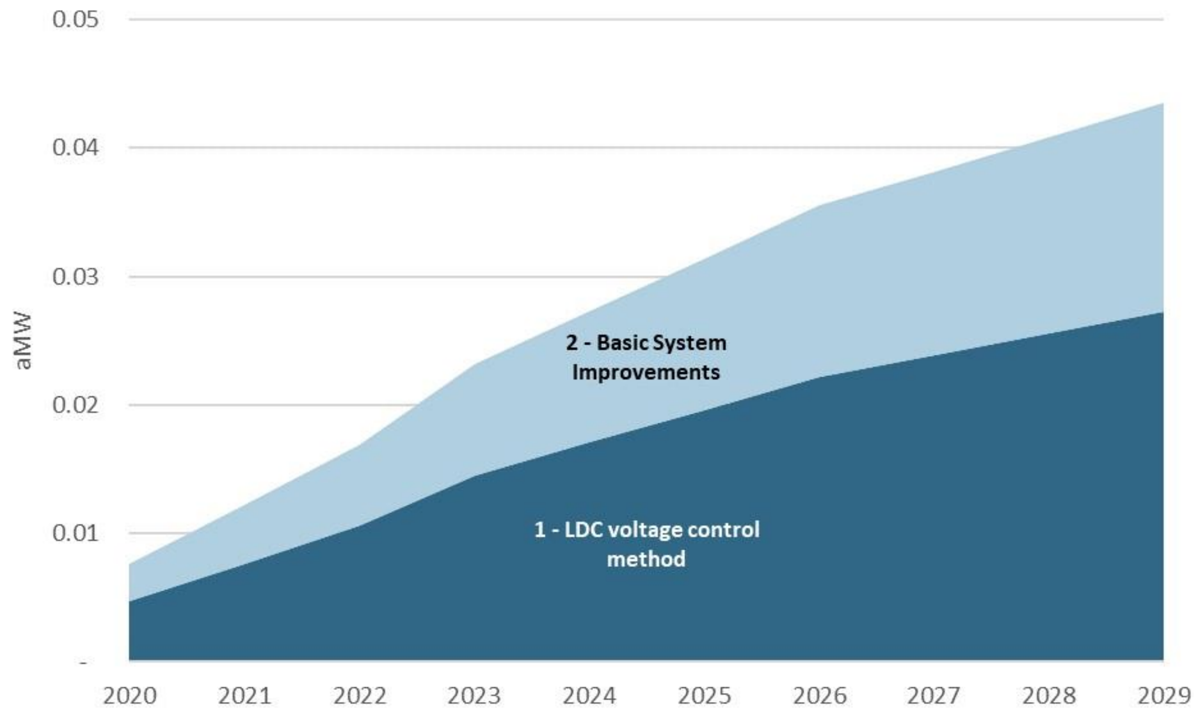
Figure 17
Industrial Potential by End Use and Measure Category

Distribution Efficiency

Distribution system energy efficiency measures regulate voltage and upgrade systems to improve the efficiency of utility distribution systems and reduce line losses. Distribution system potential was estimated using the Council's methodology, which considers five different measures. The Seventh Plan estimates distribution system potential based on end system energy sales.

Distribution system conservation potential is shown in Figure 18. Although five measures were considered in the analysis, only two measures were identified as cost effective. The cost estimates for distribution system potential shown in Table 7, in the next section, are also based on the end-system sales method.

Figure 18
Annual Distribution System Potential by End Use



Cost

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 8). The assumptions in this estimate include: 20 percent of measure cost for administrative costs and 40% for incentive costs. The assumption for administrative expenses was used in the Seventh Power Plan.

This chart shows that Franklin PUD can expect to spend $3.3 million to realize estimated savings over the next two years including program administration costs. The bottom row of Table 8 shows the cost per MWh of first-year savings.

Table 8
Utility Program Costs (2019$)

	2-Year	6-Year	10-Year	20-Year
Residential	$1,239,000	$3,728,000	$5,744,000	$8,535,000
Commercial	$1,144,000	$4,314,000	$8,258,000	$15,246,000
Industrial	$824,000	$3,171,000	$5,888,000	$7,690,000

Agricultural	$103,000	$247,000	$309,000	$322,000
Distribution Efficiency	$7,000	$39,000	$91,000	$257,000
Total	**$3,317,000**	**$11,499,000**	**$20,290,000**	**$32,050,000**
$/First Year MWh	$227	$212	$202	$205

The cost estimates above are conservative estimates for costs going forward since they are based on historic values. Future conservation achievement may be more costly since the lowest cost, easiest programs are usually implemented first. In addition, as energy efficiency markets become more saturated, it may require more effort from Franklin PUD to acquire conservation through its programs. This additional effort may increase administrative costs. The next section provides a range of cost estimates for the planning period.

Besides looking at the utility cost, Franklin PUD may also wish to consider the total resource cost (TRC) cost of energy efficiency. The total resource cost reflects the cost that the utility and ratepayer will together pay for conservation, similar to how the costs of other power resources are considered and paid. The TRC costs are shown below (Table 9), levelized over the measure life of each measure. Based on costs from the Seventh Power Plan, distribution efficiency measures are by far the lowest cost resource.

Table 9
TRC Levelized Cost (2019$/kWh)

	2-Year	6-Year	10-Year	20-Year
Residential	$0.044	$0.043	$0.041	$0.038
Commercial	$0.040	$0.039	$0.039	$0.042
Industrial	$0.034	$0.035	$0.035	$0.034
Agricultural	$0.030	$0.027	$0.027	$0.027
Distribution Efficiency	$0.006	$0.006	$0.006	$0.006
Total	**$0.038**	**$0.037**	**$0.037**	**$0.037**

Scenario Results

The costs and savings discussed in the results section describe the Base Case scenario. Under this scenario, annual potential for the planning period was estimated by applying assumptions that reflect Franklin PUD's expected most likely future loads and avoided costs. In addition, the Council's 20-year ramp rates were applied to each measure and then adjusted to more closely reflect Franklin PUD's recent historic conservation achievement.

Additional scenarios were developed to identify a range of possible outcomes that account for uncertainties over the planning period. In addition to the Base Case scenario, this assessment tested Low and High avoided cost scenarios to test the sensitivity of the results to different future avoided cost values. The avoided cost values in the Low and High scenarios reflect values that are realistic and lower or higher, respectively, than the Base Case assumptions.

To understand the sensitivity of the identified savings potential to avoided cost values alone, all other inputs were held constant while varying avoided cost inputs.

Table 10 summarizes the Base, Low, and High avoided cost input values. Rather than using a single generic risk adder applied to each unit of energy, the Low and High avoided cost values consider lower and higher potential future values for each avoided cost input. These values reflect potential price risks based upon both the energy and capacity value of each measure. The final row tabulates the implied risk adders for the Low and High scenarios by summarizing all additions or subtractions relative to the Base Case values. Risk adders are provided in both energy and demand savings values. The first set of values is the maximum (or minimum in the case of negative values). The second set of risk adder values are the average values in energy terms. Further discussion of these values is provided in Appendix IV.

Table 10
Avoided Cost Assumptions by Scenario, $2012

	Base	Low	High
Energy	Market Forecast	-50%-85% Confidence Interval*	+50%-85% Confidence Interval*
Social Cost of Carbon	CA Carbon Market	None	Federal/Council Values
Value of REC Compliance	15% RPS	15% RPS	15% RPS
Distribution System Credit, $/kW-year	$6.85	$6.85	$6.85
Transmission System Credit, $/kW-year	$3.08	$3.08	$3.08
Deferred Generation Capacity Credit, $/kW-year	$109	$0	$115

Implied Risk Adder: $/aMW $/kW-year	N/A	Up to -$32/MWh -$109/kW-year Average of -$19/MWh -$109/kW-year	Up to $29/MWh $6/kW-year Average of $22/MWh $6/kW-year

Table 11 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

Table 11
Cost-Effective Potential - Scenario Comparison (aMW)

	2-Year	6-Year	10-Year	20-Year
Base Case	1.67	6.19	11.49	17.88
Low Scenario	0.69	2.67	5.02	8.40
High Scenario	1.81	6.79	12.78	20.74

Table 11 shows that there is higher sensitivity to the lower avoided costs relative to the base case. Over the 20-year period, the 20-year potential is nearly cut in half in the low scenario, while the high avoided cost scenario only gains several additional average megawatts. While this may suggest that there may be more risk in overvaluing avoided costs, the results should be considered along with the relative likelihood of each scenario. For example, with the current low market prices and predictions of regional capacity constraints on the horizon, lower market prices may be unlikely.

