



2020 Integrated Resource Plan



Public Utility District No. 1 of Benton County

PREPARED IN COLLABORATION WITH



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Chapter 1: Executive Summary

Benton PUD's (the District) 2020 Integrated Resource Plan (IRP) lays out a strategy for meeting its energy, capacity and Washington State renewable portfolio standard (RPS) obligations over a 10-year planning horizon from 2021 through 2030.

The goal of this IRP is to provide a framework for evaluating existing resources and any new resources that may be necessary to meet the District's obligations. The IRP provides guidance towards resource strategies that will provide reliable, low cost electricity to the District's ratepayers—at a reasonable level of risk—for years to come.

Obligations and Resources

The majority of the District's wholesale electricity is supplied by the Bonneville Power Administration (BPA) under their Slice/Block contract. For Slice resource planning purposes, the District considers "critical hydro" conditions, which is defined by the lowest hydrological year on record (1937). Critical hydro conditions represent a conservative supply scenario, thus most of the time, the District will have more generation. Planning to critical water level ensures adequate supply to meet demand even under especially poor water conditions.

The District's existing non-BPA resources include the 50 MW Frederickson combined cycle combustion turbine contract ending in 2022, a seasonal capacity call option contract from 2022 through 2025 and renewable contracts including: Nine Canyon Wind, White Creek Wind and Packwood Lake Hydroelectric.

Annual Energy Net Position

Figure 1 shows that under critical hydro conditions the District's existing BPA and non-BPA resources are expected to supply enough energy to remain in load/resource balance on an average annual basis through September 2025, when the existing capacity contract expires.

Figure 1: Annual Average Load and Existing Resources in Critical Water Conditions

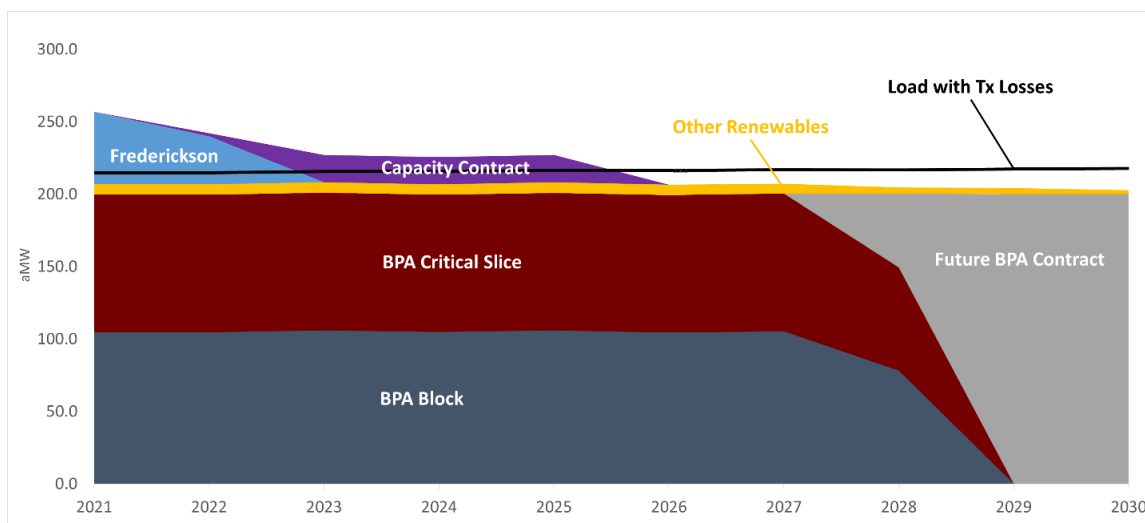
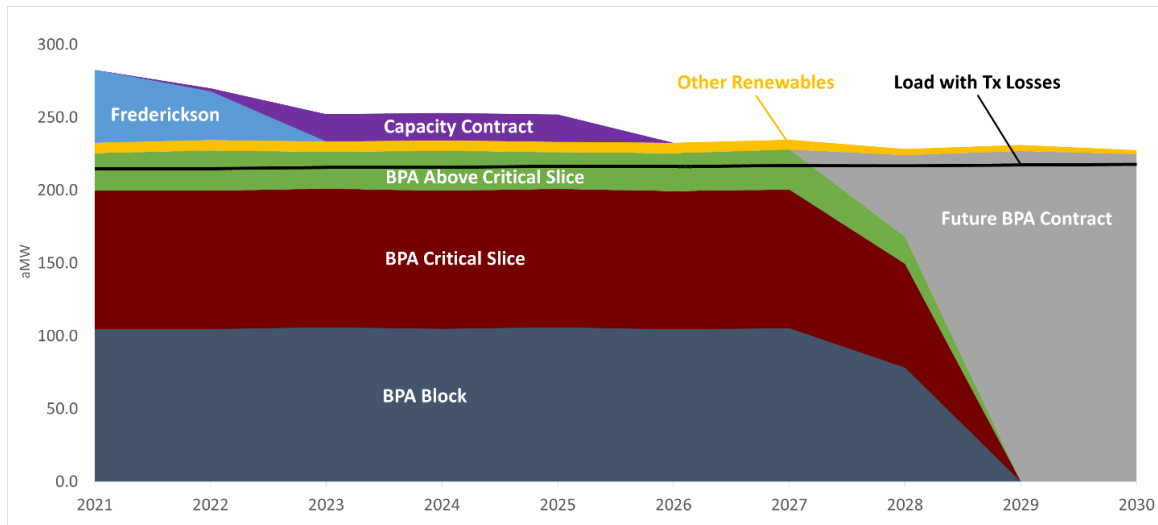


Figure 2, includes additional slice generation (“BPA Above Critical Slice”) based on the average of more than 80 years of hydro conditions, showing the District is expected to supply enough energy to remain in load/resource balance on an average annual basis beyond 2030.

Figure 2: Annual Average Load and Existing Resources in Average Water Conditions



Seasonal Capacity Net Position

While the District’s supply-side resources represent the capability to deliver annual energy amounts above its average annual load obligations, there are certain times during the year, in both winter and summer, when the maximum hourly load exceeds the District’s contracted generating capacity. Maximum power demand usually occurs in the late afternoon/early evening hours during the summer when air conditioning and irrigation loads are at their highest. The District does not currently have adequate capacity to serve its entire load during these seasonal peak periods and relies on the wholesale market to make up the deficit.

For evaluating its seasonal capacity deficits, the District examined historical loads from December 2011 through February 2020 to determine the daily average heavy load hour (HLH) (6 am to 10 pm) loads associated with a given percentile of occurrences for both summer and winter. The 99th percentile (P99)—where daily average HLH load exceeded this value only 1% of the time—was selected as a conservative peak load to utilize for evaluating capacity load/resource balance.

Figure 3 for summer and Figure 4 for winter show the P99 average HLH load/resource balance. The Slice system peak generation assumption was based on output from The Energy Authority’s Slice Water Routing Simulator (SWRS). The analysis team determined the Slice system generation across all HLH, based on the Slice system operational capabilities, to be 9,000 aMW; the District’s share of the generation is about 123 aMW, which is a reasonable assumption for summer or winter. Even in adverse water conditions, the system will, to a limited extent, be able to ramp up generation capacity when the additional energy is needed.

Figure 3: Annual Peak Load and Existing Resources in Summer

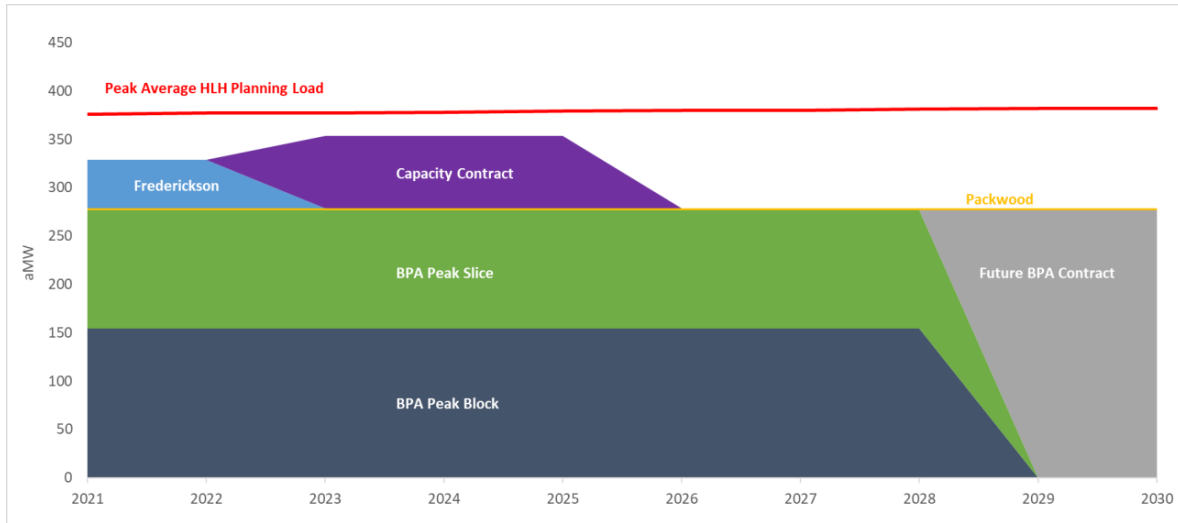
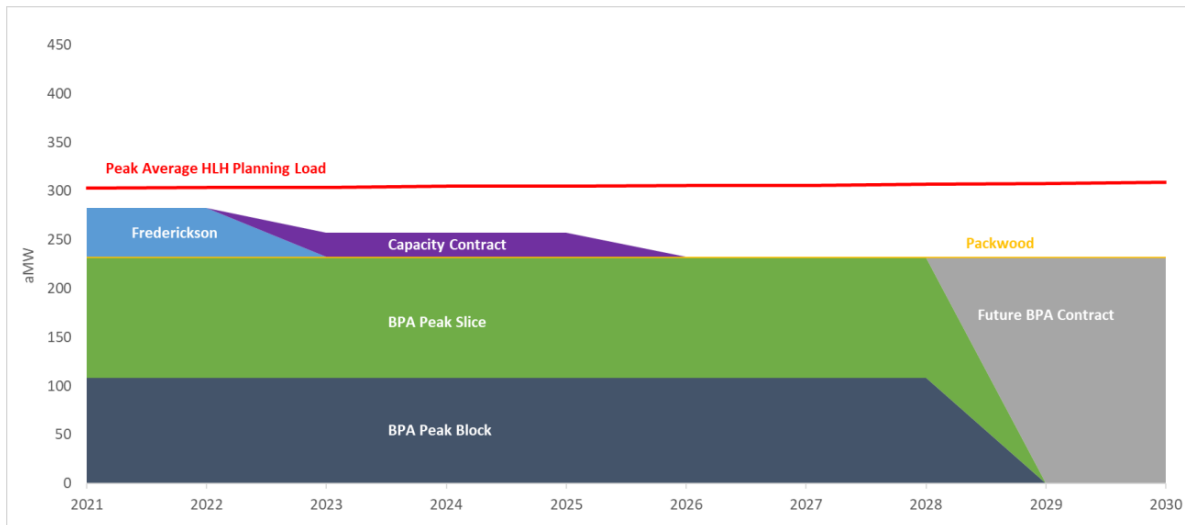


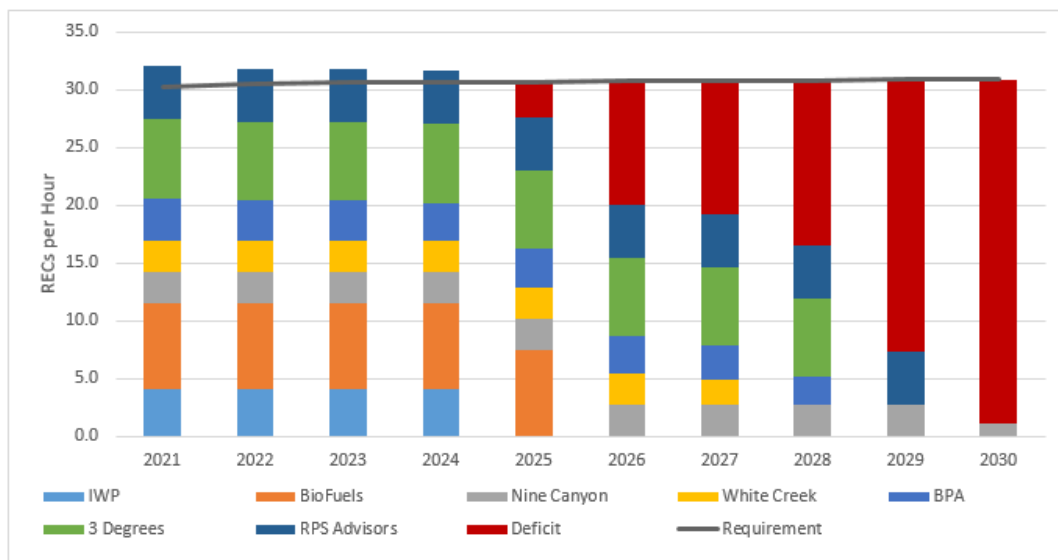
Figure 4: Annual Peak Load and Existing Resources in Winter



Renewable Portfolio Net Position

Figure 5 displays the District’s annual RPS net position with existing contracts. The black line represents the RPS requirement of 15% of the District’s retail load. Blue, green, orange, yellow, and gray represent existing Renewable Energy Credit (REC) contracts and red represents the existing deficit. The District has enough RECs based on current forecasts to comply through 2024. Beginning in 2025, the District will need to acquire additional RECs to maintain its RPS compliance.

Figure 5: Annual RPS Net Position from 2021-2030 with existing contracts



Preferred Portfolio of Resources

The District performed quantitative and qualitative financial and risk analysis of potential resource portfolios to ultimately settle on a preferred portfolio of resources. The District’s 2018 IRP identified utilizing market purchases to cover energy and capacity deficits as its preferred portfolio. At the time, the District further studied its capacity needs and committed to monitoring the supply and demand landscape to identify when unspecified market purchases would need to be supplemented with some level of additional specified physical resources to ensure the District continued meeting its load obligations.

On an average annual basis, the region’s generation assets are expected to produce more energy than is represented by utility load obligations. However, the surplus energy generation is not precisely aligned with the peak utility load profiles in the winter and summer months. This results in the export of surplus energy out of the region while leaving seasonal energy (capacity) deficits which are becoming more pronounced in each year of the forecast period.

Regional generation resource adequacy is projected to continue to decline over the initial planning horizon due to the early retirement of coal-fired resources and the lack of firm plans by utilities to build new dispatchable capacity, especially in Washington state, due in part to the Clean Energy

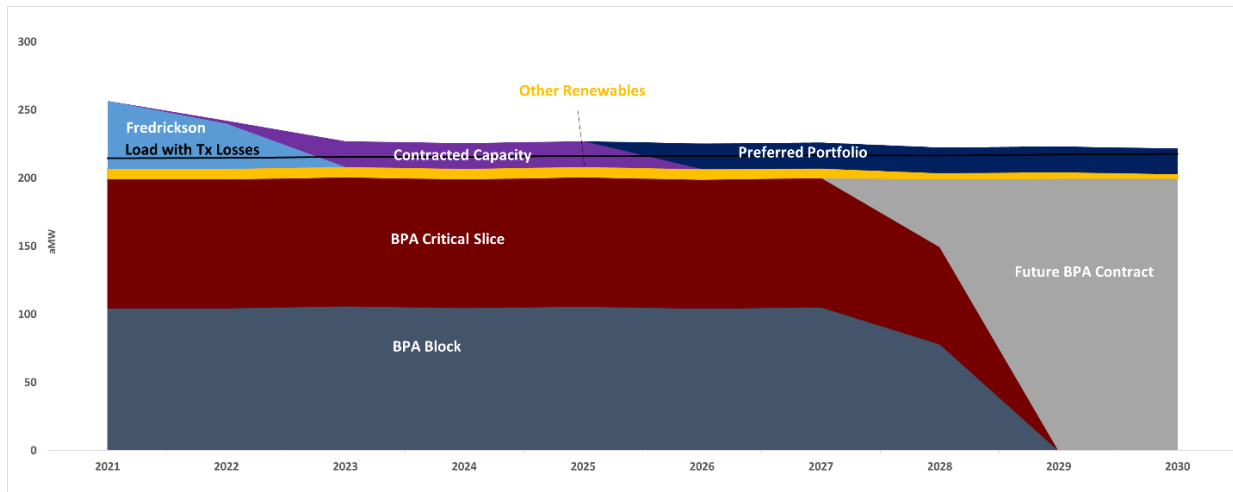
Transformation Act (CETA). The Northwest Power and Conservation Council projects the loss of load probability (LOLP) could increase to 26% by 2026, which is well above the 5% threshold used as a regional standard for adequacy. Given the District’s concerns about the region’s ability to meet its capacity requirements during peak demand periods and the increasing risk of relying on the market, the District’s strategy for this IRP is thus evolving away from relying solely on the market for seasonal capacity deficits. District staff will continue to systematically evaluate market conditions, emerging technologies, and resource availability.

Energy and Capacity Strategy

The District’s preferred resource portfolio now includes contracting with existing dispatchable generation units in the region to supplement its existing resources to cover part of its seasonal capacity deficits. The District’s preferred portfolio combines purchasing a capacity call option to insure against the growing risk of physical generation shortfalls in the region while maintaining the District’s flexibility to continue utilizing market purchases when it is more economic. The District will continue to utilize market purchases to meet average energy needs, especially during average or above average water years. 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 the carrying costs of resources surplus to actual supply needs. Financial risks will continue to be managed through the District’s hedging program.

Figure 6 shows the District’s energy position under critical hydro conditions with the preferred portfolio—continuing to utilize a contracted capacity call option.

Figure 6: Preferred Resource Plan, Energy Position in Critical Water Conditions



Since the completion of the IRP analysis, the Columbia River System Operations (CRSO) Final Environmental Impact Statement (EIS) was released and a record of decision is expected by September 30, 2020. The preferred portfolio identified in the CRSO EIS includes a significant reduction to the firm generation of the Federal Columbia River Power System (FCRPS). BPA is currently conducting the FY2022/2023 rate period high water mark (RHWM) process and has provided preliminary RHWM values

for all BPA customers. The preliminary numbers show a potential 8 aMW reduction for the District. The District will incorporate the final results of these processes into future power supply planning including the District’s 2022 IRP update.

Figure 7 and Figure 8 show the District’s seasonal capacity positions with the preferred portfolio included. Under the 99th percentile peak load scenario, the District’s capacity position with the preferred portfolio is forecasted to reduce its reliance on the market, by about two-thirds in summer (Figure 7) and about one-third in winter (Figure 8), through the end of the study period.

Figure 7: Preferred Resource Plan, Capacity Position in Summer

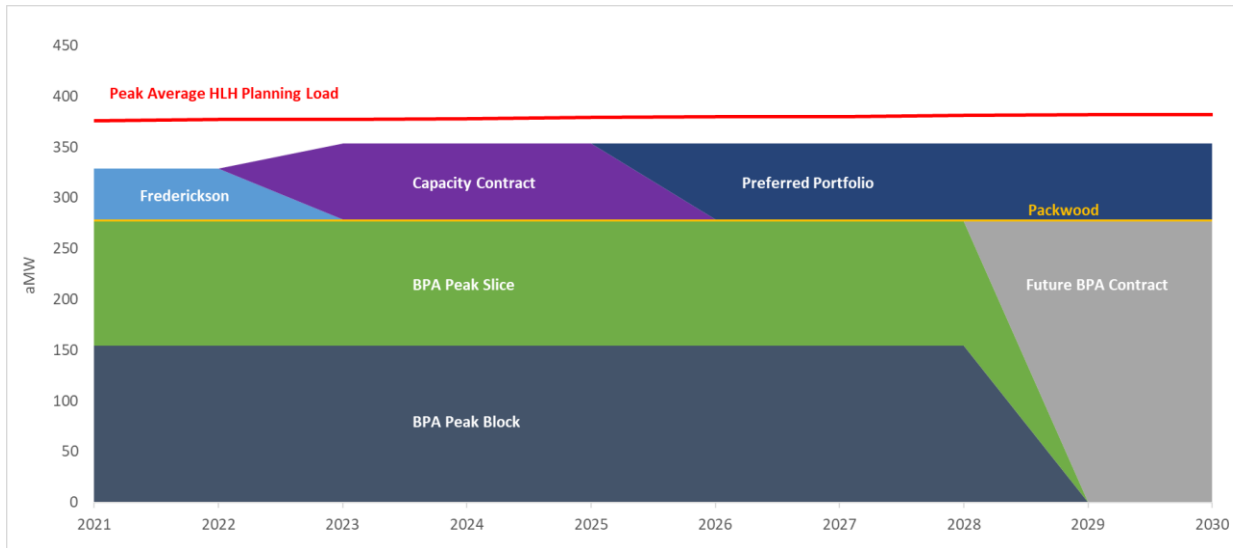
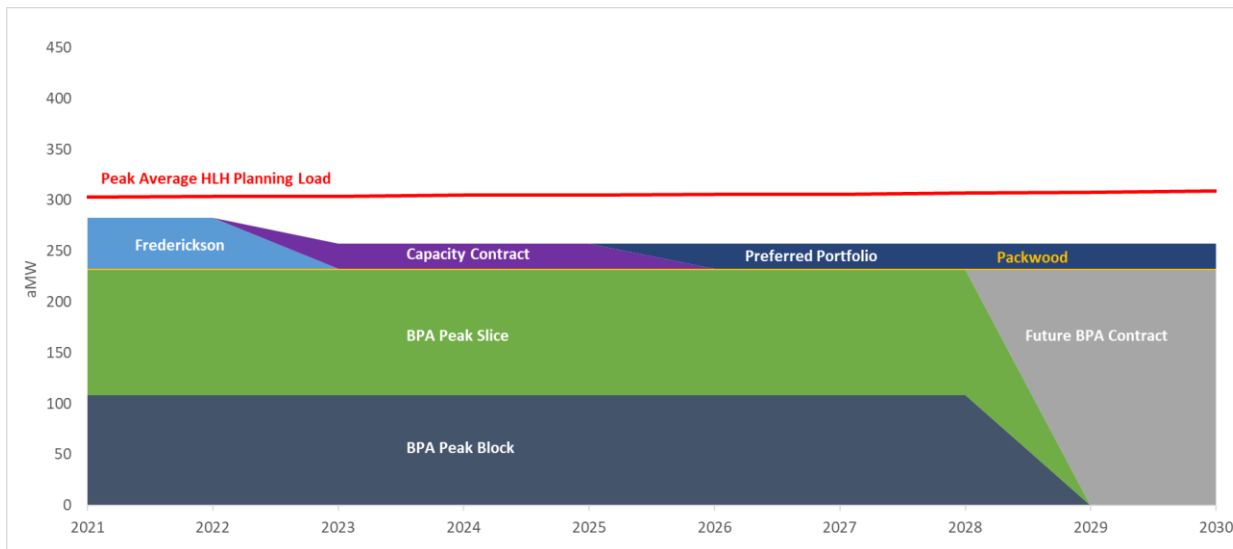


Figure 8: Preferred Resource Plan, Capacity Position in Winter

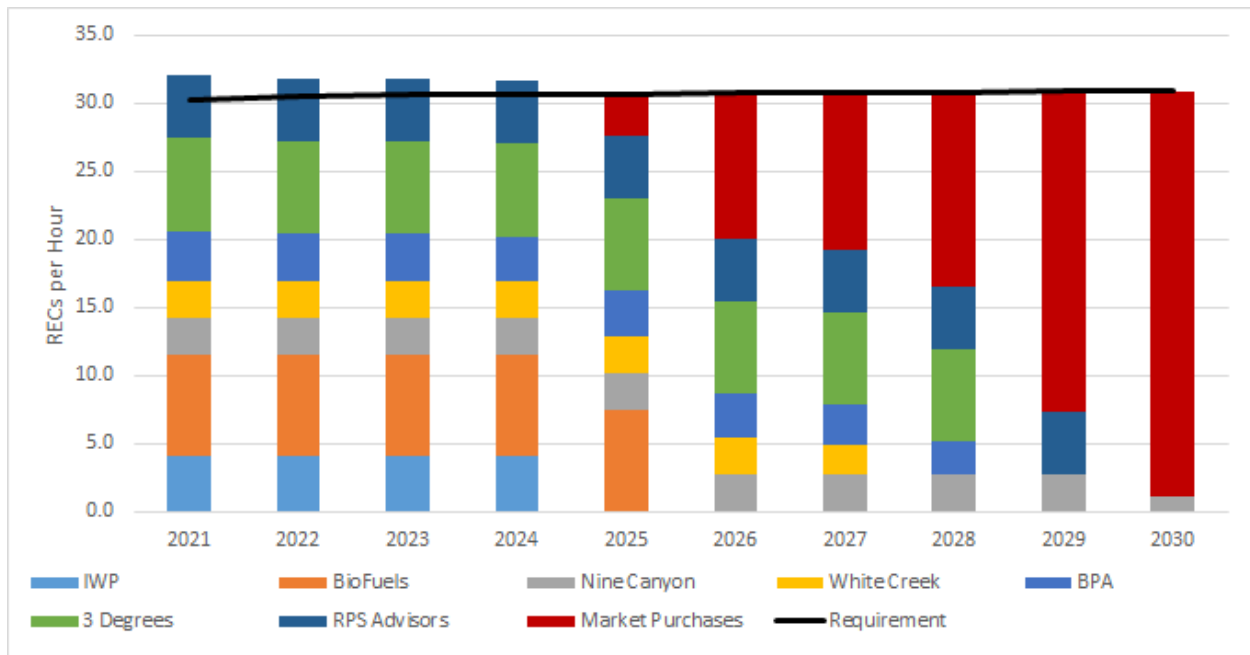


Renewable Portfolio Strategy

The REC market is expected to possess sufficient market depth to cover the District's RPS needs through the study period. Supplying RECs from the market is currently the least cost approach to meeting this requirement. The District will actively monitor market and legislative changes to continuously assess this approach.

Figure 9 shows the District's preferred resource plan to meet its RPS requirements.

Figure 9: Preferred Resource Plan, RPS Position



Chapter 2: Load Forecast

A forecast of future electric power requirements is the cornerstone of the IRP. 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 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 successfully utilized for several years to determine the requirements and resource forecasting necessary to maintain system reliability at an acceptable economic cost.

Demand and Energy Forecast Methodology

Demand forecasts facilitate the District's planning 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 utilizes historical heating degree day and cooling degree day data from the Pasco airport weather station. From the Woods and Poole data set, the load forecast model used total population, total employment, and total number of households to forecast total retail sales for the Benton 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.