Overall, energy efficiency remains a low-risk resource for Franklin PUD. Energy efficiency is purchased in small increments over time, meaning that buying too much energy efficiency is unlikely.

In addition to analyzing the sensitivity of the 20-year cost-effective potential to variation in avoided costs, this analysis considered the sensitivity of results to the avoided cost scenarios described above in combination with different sector growth rates. These scenarios are described below.

Low Scenario

The Low Conservation scenario evaluates the cost-effective energy efficiency potential under a low market price forecast and with low load growth in Franklin PUD's service territory. The Base Case market price forecast and other avoided cost assumptions were adjusted downward as outlined in Table 10 above.

Under the Low scenario, residential growth is reduced to 0.6 percent. Industrial growth was reduced to 0 percent reflecting a bear economy consistent with the lower avoided costs or falling prices. Commercial growth assumptions were also reduced to 0 percent. Results of the Low scenario analysis are shown in Table 12. For the Low scenario, potential for all energy efficiency measures is distributed evenly over the 20-year planning period.

Key parameters for the Low scenario include:

- Residential growth = 0.6%
- Commercial growth = 0%
- Industrial growth = 0%
- Low avoided cost assumptions

Table 12
Cost-Effective Potential - Low Case (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.12	0.49	1.02	1.97
Commercial	0.35	1.28	2.31	3.50
Industrial	0.12	0.47	0.88	1.15
Agricultural	0.05	0.14	0.17	0.18
Distribution Efficiency	0.02	0.12	0.28	0.78
Total	**0.66**	**2.50**	**4.66**	**7.58**

High Scenario

Franklin PUD's High Conservation scenario makes use of the high avoided cost assumptions described above in Table 10.

Under the High scenario, residential growth is 2.5 percent, 0.5 percentage points higher than the Base Case. Commercial growth is 1.2 percent, and industrial growth is 1.0 percent across all industries. Results of the High scenario are shown in Table 13.

Key parameters for the High scenario include:

- Residential growth = 2.5%
- Commercial growth = 1.2%
- Industrial growth = 1.0%
- High avoided cost assumptions

Table 13
Cost Effective Achievable Potential - High AC + Growth Case (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.44	1.66	3.20	6.42
Commercial	0.69	2.55	4.83	8.15
Industrial	0.64	2.48	4.70	6.22
Agricultural	0.09	0.23	0.29	0.31
Distribution Efficiency	0.03	0.17	0.39	1.10
Total	**1.88**	**7.09**	**13.41**	**22.19**

Scenario Summary

A comparison of the 20-year cost-effective potential for the five avoided cost and load growth scenarios outlined above is shown in Table 14 below. Based on the results of this table, it is evident that the results of the analysis are more sensitive to changes in avoided cost then load growth. Changes to load growth changed the results very little beyond the impact of the avoided cost assumptions. As discussed above, the results are most sensitive to decreases in avoided cost assumptions.

Table 14

Scenario Comparison - 20-Year Cost-Effective Potential (aMW)

		Load Growth		
		Low	Base	High
Avoided Costs	Low	7.58	8.40	
	Base		17.88	
	High		20.74	22.19

Summary

This report summarizes the results of the 2019 CPA conducted for Franklin Public Utility District. The assessment provides estimates of energy savings by sector for the period 2020 to 2039, with a focus on the first 10 years of the planning period, as per EIA requirements. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

Growth in the commercial sector and model updates from the 2015 CPA have resulted in more cost-effective potential than was identified in the 2015 CPA. Federal lighting standards impacting many residential lighting measures has resulted in slightly lower residential potential. The costeffective potential identified in this report remains the lowest cost and lowest risk resource and will serve to keep future electricity costs to a minimum.

Methodology and Compliance with State Mandates

The energy efficiency potential reported in this document is calculated using methodology consistent with the Council's methodology for assessing conservation resources. Appendix III lists each requirement and describes how each item was completed. In addition to using methodology consistent with the Council's Seventh Power Plan, this assessment utilized many of the measure assumptions that the Council developed for the Seventh Regional Power Plan. Additional measure updates subsequent to the Seventh Plan were also incorporated. Utilityspecific data regarding customer characteristics, service-area composition, and historic conservation achievements were used, in conjunction with the measures identified by the Council, to determine available energy-efficiency potential. This close connection with the Council methodology enables compliance with the Washington EIA.

Three types of energy-efficiency potential were calculated: technical, achievable, and economic. Most of the results shown in this report are the economic potential, or the potential that is cost effective in the Franklin PUD service territory. The economic and achievable potential considers savings that will be captured through utility program efforts, market transformation and implementation of codes and standards. Often, realization of full savings from a measure will require efforts across all three areas. Historic efforts to measure the savings from codes and standards have been limited, but regional efforts to identify and track savings are increasing as they become an important component of the efforts to meet aggressive regional conservation targets.

Conservation Targets

The EIA states that utilities must establish a biennial target that is "no lower than the qualifying utility's pro rata share for that two-year period of its cost-effective conservation potential for the subsequent ten-year period."[26] However, the State Auditor's Office has stated that:

> The term pro-rata can be defined as equal portions but it can also be defined as a proportion of an "exactly calculable factor." For the purposes of the Energy

[26] RCW 19.285.040 Energy conservation and renewable energy targets.

> Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10-year assessment but state law does not require an even 20 percent.[27]

The State Auditor's Office expects that qualifying utilities have analysis to support targets that are more or less than the 20 percent of the ten-year assessments. This document serves as support for the target selected by Franklin PUD and approved by its Commission.

Summary

This study shows a range of conservation target scenarios. These scenarios are estimates based on the set of assumptions detailed in this report and supporting documentation and models. Due to the uncertainties discussed in the Introduction section of this report, actual available and costeffective conservation may vary from the estimates provided in this report.

[27] State Auditor's Office. Energy Independence Act Criteria Analysis. Pro-Rata Definition. CA No. 2011-03. https://www.sao.wa.gov/local/Documents/CA_No_2011_03_pro-rata.pdf

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Appendix I – Acronyms

aMW –Average Megawatt

BPA – Bonneville Power Administration

CETA – Clean Energy Transformation Act CFL –

Compact Fluorescent Light Bulb

EIA – Energy Independence Act EES –

EES Consulting

HLH – Heavy load hour energy HVAC – Heating,

ventilation and air-conditioning kW – kilowatt kWh –

kilowatt-hour LED – Light-emitting diode

LLH – Light load hour energy

MF –Multi-Family

MH –Manufactured House

MW –Megawatt aMW –

Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance RPS –

Renewable Portfolio Standard

RTF – Regional Technical Forum

SB 5116 – Washington Senate Bill 5116 UC –

Utility Cost

Appendix II – Glossary

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan, Feb 2016. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that considers how many measures will actually be implemented after considering market barriers. For lost-opportunity measures, there is only a certain number of expired units or new construction available in a specified time frame. The Council assumes 85% of all measures are achievable. Sometimes achievable potential is a share of economic potential, and sometimes achievable potential is defined as a share of technical potential.

Cost Effective: A conservation measure is cost effective if the present value of its benefits is greater than the present value of its costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. All benefits and costs for the utility and its customers are included, regardless of who pays the costs or receives the benefits.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straightforward comparison.

Lost Opportunity: Lost-opportunity measures are those that are only available at a specific time, such as new construction or equipment at the end of its life. Examples include heat-pump upgrades, appliances, or premium HVAC in commercial buildings.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energyefficient products and services.

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards: Washington state utilities with more than 25,000 customers are required to meet defined %ages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that can be replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the ratio of the present value of all benefits (no matter who receives them) to the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix III – Documenting Conservation Targets

References:

1) Report – “Franklin PUD 2019 CPA.” Final Report – November 12, 2019.
2) Model – “EES CPA Model-v3.3_base.xlsm” and supporting files
    a. MC_AND_LOADSHAPE-Franklin PUD-Base.xlsm – referred to as “MC and Loadshape file” – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
a) **Technical Potential:** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could be physically be installed or implemented, without regard to achievability or cost.	The model includes estimates for stock (e.g. number of homes, square feet of commercial floor area, industrial load) and the number of each measure that can be implemented per unit of stock. The technical potential is further constrained by the amount of stock that has already completed the measure.	Model – the technical potential is calculated as part of the achievable potential, described below.
b) **Achievable Potential:** Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired.	The assessment conducted for Franklin PUD used ramp rate curves to identify the amount of achievable potential for each measure. Those assumptions are for the 20-year planning period. An additional factor of 85% was included to account for market barriers in the calculation of achievable potential.	Model – the use of these factors can be found on the sector measure tabs, such as ‘Residential Measures’. Additionally, the complete set of ramp rates used can be found on the ‘Ramp Rates’ tab.
c) **Economic Achievable Potential**: Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a benefit-cost ratio greater than one were tallied. These measures are considered achievable and cost-effective (or “economic”).	Model – BC Ratios are calculated at the individual level by ProCost and passed up to the model.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
d) **Total Resource Cost**: In determining economic achievable potential, perform a life-cycle cost analysis of measures or programs	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
e) Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits	Cost analysis was conducted per the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (I.e., those greater than one are costeffective).	Model – the "Measure Info Rollup" files pull in all the results from each avoided cost scenario, including the BC ratios from the ProCost results. These results are then linked to by the Conservation Potential Assessment model. The TRC analysis is done at the lowest level of the model in the ProCost files.
f) Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes	Savings, cost, and lifetime assumptions from the Council's 7th Plan and RTF were used.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
g) Calculate the value of energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation	The Council's Seventh Plan measure load shapes were used to calculate time of day of savings and measure values were weighted based upon peak and off-peak pricing. This was handled using the Council's ProCost program, so it was handled in the same way as the Seventh Power Plan models.	Model – See MC file for load shapes. The ProCost files handle the calculations.
h) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures	Operations and maintenance costs for each measure were accounted for in the total resource cost per the Council's assumptions.	Model – the ProCost files contain the same assumptions for periodic O&M as the Council and RTF.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
i) Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	A regional market price forecast for the planning period was created and provided by EES. A discussion of methodologies used to develop the avoided cost forecast is provided in Appendix IV.	Report –See Appendix IV. Model – See MC File ("TEA Base" worksheet).
j) Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission capacity expansion benefits were given a benefit of $2.85/kW-year in the costeffectiveness analysis. A distribution system credit of $6.33/kW-year was also used.	Model – this value can be found on the ProData page of each ProCost file.
k) Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion benefits were given a value of $ 88/kW-year in the base case cost effectiveness analysis. This is based upon Franklin PUD's marginal cost for generation capacity. Alternate values were used for the low and high scenarios.	Model – this value can be found on the ProData page of the ProCost Batch Runner file. The generation capacity value was not originally included as part of ProCost during the development of the 7th Plan, so the value has been combined with the distribution capacity benefit, since the timing of Franklin PUD's system peak and the regional peak are different.
l) Include the social cost of carbon emissions from avoided non-conservation resources	The avoided cost data include estimates of future high, medium, and low CO_2 costs.	Multiple scenarios were analyzed, and these scenarios include different levels of estimated costs and risk.
m) Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided nonconservation resources	In this analysis, risk was considered by varying avoided cost inputs and analyzing the variation in results. Rather than an individual and nonspecific risk adder, our analysis included a range of possible values for each avoided cost input.	The scenarios section of the report documents the inputs used and the results associated.

n) Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Council's Seventh Power Plan. Nonenergy benefits include, for example, water savings from clothes washers.	Model – the ProCost files contain the same assumptions for nonpower benefits as the Council and RTF. The calculations are handled in by ProCost.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
o) Include an estimate of program administrative costs	Total costs were tabulated and an estimated 20% of total was assigned as the administrative cost. This value is consistent with regional average and BPA programs. The 20% value was used in the Fifth, Sixth, and Seventh Power plans.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
p) Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure	Costs of financing measures were included utilizing the same assumptions from the Seventh Power Plan.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
q) Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating nonconservation resources	Discount rates were applied to each measure based upon the Council's methodology. A real discount rate of 4% was used, based on the Council's most recent analyses in support of the Seventh Plan	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
r) Include a ten percent bonus for the energy and capacity benefits of conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act	A 10% bonus was added to all measures in the model parameters per the Conservation Act.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.

Appendix IV – Avoided Cost and Risk Exposure

EES Consulting (EES) has conducted a Conservation Potential Assessment (CPA) for Franklin PUD (the District) for the period 2020 through 2039 as required under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, the District must evaluate the cost-effectiveness of conservation by setting avoided energy costs equal to a forecast of regional market prices. In addition, several other components of the avoided cost of energy efficiency savings must be evaluated including generation capacity value, transmission and distribution costs, risk, and the social cost of carbon.

This appendix describes each of the avoided cost assumptions and provides a range of values that was evaluated in the 2019 CPA. The 2019 CPA considers three avoided cost scenarios: Base, Low, and High. Each of these is discussed below.

Avoided Energy Value

For the purposes of the 2019 CPA, EES has prepared a forecast of market prices for the MidColumbia trading hub. This section summarizes the methodology used to develop the forecast and benchmarks it against other forecasts.

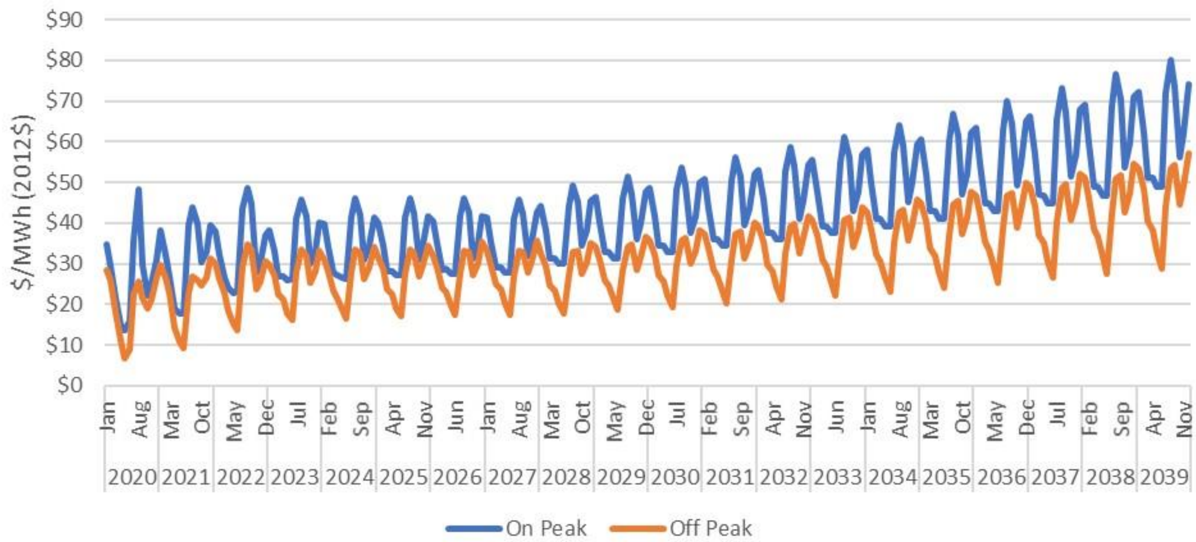
Methodology

For the period January 2020 to June 2029, projected monthly on- and off-peak market prices were provided through a subscription service. These market prices were sourced on July 29, 2019. The prices rise at an annual growth rate of 4.5 percent. This growth rate was used to extend the forecast for the remaining years of the 20-year study period.

Results

Figure IV-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of market prices over the study period is $36.40/MWh in 2012 dollars, assuming a 3.75 percent real discount rate.