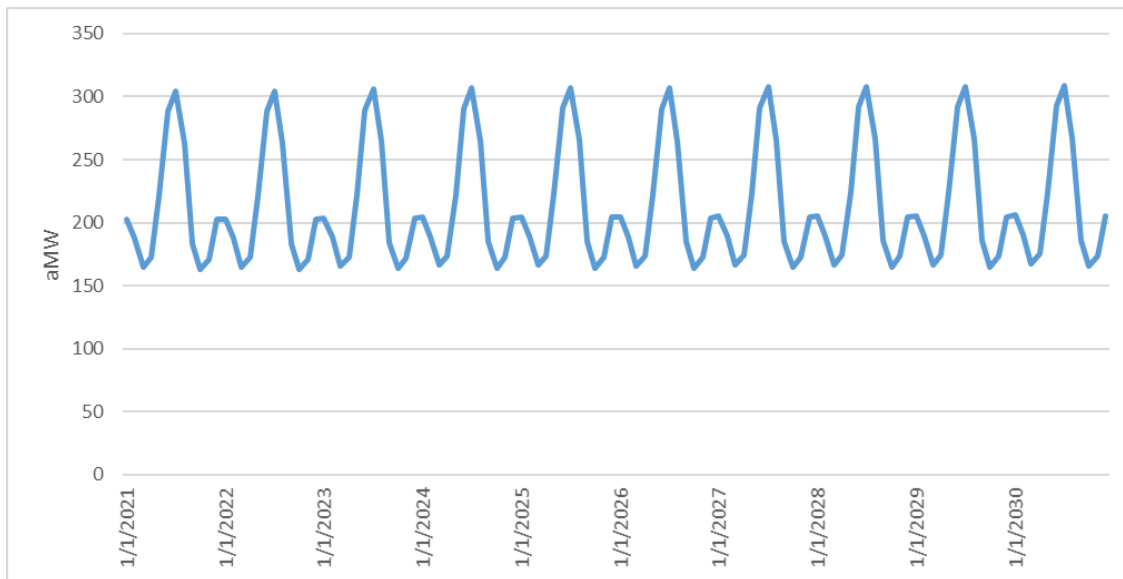
Because historical loads include the already achieved impacts of conservation, regression methods also have the benefit of capturing the effects of conservation on District consumption. The methodology carries the effect of that conservation forward. The District also separately forecasts incremental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

See Appendix A: Ten Year Load & Customer Forecast for additional details about the District's load forecast methodology. Refer to Appendix B: 2019 Conservation Potential Assessment for details about the District's latest conservation potential assessment.

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 0.17% for retail load, a decrease from the 2018 forecast which expected a 0.21% AARG. The most recent ten-year load and customer forecast was adopted by the District in May 2020 (Figure 10).

Figure 10: 2021-2030 Load Forecast



Due to seasonally warm summers and agriculture related irrigation loads, the District's peak energy usage occurs during the summer. The current forecast anticipates an increase in average energy usage of less than 4 megawatts (aMW) over the 2020 load of 213.8 aMW. The ten-year low, medium and high load and customer forecasts are each a stand-alone forecast as described in the modeling assumptions section. The District develops each forecast to establish a range of growth rates and adopts the medium case as its base case. To provide simplified and more relevant reference data, loads are expressed as average power consumption on an annual basis throughout this study.

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. The base case is the expected, the “high” scenario is approximately 4% higher load than the base case, and the “low” case scenario is approximately 4% lower than the base case.

Date	Base MWh	High MWh	Low MWh
Jan-20	150,795	156,564	143,294
Feb-20	125,855	130,670	119,595
Mar-20	122,320	126,999	116,235
Apr-20	123,946	128,688	117,780
May-20	164,192	170,473	156,024
Jun-20	207,440	215,377	197,122
Jul-20	226,346	235,006	215,087
Aug-20	195,517	202,997	185,792
Sep-20	132,007	137,057	125,440
Oct-20	120,995	125,624	114,977
Nov-20	123,267	127,983	117,135
Dec-20	150,433	156,188	142,950
Jan-21	150,943	156,605	143,324
Feb-21	125,979	130,705	119,620
Mar-21	122,439	127,033	116,260
Apr-21	124,067	128,722	117,805
May-21	164,353	170,518	156,057
Jun-21	207,643	215,433	197,163
Jul-21	226,568	235,068	215,133
Aug-21	195,709	203,051	185,831
Sep-21	132,136	137,093	125,467
Oct-21	121,114	125,657	115,001
Nov-21	123,388	128,016	117,160
Dec-21	150,580	156,229	142,980
Jan-22	151,061	156,989	143,669
Feb-22	126,077	131,025	119,908
Mar-22	122,535	127,344	116,539
Apr-22	124,165	129,037	118,089
May-22	164,481	170,936	156,433
Jun-22	207,806	215,961	197,637
Jul-22	226,746	235,644	215,650
Aug-22	195,862	203,548	186,278
Sep-22	132,240	137,429	125,769
Oct-22	121,209	125,965	115,277
Nov-22	123,484	128,330	117,442
Dec-22	150,698	156,612	143,324
Jan-23	151,588	157,267	143,917
Feb-23	126,517	131,257	120,115
Mar-23	122,963	127,569	116,740
Apr-23	124,598	129,265	118,292
May-23	165,055	171,239	156,703
Jun-23	208,531	216,343	197,978
Jul-23	227,537	236,061	216,022
Aug-23	196,545	203,908	186,599
Sep-23	132,701	137,672	125,986

Date	Base MWh	High MWh	Low MWh
Oct-23	121,631	126,188	115,476
Nov-23	123,915	128,557	117,644
Dec-23	151,224	156,889	143,571
Jan-24	152,066	157,938	144,526
Feb-24	126,916	131,817	120,623
Mar-24	123,351	128,114	117,234
Apr-24	124,991	129,817	118,793
May-24	165,576	171,969	157,366
Jun-24	209,189	217,266	198,816
Jul-24	228,254	237,068	216,936
Aug-24	197,165	204,779	187,389
Sep-24	133,119	138,260	126,519
Oct-24	122,015	126,727	115,965
Nov-24	124,306	129,106	118,142
Dec-24	151,701	157,559	144,179
Jan-25	152,162	157,745	144,342
Feb-25	126,996	131,656	120,469
Mar-25	123,428	127,958	117,085
Apr-25	125,069	129,659	118,642
May-25	165,680	171,760	157,165
Jun-25	209,320	217,002	198,563
Jul-25	228,398	236,779	216,660
Aug-25	197,289	204,529	187,150
Sep-25	133,203	138,091	126,357
Oct-25	122,092	126,572	115,817
Nov-25	124,384	128,949	117,992
Dec-25	151,796	157,367	143,995
Jan-26	152,023	157,947	144,519
Feb-26	126,880	131,824	120,618
Mar-26	123,316	128,121	117,229
Apr-26	124,955	129,824	118,788
May-26	165,529	171,979	157,358
Jun-26	209,129	217,278	198,807
Jul-26	228,189	237,081	216,926
Aug-26	197,109	204,790	187,380
Sep-26	133,082	138,267	126,513
Oct-26	121,980	126,734	115,960
Nov-26	124,271	129,113	118,137
Dec-26	151,658	157,567	144,172
Jan-27	152,481	158,156	144,705
Feb-27	127,263	131,999	120,772
Mar-27	123,687	128,291	117,379
Apr-27	125,332	129,997	118,940
May-27	166,028	172,207	157,560
Jun-27	209,760	217,567	199,062

Date	Base MWh	High MWh	Low MWh
Jul-27	228,877	237,396	217,205
Aug-27	197,703	205,062	187,621
Sep-27	133,483	138,451	126,675
Oct-27	122,348	126,902	116,108
Nov-27	124,645	129,284	118,288
Dec-27	152,115	157,777	144,357
Jan-28	152,733	158,813	145,301
Feb-28	127,473	132,547	121,270
Mar-28	123,892	128,823	117,863
Apr-28	125,539	130,536	119,430
May-28	166,302	172,922	158,210
Jun-28	210,107	218,470	199,882
Jul-28	229,256	238,381	218,100
Aug-28	198,031	205,913	188,394
Sep-28	133,704	139,026	127,197
Oct-28	122,551	127,429	116,587
Nov-28	124,851	129,821	118,776
Dec-28	152,367	158,432	144,952
Jan-29	152,754	158,647	145,142
Feb-29	127,491	132,409	121,138
Mar-29	123,909	128,689	117,734
Apr-29	125,556	130,400	119,300
May-29	166,325	172,742	158,037
Jun-29	210,135	218,242	199,664
Jul-29	229,287	238,133	217,862
Aug-29	198,058	205,698	188,188
Sep-29	133,722	138,881	127,058
Oct-29	122,567	127,296	116,460
Nov-29	124,869	129,686	118,646
Dec-29	152,388	158,266	144,794
Jan-30	153,166	158,943	145,408
Feb-30	127,835	132,656	121,360
Mar-30	124,243	128,929	117,950
Apr-30	125,895	130,643	119,518
May-30	166,774	173,064	158,326
Jun-30	210,702	218,649	200,030
Jul-30	229,906	238,577	218,261
Aug-30	198,592	206,082	188,533
Sep-30	134,083	139,140	127,291
Oct-30	122,898	127,533	116,673
Nov-30	125,205	129,928	118,864
Dec-30	152,799	158,562	145,059

Chapter 3: Existing Resources

The District sources about 90% of its power supply requirements through purchases from the Bonneville Power Administration (BPA) and the remainder is sourced from non-BPA sources. The District's generation mix is primarily made up of hydroelectric, nuclear, wind and natural gas generation resources. Refer to the District's website¹ for its latest fuel mix disclosure as required by 19.29A RCW. In addition to its physical generation resources, the District makes physical purchases of power from the open market. Lastly, the District has a physical capacity call option available to help meet its seasonal load obligations. This section provides an overview of the District's existing supply-side resource portfolio and concludes with an evaluation of its projected annual energy requirements versus its existing resources (load/resource balance).

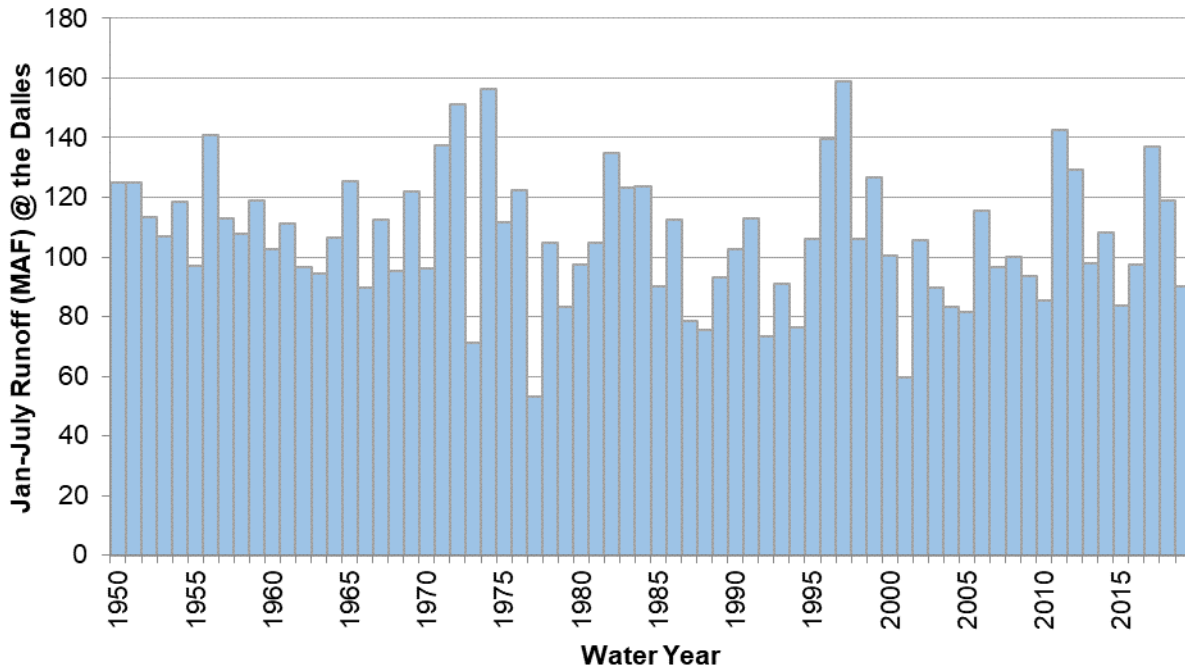
Overview of Existing BPA Resources

BPA Slice/Block Power Sales Agreement

Bonneville Power Administration (BPA) is the marketer and distributor of power generation provided by the Federal Columbia River Power System (FCRPS) and the Columbia Generation Station nuclear plant. The FCRPS is managed and operated by a collaboration of three federal agencies: BPA, the U.S. Army Corps of Engineers (Corps of Engineers) 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). 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 Dam between January and July. Hydrological conditions at The Dalles Dam 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 11 below.

¹ <https://www.bentonpud.org/About/Your-PUD/Overview/Energy-Mix>

Figure 11: Historical Water Years (1949-2019)



The 1937 water year streamflow represented the worst (lowest) on record at the time it 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 extremely adverse hydrological conditions, the FCRPS is expected to 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 aMW and 6,994 aMW respectively (slightly lower in 2021 due to refueling outage at CGS). System generation will exceed 7,054 aMW and 6,994 aMW in non-critical water years, which should occur the vast majority of the time.

As a Tier 1 Slice/Block customer, The District 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. The District can receive up to 2.85022% of the Slice/Block product. The quantity of power a utility is entitled to is 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.

The District currently receives its full RHWM allocation from BPA from October 2019 through September 2020. The District’s share of output is about 228 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 about 200 aMW. In water conditions greater than critical, total system output will be greater than 7,054 aMW. Based on an 80-

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.

The system allocation is calculated by dividing a utility's RHW (or net requirements, whichever is lower) by the sum of all utilities RHW (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 The District 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 The District 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 the 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. The District 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 The District to fulfill its load obligations with resources other than what is provided by BPA.

Columbia Generating Station Nuclear Plant

The largest non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, WA, with a generation capacity of 1,190 MW. It is owned and operated by Energy Northwest (ENW), a joint operating agency that consists of 28 public utilities in Washington State. The District receives a share of the output from CGS as part of the BPA Slice contract.

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, some of which is eligible for meeting the Renewable Portfolio Standard (RPS) requirements of Washington's Energy Independence Act (EIA). The energy and Renewable Energy Credits (RECs) associated with the wind resources are included in the BPA Tier 1 rate. In accordance with the District's election under section 5 of Exhibit H of the District's Slice Agreement, BPA annually transfers the District's share of available Tier 1 RECS into the District's Western Renewable Energy Generation Information System (WREGIS) account. The District's entitlement of those resources is approximately 6.4 MW of capacity but varies annually. BPA's forecasted wind resources allocated to the District are declining annually from current estimates of 12,057 RECs in CY 2020 to 3,998 RECs in CY 2027.

The District's Slice contract also includes Incremental Hydro Tier 1 RECs associated with incremental generation from efficiency upgrades at various generation facilities such as Grand Coulee Dam, Bonneville Dam, Chief Joseph Dam, and Cougar Dam. The RECs from hydro efficiency upgrades allocated by BPA are eligible for meeting RPS requirements beginning in 2020. BPA's forecasted incremental hydro resources allocated to the District, based on average water years, is currently estimated at 20,923 RECs in CY 2020 to 21,139 RECs in CY 2027.

Overview of Existing Non-BPA Resources

Frederickson Natural Gas Plant

In March 2001, the District entered into a twenty-year agreement with Frederickson Power LP for the purchase of 50 MW of contract capacity from the 249 MW Frederickson combined-cycle natural gas fired combustion turbine project near Tacoma, Washington. The term of the agreement is September 1, 2002 through August 31, 2022. Power deliveries and variable energy costs are based on a deemed heat rate of 7,100 BTU/kWh (British Thermal Units per kilowatt hour). Power costs include a capacity charge, fixed and variable operation and maintenance charges, and a pass-through of the cost of natural gas transportation on Northwest Pipeline. Capacity and fixed O&M charges are indexed to project performance, and both fixed and variable O&M charges contain escalation factors. The District is responsible for delivering to the project its share of the natural gas required to fuel the project. Each

day, the District has the right, but not the obligation, to purchase output from Frederickson. The decision to buy from Frederickson is based on a comparison of the spot price of power to the variable cost of generation.

Nine Canyon Wind Project

The District entered into a Nine Canyon Wind Project Power Purchase Agreement with Energy Northwest for the purchase of 3 MW of the project generating capacity of Phase I. Assuming a 30% capacity factor, this purchase produces about 1 aMW of energy. The Phase I project reached commercial operation in late 2002, and the original term of the District's purchase commitment continues through June 30, 2023. The District on October 30, 2006, signed an Amended and Restated Agreement with Energy Northwest, and the other purchasers, which extended the term of the Agreement through July 1, 2030 (with rights to extend the agreement in five-year terms), and provided the District with 6 MW of capacity (about 2 aMW of energy) from the Phase III expansion of Nine Canyon. The Nine Canyon Wind Project is a renewable energy resource eligible for meeting the RPS requirements of Washington's EIA.

White Creek Wind Project

In 2008, the District started purchasing renewable energy from the 205 MW White Creek Wind Project near Goldendale, WA. The District signed long-term purchase agreements with two power suppliers to purchase approximately 9.1 MW (3 aMW output) of total project output from the White Creek project, purchasing 1.47% from Lakeview Light and Power and 3% from White Creek Wind I, LLC. Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 x 2.3 MW turbines that have a combined capacity of 205 MW. It came online and began generating electricity in November 2007. White Creek is a renewable energy resource eligible for meeting the RPS requirements of Washington's EIA. The District has contractual rights to a portion of the project's output, including all associated environmental attributes, through 2027. Four Washington public utilities—Cowlitz PUD, Klickitat PUD, Lakeview Light & Power, and Tanner Electric Co-op—and the District's 3% share from WCWI, collectively have the option to purchase the project in 2021.

Packwood Lake Hydroelectric Project

The District is a 14% participant in Energy Northwest's 26.125 MW Packwood Hydroelectric Project, located on Lake Creek, a tributary to the Cowlitz River, in Lewis County, southwestern Washington near the unincorporated town of Packwood. The project occupies 511.65 acres of federal land within the Gifford Pinchot National Forest and Goat Rocks Wilderness, administered by the U.S. Department of Agriculture, Forest Service. The project received a new operating license effective October 1, 2018, for a period of 40 years. This license is subject to the terms and conditions of the Federal Power Act (FPA), which is incorporated by reference as part of this license, and subject to the regulations the Commission issues under the provisions of the FPA. The District receives about 0.9 aMW output from the project. Packwood does not count as a qualified resource eligible for meeting the RPS requirements of Washington's EIA.

Community Solar Projects

In early 2015, the Commissioners adopted a resolution authorizing the Solar Connections Program and a community solar project. The Solar Connections Program provides solar power information resources, supports customers who want to install their own solar power equipment, or participate in a community solar project. The program currently has two community solar projects that provide District customers an opportunity to participate in solar energy without needing to install solar panels on their homes or property. The first solar project, built in Kennewick, WA, is approximately 75 kW and became operational in July 2015, with 112 customers participating and the second project, built in Prosser, WA, is approximately 25 kW and became operational in March 2016, with 42 customers participating. The customer agreements extend through June 30, 2035 for the Kennewick project and through December 15, 2035 for the Prosser project, however, both projects are subject to early termination at the sole discretion of the District for any or no reason. The District anticipates, but does not guarantee, that the projects will extend through these dates.

Capacity Call Option

In 2020, the District purchased a physically-settled daily call option that gives them the right, but not the obligation, to call upon should the District require capacity. The District may, at its option, elect to take delivery of energy, in each case in whole MW increments in a single fixed block hourly MWh quantity for all heavy load delivery hours, up to a maximum of 25 MW per hour during all delivery hours for the months of January, February, and December. Similarly, they may elect to take the delivery of energy up to 75 MW per hour for the months of July and August during all heavy load delivery hours. The capacity purchase agreement is set to begin December 1, 2022 and terminate September 1, 2025.

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: Scaled DER Capacity Projection

Year	Benton Scaled Capacity (MW)	NREL Mid-Case Rooftop PV Capacity (MW)
2020	4.474	153.275
2022	4.647	159.198
2024	4.749	162.672
2026	5.167	177.005
2028	6.187	211.954
2030	8.792	301.188
2032	12.112	414.915
2034	13.773	471.835
2036	15.234	521.872
2038	16.274	557.510
2040	17.289	592.276
2042	17.892	612.910
2044	18.869	646.395
2046	19.378	663.826
2048	19.378	663.828
2050	19.426	665.463

Overview of 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 net positive benefits and is currently expected to join the EIM in 2022.

On January 5, 2020 Colstrip units 1 and 2 in Montana were retired, freeing up 614MW of transmission. On April 8th The Bureau of Land Management received the final Federal right of way for the Gateway West project which will add approximately 1,000 miles of new high-voltage transmission lines between the Windstar substation near Glenrock, Wyoming and the Hemingway substation near Melba, Idaho. The project will include approximately 150 miles of 230 kilovolt (kV) lines in Wyoming and approximately 850 miles of 500 kV lines in Wyoming and Idaho

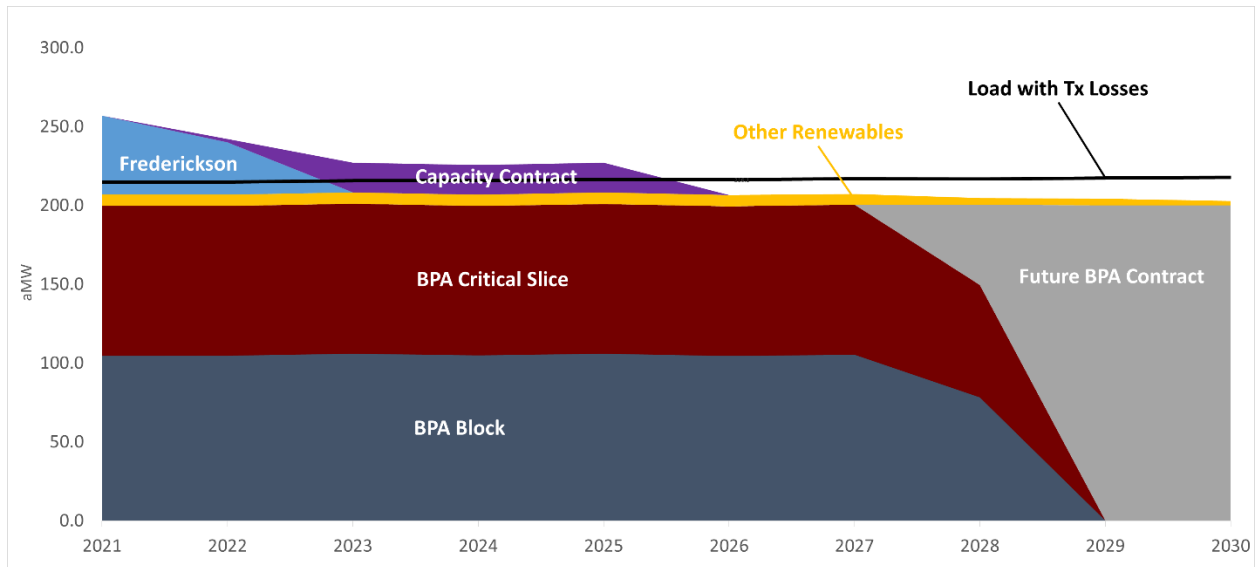
BPA expects the transmission system to serve expected loads and load growth for at least the next ten years based on forecasts with the addition of specified transmission upgrades detailed in their 2019 Transmission Plan². The forecasted peak loads, plus existing long-term firm transmission service obligations, 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.

² <https://www.bpa.gov/transmission/Customervolvement/AttachmentK/Documents/2019-bpa-transmission-plan.pdf>

Load/Resource Balance with Existing Resources

Figure 13 compares the District’s long-term load forecast under the expected load scenario to the District’s projected BPA HWM plus already contracted for resources. The District is in an energy surplus resource position under the expected load forecast through August 2025, when the capacity contract expires, after which energy deficits appear on an average annual basis.

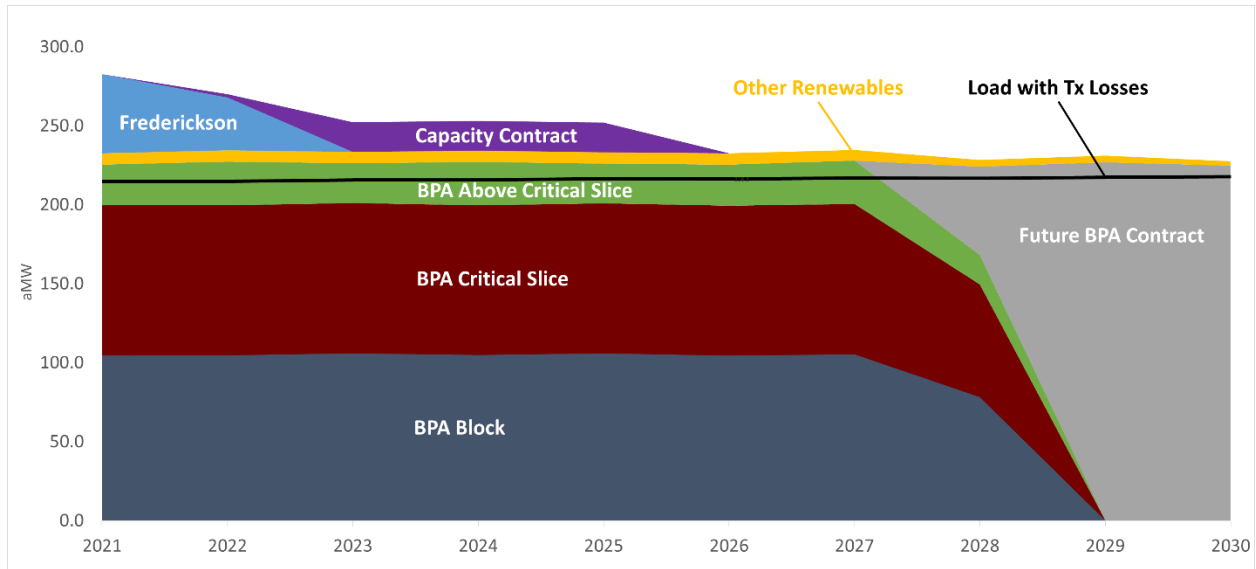
Figure 13: Annual Average Load and Existing Resources in Critical Water Conditions



All Units aMW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load with Tx Losses	214.6	214.8	215.5	215.6	216.3	216.1	216.8	216.6	217.2	217.8
BPA Block	104.4	104.5	105.9	104.7	105.8	104.4	105.2	78.2	0.0	0.0
BPA Critical Slice	95.1	94.9	95.1	94.8	95.1	94.9	95.1	71.1	0.0	0.0
Other Renewables	7.2	7.2	7.2	7.2	7.2	7.2	6.7	4.2	4.2	2.7
Frederickson	50.0	33.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Contract	0.0	2.1	18.9	18.9	18.9	0.0	0.0	0.0	0.0	0.0
Future BPA Contract	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.0	200.0	200.0
Net Position	42.1	27.2	11.6	10.0	10.7	-9.6	-9.8	-12.1	-13.0	-15.1

Figure 14 compares the District’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. In this scenario, the District is not expected to have any deficits in the expected load scenarios through the entire study period.