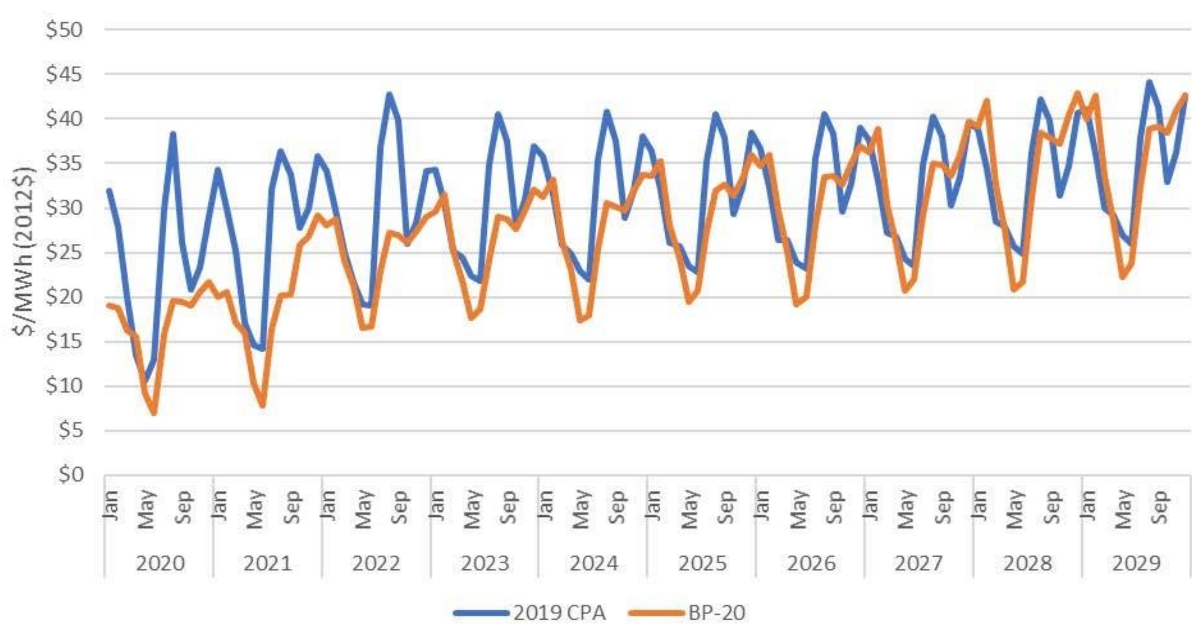
Figure IV-1 Forecast Market Prices



Benchmarking

Figure IV-2 compares the EES market price forecast with the forecast included in BPA's Initial Proposal for FY20-21 rates over the years 2020-2029. The monthly shapes differ in the short term as the BPA market price forecast is lower through June 2021, likely due to lower power prices at the time it was prepared, near the end of 2018. The forecasts are similar from summer 2021 forward, noting the CPA forecast peaks higher in the summer months.

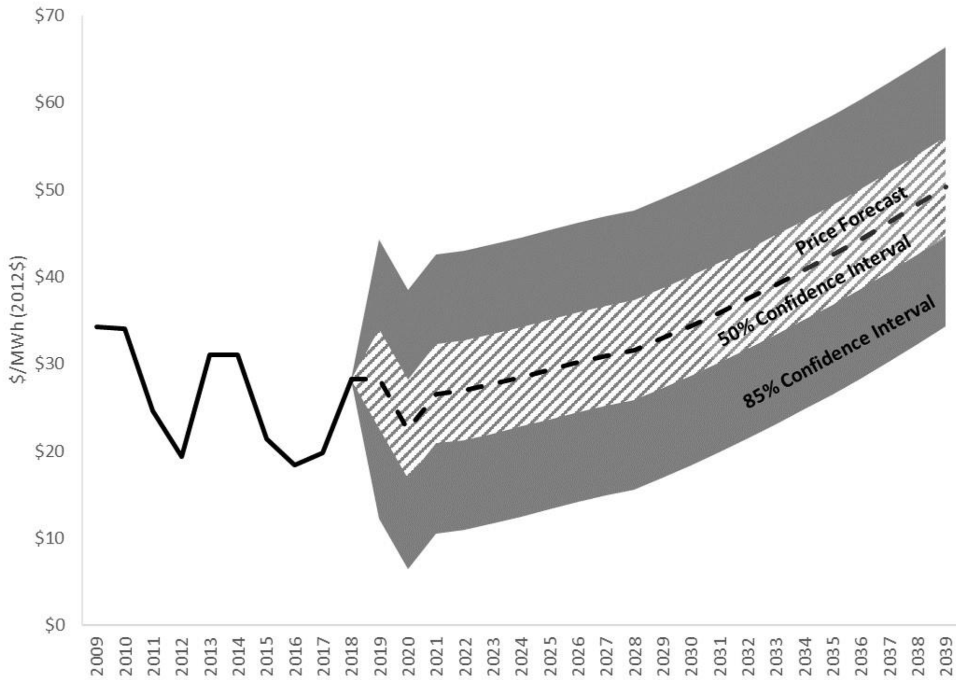
Figure IV-2 Forecast Market Prices compared to BPA's Market Price Forecast



High and Low Scenarios

To reflect a range of possible future outcomes, EES calculated high- and low-case market price forecasts. To do this, EES looked at a history of monthly mid-Columbia energy prices from the past ten years and fit a simple model controlling for monthly variation and a time trend. From this model a prediction interval was calculated moving from a 50% to 85% confidence interval over time to estimate the high and low market price forecasts. Figure IV-3 illustrates how the historic prices and price forecast were used to develop the confidence intervals used to develop the high and low forecasts.

Figure IV-3 Market Price History and Forecast with Confidence Intervals



Figures IV-4 and IV-5 compare the resulting price forecasts, for high and low load hours, respectively.

Figure IV-4
High Load Hour Market Price Forecast

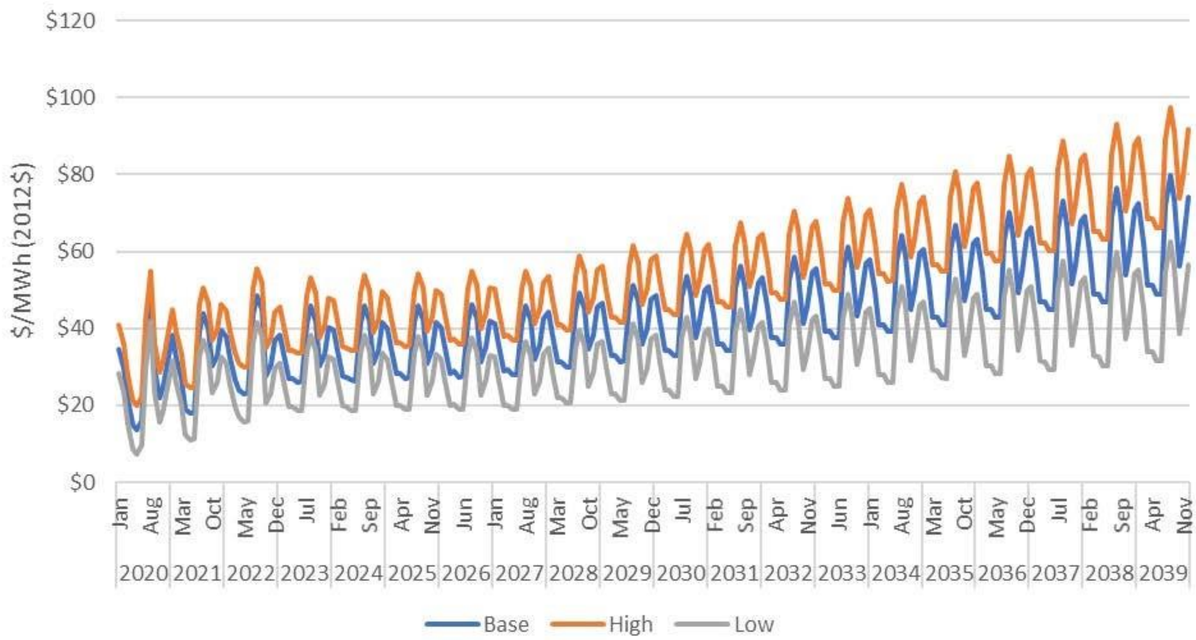
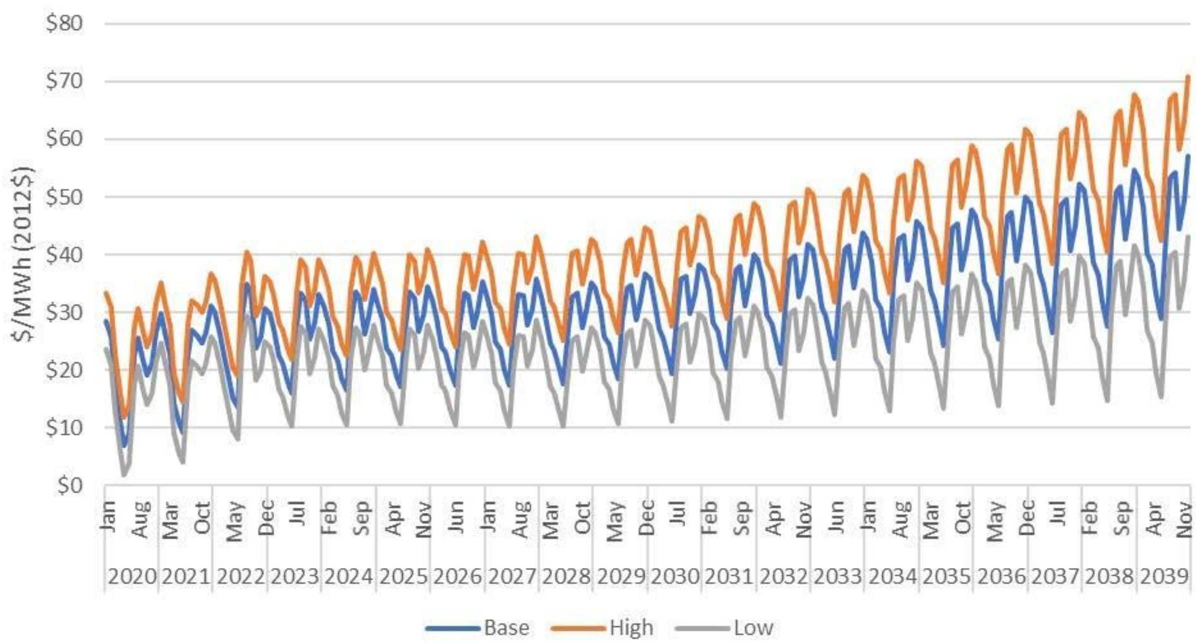


Figure IV-4
Low Load Hour Market Price Forecast



Avoided Cost Adders and Risk

From a total resource cost perspective, energy efficiency provides multiple benefits beyond the avoided cost of energy. These include deferred capital expenses on generation, transmission, and distribution capacity; as well as the reduction of required renewable energy credit (REC) purchases, avoided social costs of carbon emissions, and the reduction of utility resource portfolio risk exposure. Since energy efficiency measures provide both peak demand and energy savings, these other benefits are monetized as value per unit of either kWh or kW savings.

Energy-Based Avoided Cost Adders:

1. Social Cost of Carbon
2. Renewable Energy Credits
3. Risk Reduction Premium Peak Demand-Based Adders:

1. Generation Capacity Deferral
2. Transmission Capacity Deferral
3. Distribution Capacity Deferral

The estimated values and associated uncertainties for these avoided cost components are provided below. EES evaluated the energy efficiency potential under a range of avoided cost adders and identified the sensitivity of the results to changes in these values.

Social Cost of Carbon

The social cost of carbon is a cost that society incurs when fossil fuels are burned to generate electricity. EIA rules require that the social cost of carbon be included in the total resource cost (TRC) test. While Washington's recently enacted clean energy law (SB 5116) dictates the value of the social cost of carbon that is to be used in utility planning, for the purposes of this CPA, Franklin PUD assumes the social cost of carbon to be unaffected by the new law and will incorporate any changes in the next biennium, once rulemaking is complete.

Therefore, the CPA includes the social cost of carbon in an uncertainty analysis through scenario modeling of the carbon market. The scenarios modeled include the value of the social cost of carbon from various sources.

In the Base scenario, carbon pricing from California's cap and trade was used, which is currently around \$5.40/MWh (2012\$). The Power Council used the federal interagency estimate of a social cost of carbon in scenarios of the Seventh Power Plan. The federal carbon cost estimates range from \$17.70 to \$24.8/MWh (2012\$) over the 20-year planning period. These values were used in the set of high avoided cost assumptions. Finally, a value of zero is included in the low avoided cost assumptions. The zero value reflects that carbon costs are not likely to be borne by only utility ratepayers.

Value of Renewable Energy Credits

Related to the social cost of carbon is the value of renewable energy credits. Washington's Energy Independence Act established a Renewable Portfolio Standard (RPS) for utilities with 25,000 or more customers. Currently, utilities are required to source 9% of all electricity sold to retail customers from renewable energy resources. In 2020, the requirement increases to 15%.

Energy savings from conservation measures reduces this expense by reducing the District's overall load.

Under a 15% RPS requirement, for every 100 units of energy efficiency acquired, the District's RPS spending requirement is reduced by 15 units. In effect, this adds 15% of the costs of RECs to the avoided costs of energy efficiency.

EES has used a forecast of REC prices and incorporated them into the avoided costs of energy efficiency accordingly.

Risk Adder

In general, the risk that any utility faces is that energy efficiency will be undervalued, either in terms of the value per kWh or per kW of savings, leading to an under-investment in energy efficiency and exposure to higher market prices or preventable investments in infrastructure. The converse risk—an over-valuing of energy and subsequent over-investment in energy efficiency— is also possible, albeit less likely. For example, an over-investment would occur if an assumption is made that economies will remain basically the same as they are today and subsequent sector shifts or economic downturns cause large industrial customers to close their operations. Energy efficiency investments in these facilities may not have been in place long enough to provide the anticipated low-cost resource.

In order to address risk, the Council develops a risk adder ($/MWh) for its cost-effectiveness analysis of energy efficiency measures. This adder represents the value of energy efficiency savings not explicitly accounted for in the avoided cost parameters. The risk adder is included to ensure an efficient level of investment in energy efficiency resources under current planning conditions. Specifically, in cases where the market price has been low compared to historic levels, the risk adder accounts for the likely possibility that market prices will increase above current forecasts.

The value of the risk adder has varied depending on the avoided cost input values. The adder is the result of stochastic modeling and represents the lower risk nature of energy efficiency resources. In the Sixth Power Plan the risk adder was significant (up to $50/MWh for some measures). In the Seventh Power Plan the risk adder was determined to be $0/MWh after the addition of the generation capacity deferral credit. While the Council uses stochastic portfolio modeling to value the risk credit, utilities conduct scenario and uncertainty analysis. The scenarios modeled in the District's CPA include an inherent value for the risk credit.

For the District's 2019 CPA, the avoided cost parameters have been estimated explicitly and a scenario analysis is performed. Therefore, no risk adder was used for the base case. Variation in other avoided cost inputs covers a range of reasonable outcomes and is sufficient to identify the sensitivity of the cost-effective energy efficiency potential to a range of outcomes. The scenario results present a range of cost-effective energy efficiency potential, and the identification of the District's biennial target based on the range modeled is effectively selecting the utility's preferred risk strategy and associated risk credit.

Deferred Transmission and Distribution System Investment

Energy efficiency measure savings reduce capacity requirements on both the transmission and distribution systems. The Council recently updated its estimates for these capacity savings, $31/kW-year and $26/kW-year for distribution and transmission systems, respectively ($2012). These values were used in the Seventh Plan. The new values, $3.08/kW-year and $6.85/kW-year for transmission and distribution systems, respectively will be used in the next Power Plan. These assumptions are used in all scenarios in the CPA.