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

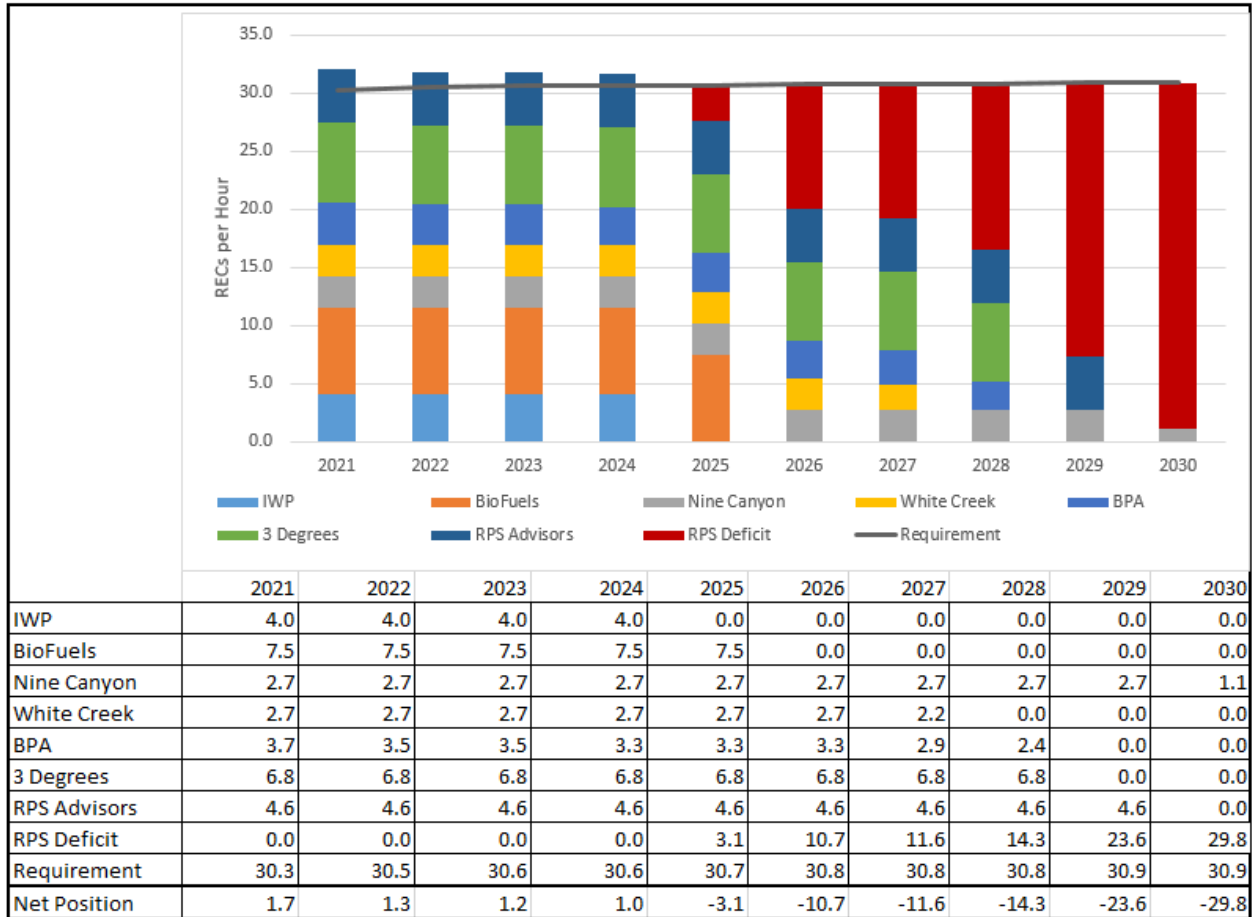


All Units aMW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load with Tx Losses	214.6	214.8	215.5	215.6	216.3	216.1	216.8	216.6	217.2	217.8
BPA Block	104.4	104.5	105.9	104.7	105.8	104.4	105.2	78.2	0.0	0.0
BPA Critical Slice	95.1	94.9	95.1	94.8	95.1	94.9	95.1	71.1	0.0	0.0
BPA Above Critical Slice	25.8	27.8	25.1	27.4	25.0	26.1	27.6	18.7	0.0	0.0
Other Renewables	7.2	7.2	7.2	7.2	7.2	7.2	6.7	4.2	4.2	2.7
Frederickson	50.0	33.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Contract	0.0	2.1	18.9	18.9	18.9	0.0	0.0	0.0	0.0	0.0
Future BPA Contract	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.9	226.8	224.6
Net Position	67.9	55.0	36.7	37.4	35.7	16.5	17.8	11.5	13.8	9.5

Although the District is surplus energy on an average annual load/resource view, the District does have seasonal 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 Washington State Renewable Portfolio Standard (RPS) requires the District to supply the following amounts of its load requirements with renewable resources: 3 percent by 2012, 9 percent by 2016, and 15 percent by 2020. State law also requires the IRP process to develop a plan for acquiring renewable resources and all cost-effective conservation. The District’s RPS requirements, existing resources and net position are depicted Figure 15 below.

Figure 15: Renewable Portfolio Requirement and Existing Resources

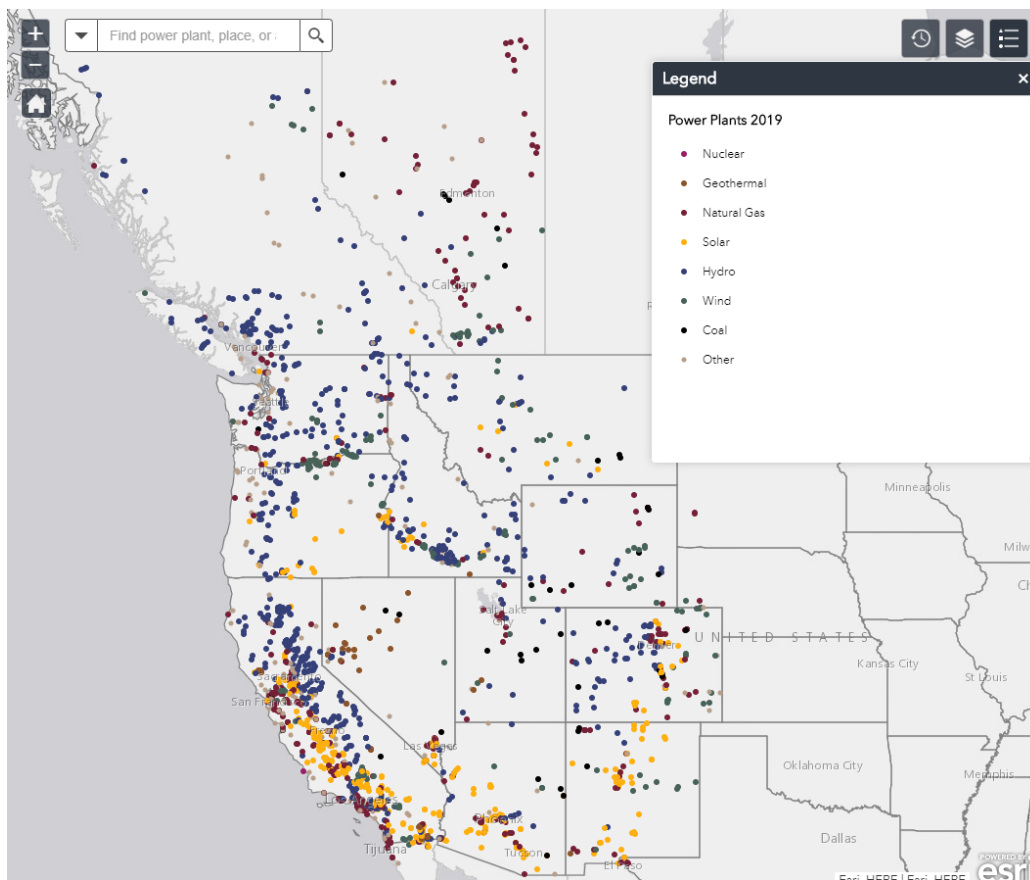


10 Year Generation Assessment

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 of intermittent energy is coming from renewable sources. This has left significant uncertainty on the future of the generation stack available to the region to serve load. Of particular concern is the area of dispatchable generating capacity, which if not planned for correctly could undermine the reliability of the grid. This issue is especially acute given the areas large interconnected transmission system and marketplace where electricity purchases and sales between utilities have flowed freely. The current surplus of resources within the Western Interconnection is expected to diminish as regional loads grow and as the trend of dispatchable fossil fuel generator retirements continues.

Figure 16 below is a visualization of the power plants in operation in the WECC footprint (WECC State of the Interconnection)³.

Figure 16: WECC Power Plants 2019

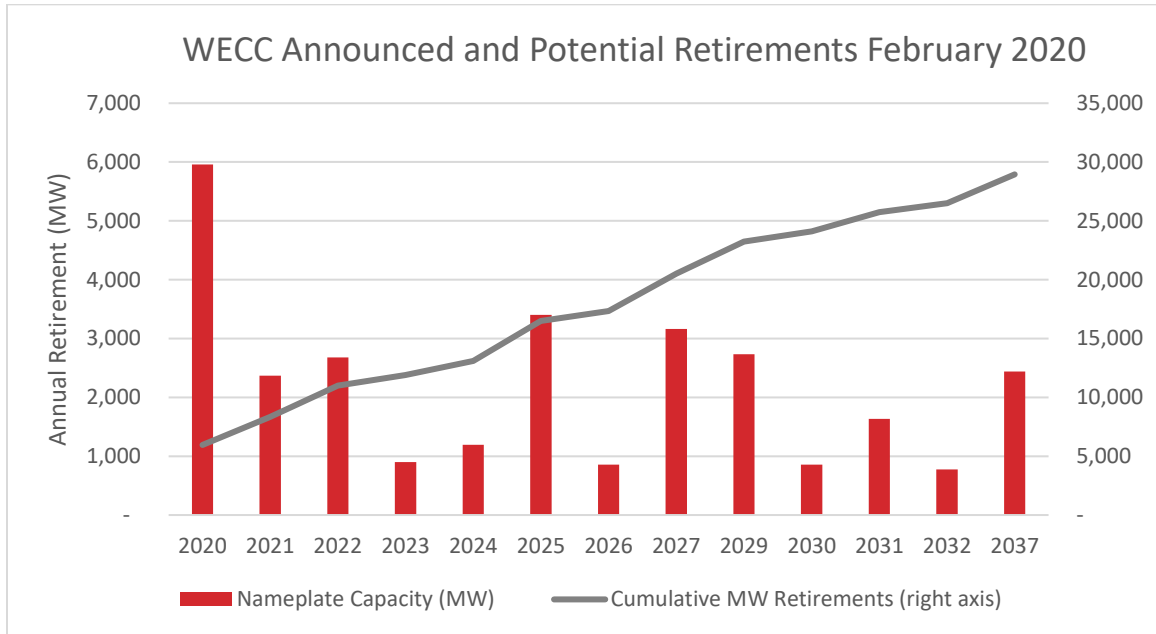


While fossil fueled plants carry emissions concerns, their dispatchable nature makes them more difficult to fully replace by renewable generation absent levels of energy storage which are not currently commercially feasible. Figure 17 below summarizes data published by WECC of announced and potential

³ <https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Resource-Portfolio.aspx>

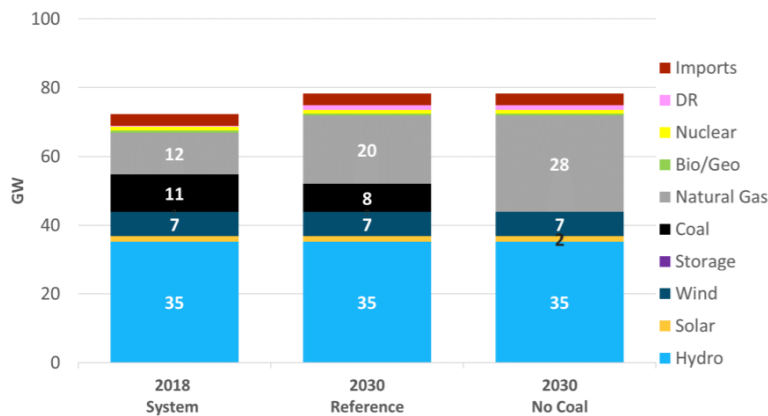
generation retirements⁴. While much of the energy will be replaced by cleaner gas or renewable sources in the future, resource adequacy is a major source of concern for reliability in the future.

Figure 17: WECC Announced and Potential Retirements



The Public Generating Pool (“PGP”) commissioned E3 Consulting (“E3”), a well-respected firm with experience performing regional resource adequacy⁵, 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 as shown in Figure 18. 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.

Figure 18: E3 Northwest Resource Adequacy Generation Portfolios for 2030 Scenarios



⁴ [https://www.wecc.org/Administrative/15 Brown Resource%20Retirements February%202020.pdf](https://www.wecc.org/Administrative/15%20Brown%20Resource%20Retirements%20February%202020.pdf)

⁵ https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

As part of the study, which predated CETA being signed into law, E3 also considered the resource mix necessary for deep decarbonization in 2050. Figure 19 below displays the portfolios necessary to achieve differing levels of carbon reductions. While this exact resource mix is not regionally prescribed, it reflects a reasonable projection of the future state of the grid in the later stages of CETA implementation.

Figure 19: E3 Northwest Resource Adequacy Generation Portfolios for 2050 Scenarios

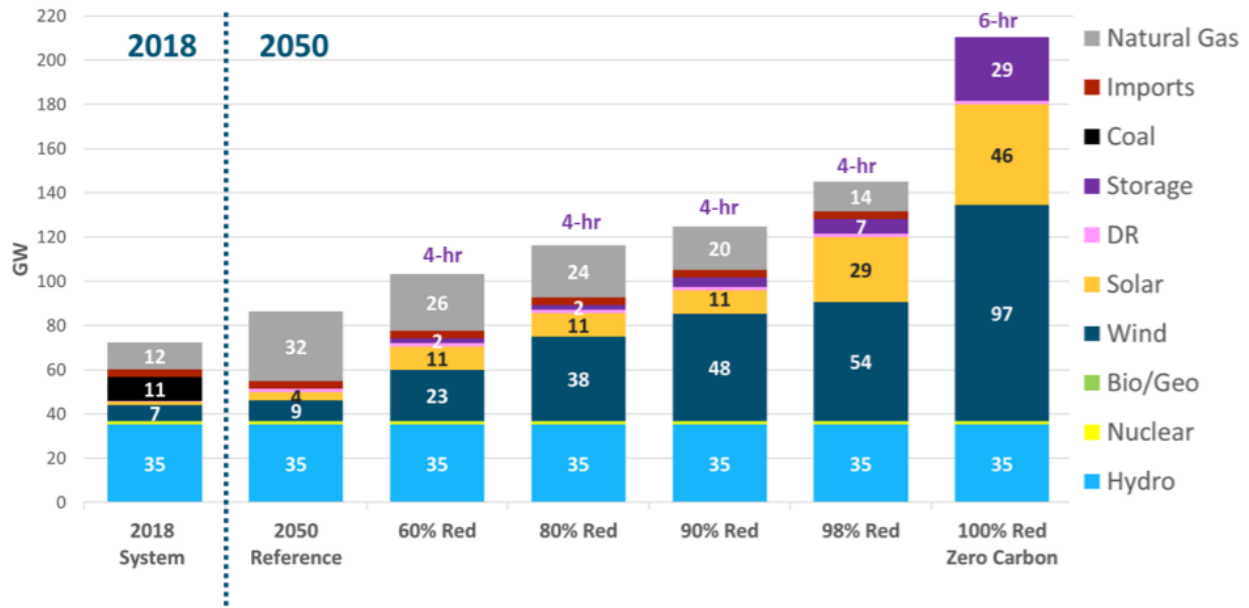


Figure 20 below details the greenhouse gas (GHG) reductions for the scenarios outlined in Figure 19.

Figure 20: E3 Northwest Resource Adequacy Greenhouse Gas (GHG) Reduction for 2050 Scenarios

Metric	Units	Reference Scenario	GHG Reduction Scenarios				
			60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
GHG Emissions	MMT/yr	50	25	12	6	1	0
GHG Reductions	% below 1990	16%	60%	80%	90%	98%	100%
GHG-Free Generation	% of load	60%	80%	90%	95%	99%	100%
Clean Portfolio Standard	% of sales	63%	86%	100%	108%	117%	123%
Annual Renewable Curtailment	% of potential	Low	Low	4%	10%	21%	47%

In response to regional resource adequacy concerns, 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 complexity⁶” and commissioned E3 to perform the supporting analysis surrounding the initiative. Figure 21 below outlines the expected program design timeline.

Figure 21: 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.

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

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, BPA 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.⁷ 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 full version of the report containing the proposed reinforcements can be found on BPA’s website⁸.

⁶ April 2020 Public Webinar

⁷ <https://www.bpa.gov/transmission/CustomerInvolvement/AttachmentK/Documents/2019-bpa-transmission-plan.pdf>

⁸ <https://www.bpa.gov/transmission/CustomerInvolvement/AttachmentK/Documents/2019-bpa-transmission-plan.pdf>

As part of the BPA’s planning activities detailed in the report, Figure 22 illustrates several reinforcements which are already planned for the Tri-Cities area to improve reliability. A further reinforcement for South Tri-Cities is in the early scoping phases as BPA has noted that while the area is compliant with planning standards on the loss of a single element, the lack of additional redundancy “hinders the ability to take any transmission facilities in the area out for maintenance since plans must be in place to address the potential loss of a second element⁹.”

Figure 22: BPA Planned Transmission Projects for Tri-Cities Load Service Area

Tri-Cities			
McNary-Paterson Tap 115 kV Line	P02364	2022	\$4,600,000
Red-Mountain – Horn Rapids 115 kV Line Reconductor	P03102	2022	\$3,700,000
Jones Canyon 230 kV Shunt Reactor Addition	P00841	2022	\$3,300,000
Richland-Stevens Drive 115 kV Line	P02365	2024	\$4,000,000
South Tri-Cities Reinforcement	P03264	To be determined	To be determined

⁹ <https://www.bpa.gov/transmission/Customervolvement/AttachmentK/Documents/2019-bpa-transmission-plan.pdf>

Chapter 4: Policy & Regulatory Landscape

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 or 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 has complied with the requirements of this legislation since September of 2008. This IRP serves to comply with the requirements described above.

Energy Independence Act (EIA)

In 2006, Washington State voters approved Initiative 937 for the Energy Independence Act (EIA), RCW 19.285, 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 EIA required the District to meet 9% of its retail loads with qualified renewable resources. The third phase of the renewable requirement is now in effect and requires the District to meet 15% of retail loads with qualified renewable resources. 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. At this time, District does not expect a need to utilize this mechanism but will continue to analyze the potential going forward.

The EIA also requires that the District implement all cost-effective, reliable, and feasible 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 23). 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 23: 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 CO₂ 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 CO₂ emissions or find other means of emissions reductions, the law in effect bans new coal fired generation. While CO₂ 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. The District expects to begin work on the implementation plan in the second quarter of 2021 with completion targeted in the fourth quarter of 2021.

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. A utility must use renewable or non-emitting resources in an amount equal to at least 80% of their retail load over each four-year compliance period combined with the use of an alternative compliance option equal to the remaining percentage of their retail load. 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.¹⁰

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. The Department of Commerce is currently working to write the rules that will determine how these, and other details may be implemented. Because the rules are still under development, some of these issues are not addressed in this IRP. If necessary, the District will issue a revision to this document after all of the rules are developed and understood.

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.

¹⁰ <https://www.commerce.wa.gov/growing-the-economy/energy/ceta/>

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 to follow suit. California and Oregon both have 50% or greater RPS mandates; more renewable buildout is expected, particularly 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 2020¹¹. 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 (15.12 MW). 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

¹¹ <https://www.oregon.gov/deq/aq/programs/Pages/Clean-Fuel-Pathways.aspx>

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 a voluntary option to purchase qualified alternative energy resources (RCW 19.29A.090). This is often referred to as green power. The District offers a voluntary green power pricing program which allows retail customers to contribute any amount above the existing retail rate for their rate class. The PUD retires RECs in WREGIS that equate to the annual amount contributed by customers.

Renewable Energy System Cost Recovery Program

The District participates in RCW 82.16.110, 82.16.120, 82.16.130 and 80.16.150, which allows the District to voluntarily administer Renewable Energy Incentive Payments to Net Metering customer and Community Solar customers. A new incentive program was adopted in July 2017, which allows customers that acquire eligible systems to receive incentives for eight fiscal years from the in-service date or until 50 percent of the total system cost is paid out. Renewable energy systems must be certified by the Washington State University Energy Program in order to qualify for the incentive. This program incentivized customers to build their own generation which reduces the District's energy loads. The program ceased payments for energy produced after June 30, 2020.¹²

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

¹² <https://dor.wa.gov/content/renewable-energy-cost-recovery-incentive-payment-program-electrical-energy-production-using-power-solar-wind-anaerobic-digester>

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 low wholesale market prices often make 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 FERC on July 16, 2020 approved a final rule revising PURPA.¹³ The District is in the process of reviewing the revised regulations for implementing PURPA.

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.

¹³ <https://www.publicpower.org/periodical/article/ferc-approves-final-rule-overhauls-purpa-regulations>

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 will expire 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 24.

Figure 24: ITC Eligibility by Resource Type

Resource Type	Eligible Expenditures	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: Resource Options

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 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.

Thermal Generation

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 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 can quickly respond and balance the sometimes-rapid fluctuations in wind and solar 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 2,500 MW to the region's 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.

Small Modular Reactor (SMR)

Several companies are in the process of developing commercially available small modular reactors (SMR), which are a new class of nuclear power plant 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.

Figure 25: NuScale Power Reactor Building¹⁴



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 come online in 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,

¹⁴ <https://www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors>

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.

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).^{15,16} 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.

¹⁵ Renewable Energy Production Tax Credit. *US Energy Information Administration*. US Energy Information Administration. Web. May 24, 2016

¹⁶ Business Energy Investment Tax Credit. *US Energy Information Administration*. US Energy Information Administration. Web. May 24, 2016

The subsidy schedule for the ITC varies significantly by generation resource gradually ramping down until its expiration. Figure 26 below displays the credit provided by the ITC as a percent of capital expenditures.

Figure 26: 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%	-	-	-	-

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.

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 foreseeable 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.

Combined Heat and Power (CHP)

Combined heat and power (CHP), also referred to as cogeneration, represents:

- The concurrent production of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy.
- A type of distributed generation, which, unlike central station generation, is located at or near the point of consumption.
- A suite of technologies that can use a variety of fuels to generate electricity or power at the point of use, allowing the heat that would normally be lost in the power generation process to be recovered to provide needed heating and/or cooling.

CHP technology can be deployed quickly and with few geographic limitations. CHP can use a variety of fuels, both fossil- and renewable-based. It has been employed for many years, mostly in industrial, large commercial, and institutional applications. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat to some of the most vital industries, largest employers, urban centers, and campuses in the United States. It is reasonable to expect CHP applications to operate at 65-75% efficiency, a large improvement over the national average of approximately 50% for these services when separately provided. The District currently has no identified combined heat and power opportunities in its service territory.

New Resource Costs

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 27 and Figure 28 below includes the supply-side resource options evaluated for this IRP. All costs are expressed in nominal dollars.

Figure 27: 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 28: Potential per unit resources

Resources Modeled Per Unit			
Resource Type	PPA Cost*	Capacity Factor	Fuel Type
Eastern Montana Wind †	\$27.00	37%	Wind
Columbia Gorge Wind †	\$35.00	32%	Wind
Single Axis Tracking Solar Photovoltaic‡	\$37.00	20%	Solar
Solar + Storage	\$65.00		Solar

†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

*Power Purchase Agreement (PPA) costs are estimates received from a leading renewable energy developer.

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 Social Cost of Carbon, as outlined in CETA beginning at \$74 per metric ton in 2020 (in 2018 real dollars), escalating to \$87 per ton by the end of the study period.

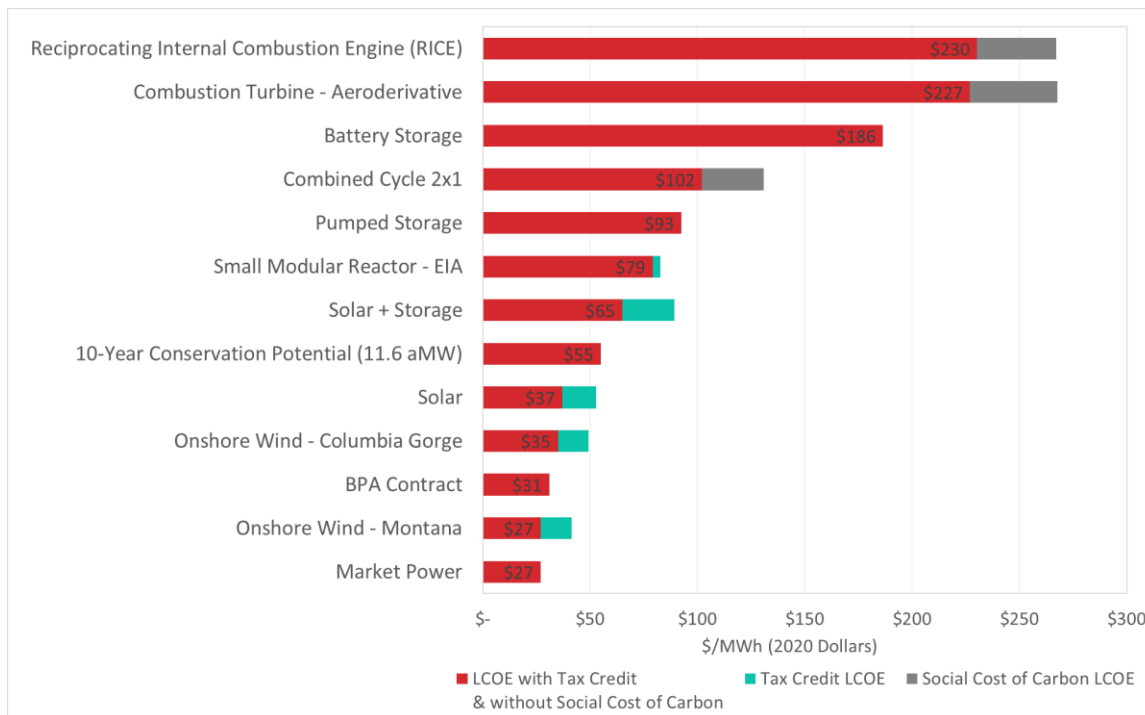
Renewable Integration Costs

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, estimated the integration costs of \$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 of 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. Figure 29 below shows the levelized cost of energy (LCOE) for resource alternatives considered in this IRP.

Figure 29: Levelized Cost of Energy (LCOE) of Resource Alternatives



Outside of hydroelectricity, the Northwest possesses poor 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 levelized cost of energy (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 CCGTs 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.

Chapter 6: Macro Utility Environment

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.¹⁷ More significantly, the Safer Affordable Fuel Efficient (SAFE) Vehicles Rule lowered the annual increase in vehicle fuel efficiencies from 5% to 1.5%. While the current regulatory environment and low fossil fuel prices may be poised to impact electric vehicle (EV) adoption rates, there is no consensus on overall impacts. On the other side of the equation, all large auto manufacturers have made significant investments in EV's, driving declining costs and improved technology. Premium EVs are already quantifiably better than their internal combustion counterparts, with more horsepower, torque, and optional technology. Historically premium features lag mainstream autos by a few years, and as this gap closes, many consumers are likely to select EVs on merit rather than due to environmental concern or due to tax incentives.

¹⁷ <https://www.utilitydive.com/news/epa-gives-power-plants-regulated-entities-pollution-compliance-flexibility/575103/>

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.