Deferred Investment in Generation Capacity

The District's 2018 Integrated Resource Plan states that the District will rely upon market purchases to meet peak demands. Thus, the District does not currently avoid any capital expenses associated with generation resources by reducing peak demands. However, there is no guarantee that the market will continue to be a reliable resource for peak capacity. Regional power planners are calling attention to potential regional capacity deficits in the near future, exacerbated by the retirements of several coal plants. The potential of a Northwest capacity market may also change things, although its effect is uncertain.

As a slice block customer of BPA, the District can purchase capacity when needed and sell excess capacity when it is not. Thus, saved capacity represents either an avoided cost of purchased capacity or an opportunity cost of capacity that could potentially be sold.

To represent the value of capacity, EES used BPA's monthly demand charges as a proxy value for the monthly value of generation capacity, as those charges are based upon the cost of a gas generating unit. EES also applied a monthly shape to approximate the District's peak demand reductions due to conservation.

With these two factors, the value of generation capacity was calculated to be $85/kW-year. For the base case, it was assumed the demand charges would increase in real terms by 3% annually. Over the 20-year analysis period, the resulting cost of avoided capacity is $109/kW-year (2012$) in levelized terms.

In the low scenario, it is assumed that a market will continue to be available to meet the District's needs for peak demands, so no capacity value is included.

In the Council's Seventh Power Plan[28], a generation capacity value of $115/kW-year was explicitly calculated ($2012). This value will be used in the high scenario.

Summary of Scenario Assumptions

Table 1 summarizes the recommended scenario assumptions. The Base Case represents the most likely future.

Table 1
Avoided Cost Assumptions by Scenario, $2012

	Base	Low	High
Energy	Market Forecast	-50%-85% Confidence Interval*	+50%-85% Confidence Interval*
Social Cost of Carbon	CA Carbon Market	None	Federal/Council Values
Value of REC Compliance	15% RPS	15% RPS	15% RPS
Distribution System Credit, $/kW-year	$6.85	$6.85	$6.85

[28] https://www.nwcouncil.org/energy/powerplan/7/home/

Transmission System Credit, $/kW-year	$3.08	$3.08	$3.08
Deferred Generation Capacity Credit, $/kW-year	$109	$0	$115
Implied Risk Adder	N/A	Up to -$32/MWh -$109/kW-year Average of -$19/MWh -$109/kW-year	Up to $29/MWh $6/kW-year Average of $22/MWh $6/kW-year

**As noted above prediction intervals were used based on the last 10 years of data for high and low estimates.*

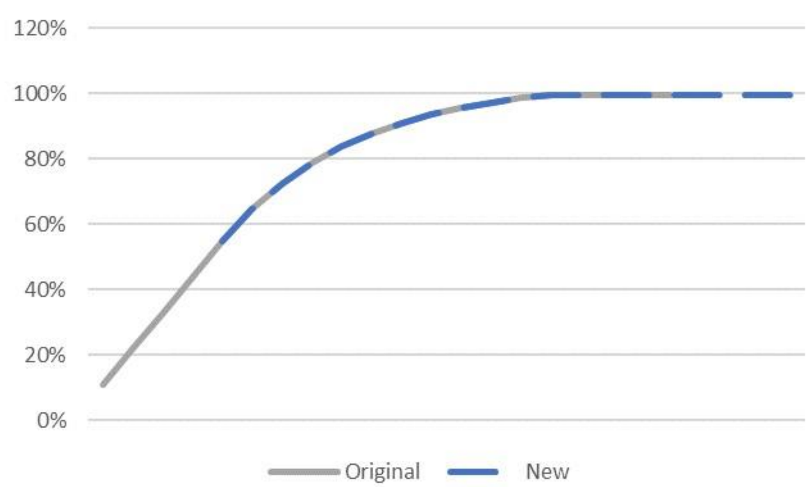
Appendix V – Ramp Rate Documentation

This section is intended to document how measure-level ramp rates were adjusted to align near term potential with recent achievements of Franklin PUD programs.

Modelling work began with the Seventh Plan ramp rate assignments for each measure. For new measures added to the model, an appropriate ramp rate was selected based on the maturity of each measure. Seventh Plan ramp rates were also adjusted to fit the 2020-2039 timeline of this CPA. The adjustment made to each ramp rate varied depending on the type of ramp rate, since different types of ramp rates are applied to retrofit and lost opportunity measures.

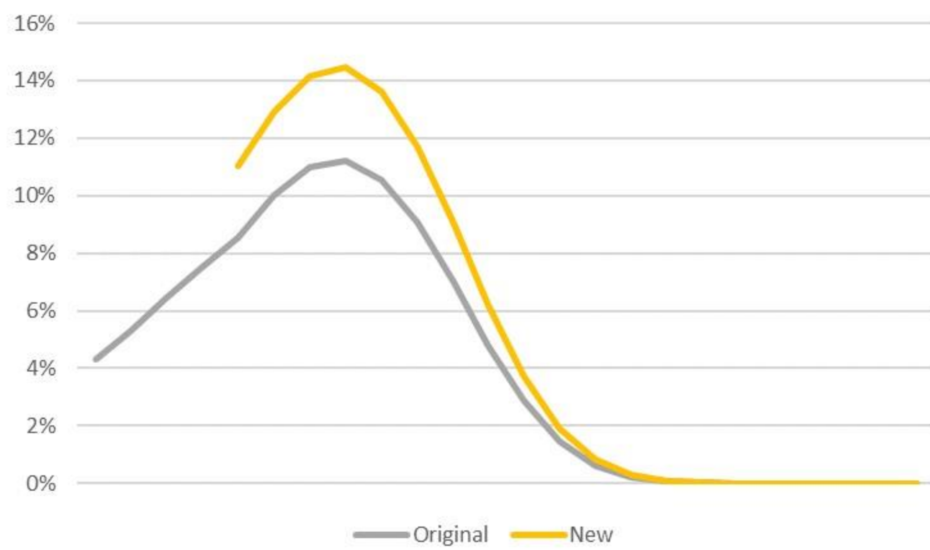
For lost opportunity measures, the ramp rates represent the share of equipment turning over in a given year that is achieved by efficiency programs. For these ramp rates, the only modification necessary was to extrapolate the final years to cover the time period relevant to the 2019 CPA. An example of this is shown in Figure V-1 below.

Figure V-1 Example Lost Opportunity Ramp Rate Modification



For retrofit ramp rates, a different adjustment was necessary. The ramp rates applied to retrofit measures describe the portion of the entire stock that is acquired in a given year. For these ramp rates, new values were calculated based on the original ramp rate values. The new value was set as the original ramp rate value for a given year, divided by the sum of original ramp rate values over the 2020-2039 timeframe. This approach reflects the fact that a portion of the stock has already been acquired and continuing with the pace projected by the Seventh Plan would mean acquiring a larger percentage of a smaller remaining stock. An example of this is shown below.

Figure V-2 Example Retrofit Ramp Rate Modification



With these modified ramp rates, Franklin PUD's program achievements from 2017-2018 and estimates for 2019 were compared at a sector level with the first three years of the study period, 2020-2022. Savings from NEEA's market transformation initiatives were allocated to the appropriate sectors. This allowed for the identification of sectors where ramp rate adjustments may be necessary.

Table V-1 below shows the results of the comparison by sector *after* ramp rate adjustments were made. Note that these totals do not include savings from Franklin PUD's residential lighting program.

Table V-1
Comparison of Sector-Level Program Achievement and Potential (aMW)

	Program History				Potential		
	2017	**2018**	**2019**	**Average**	**2020**	**2021**	**2022**
Residential	0.26	0.29		0.28	0.18	0.20	0.21
Commercial	0.25	0.36		0.30	0.27	0.32	0.36
Industrial	0.11	0.59		0.35	0.28	0.32	0.36
Agricultural	0.06	0.06		0.06	0.04	0.04	0.04
Distribution Efficiency	-	-		-	0.01	0.01	0.02
Total	**0.68**	**1.30**		**0.99**	**0.77**	**0.89**	**0.98**

Measure detail for each sector was acquired from BPA reporting, allowing for additional comparisons at the end use level, although savings from NEEA could not be allocated to individual measures or end uses.

Table V-2 below shows a comparison of historical accomplishments and future potential for the residential sector, by end use. Additional commentary is provided below.