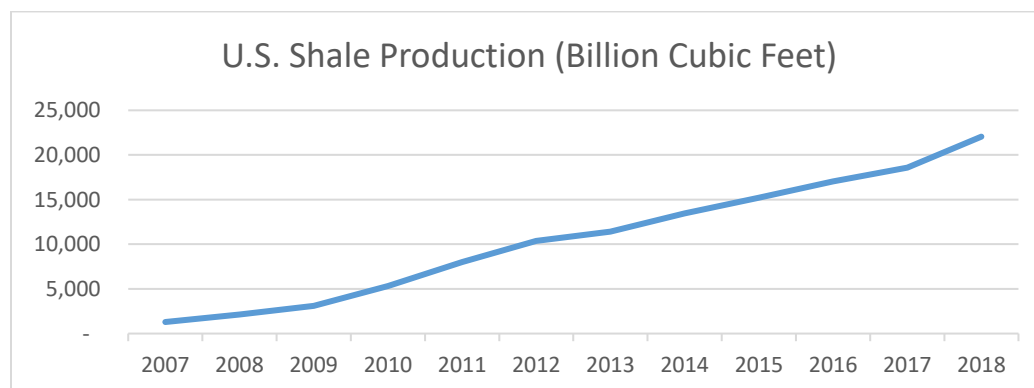
COVID-19's Effects on Energy Demand

Utilities, regional transmission organizations, and system operators throughout the country have been working hard to determine the impacts of COVID-19 on loads since the first school closures and shelter-in-place orders began in March. In order to isolate COVID-19 impacts, any analysis needs to isolate the weather variable. A cold COVID-19 day in Spring 2020 could have higher loads than a pre-COVID-19 day from Spring 2019. Inaccurate conclusions would likely be drawn if the periods were compared without adjusting for weather. One approach is to re-forecast loads with perfect weather assumptions. In theory, the difference between the perfect foresight model output and the actuals can be attributed to shelter-in-place, school closures, or other COVID-19 mitigation related impacts. This is difficult for the District to perform due to the configuration of its forecast models and large swings associated with industrial loads. In order to get a sense of COVID-19 impacts, the District is relying on regional studies, and simple comparable day analysis of its non-industrial loads. Similar to the regulatory landscape, the energy impacts are still uncertain and vary across the industry. The District will continue to assess the impacts and adjust accordingly.

Fracking and Natural Gas

Prior to the COVID-19 pandemic, gross production of natural gas in the US had grown steadily for more than a decade, driven primarily by technologically-enabled production of the abundant gas resources found in shale formations across the nation (Figure 30). However, the COVID-19 pandemic poses a 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 2020¹⁸. Evidence of this trend is beginning to materialize, and experts anticipate continued decline in demand as the pandemic continues to negatively impact the global economy. Overall, the debt-intensive industry is expected to see consolidation, disproportionately impacting less efficient producers.¹⁹

Figure 30: U.S. Natural Gas Production from Shale Resources (Billion Cubic Feet)



¹⁸ <https://www.naturalgasintel.com/coronavirus-seen-driving-record-5-plunge-in-2020-natural-gas-demand/>

¹⁹ <https://www.theguardian.com/business/2020/apr/25/fracking-america-boom-founders-prices-demand-collapse-covid-19>

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, applications for permits to drill on public land have increased 300 percent due in part to regulatory rollbacks.²⁰ This will continue to be a political issue for continued observation in the future.

Electric Vehicles (EVs)

Around the world, automakers are ramping up their EV output and targeting more aggressive timelines goals for electrifying their fleets. Business Insider reported in January 2020

- Toyota plans to generate half its sales from EVs by 2025, moving up the target date from a previous goal of 2030.
- Volkswagen signals 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 2025.²¹

Spurred by improving battery cost economics and regulatory objectives, automakers are speeding up their adoptions of EVs. Sales of EVs are projected to grow in the coming years, and manufacturers are ramping up their ability to meet the demand.

Aside from changes at the federal level, laws have been passed in some states that are intended to increase the expansion of the market for EVs. Legislation passed this year in New Jersey put forth an ambitious plan to spur the demand for and adoption of EVs in the state. Broadly, New Jersey set a goal to have 2 million EVs on its roads by 2035.²² The cost of EVs have dropped by 13 percent in the last year alone. Additionally, New Jersey will be offering additional rebates of up to \$5,000 on new EVs for the next decade. The State also plans to build infrastructure to support the anticipated surge in demand, by adding 1,500 chargers across the state. In addition, the plan includes a goal to electrify state-owned light duty fleet vehicles and aims to extend this to heavy-duty vehicles once large vehicle electrification R&D advances. The initiative undertaken by New Jersey is the most ambitious seen so far, but past trends have shown that early states plans may cause others to follow suit.

Corporate Procurement

Relative to 2017 levels, the amount of onsite generation, corporate power purchase agreements (PPAs), and utility purchasing have all increased by about 400 percent, with the largest growth in procurement occurring in the northeast of the country.²³

²⁰ <https://www.doi.gov/pressreleases/energy-revenues-and-disbursements-soar-under-trump-administration>

²¹ <https://www.businessinsider.com/promises-carmakers-have-made-about-their-future-electric-vehicles-2020-1#toyota-1>

²² <https://www.utilitydive.com/news/ahead-of-the-ev-pack-how-other-states-can-replicate-new-jerseys-legislati/575744/>

²³ <https://www.utilitydive.com/news/green-tariffs-drive-big-increases-in-corporate-renewable-procurement/574060/>

A large and diverse number of businesses are participating in procurement as well. In 2018, this trend was mostly limited to tech giants such as Facebook, Apple, Amazon, and Google, which used procurement to meet its aggressive sustainability targets. However, now mid-size companies are looking to use procurement to meet renewable energy goals that are increasingly ambitious.²⁴ As these practices become more widespread, more tools to ease the transaction costs associated with procurement become available, which in turn serves to only increase the adoption of corporate procurement. Furthermore, subsidies and advancements in storage technologies have boosted the viability of onsite generation and procurement more broadly.

COVID-19 is expected to have little long-term impacts on the adoption of corporate procurement.²⁵ The main concern regarding procurement is disruption of supply chains and development. However, supply chains for renewable resources seem to be resilient at least partly as a result of having to navigate regulatory uncertainty in recent years. As a result, it is unlikely corporate procurement will grind to a total halt. Once business returns to normal, it is expected that resource development will resume relatively smoothly, as the driving factor behind the adoption of procurement is a perception of social responsibility and public relations value, which will likely continue to be a contributing factor after the pandemic fades. Storage is discussed in further detail in subsequent sections.

Coal

In 2018, coal was 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 percent of the generation mix by 2020, and potentially below 10% by 2025 as wind and solar continue to increase their market share.^{26,27} As evidence of this, February 2020 marked the first time that renewable generation in the US has surpassed coal generation in a calendar month.

In many states, there is still support for the coal industry from lawmakers. For example, Ohio utility rates have increased in order to keep two older plants open in the short-term. Investor owned utilities (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 expected to accelerate in the near future as coal faces an increasingly challenging economic and regulatory environment. Some plants are reaching physical limits of coal storage and may need to stay operational over the summer of 2020, even at a loss, in order to burn off excess fuel supply. All of these factors point to a quickening of the pace for coal retirements in the coming years.

Wind

Wind energy generation's rapid growth in past years may slow soon. Much of the geographic area which is most suitable for wind generation has already been saturated, and the high cost of transmission is a

²⁴ <https://leveltenenergy.com/blog/clean-energy-experts/5-corporate-renewable-energy-procurement-trends-to-watch-in-2020/>

²⁵ <https://www.greenbiz.com/article/corporate-renewable-energy-age-covid-19>

²⁶ <https://about.bnef.com/blog/covid-19-wreaks-havoc-on-the-wind-industry/>

²⁷ https://ieefa.org/wp-content/uploads/2020/03/US-Coal-Outlook-2020_March-2020.pdf

significant barrier for the development of additional wind resources in more isolated areas where suitable conditions do exist.²⁸ As states push for higher amounts of renewable energy in the generation supply 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 the largest portion 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 created by COVID-19 are causing many projects to be in danger of failing to qualify for tax credits, despite pushes by industry to extend the deadline for subsidies in response to the pandemic. COVID-19 also poses challenges to completing major turbine maintenance activities which generally requires teams to accomplish and is 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.²⁹ 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.³⁰ While the offshore wind industry is still relatively in its infancy, costs are dropping rapidly supporting its forecasted future development. The West coast is a less effective offshore wind site when compared to the East Coast due to rapidly increasing ocean depth. Despite this topological disadvantage, the Bureau of Ocean Energy Management intends to hold an offshore wind lease sale next year.³¹

Solar

The proliferation of solar energy generation must be considered separately at the utility and residential scale. Residentially, the adoption of rooftop photovoltaic (PV) is quickening, and the technology, when paired with improvements to home energy efficiency and distributed storage as well as subsidies, is making it easier for homes to achieve zero net energy. The expansion in use of rooftop PV is the major driver for the 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 drop nationally in total energy delivered to homes by 2050³². This is particularly true in states with good solar resource potential, but less so for Washington State. For those states significantly impacted, 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.

Nationally, 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.³³ Currently, there are about 40 solar plus storage developments across the country, offering about 1,200 MW of solar

²⁸ <https://www.utilitydive.com/news/woodmac-sees-challenges-for-onshore-wind-low-hanging-fruit-has-already-be/571801/>

²⁹ <https://www.utilitydive.com/news/2020-outlook-us-renewable-resources-on-steady-course-for-increased-deploy/570181/>

³⁰ <https://www.utilitydive.com/news/new-jersey-more-than-doubles-offshore-wind-energy-target-to-75-gw/567672/>

³¹ <https://energynews.us/2019/08/21/west/offshore-wind-could-save-california-2-billion-report-says/>

³² <https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf>

³³ <https://www.utilitydive.com/news/2020-outlook-renewables-resilience-and-reliability-needs-will-drive-stora/569612/>

generation with 533 MW of storage capability. However, more than 80 projects are currently in development, which could add nearly 9,000 MW of solar generation and over 4,100 MW of storage.³⁴

Solar is expected to be at the forefront of growth in renewable energy jobs. Already, solar installation technicians have been one of the fastest-growing sources of employment in the US. However, the COVID-19 pandemic is threatening the job gains that the sector has made over the last few years. In March 2020 alone, the number of overall clean energy jobs lost is greater than the total gains across all of 2019

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 struck down by the Kansas State Supreme Court.³⁵ 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, 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 price³⁶. 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 highlights 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 2030.³⁷ 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.³⁸

Regulation and legislation, however, have not always benefitted storage technology in this way. For example, in states like Texas, utilities are prohibited from owning large-scale battery projects. Moreover, even in states like New York, there have been difficulties installing batteries that are in compliance with

³⁴ https://www.spglobal.com/marketintelligence/en/documents/111919_the-2020-us-renewable-energy-outlook_finalv4-revised.pdf

³⁵ <https://www.utilitydive.com/news/kansas-supreme-court-evergy-rooftop-solar-demand-charges-impacts/575894/>

³⁶ <https://www.eia.gov/todayinenergy/detail.php?id=43255>

³⁷ <https://www.utilitydive.com/news/doe-unveils-plan-to-make-us-global-storage-leader-by-2030-reduce-foreign-d/570164/>

³⁸ <https://www.utilitydive.com/news/us-storage-market-value-to-surge-737-by-2024-driven-mostly-by-utility-pro/568393/>

safety regulations, especially when extra precautions are being taken following the 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 a market participant and an integral part of transmission infrastructure and partially due to the use of solar + storage to fill the gap left by the retirement of coal plants.

Carbon Offsets

Carbon Offsets are in their infancy; 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 goals³⁹. This extends to the private sector as well. Microsoft has invested in offsets to help the company become carbon neutral and intends to reach carbon neutrality by 2030⁴⁰. 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.⁴¹ The fact that these guidelines have been released 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 lead to projections that the market for Carbon Offsets could eclipse \$200 billion by 2050, from their current value of just under \$1 billion.⁴² 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.⁴³ 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.

³⁹ <https://apnews.com/4287a17de40a482fbb407617428abddb>

⁴⁰ <https://blogs.microsoft.com/blog/2020/01/16/microsoft-will-be-carbon-negative-by-2030/>

⁴¹ <https://www.scientificamerican.com/article/u-n-unveils-new-rules-for-aviation-carbon-offsets/>

⁴² <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/051320-global-carbon-offsets-market-could-be-worth-200-bil-by-2050-berenberg>

⁴³ <https://apnews.com/a299352c7c3a450c8223815cf16877bb>

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 Analysis and Capacity Position

As discussed in Chapter 3: Existing Resources, the District is surplus energy on an average annual basis; however, the District does have seasonal capacity shortages when the demand exceeds the District's supply.

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 31 displays the hourly load for the summer and winter peak days from October 2011 through February 2020.

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 338 aMW and highest HLH summer peak has been 384 aMW. Figure 31 displays the hourly load for the summer and winter peak days from October 2011 through February 2020.

Figure 31: Winter and Summer Historical Peak Loads

Season	Hourly Peak	HLH Peak
Winter11/12	288	260
Summer 12	394	350
Winter 12/13/	265	243
Summer 13	415	376
Winter 13/14	338	303
Summer 14	431	384
Winter 14/15	291	256
Summer 15	429	384
Winter 15/16	285	270
Summer 16	425	377
Winter 16/17	371	338
Summer 17	426	373
Winter 17/18	292	239
Summer 18	419	373
Winter 18/19	354	282
Summer 19	408	364
Winter 19/20	312	271
All Data	431	384
All Winters	371	338
All Summers	431	384

Figure 32 charts the daily average temperature vs. the daily average heavy load hour (HLH) demand between 2017 and 2019. Loads are generally the lowest during periods when the temperature is between roughly 50°F and 60°F. The highest demand occurs in the heat of summer. The demand is lower and less frequent during the cold of winter. The red lines in Figure 32 indicate the approximate seasonal generation capacity in 2021 for the District’s BPA resources plus the Frederickson 50 MW gas plant. These resources have a peak hour capacity of about 348 MW in summer and about 302 MW in winter, assuming BPA block amounts of 154 MW in summer and 108 MW in winter, plus a typical BPA system peak slice generation level of 10,500 MW (144 MW for the District). 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. Historical peak loads—both daily average HLH load and single hour peak load—have often exceeded this peak hour capacity during certain periods.

Figure 32: Daily Average Temperature vs. Daily HLH Average Load from 2017-2019

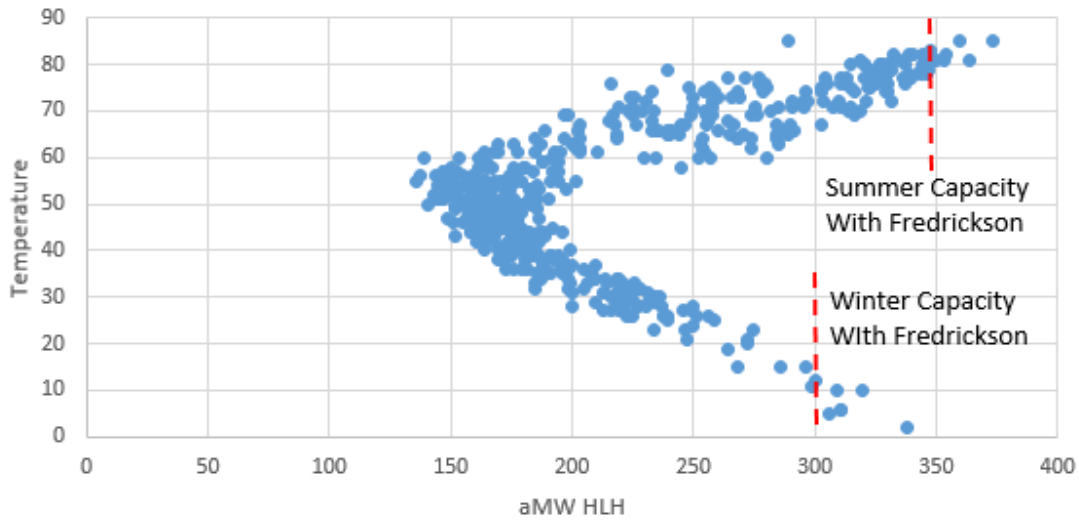


Figure 33 displays the daily peak demand net position by month based on historical actuals of daily peak hour generation and peak hour load observed between 2015 and 2019. A majority of the capacity deficits occurred during the summer, with minimal deficit periods appearing in the winter. Most of the deficits were less than 30 MW. The largest deficit occurred in June 2015 when the peak hourly deficit was 141 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 50 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 2025 with the purchase of a daily physical call option (25 MW for the winter months of December through February, starting in December 2022, and 75 MW for the summer months of July and August, starting in July 2023).

Figure 34 replicates Figure 32 but does not count Frederickson or any physical call option as a resource.

Figure 33: Daily Peak Demand Net Position by Month with Frederickson

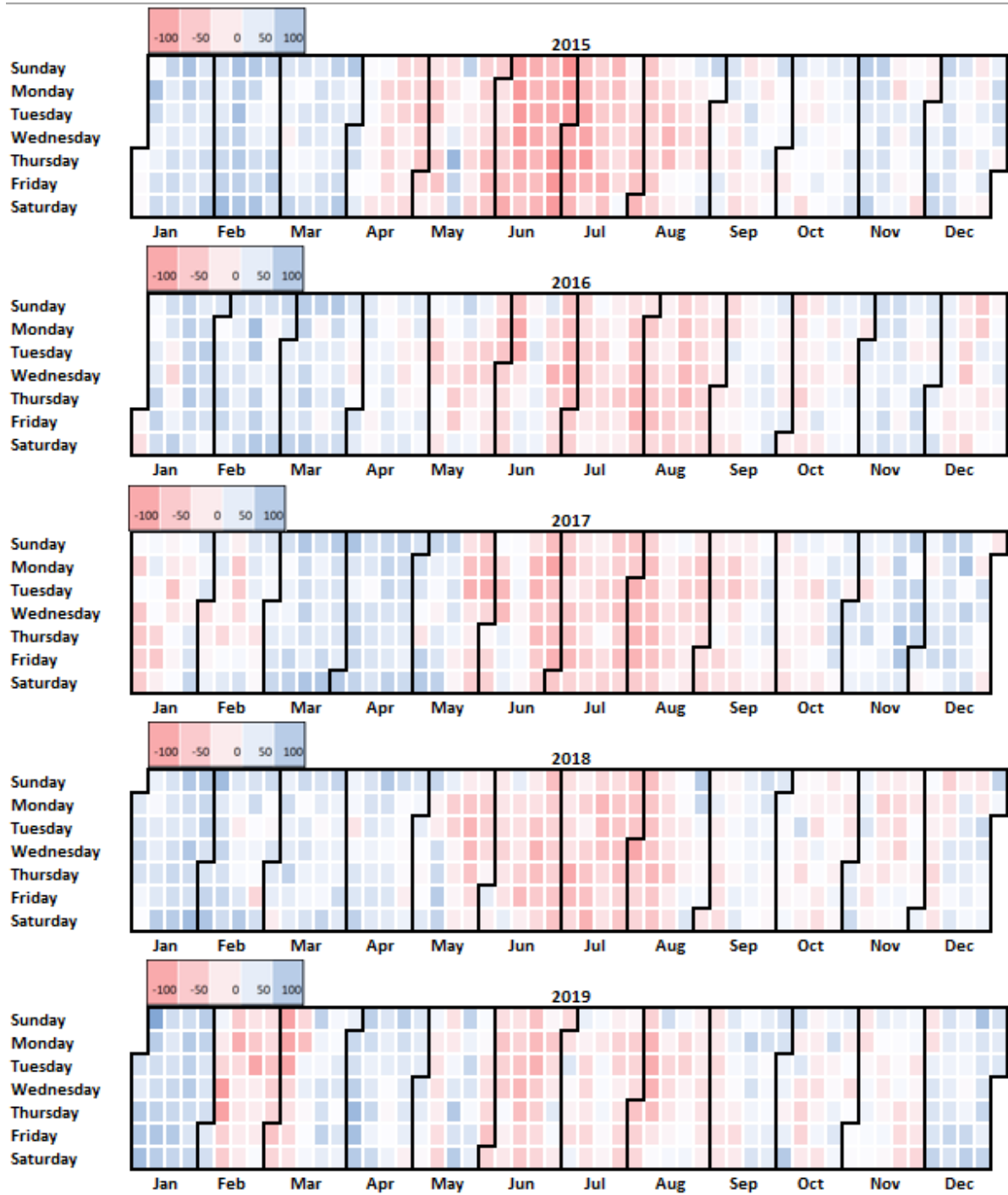


Figure 34: Daily Peak Demand Net Position by Month without Frederickson or Physical Call Option Purchase

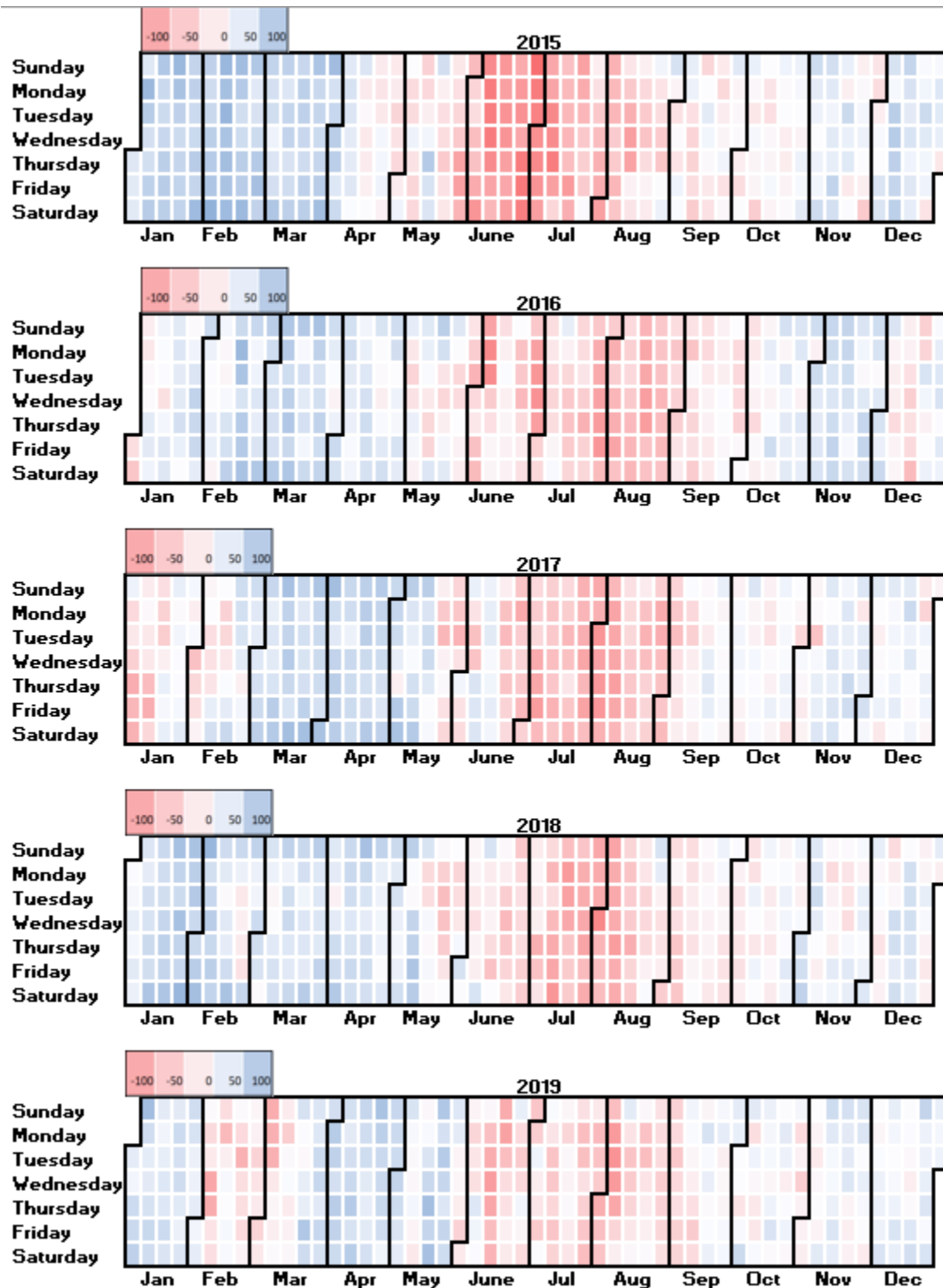


Figure 35 shows a historical view of the districts daily heavy load hour profile from 2013-2019, showing the frequency of days in which average HLH load reached certain levels.

Figure 35: Daily Peaks sorted Annually

Events	Daily aHLH Load (MW)				
	251-280	281-310	311-340	341+	
Annual	2011	1	0	0	0
	2012	14	25	11	4
	2013	19	20	13	12
	2014	9	15	11	20
	2015	14	15	16	10
	2016	26	29	7	4
	2017	22	8	30	15
	2018	7	13	13	20
	2019	23	24	13	5

Figure 36 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 100 aMW higher than the Winter peaks.

Figure 36: Summer Hourly Peak and HLH Average

Events	Month		Events	Month			
	July	Aug		July	Aug		
Daily aHLH Load (MW)	300-310	22	19	Daily Peak Load	350-360	16	17
	310-320	26	17		360-370	20	14
	320-330	26	10		370-380	21	5
	330-340	25	5		380-390	29	8
	340-350	30	9		390-400	22	5
	350-360	19	4		400-410	15	6
	361+	27	1		411+	23	0

Figure 37 shows a similar look for winter. Note that there are much fewer dates with extreme loads in the winter compared to the summer.

Figure 37: Winter Hourly Peak and HLH Average

Events	Month			Events	Month				
	Dec	Jan	Feb		Dec	Jan	Feb		
Daily aHLH Load (MW)	280-290	4	1	2	Daily Peak Load	301-310	3	0	2
	291-300	1	2	0		311-320	4	3	2
	301-310	0	3	1		321-330	2	2	1
	311-320	1	3	0		331-340	1	2	1
	321-330	0	0	0		341-350	0	1	0
	331-340	0	1	0		351-360	0	0	1
	341+	0	0	0		361+	0	3	0

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 38):

Figure 38: 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 is not a single standard that is being 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 (July-August) actual single-hour daily peak load and HLH average load for December 2011 through February 2020 and determine the load associated with a given percentile.
2. Establish this value as expected winter and summer hourly and HLH peak planning 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 39, using a P99 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 39 displays the Peak Load scenarios studied to assess the District’s peak load/resource balance. The 2030 values were derived by escalating the 2020 values by 0.17% per year, which is the District’s 10-year annual energy growth rate. The “winter” scenario includes the months of December, January, and February. The “summer” scenario includes the months of July and August.

Figure 39: Peak Load Scenarios

Peak Load (aMW)			
	Load 50th	Load 50th * 1.12	Load 99th
Winter Average HLH	195	219	303
Winter Peak	218	244	333
Summer Average HLH	298	334	376
Summer Peak	339	380	423
2030 Peak Load (aMW)			
10 Year AARG	0.17%	0.17%	0.17%
Winter Average HLH	199	222	309
Winter Peak	222	249	339
Summer Average HLH	303	340	382
Summer Peak	345	386	430

Figure 40 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 40: Forecasted Peaking Resources

	Expected Resources			
	Slice	Block	Frederickson	Total Resource
Winter Peak 2021	144	108	50	302
Summer Peak 2021	144	154	50	348
Winter HLH Average 2021	123	108	50	281
Summer HLH Average 2021	123	154	50	327
	Slice	Block	Call Option	Total Resource
Winter Peak 2025	144	108	25	277
Summer Peak 2025	144	154	75	373
Winter HLH Average 2025	123	108	25	256
Summer HLH Average 2025	123	154	75	352

Figure 41 shows the one-hour peak resource generation over the winter and summer months. Slice generation is assumed to be 10,500 MW at the system level, which equals 144 aMW of generation for the District.

Figure 41: Existing Peak Resources

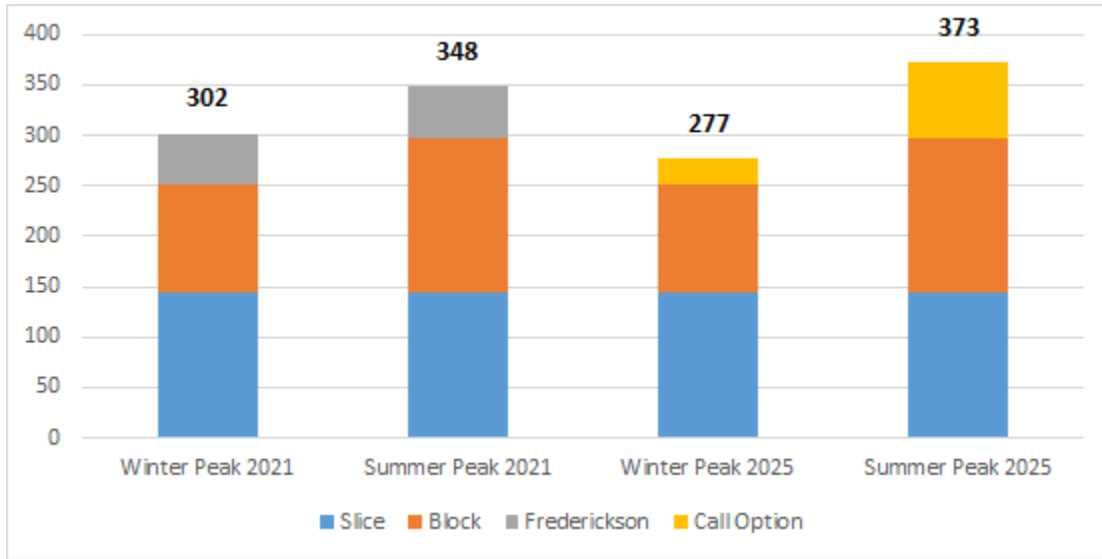
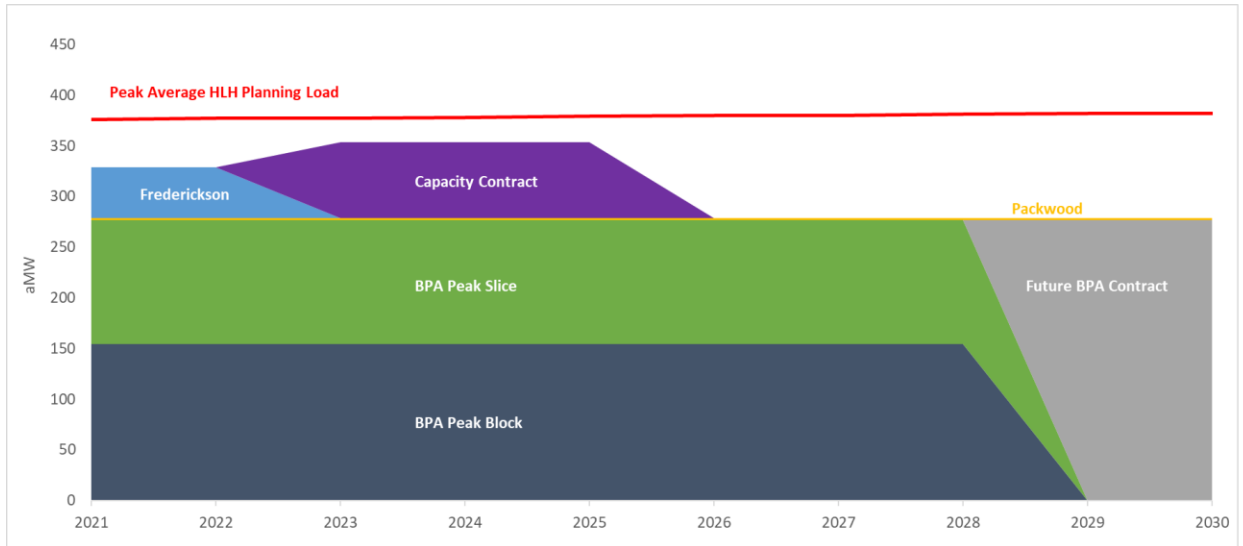


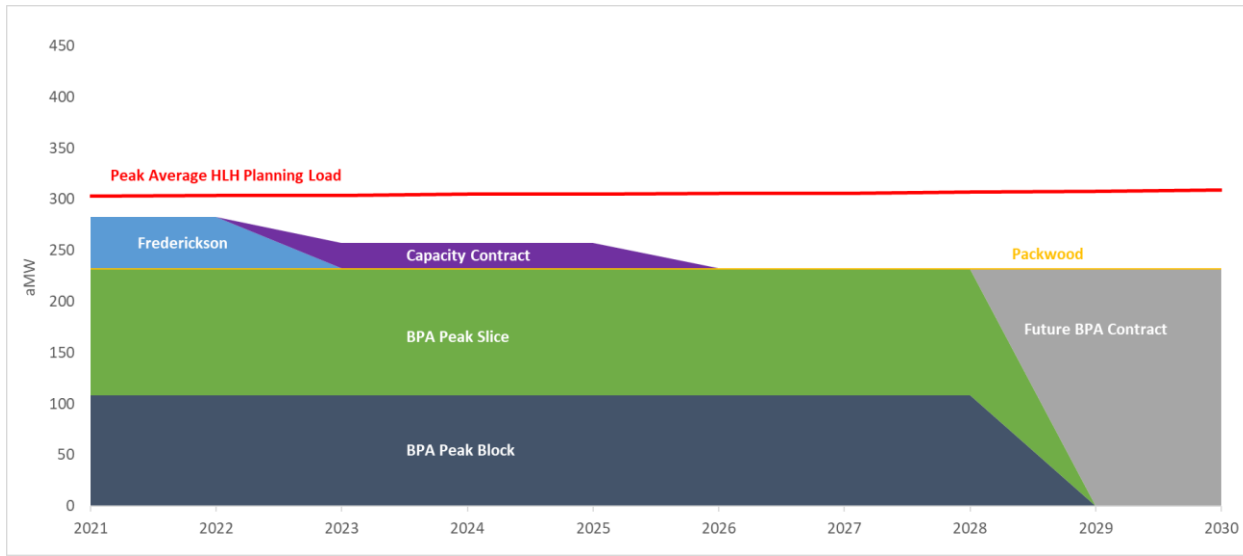
Figure 42 for summer and Figure 43 for winter show the P99 average HLH load/resource balance by year.

Figure 42: Annual Peak Load and Existing Resources in Summer



All Units MW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Average HLH Load	376	377	377	378	379	380	380	381	382	382
BPA Peak Block	154	154	154	154	154	154	154	154	0	0
BPA Peak Slice	123	123	123	123	123	123	123	123	0	0
Packwood	2	2	2	2	2	2	2	2	2	2
Frederickson	50	50	0	0	0	0	0	0	0	0
Capacity Contract	0	0	75	75	75	0	0	0	0	0
Future BPA Contract	0	0	0	0	0	0	0	0	277	277
Net Position	-47	-48	-23	-24	-25	-101	-101	-102	-103	-103

Figure 43: Annual Peak Load and Existing Resources in Winter



All Units MW	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Average HLH Load	303	304	304	305	305	306	306	307	308	309
BPA Peak Block	108	108	108	108	108	108	108	108	0	0
BPA Peak Slice	123	123	123	123	123	123	123	123	0	0
Packwood	2	2	2	2	2	2	2	2	2	2
Frederickson	50	50	0	0	0	0	0	0	0	0
Capacity Contract	0	0	25	25	25	0	0	0	0	0
Future BPA Contract	0	0	0	0	0	0	0	0	231	231
Net Position	-20	-21	-46	-47	-47	-73	-73	-74	-75	-76

Figure 44 shows the monthly HLH average planning net position for historical P99 HLH load and using current resources with Frederickson, without Frederickson, and without Frederickson but with a physical call option purchase of 75 MW in the summer and 25 MW in the winter. Actual loads from October 2011 – June 2020 were used to assess the P99 load scenario. For winter months, the P99 value was based on January, February, and December. For summer months, the P99 value was based on July and August. Some shortfalls remain even with the purchase of physical call options under this methodology. These shortfalls, however, exist only in the most extreme weather situations.

Figure 44: Monthly HLH Average Planning Net Position Using Historical P99 HLH Load

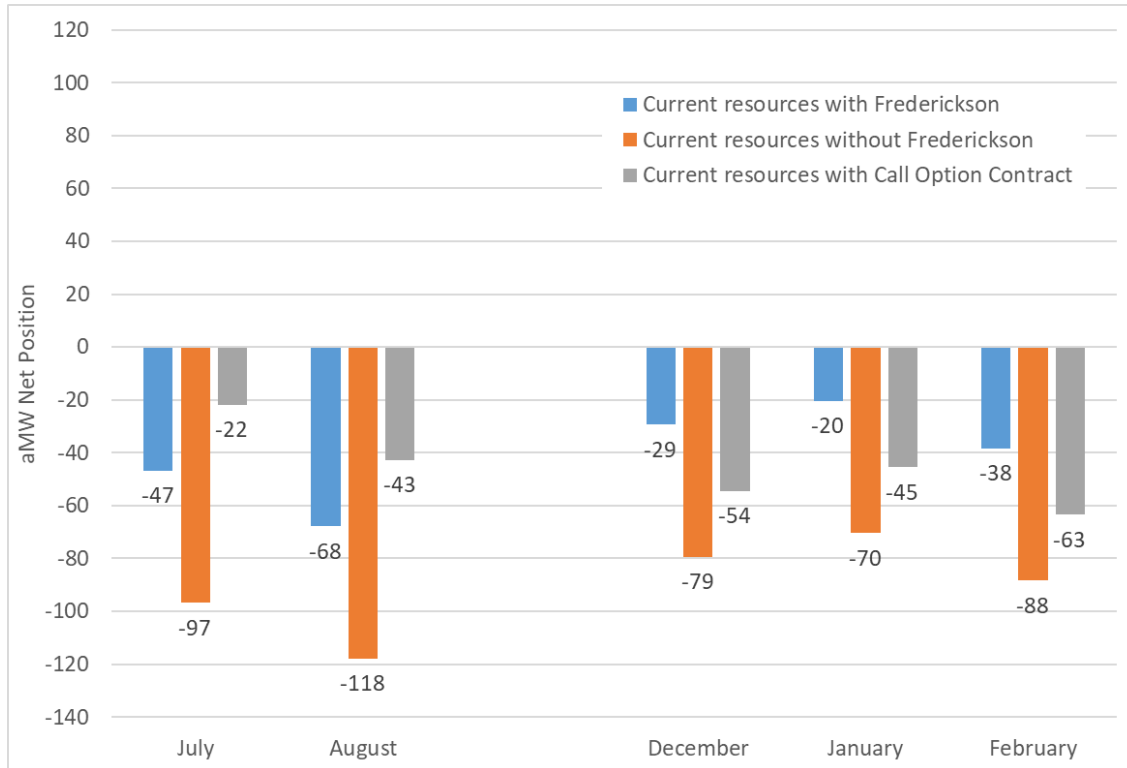
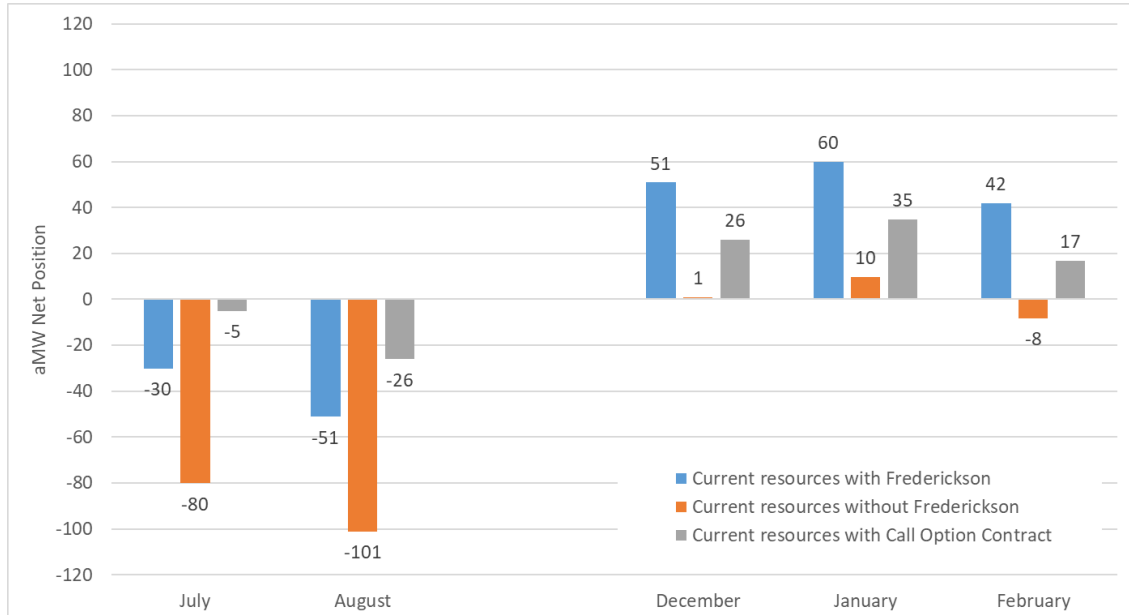


Figure 45 shows the monthly single-hour peak planning net position using a 12% Planning Reserve Margin (PRM) based on P50 historical loads. Using this approach, the District’s summer and winter capacity shortfalls are reduced.

Figure 45: Monthly Single-Hour Peak Planning Net Position Using a 12% PRM With Historical P50 loads



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 46, when several large coal plants are scheduled to shut down (Figure 47). This increased to 8.2% by 2024 in the 2019 study displayed in Figure 47.

Figure 46: 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 47: NWPCC 2024 LOLP Assessment

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

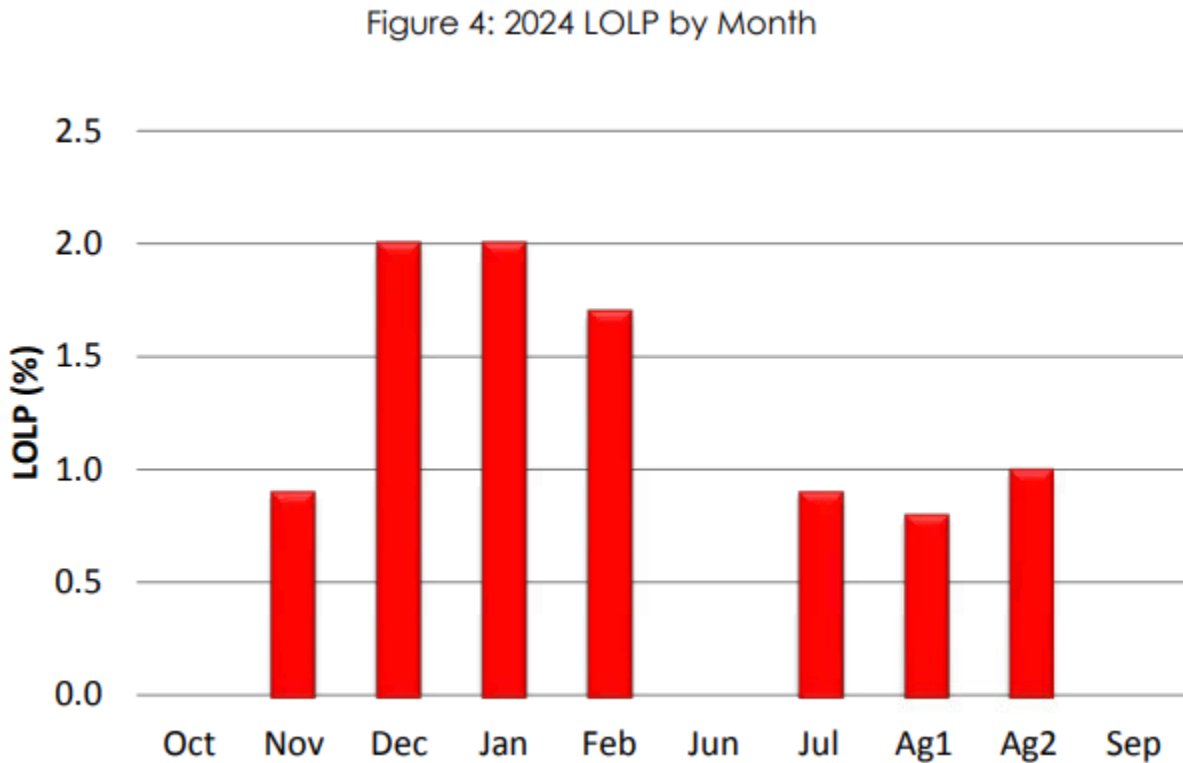
Import (MW)	1500	2000	2500	3000	3500
High Load (3% higher)	21.1	18.0	16.0	14.4	12.0
Medium Load	12.5	10.2	8.2	6.9	5.2
Low Load (3% lower)	7.0	5.2	4.0	3.1	2.0

Figure 48: 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 49).

Figure 49: 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

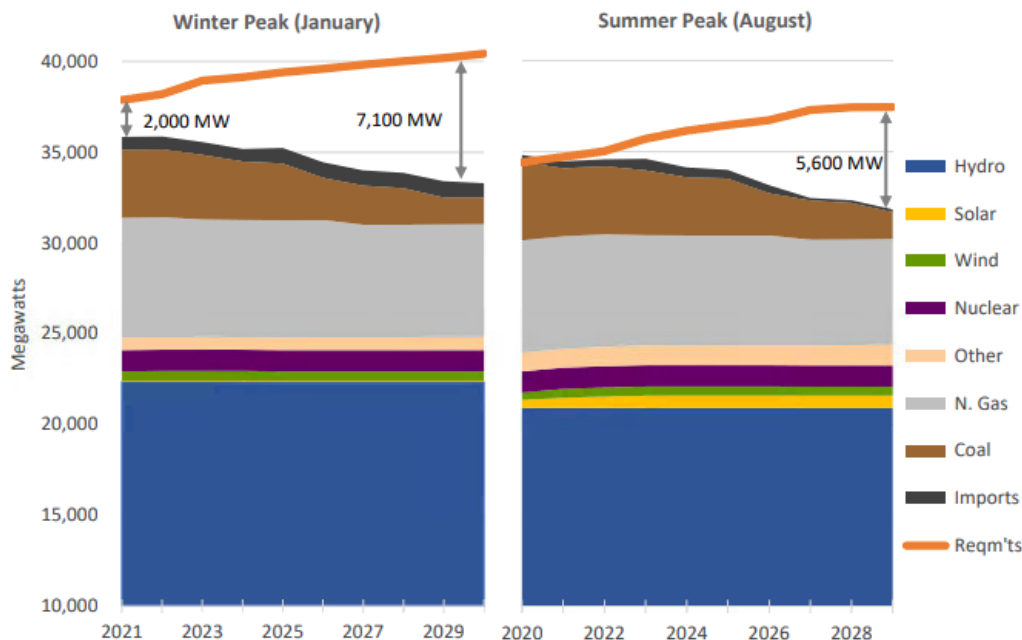
During regional meetings, staff has heard from a number of other electric utilities that they all are currently relying on the market for energy and capacity needs. Since that is the preferred portfolio from previous IRPs and likely the least cost, least risk portfolio and so many other utilities are 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 NRF⁴⁴ indicates in Figure 50 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 50 also indicates a potential summer capacity constraint starting in 2022 if average hydro conditions are not observed.

Figure 50: PNUCC Region-wide Winter and Summer Peak Capacity

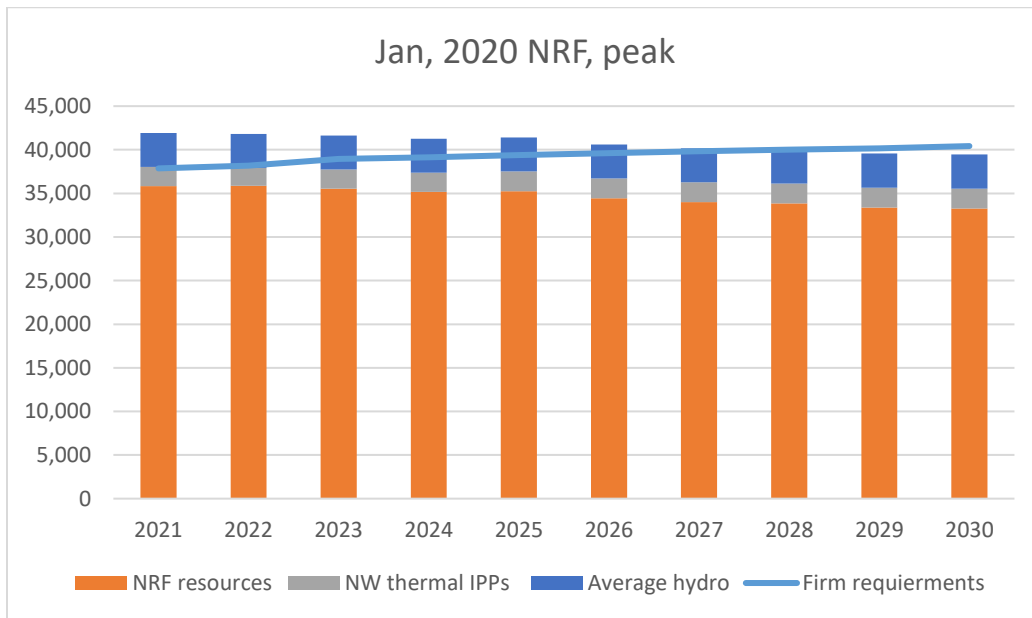


⁴⁴https://pnucc.org/sites/default/files/Xdak24C14w3677n7KsL43OEL4J25MW0b3d5cmx3FGD4d9OQ3B189OF/2020%20PNUCC%20NRF_0.pdf

Analysis of Regional Studies of Winter Loads and Resources

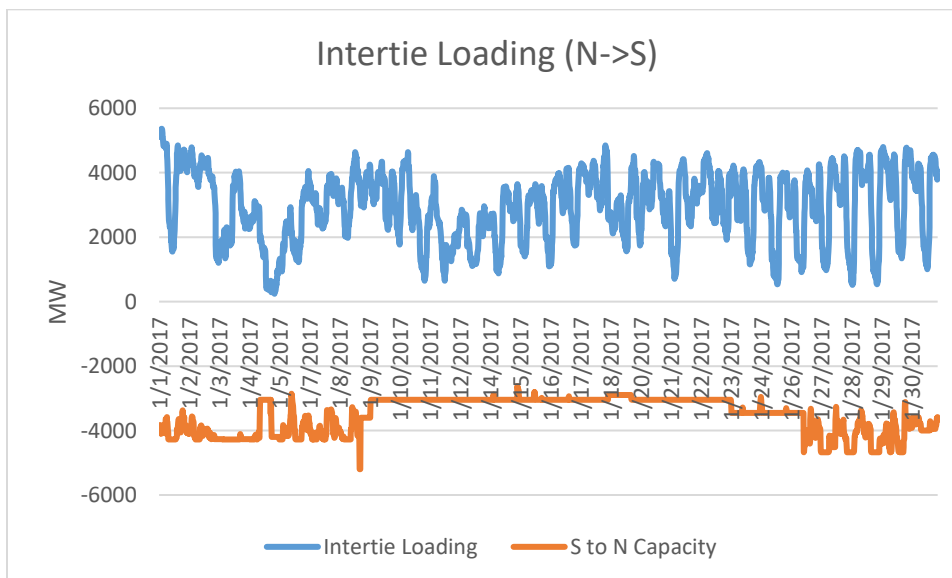
Since the NRF shows large deficits during winter peak events, additional analysis was performed to better understand the regional picture. IPP resources and average hydro are added to the NRF resources in Figure 51: PNUCC NRF January Peak L/R Balance. As stated previously, the District is near Load/Resource (L/R) balance during a winter peaking event so the results of the NRF are less concerning.

Figure 51: 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 52, significant import capability is available in the winter, even when regional load is peaking.

Figure 52: Pacific NW/SW Intertie Loading in Winter

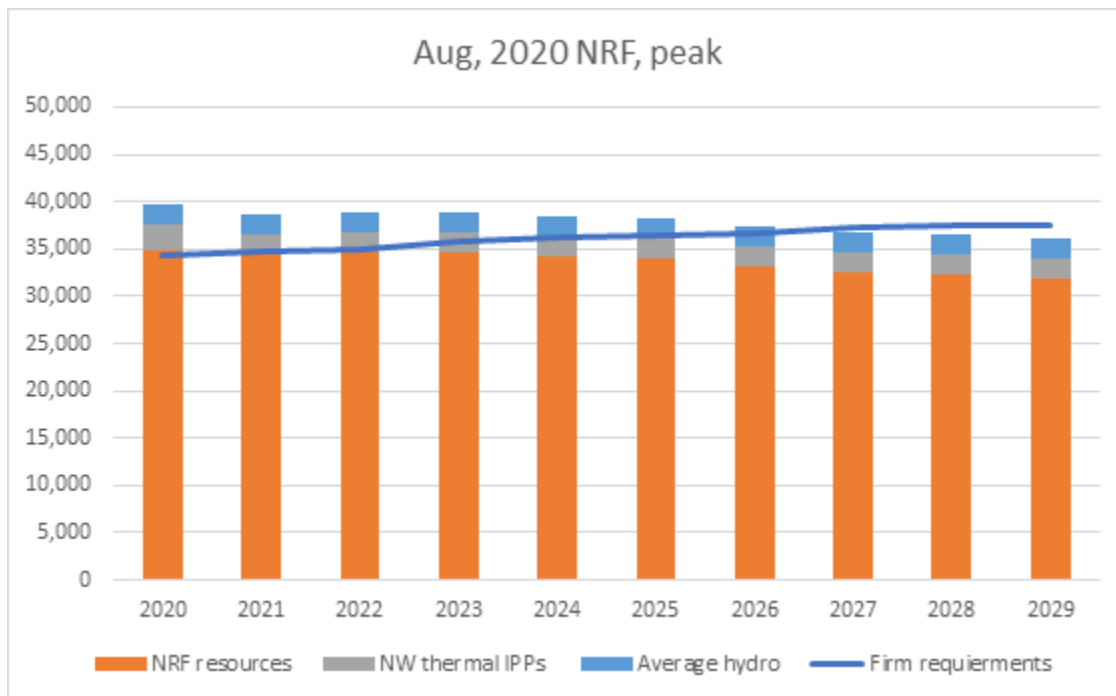


CAISO’s winter peak is typically 30 GW, with 40 GW of thermal capacity (plus renewables). However, while the thermal capacity units are currently available, they are becoming uneconomical to operate due to regulatory policy. Retirement of thermal units in CAISO could remove valuable import related resources 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 53. In addition, if average hydro generation is taken into account, the region shows a surplus through 2026.