Table V-2
Comparison of Residential Achievement and Potential (aMW)

	Program History				Potential		
End Use	**2017**	**2018**	**2019**	**Average**	**2020**	**2021**	**2022**
Dryer	-	-		-	-	-	-
Electronics	0.00	0.00		0.00	0.00	0.00	0.01
Food Preparation	-	-		-	0.00	0.00	0.00
HVAC	0.12	0.10		0.11	0.14	0.14	0.13
Lighting	0.05	0.00		0.03	-	-	-
Refrigeration	-	-		-	-	-	-
Water Heating	0.01	0.01		0.01	0.04	0.06	0.07
Whole Bldg/Meter Level	-	0.00		0.00	-	-	-
NEEA	0.14			0.16	-	-	-
Total	**0.26**	0.19		**0.28**	**0.18**	**0.20**	**0.21**
		0.29	**-**				

Electronics – Savings in this category were delayed and spread out as Franklin PUD has not achieved savings in this category in recent years. Savings from NEEA's consumer electronics initiative may apply here.

HVAC – This category was set to align approximately with the historical savings. Additional savings from NEEA's market transformation may apply here. Slower ramp rates were applied to some measure to align with program potential.

Water Heating – This category was set to align approximately with the historical savings. Additional savings from NEEA's market transformation may apply here. Slower ramp rates were applied to some measure to align with program potential.

Other Categories – Franklin PUD reported savings in the lighting level category, but due to lighting standards this end use has not been considered in this CPA.

The commercial sector achievements and estimated potential are shown in Table V-3, with additional commentary below.

Table V-3 Comparison of Commercial Achievement and Potential (aMW)							
	Program History				Potential		
End Use	**2017**	**2018**	**2019**	**Average**	**2020**	**2021**	**2022**
Compressed Air	-	-		-	0.00	0.00	0.01
Electronics	-	-		-	0.00	0.01	0.01
Food Preparation	-	-		-	0.00	0.00	0.01
HVAC	-	0.00		0.00	0.02	0.04	0.05
Lighting	0.21	0.30		0.26	0.21	0.24	0.25
Motors/Drives	-	-		-	0.00	0.00	0.00
Process Loads	-	-		-	0.00	0.00	0.00
Refrigeration	-	0.00		0.00	0.01	0.02	0.02
Water Heating	0.00	-		0.00	0.00	0.00	0.00
NEEA	0.03	0.05		0.04	-	-	-
Total	**0.25**	**0.36**		**0.30**	**0.27**	**0.32**	**0.36**

Lighting – Commercial lighting ramp rates were decreased from Seventh Plan rates to more closely align with historical savings.

HVAC – Commercial HVAC ramp rates were decreased from Seventh Plan rates to more accurately reflect Franklin PUD's historical savings.

Refrigeration – Commercial refrigeration ramp rates were decreased from Seventh Plan Rates to more accurately reflect Franklin PUD's historical savings.

Franklin PUD did not report savings in other end uses and ramp rates were decreased from Seventh Plan rates where cost-effective potential was identified.

EES slowed down ramp rates in the industrial sector to more closely align with recent levels of program achievement.

EES slightly accelerated agricultural ramp rates to align with recent levels of program achievement.

Appendix VI – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2019 CPA. The CPA evaluated thousands of measures; the measure list does not include each individual measure; rather it summarizes the measures at the category level, some of which are repeated across different units of stock, such as single family, multifamily, and manufactured homes. Specifically, utility conservation potential is modeled based on incremental costs and savings of individual measures. Individual measures are then combined into measure categories to more realistically reflect utility-conservation program organization and offerings. For example, single-family attic insulation measures are modeled for a variety of upgrade increments: R-0 to R-38, R-0 to R-49, or R-19 to R-38. The increments make it possible to model measure savings and costs at a more precise level. Each of these individual measures are then bundled across all housing types to result in one measure group: attic insulation.

The measure list used in this CPA was developed based on information from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council). The RTF and the Council continually maintain and update a list of regional conservation measures based on new data, changing market conditions, regulatory changes, and technological developments. The measure list provided in this appendix includes the most up-to date information available at the time this CPA was developed.

The following tables list the conservation measures (at the category level) that were used to model conservation potential presented in this report. Measure data was sourced from the Council's Seventh Plan workbooks and the RTF's Unit Energy Savings (UES) workbooks. Note that some measures may not be applicable to an individual utility's service territory based on characteristics of the utility's customer sectors.

Table VI-1
Residential End Uses and Measures

End Use	Measures/Categories	Data Source
Dryer	Heat Pump Clothes Dryer	7th Plan
Electronics	Advanced Power Strips	7th Plan, RTF
	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
Food Preparation	Electric Oven	7th Plan
	Microwave	7th Plan
HVAC	Air Source Heat Pump	7th Plan, RTF
	Controls, Commissioning, and Sizing	7th Plan, RTF
	Ductless Heat Pump	7th Plan, RTF
	Ducted Ductless Heat Pump	7th Plan
	Duct Sealing	7th Plan, RTF
	Ground Source Heat Pump	7th Plan, RTF
	Heat Recovery Ventilation	7th Plan
	Attic Insulation	7th Plan, RTF

	Floor Insulation	7th Plan, RTF
	Wall Insulation	7th Plan, RTF
	Windows	7th Plan, RTF
	Wi-Fi Enabled Thermostats	7th Plan
Lighting	Linear Fluorescent Lighting	7th Plan, RTF
	LED General Purpose and Dimmable	7th Plan, RTF
	LED Decorative and Mini-Base	7th Plan, RTF
	LED Globe	7th Plan, RTF
	LED Reflectors and Outdoor	7th Plan, RTF
	LED Three-Way	7th Plan, RTF
Refrigeration	Freezer	7th Plan
	Refrigerator	7th Plan
Water Heating	Aerator	7th Plan
	Behavior Savings	7th Plan
	Clothes Washer	7th Plan
	Dishwasher	7th Plan
	Heat Pump Water Heater	7th Plan, RTF
	Showerheads	7th Plan, RTF
	Solar Water Heater	7th Plan
	Thermostatic Valve	RTF
	Wastewater Heat Recovery	7th Plan
Whole Building	EV Charging Equipment	7th Plan

Table VI-2
Commercial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Controls, Equipment, & Demand Reduction	7th Plan
Electronics	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
	Smart Plug Power Strips	7th Plan, RTF
	Data Center Measures	7th Plan

Food Preparation	Combination Ovens	7th Plan, RTF
	Convection Ovens	7th Plan, RTF
	Fryers	7th Plan, RTF
	Hot Food Holding Cabinet	7th Plan, RTF
	Steamer	7th Plan, RTF
	Pre-Rinse Spray Valve	7th Plan, RTF
HVAC	Advanced Rooftop Controller	7th Plan
	Commercial Energy Management	7th Plan
	Demand Control Ventilation	7th Plan
	Ductless Heat Pumps	7th Plan
	Economizers	7th Plan
	Secondary Glazing Systems	7th Plan
	Variable Refrigerant Flow	7th Plan
	Web-Enabled Programmable Thermostat	7th Plan
Lighting	Bi-Level Stairwell Lighting	7th Plan
	Exterior Building Lighting	7th Plan
	Exit Signs	7th Plan
	Lighting Controls	7th Plan
	Linear Fluorescent Lamps	7th Plan
	LED Lighting	7th Plan
	Street Lighting	7th Plan
Motors/Drives	ECM for Variable Air Volume	7th Plan
	Motor Rewinds	7th Plan
Process Loads	Municipal Water Supply	7th Plan
Refrigeration	Grocery Refrigeration Bundle	7th Plan, RTF
	Water Cooler Controls	7th Plan
Water Heating	Commercial Clothes Washer	7th Plan, RTF
	Showerheads	7th Plan
	Tank Water Heaters	7th Plan