Figure 53: 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 54 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 54: Pacific NW/SW Intertie Loading in Summer

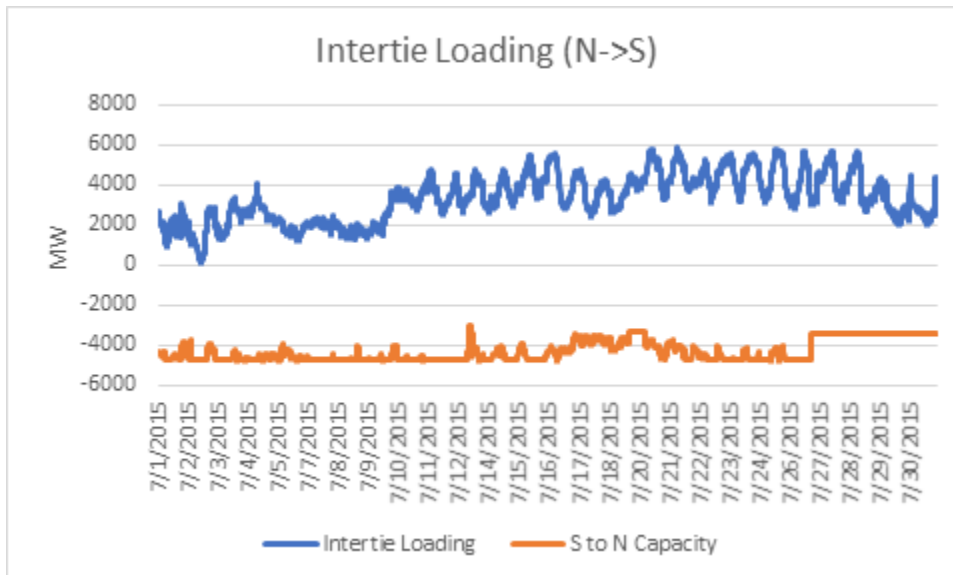
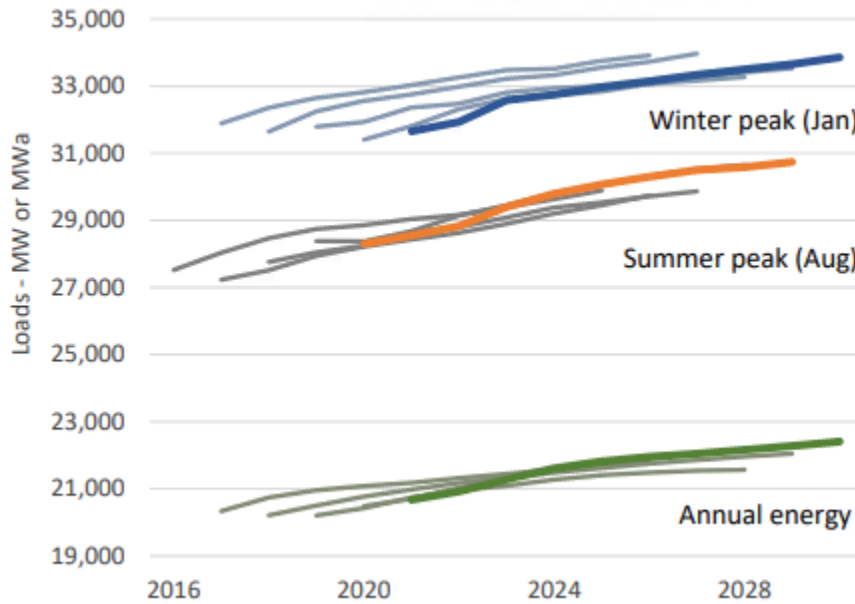


Figure 55 also notes that looking at past reports, firm annual energy and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply. This trend is not found in the summer peak forecasts which continue to trend as expected.

Figure 55: 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 56):

- 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 56: 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 <i>(2018 WBK – 2017 WBK)</i>	26	124	-69	-85	-28	69	47	109	114	n/a

Table 3-12

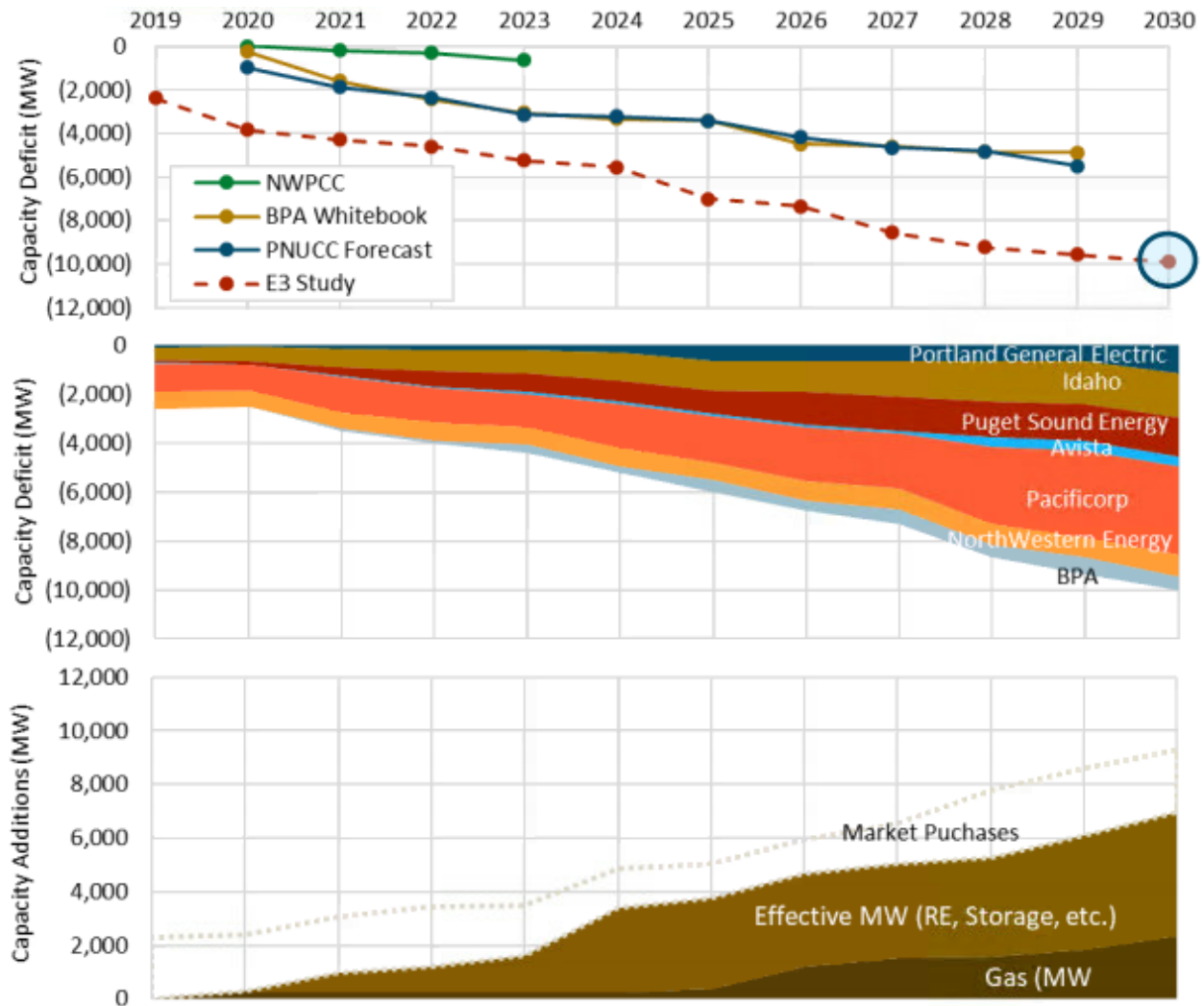
**PNW Region
January 120-Hour Capacity Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2020 through 2029
1937-Critical Water Conditions**

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 <i>(2018 WBK – 2017 WBK)</i>	-553	-404	-791	-725	-738	-597	-717	-570	-692	n/a

Summary of NW IOU Resource Procurement Plans in most Recent IRPs

Figure 57 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 57: E3 Summary of Regional IOU IRP Capacity Deficits and Additions

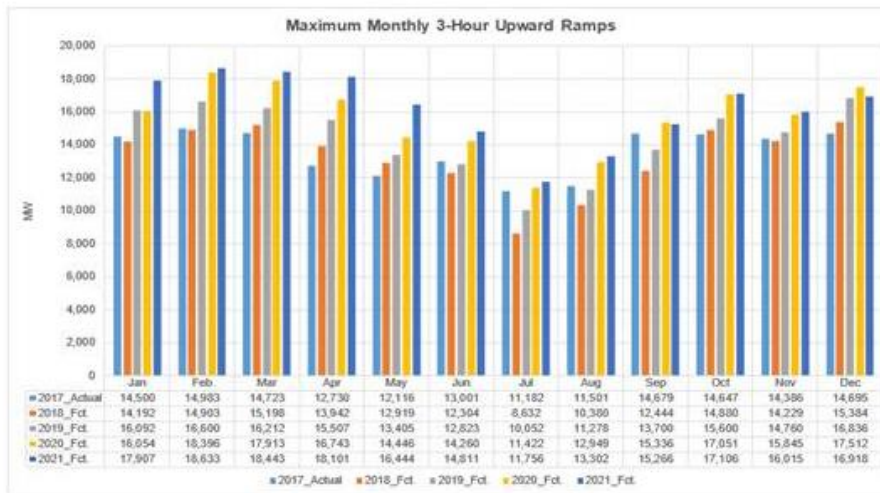


Summary of Impacts of CA need for Ramping due to Solar

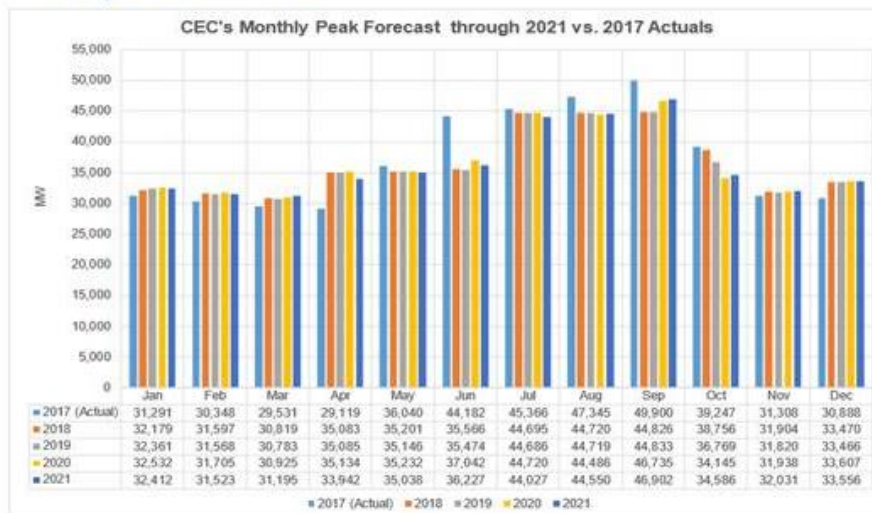
Could the need in CA for ramping resources due to the solar “Duck Curve” impact the ability to access market resources to meet the District’s summer peak load? CAISO has recently analyzed the monthly ramping need. As noted in the following charts, CAISO’s summer peak is decreasing and their need for ramping resources are at their minimums in the summer months (Figure 58).

Figure 58: CAISO Net Load Ramps and Peak Forecast

Maximum monthly three-hour upward net-load ramps for 2017 through 2021



CEC (mid baseline, mid AAEE) projected 1 in 2 CAISO coincident 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, such as a seasonal daily physical call option) to meet its needs if LOLP projections rise above 5% in the one to two-year time horizon.

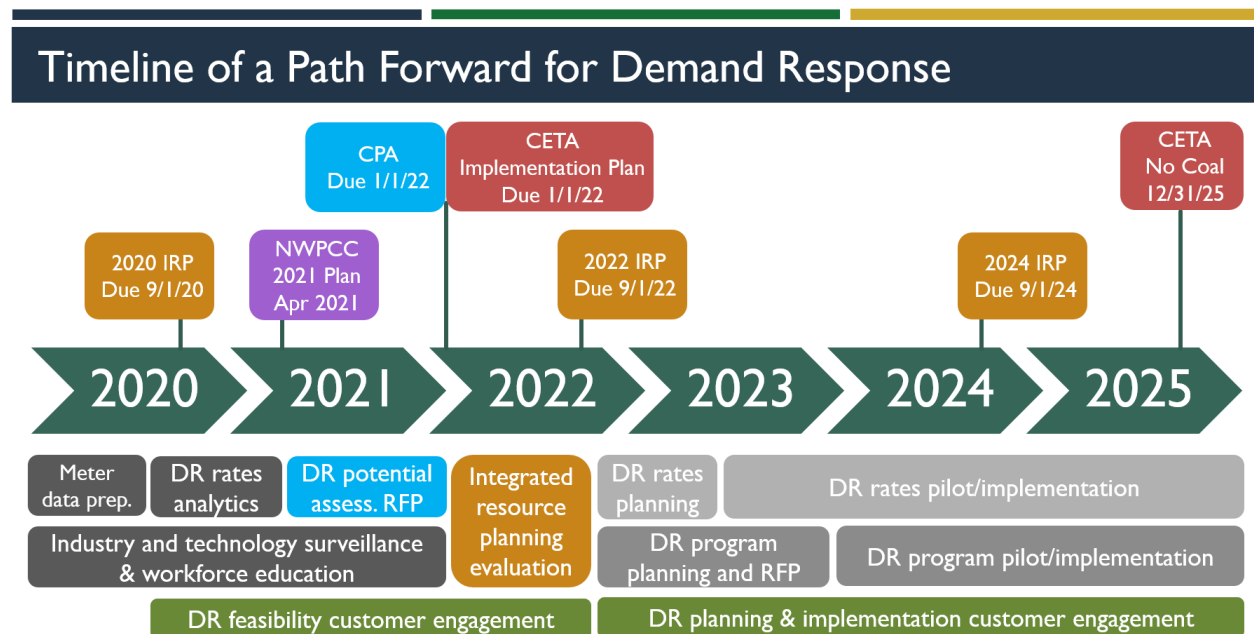
Demand Response

The District does not currently have a Demand Response (DR) program. Starting in 2019, the District began investigating the potential for DR as a capacity resource. At the October 8, 2019 Commission meeting, District staff delivered a strategic planning presentation titled, “What About Demand Response? As a capacity resource”.⁴⁵ The presentation concluded that DR should be considered as a potential capacity resource, but also emphasized the complexity of implementing a DR program.

The Oct 2019 presentation can be summarized by its three main recommendations for the District:

1. Proceed with evaluating DR programs, including rate-based options, for cost effectiveness, reliability and feasibility, consistent with the requirements of the Clean Energy Transformation Act (RCW 19.405).
2. Move towards an IRP process that evaluates the economic potential of DR as a capacity resource.
3. Consider the preliminary timeline, as shown below in Figure 59, as a path forward for DR program implementation.

Figure 59: Timeline of a Path Forward for Demand Response (as of Oct 2019)



Note: CETA = Clean Energy Transformation Act, CPA = Conservation Potential Assessment, DR = Demand Response, IRP = Integrated Resource Plan, NWPCC = Northwest Power and Conservation Council, RFP = Request for Proposal. **TIMELINE IS PRELIMINARY FOR FACILITATING ADDITIONAL PLANNING DISCUSSION** 43

⁴⁵ District Commission meeting presentations for 10/8/2019 (Pages 65-108), <https://www.bentonpud.org/getattachment/Board-Meetings/2019/2019-10-08/Commission-Handouts-2019-10-08-website.pdf.aspx?lang=en-US&ext=.pdf>

Following this IRP, the District expects to continue evaluating DR as a capacity resource, including issuing a request for proposal to complete a DR potential assessment, which will be a key input to the next IRP's evaluation of DR's economic potential as a capacity resource. Additionally, the District will also be monitoring significant industry issues that may alter the District's schedule and prioritization of a DR program, including the following items:

1. Treatment of DR within the Northwest Power and Conservation Council's 2021 Plan.
2. Northwest Power Pool's resource adequacy program design in 2020.
3. Clean Energy Transformation Act final rule making.
4. BPA 2028 contract negotiations and the potential for new contracts signed by 2025.
5. DR program implementations of other utilities or the District's technology partners.

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.⁴⁶ 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.

⁴⁶ "Lazard's Levelized Cost of Storage Analysis Version 1.0." Lazard. Web. 11 June 2016

The cost of battery packs declined from \$1,000/kWh in 2010 to \$350/kWh by 2015.⁴⁷ Battery capacity for the upcoming generation of electric vehicles dropped to \$145/kWh as displayed in Figure 60, arriving at that price point 15 years ahead of current forecasts.^{48,49} Energy storage will continue to be evaluated and is addressed as an action item in Chapter 10: Action Plan Summary.

Figure 60: Cost of EV Batteries

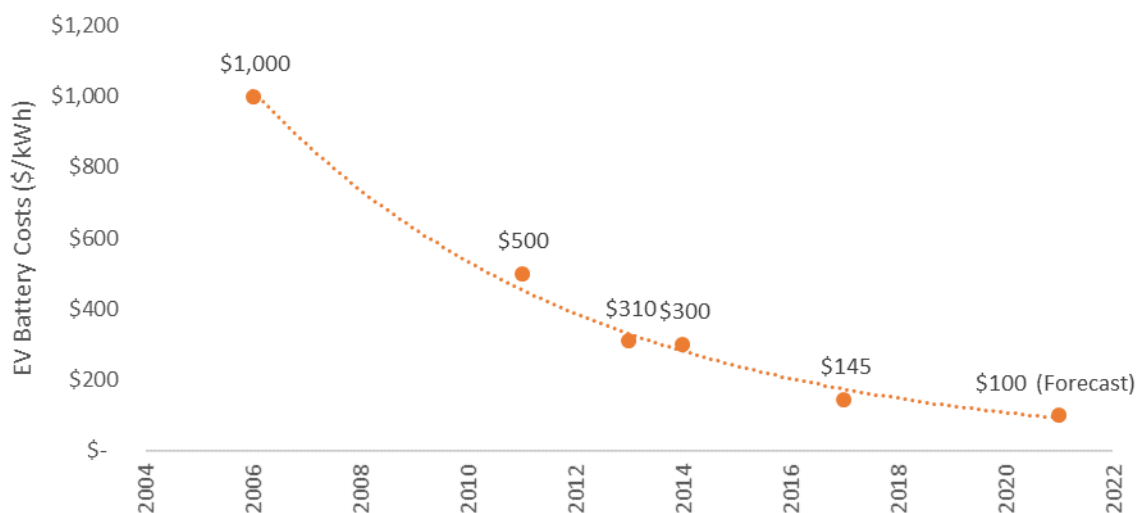


Figure 60 is a forecast of electric vehicle battery cost, which are forecasted to decline by 85 percent in six years, and seemingly follows a similar cost trajectory as wind and solar. Exponential cost declines continuously exceed the pace of forecasts along with higher than forecasted rates of adoption. 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.⁵⁰ 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

⁴⁷ Bandyk, Matthew. "Battery Storage Mandates Could Become Policy Norm, Report Says." SNL. N.p., 10 June 2016. Web. 14 June 2016.

⁴⁸ Cole, Jay. "LG Chem "Ticked Off" With GM For Disclosing \$145/kWh Battery Cell Pricing." Inside EVs. 23 Oct. 2015. Web. 30 May 2016.

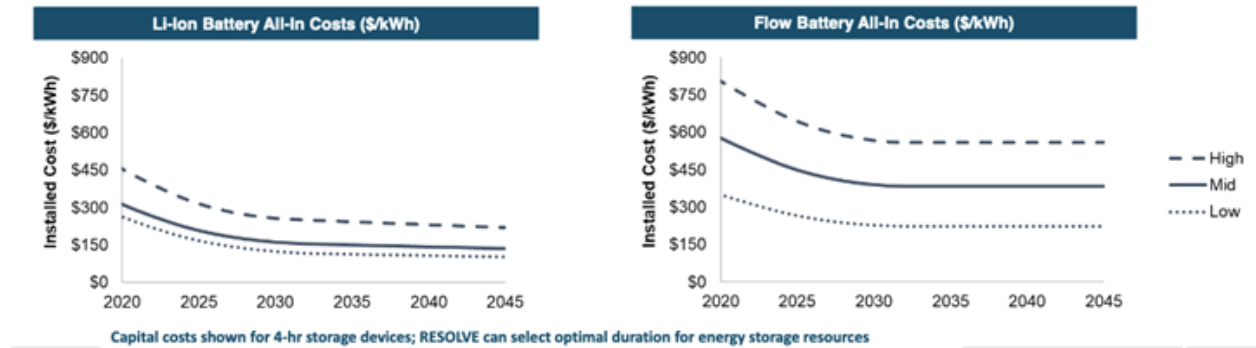
⁴⁹ "BNEF: Wind, Solar to Grab Majority of Power-sector Investments." SNL. N.p., 15 June 2016. Web. 15 June 2016.

⁵⁰ Lambert, Fred. "Tesla Opens Direct Orders of up to 54 Powerpacks and Reveals Pricing." Electrek. N.p., 22 Apr. 2016. Web. 16 July 2016.

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.

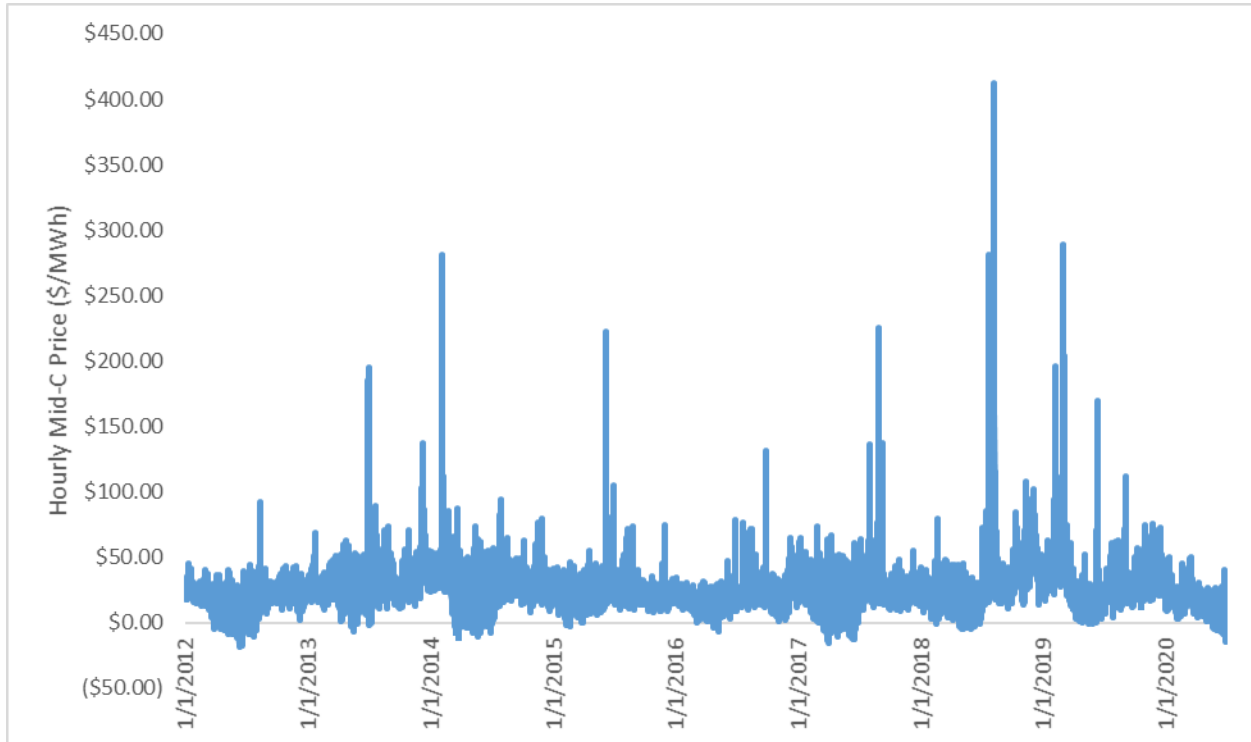
E3 provided estimates of battery storage system costs in their Carbon Markets analysis (Figure 61)

Figure 61: 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.⁵¹ An analysis of five year historical wholesale market data (Figure 62) reveals that there are very few hours and even fewer days where batteries are cost competitive.

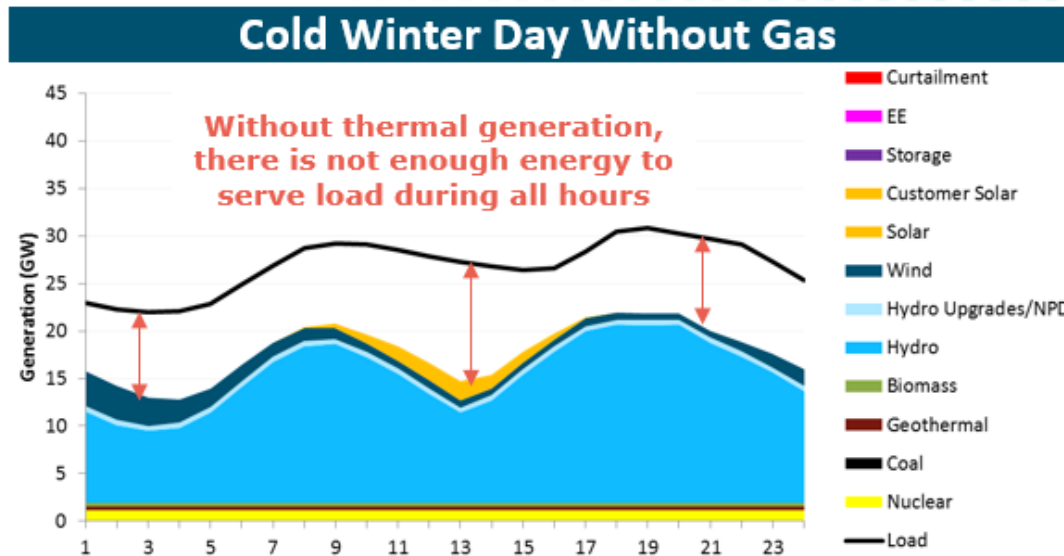
Figure 62: Hourly Mid-C Power Prices Through Time



⁵¹ *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 are not sufficient to meet load on a cold winter day (Figure 63).

Figure 63: 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 64). 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 64: 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.				Aug	25.24	9.80%	\$ 12.10
13	Eastside Fixed Fuel \$/kW/yr with 10000 Heat Rate 2012S	\$ 41.17 ³		Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 26, 2019				Sep	24.86	9.65%	\$ 11.91
14	Westside Fixed Fuel \$/kW/yr with 10000 Heat Rate 2012S	\$ 45.76 ³						Average \$/kW/mo		\$ 10.29	
15	Eastside Fixed Fuel \$/kW/yr with 10000 Heat Rate 2020S	\$ 46.90									
16	Westside Fixed Fuel \$/kW/yr with 10000 Heat Rate 2020S	\$ 52.12									
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2020S	\$ 49.51									
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2020S	\$ 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 2020S	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 2012S, with 100% PUD ownership at 3.94% with plant in service 2020.										
29	⁵ Source NWPCC Microfin Model assumption of \$11/kW/yr in 2012S.										