Table VI-3 Industrial End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Compressed Air	Air Compressor Equipment	7th Plan
	Demand Reduction	7th Plan
Energy Management	Air Compressor Optimization	7th Plan
	Energy Project Management	7th Plan
	Fan Energy Management	7th Plan
	Fan System Optimization	7th Plan
	Cold Storage Tune-up	7th Plan
	Chiller Optimization	7th Plan
	Integrated Plant Energy Management	7th Plan
	Plant Energy Management	7th Plan
	Pump Energy Management	7th Plan
	Pump System Optimization	7th Plan
Fans	Efficient Centrifugal Fan	7th Plan
	Fan Equipment Upgrade	7th Plan
Hi-Tech	Clean Room Filter Strategy	7th Plan
	Clean Room HVAC	7th Plan
	Chip Fab: Eliminate Exhaust	7th Plan
	Chip Fab: Exhaust Injector	7th Plan
	Chip Fab: Reduce Gas Pressure	7th Plan
	Chip Fab: Solid State Chiller	7th Plan
Lighting	Efficient Lighting High-	7th Plan
	Bay Lighting	7th Plan
	Lighting Controls	7th Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	7th Plan
	Cold Storage Retrofit	7th Plan
	Grocery Distribution Retrofit	7th Plan
Material Handling	Material Handling Equipment	7th Plan
	Material Handling VFD	7th Plan
Metals	New Arc Furnace	7th Plan
Misc.	Synchronous Belts	7th Plan
	Food Storage: CO2 Scrubber	7th Plan
	Food Storage: Membrane	7th Plan
Motors	Motor Rewinds	7th Plan
Paper	Efficient Pulp Screen	7th Plan
	Material Handling	7th Plan
	Premium Control	7th Plan

	Premium Fan	7th Plan
Process Loads	Municipal Sewage Treatment	7th Plan
Pulp	Efficient Agitator	7th Plan
	Effluent Treatment System	7th Plan
	Premium Process	7th Plan
	Refiner Plate Improvement	7th Plan
	Refiner Replacement	7th Plan
Pumps	Equipment Upgrade	7th Plan
Transformers	New/Retrofit Transformer	7th Plan
Wood	Hydraulic Press	7th Plan
	Pneumatic Conveyor	7th Plan

Table IV-4
Agriculture End Uses and Measures

End Use	Measures/Categories	Data Source
Dairy Efficiency	Efficient Lighting	7th Plan
	Milk Pre-Cooler	7th Plan
	Vacuum Pump	7th Plan
Irrigation	Low Energy Sprinkler Application	7th Plan
	Irrigation Hardware	7th Plan, RTF
	Scientific Irrigation Scheduling	7th Plan, BPA
Lighting	Agricultural Lighting	7th Plan
Motors/Drives	Motor Rewinds	7th Plan

Table VI-4
Distribution Efficiency End Uses and Measures

End Use	Measures/Categories	Data Source
Distribution Efficiency	LDC Voltage Control	7th Plan
	Light System Improvements	7th Plan
	Major System Improvements	7th Plan
	EOL Voltage Control Method	7th Plan
	SCL Implement EOL w/ Improvements	7th Plan

Appendix VII – Energy Efficiency Potential by End-Use

Residential **aMW**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Dryer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electronics	0.003	0.005	0.006	0.008	0.010	0.011	0.012	0.014	0.013	0.004	0.002	0.002	0.002	0.002	0.002	0.002
Food Preparation	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.002	0.002	0.002	0.001	0.001
HVAC	0.135	0.137	0.130	0.124	0.115	0.104	0.092	0.079	0.067	0.058	0.052	0.049	0.040	0.040	0.040	0.040
Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heating	0.038	0.051	0.067	0.085	0.104	0.123	0.139	0.152	0.160	0.163	0.161	0.155	0.147	0.140	0.133	0.127
Whole Bldg/Meter Level	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.177**	**0.194**	**0.204**	**0.218**	**0.230**	**0.240**	**0.245**	**0.247**	**0.243**	**0.228**	**0.218**	**0.208**	**0.192**	**0.184**	**0.176**	**0.170**

Commercial **aMW**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Compressed Air	0.003	0.005	0.006	0.008	0.010	0.012	0.013	0.014	0.014	0.013	0.012	0.010	0.008	0.006	0.004	0.002
Electronics	0.004	0.007	0.011	0.015	0.021	0.028	0.037	0.046	0.056	0.065	0.075	0.014	-	-	-	-
Food Preparation	0.004	0.005	0.006	0.006	0.008	0.009	0.010	0.011	0.012	0.013	0.014	0.015	0.015	0.011	0.009	0.009
HVAC	0.025	0.037	0.051	0.066	0.082	0.098	0.111	0.120	0.124	0.120	0.111	0.097	0.082	0.066	0.054	0.043
Lighting	0.210	0.237	0.247	0.261	0.266	0.237	0.247	0.257	0.243	0.215	0.216	0.187	0.167	0.159	0.162	0.165
Motors/Drives	0.003	0.004	0.004	0.005	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005
Process Loads	0.002	0.003	0.004	0.005	0.006	0.007	0.008	0.009	0.009	0.008	0.007	0.006	0.005	0.003	0.002	0.001
Refrigeration	0.011	0.016	0.022	0.029	0.036	0.040	0.044	0.047	0.047	0.044	0.039	0.032	0.024	0.016	0.010	0.005
Water Heating	0.003	0.004	0.005	0.005	0.006	0.007	0.008	0.008	0.009	0.010	0.010	0.010	0.010	0.010	0.010	0.008
Total	**0.266**	**0.317**	**0.355**	**0.401**	**0.440**	**0.444**	**0.483**	**0.518**	**0.519**	**0.495**	**0.490**	**0.377**	**0.316**	**0.276**	**0.255**	**0.239**

Industrial **aMW**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035

Compressed Air	0.004	0.004	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000
Energy Management	0.123	0.154	0.184	0.217	0.252	0.284	0.308	0.321	0.317	0.297	0.261	0.214	0.162	0.114	0.074	0.042
Fans	0.003	0.003	0.004	0.004	0.003	0.003	0.002	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hi-Tech	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Lighting	0.040	0.037	0.034	0.031	0.030	0.028	0.027	0.025	0.023	0.020	0.017	0.014	0.010	0.007	0.005	0.003
Low & Med Temp Refr	0.056	0.070	0.086	0.105	0.124	0.142	0.157	0.165	0.166	0.157	0.139	0.116	0.090	0.066	0.046	0.029
Material Handling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Metals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Motors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Paper	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Loads	0.024	0.029	0.032	0.033	0.032	0.028	0.022	0.015	0.009	0.005	0.002	0.001	0.000	0.000	0.000	0.000
Pulp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumps	0.028	0.025	0.020	0.016	0.013	0.010	0.008	0.007	0.005	0.004	0.003	0.003	0.000	0.000	0.000	0.000
Transformers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.279**	**0.322**	**0.363**	**0.409**	**0.456**	**0.498**	**0.526**	**0.535**	**0.522**	**0.484**	**0.424**	**0.348**	**0.262**	**0.187**	**0.125**	**0.074**

Agricultural **aMW**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Dairy Efficiency	0.001	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Irrigation	0.032	0.033	0.031	0.029	0.026	0.022	0.018	0.013	0.009	0.006	0.004	0.002	0.000	0.000	0.000	0.000
Lighting	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Motors/Drives	0.006	0.005	0.004	0.004	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000
Total	**0.042**	**0.042**	**0.039**	**0.036**	**0.032**	**0.028**	**0.022**	**0.016**	**0.011**	**0.007**	**0.005**	**0.003**	**0.000**	**0.000**	**0.000**	**0.000**

Distribution Efficiency **aMW**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1 - LDC voltage control method	0.005	0.008	0.011	0.014	0.017	0.020	0.022	0.024	0.026	0.027	0.029	0.031	0.031	0.031	0.031	0.032
2 - Light system improvements	0.003	0.005	0.006	0.009	0.010	0.012	0.013	0.014	0.015	0.016	0.017	0.018	0.019	0.019	0.019	0.019
3 - Major system improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 - EOL voltage control method	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A - SCL implement EOL w/ major system imp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.008**	**0.012**	**0.017**	**0.023**	**0.027**	**0.031**	**0.036**	**0.038**	**0.041**	**0.044**	**0.046**	**0.049**	**0.049**	**0.050**	**0.050**	**0.050**