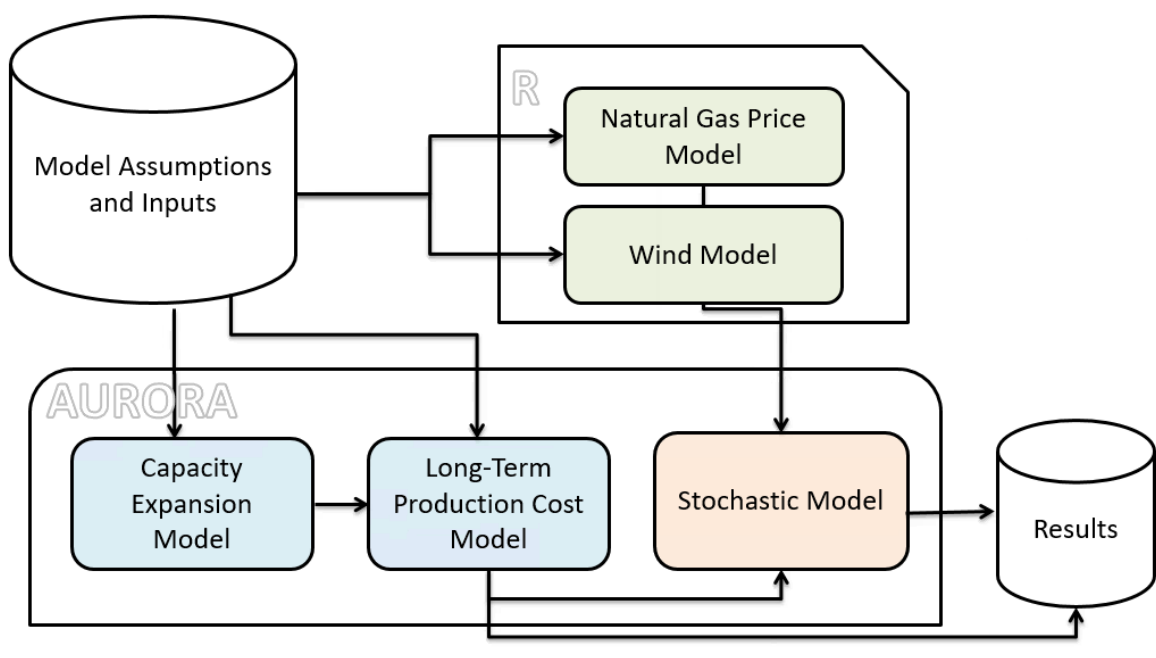
Chapter 8: Market Simulation

Methodology Overview

Approach

The electricity price simulation is created by several fundamental models working in concert. Figure 65 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 to 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 65: 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.

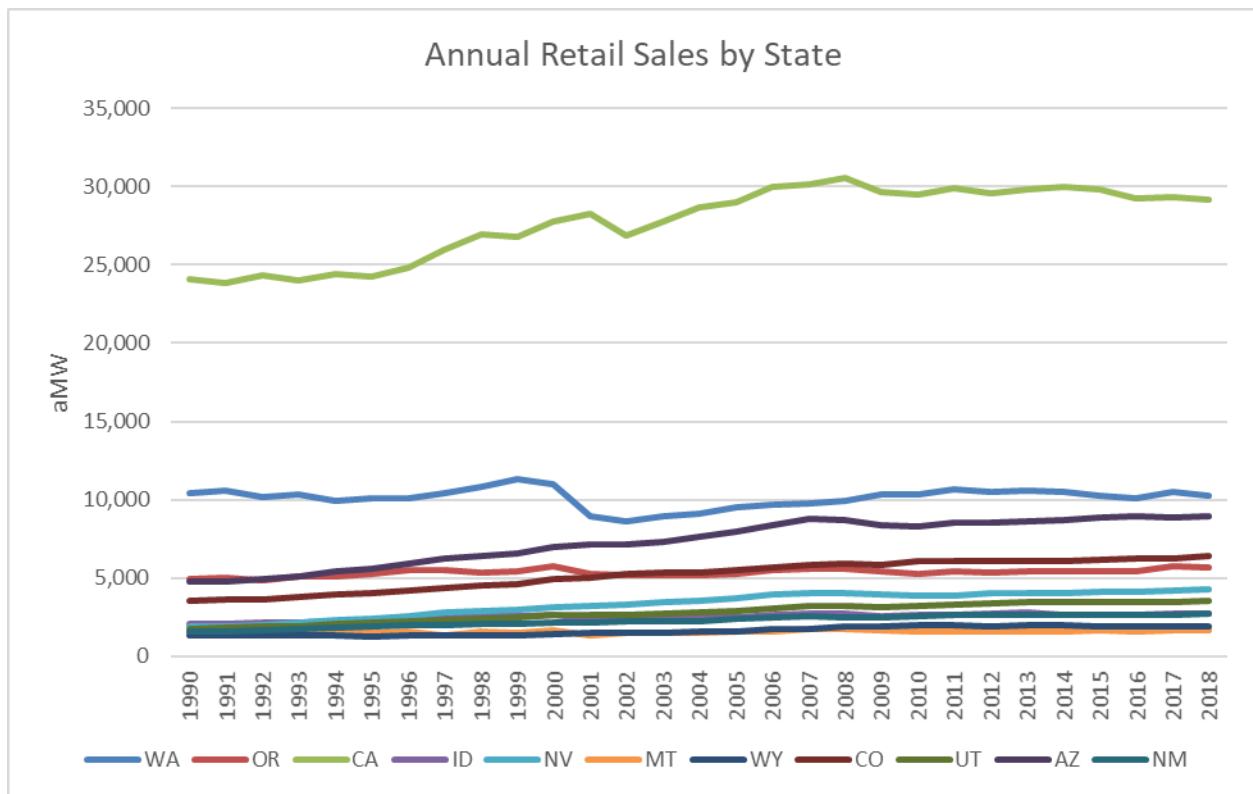
Principal Assumptions

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 Report⁵² 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.⁵³ 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 66 below shows the clear flattening/declining trend to retail loads in nearly every state in the WECC over the past two decades.⁵⁴

Figure 66: Historical WECC Retail Loads



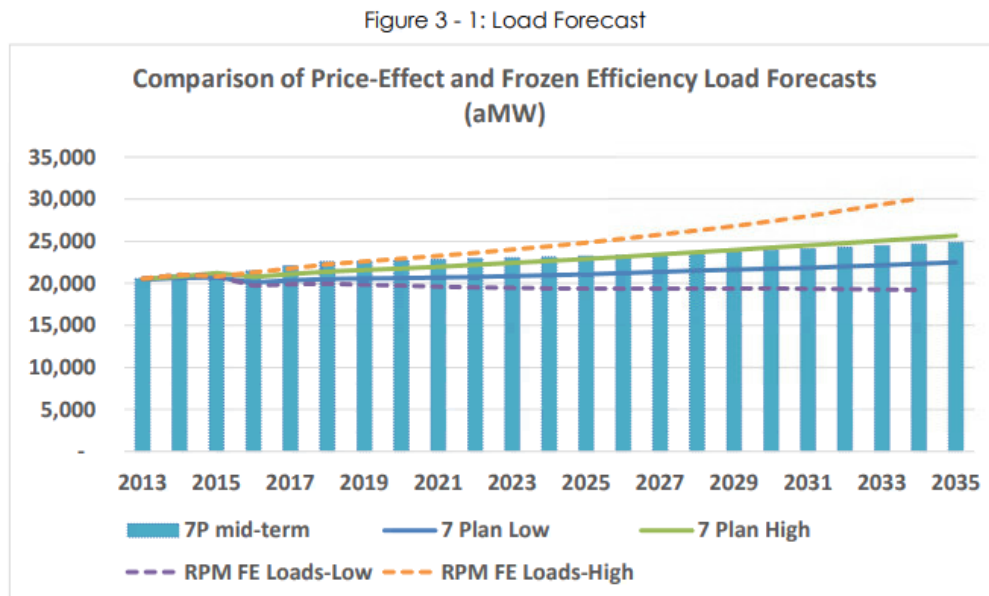
⁵² https://www.wecc.biz/Administrative/150805_2024%20CCV1.5_StudyReport_draft.pdf

⁵³ <https://www.nwcouncil.org/sites/default/files/7th%20Plan%20Midterm%20Assessment%20Final%20Cncl%20Doc%20%232019-3.pdf>

⁵⁴ 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 67 below. The average annual load growth for the Pacific Northwest for the Base Case the District used was approximately 0.4%.

Figure 67: NWPCC Load Projections



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.

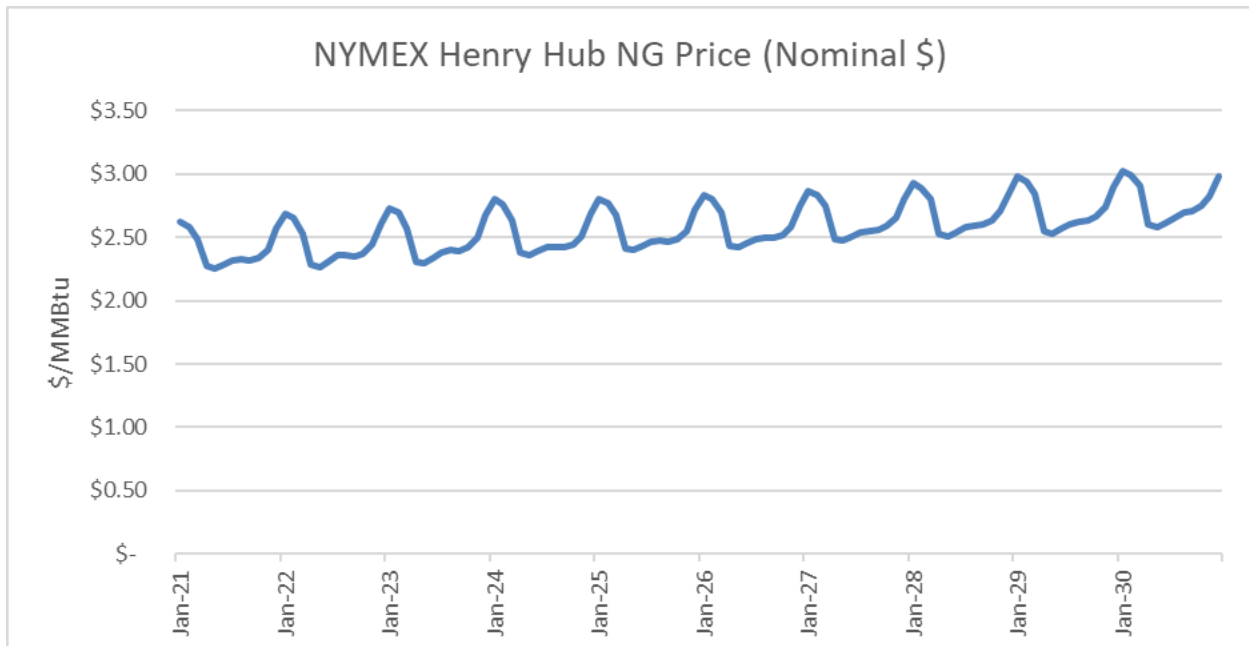
Among states in the WECC, California has the highest RPS requirement at 60% by 2030, with Oregon following shortly behind it with a 50% requirement for its IOUs by 2040. In Washington, there is a 15%

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 68 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.

Figure 68: Natural Gas Price Assumptions



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.

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.

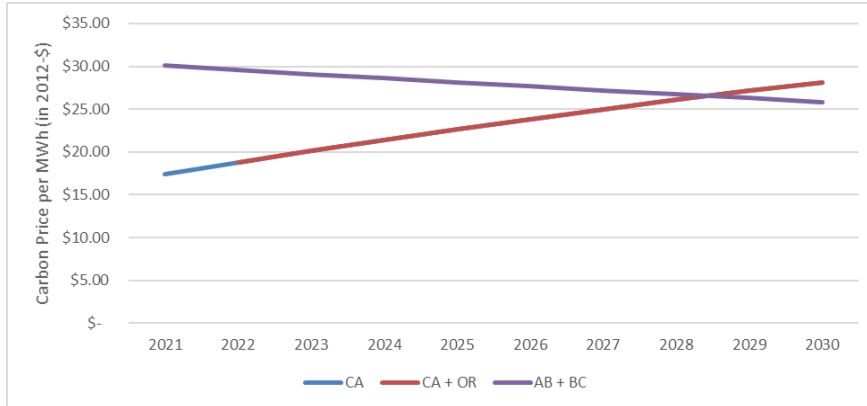
Although Washington State does not have a carbon trading market, there has been a push in recent years to set one up. For example, the Clean Air Rule (“CAR”) went into effect in 2016; this rule, however, was challenged in court and eventually ruled unconstitutional. In addition, carbon tax initiatives 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 69 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 69: 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 70.

Figure 70: 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.⁵⁵ This added a total of 6,140 MW of Solar, 1,868 MW of Wind, and 9,892 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.⁵⁶ Lastly, based on the most recent AESO 2019 Long-term Outlook, 5,171 MW of Alberta coal resources are converted to gas-fired resources during the study period.⁵⁷

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 71 and Figure 72 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.

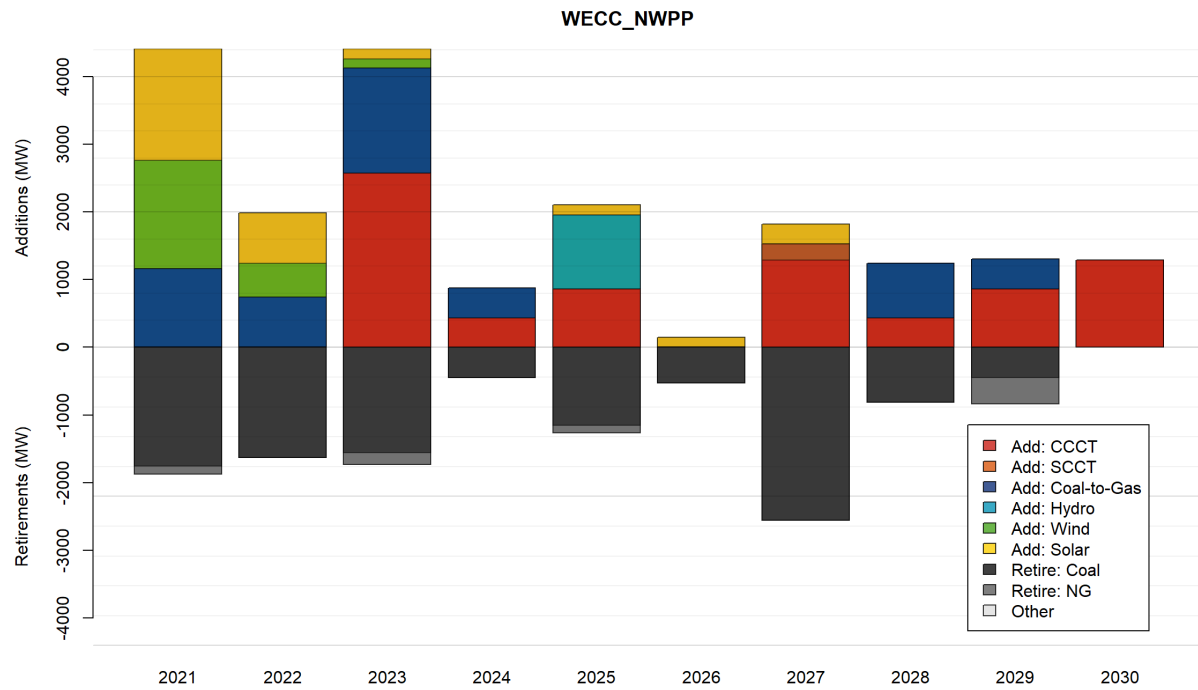
Throughout the WECC region coal output is forecasted to decline substantially, with new coal plants not being developed due to tighter emissions regulations and economics. By 2030, nearly 13,000 MW of coal capacity will be retired or converted into natural gas resources. Nuclear output will decline as aging resources are taken off-line, and hydro output will increase slightly with the addition of BC Hydro's 1,100 MW Site C Project, scheduled to come fully online in 2025.

⁵⁵ <http://www.caiso.com/PublishedDocuments/PublicQueueReport.pdf>

⁵⁶ <https://majorprojects.alberta.ca>

⁵⁷ <https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf>

Figure 71: Forecasted Pacific Northwest Generation Capacity Additions through 2030

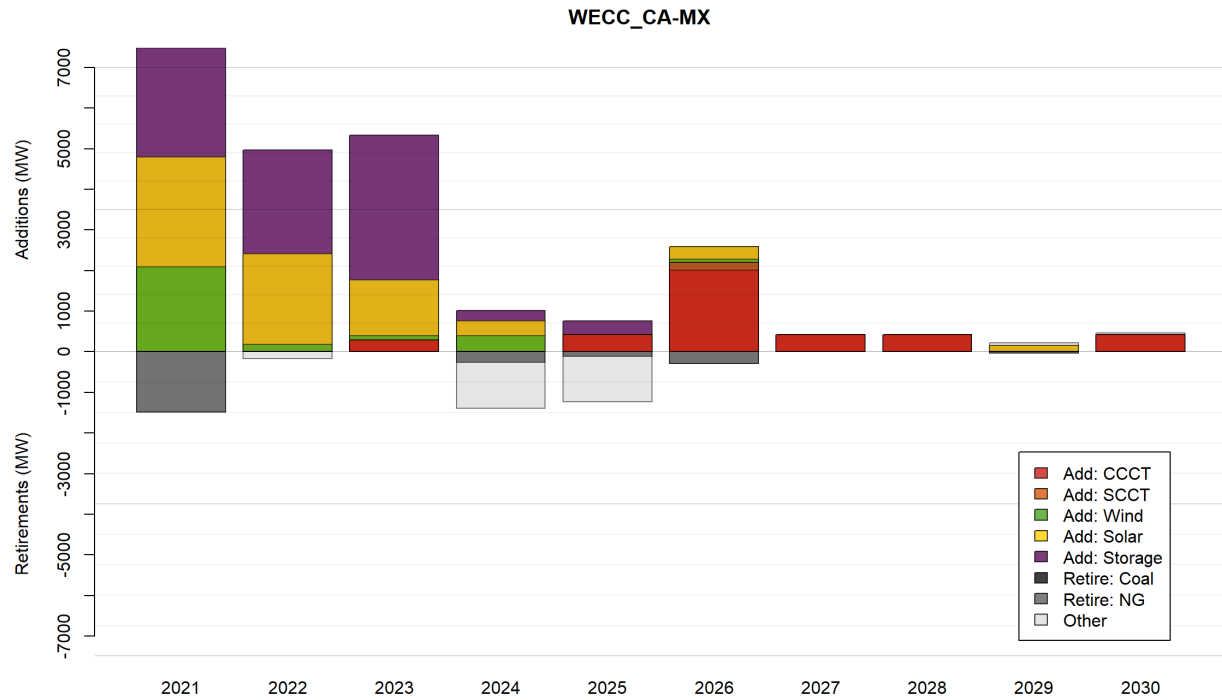


Within the Northwest Power Pool region, which includes the Canadian provinces of British Columbia and Alberta, and the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, Utah, and a small portion of northern California, hydro will remain the largest single generating resource through the 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 72: Forecasted California Generation Capacity Additions through 2030

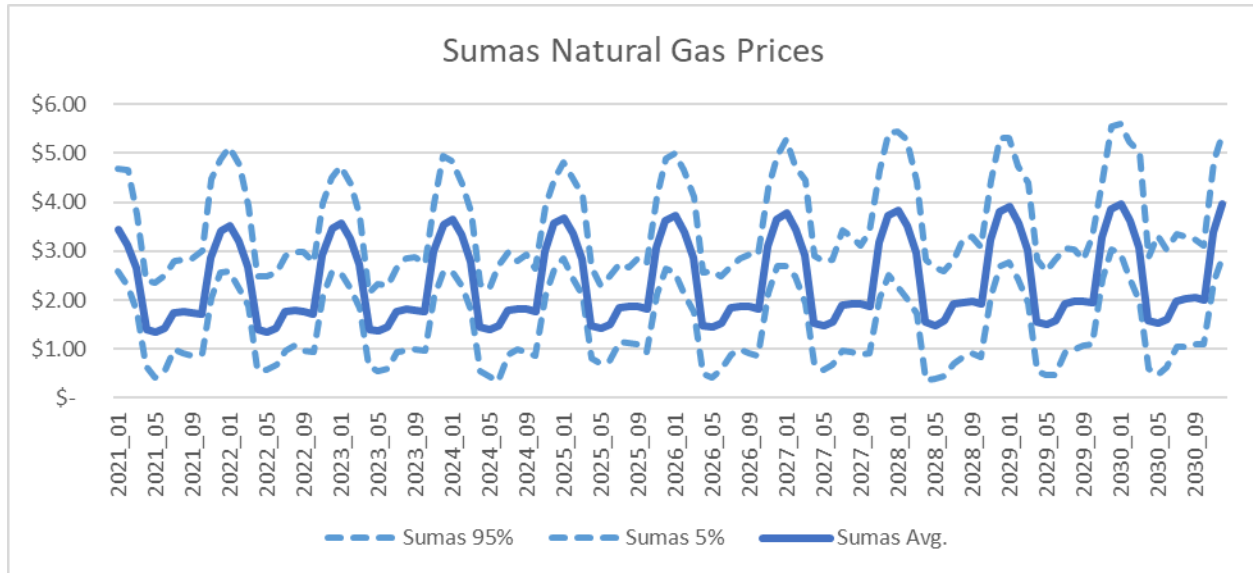


In California, although there are substantial natural gas resource retirements through 2021 (almost entirely made up of previously announced retirements of once-through-cooling units) and the retirement by 2025 of Diablo Canyon, the final nuclear facility in CAISO, the story is similar. With the large 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 73.

Figure 73: Sumas Natural Gas Price Simulation

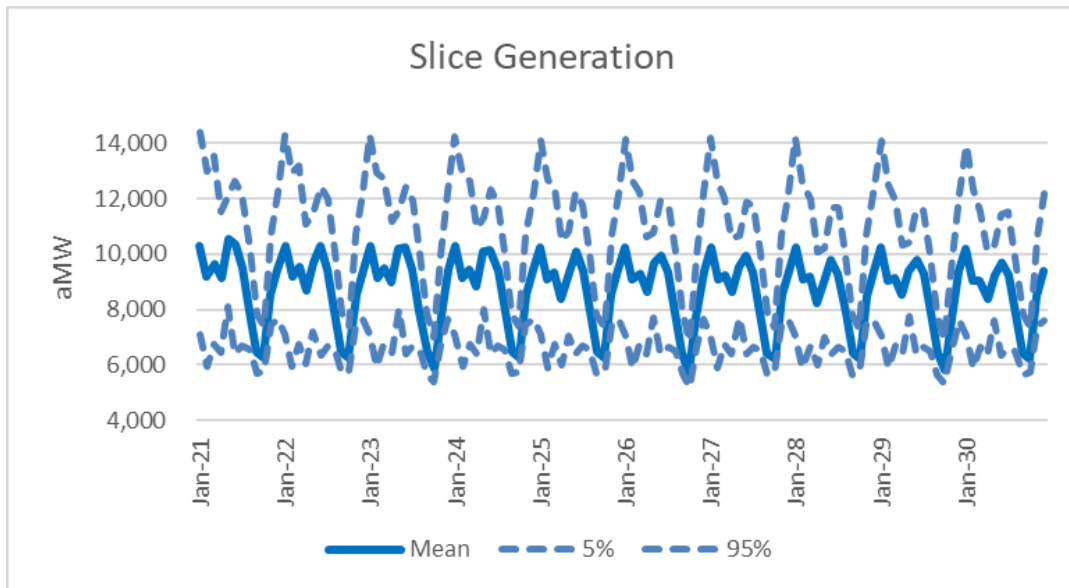


The middle line represents the average of all the iterations, and the dashed lines represent the 5th and 95th percentiles. A multi-factor mean-reverting Monte Carlo process was used to simulate the volatility of daily spot gas prices, which is then used in a Heston Model to generate prices. The model 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 74 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 74: 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 75 shows the expected Mid-C power prices from the long-term capacity expansion run, while Figure 76 and Figure 77 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 75: Mid-Columbia Prices

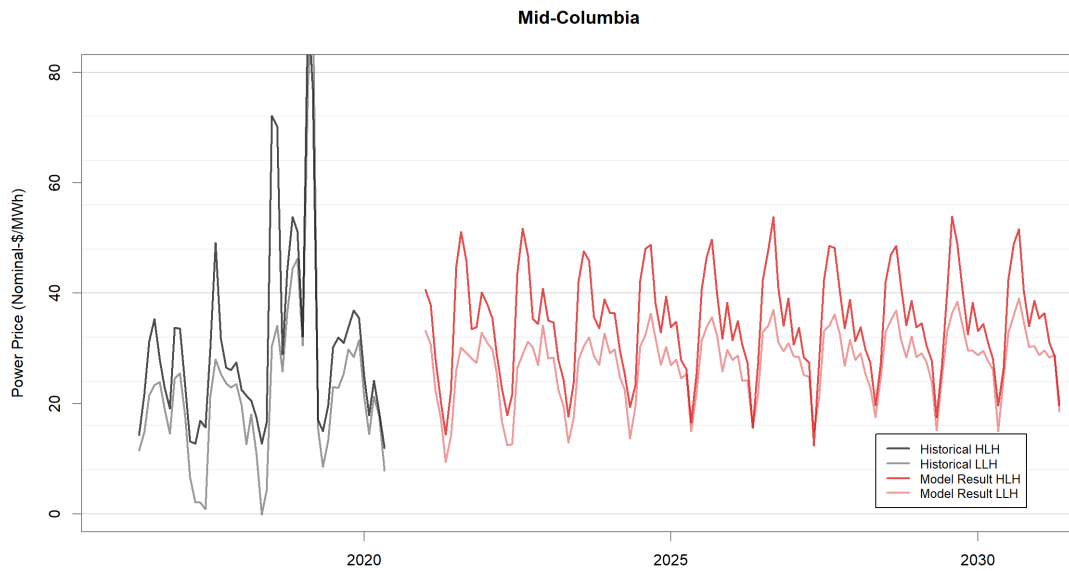


Figure 76: Mid-Columbia HLH Price Simulation

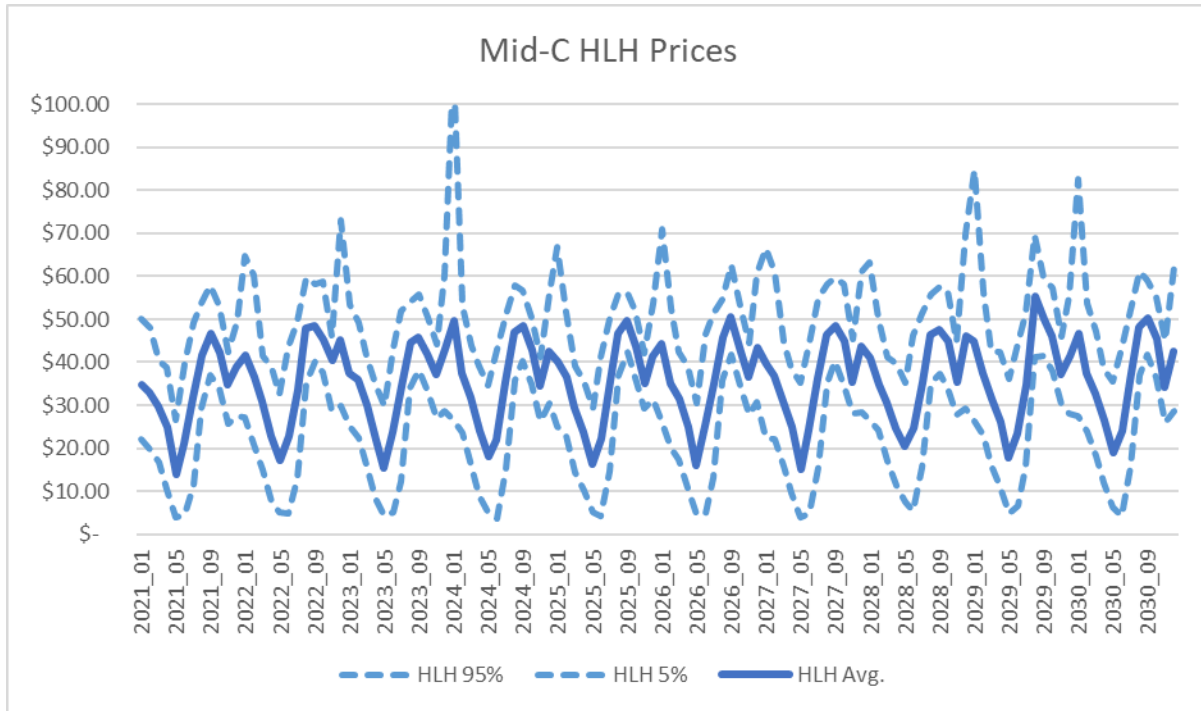
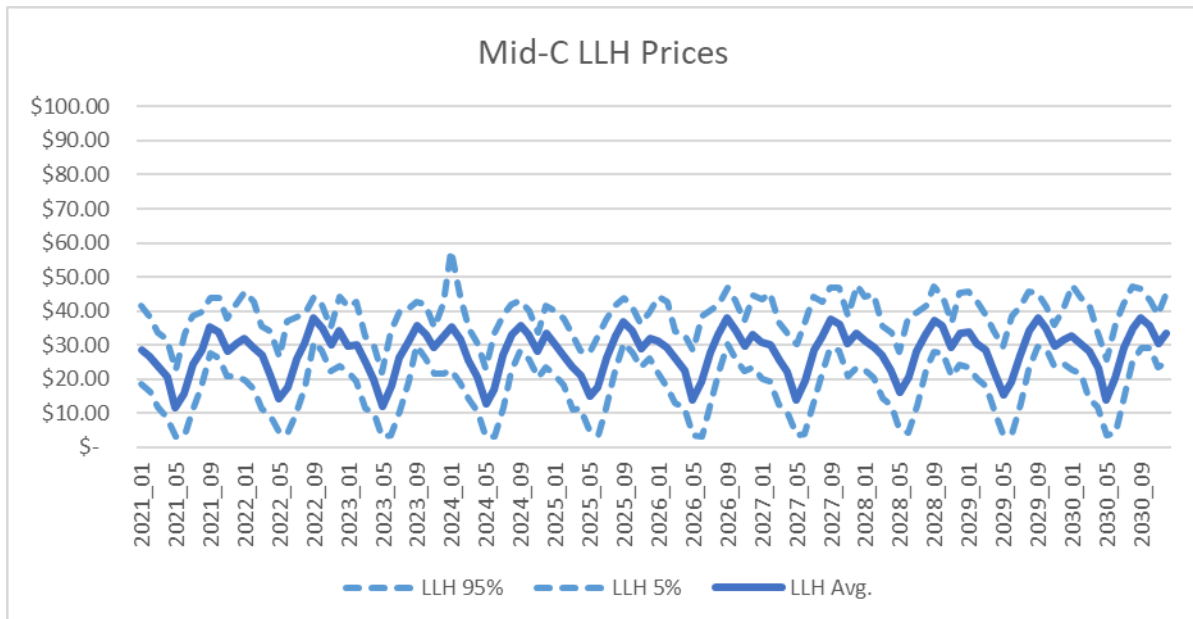


Figure 77: Mid-Columbia LLH Price Simulation



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 78. 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 78: Mid-C HLH/LLH Spread

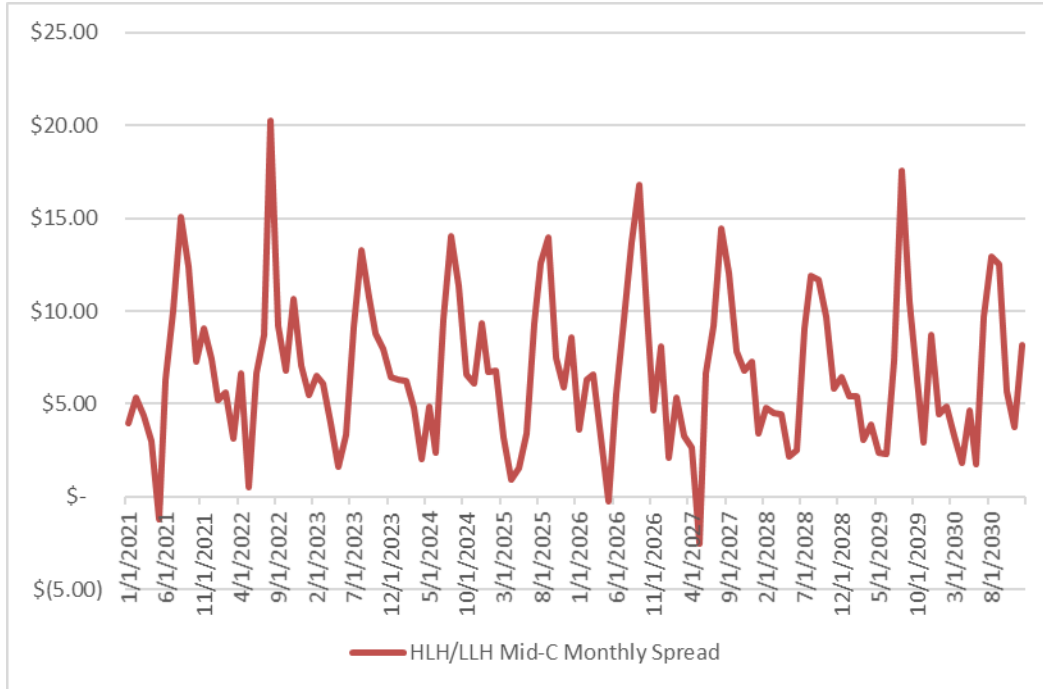


Figure 79, Figure 80 and Figure 81 below show the average hourly profile of Mid-Columbia power prices for the months of April, August, and December in the years 2021, 2024, 2027, and 2030. As can be seen, there is a clear increase in prices for the evening peak, as thermal generation must come online to make up for the decreased solar generation in the evening.

Figure 79: Mid-C Average Hourly Price Profile for April 2021, 2024, 2027 and 2030

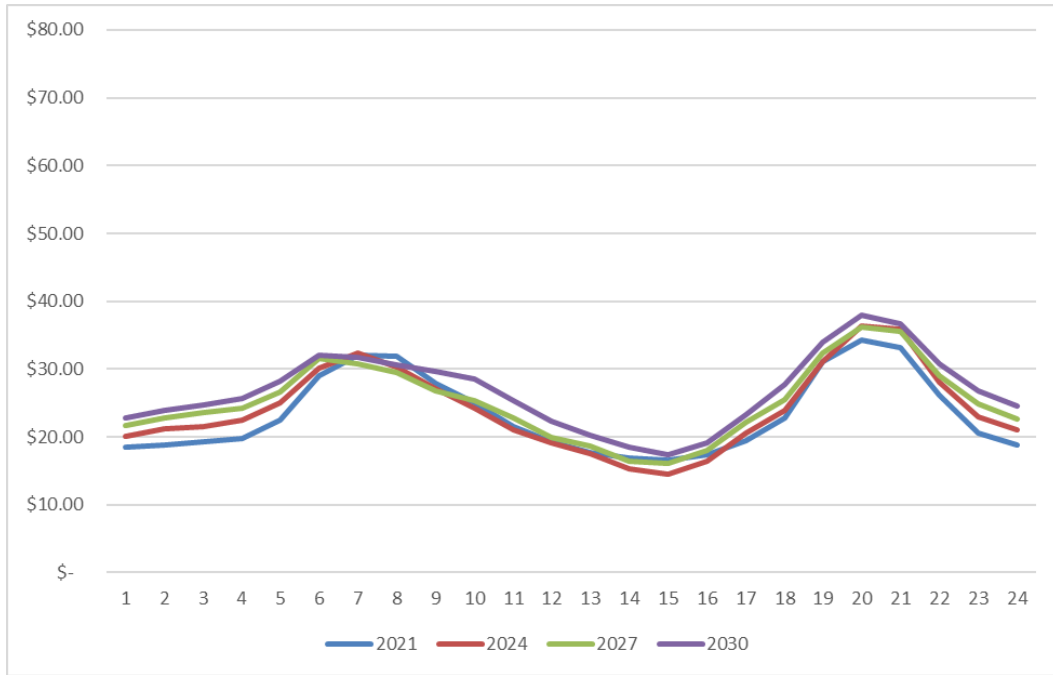


Figure 80: Mid-C Average Hourly Price Profile for August 2021, 2024, 2027 and 2030

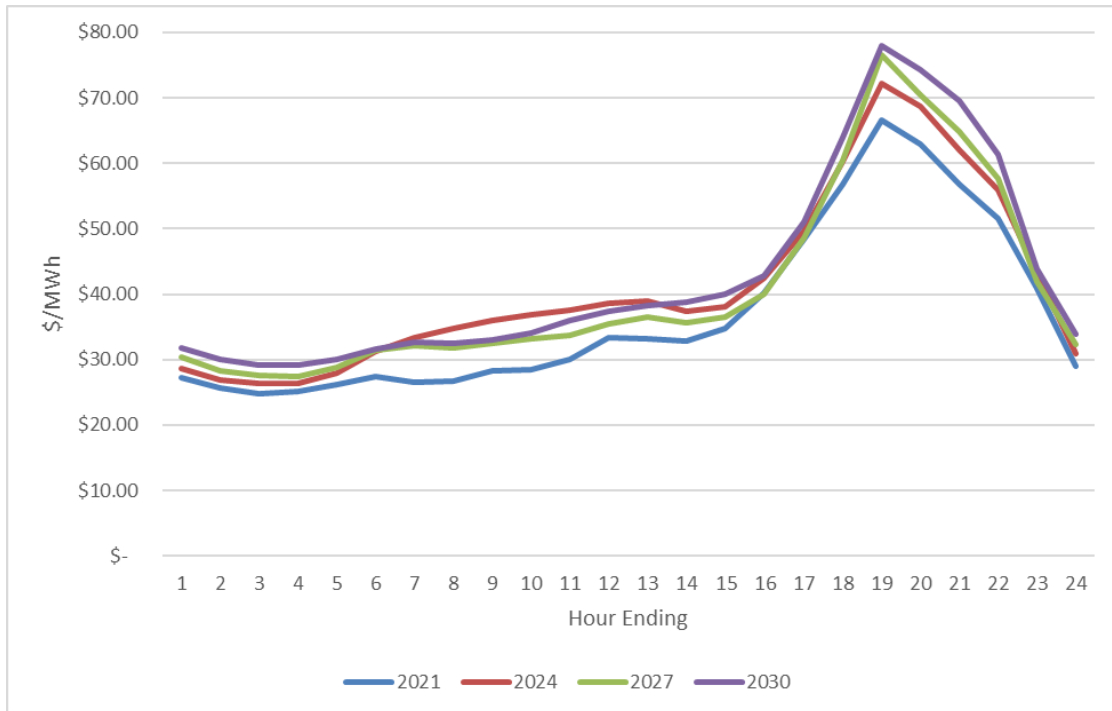
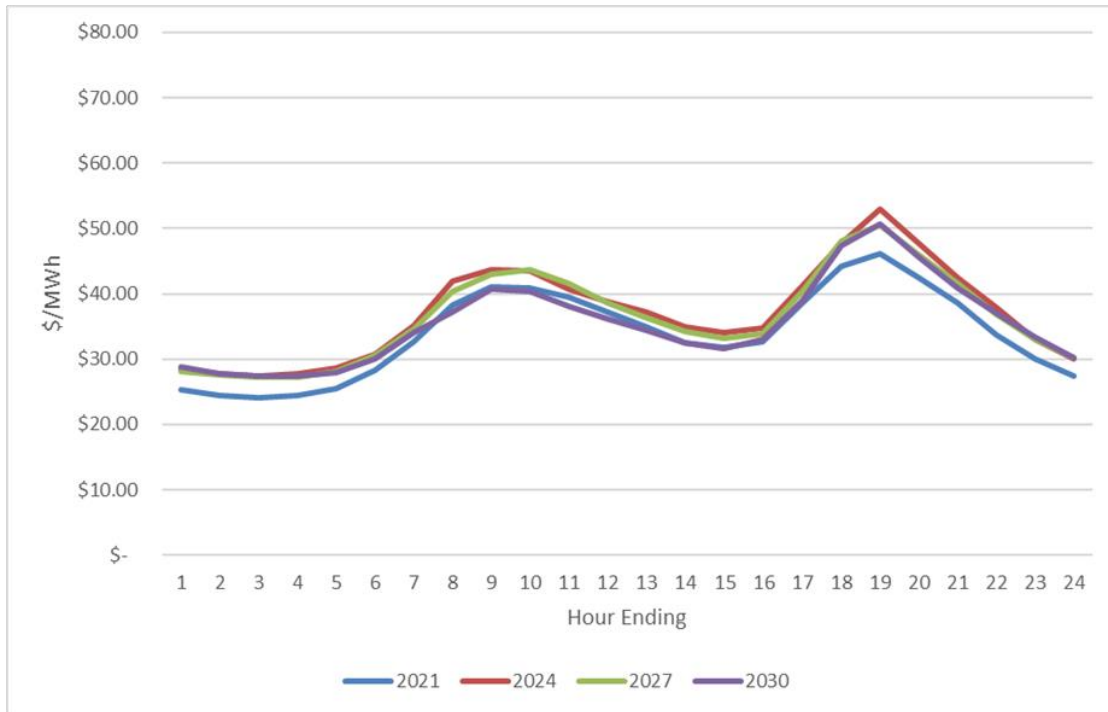


Figure 81: Mid-C Average Hourly Price Profile for December 2021, 2024, 2027 and 2030



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 82 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 82: Forecasted Resource Additions under the Low Load Growth Scenario

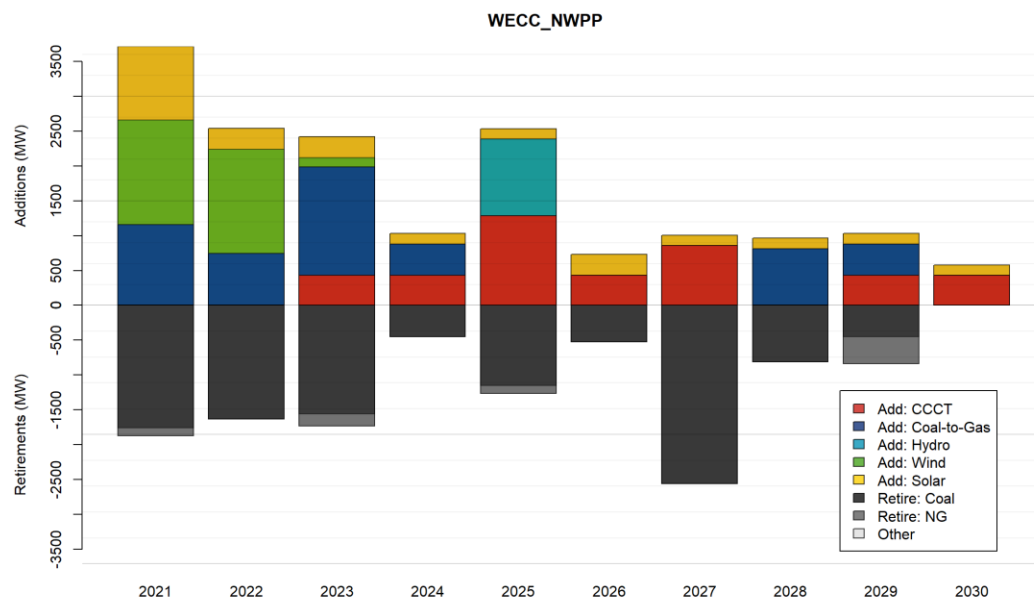
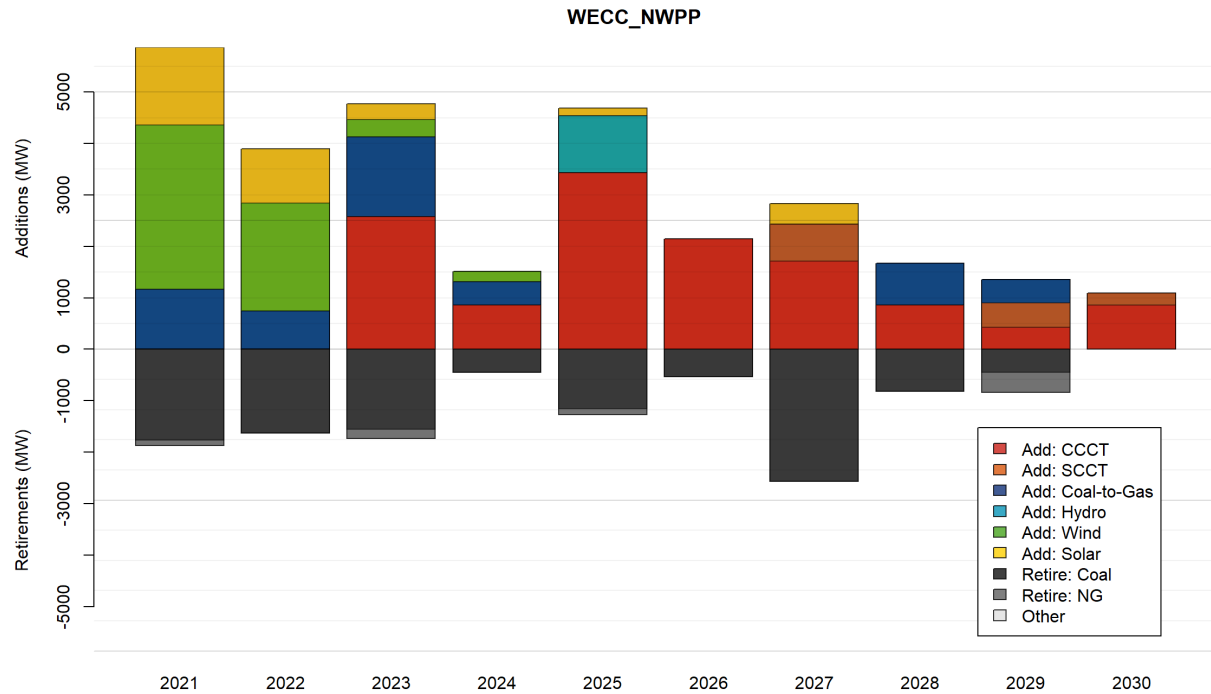


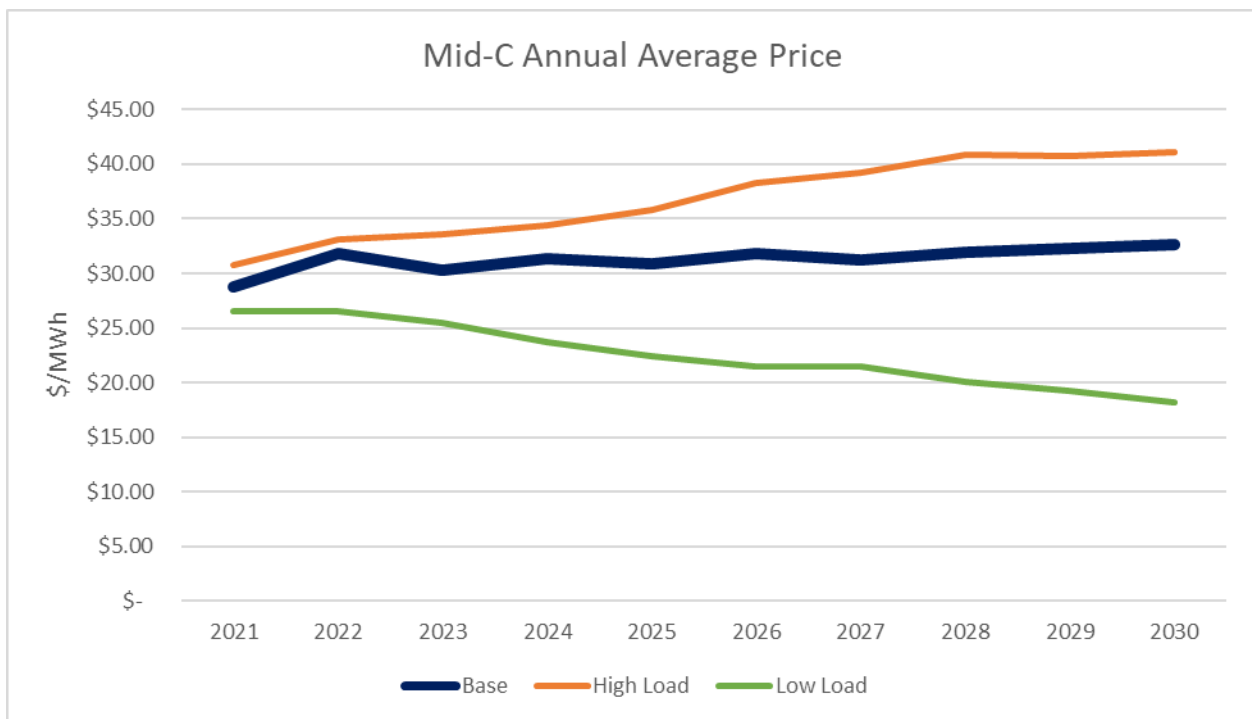
Figure 83 below is the projected resource additions in the Northwest through time for the High Load Growth scenario. Note that there are significant CCGT additions in the back half of the study period to meet the higher load, and a total of 6,000 MW more natural gas generation in the region compared 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 83: Forecasted Resource Additions under the High Load Growth Scenario



The effects on power prices are illustrated below in Figure 84. 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 84: 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.

Portfolio Selection

The portfolios selected for analysis in this IRP were structured to accomplish different goals according to meeting the District's energy, capacity and RPS needs. The District's needs assessment is summarized below:

Energy - Under the medium load forecast and critical hydro scenario, the District has sufficient resources to meet average annual energy needs until after its existing capacity contract expires in 2025 and then the deficit is about 10-15 aMW. In average water conditions the District has sufficient resources on an average annual basis to meet energy needs through the end of the study period. For additional details, refer to Chapter 3: Existing Resources and the following figures:

- Figure 13: Annual Average Load and Existing Resources in Critical Water Conditions
- Figure 14: Annual Average Load and Existing Resources in Average Water Conditions

Capacity – After the Frederickson contract expires in 2022 and its existing capacity contract expires in 2025, the District's seasonal peak capacity deficits are about 100 MW in summer and 75 MW in winter. For additional details, refer to Chapter 7: Capacity Requirements, Energy Storage and Demand Response and the following figures:

- Figure 42: Annual Peak Load and Existing Resources in Summer
- Figure 43: Annual Peak Load and Existing Resources in Winter
- Figure 44: Monthly HLH Average Planning Net Position Using Historical P99 HLH Load

Renewable Portfolio – The District has sufficient resources to meet its forecasted RPS requirement through the end of 2024. That surplus turns into a deficit beginning in 2025 and increasing to about 30 aMW by 2030. For additional details, refer to text of Chapter 3: Existing Resources and the following figure:

- Figure 15: Renewable Portfolio Requirement and Existing Resources

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

The portfolios examined in this IRP are described in the list below and in Figure 85.

- 1. Keep the status quo
 - Rely on the market to cover energy, capacity, and RPS deficits
- 2. Acquire 75/25 MW summer/winter physical call option starting in 2026/2025
 - Call option allows the District to better manage summer and winter capacity needs
 - RPS requirements would be met through market purchases
- 3. Acquire 25 MW solar + storage in 2025 and a 50/25 MW summer/winter physical call option in 2026/2025
 - Call option allows the District to better manage summer/winter capacity needs
 - The solar + storage component would help the District meet a portion of its RPS requirements with the remainder being met through market purchases
- 4. Acquire 50 MW reciprocating engine (“recip”) and a 25 MW physical call option in summer 2026
 - The recip would help replace the current physical call option once it expires
 - Call option allows the District to better manage summer capacity needs
- 5. Acquire 25 MW solar in 2025 and 50/25 MW summer/winter physical call option in 2026/2025
 - Call option allows the District to better manage summer/winter capacity needs
 - The solar component would help the District meet a portion of its RPS requirements with the remainder being met through market purchases
- 6. Acquire 25 MW solar + storage in 2025, a 25 MW recip in 2026, and a 25 MW physical call option in summer 2026.
 - The last portfolio we reviewed was a combination of portfolios 1, 3, and 4
 - Call option allows the District to better manage summer capacity needs
 - The recip would help replace a portion of the current physical call option once it expires
 - The solar + storage component would help the District meet a portion of its RPS requirements with the remainder being met through market purchases

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 a wind resource, which is an intermittent and non-dispatchable resource and therefore cannot be counted on during the District's summer and winter peak load events. Furthermore, a wind resource would provide energy at times of the year, like springtime, when the District is already in a surplus position and does not require any additional energy.

Another example not considered in the analysis 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

Portfolio	>	P1	P2	P3	P4	P5	P6
Energy Source	>	Market	Call Option	Solar + Storage & Call Option	Recip + Summer Call Option	Solar + Call Option	Solar+Storage, Recip, & Summer Call Option
REC Source	>	Market	Market	Solar + Storage	Market	Solar	Market
Strategy	>	Utilize wholesale market purchases for all capacity needs during the summer; market for RPS needs	Acquire physical call options of 75 MW/25 MW summer/winter to help meet capacity needs; market for RPS needs	Acquire solar + storage and physical call options of 50 MW/25 MW summer/winter to help meet capacity needs; market for RPS needs	Acquire recip and a 25 MW summer physical call option to help meet capacity needs during summer events; market for RPS needs	Acquire solar and physical call options of 50 MW/25 MW summer/winter to help meet capacity needs;market for RPS needs	Acquire solar + storage, a recip, and a 25 MW summer physical call option to help meet capacity needs during summer events; market for RPS needs

Year	Energy net Position			New Generation Capacity Installed									
	(aMW)	REC Net Position (aMW)	Summer Capacity Position P99 aHLH)	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource	Energy Resource	Renewable Resource
2021	42	2	-49	0	0	0	0	0	0	0	0	0	0
2022	26	1	-50	0	0	0	0	0	0	0	0	0	0
2023	3	1	-25	0	0	0	0	0	0	0	0	0	0
2024	2	1	-26	0	0	0	0	0	0	0	0	0	0
2025	1	-3	-27	0	0	25	0	50	25	0	0	50	25
2026	-10	-11	-102	0	0	75	0	75	25	75	0	75	25
2027	-10	-12	-103	0	0	75	0	75	25	75	0	75	25
2028	-13	-14	-103	0	0	75	0	75	25	75	0	75	25
2029	-14	-24	-104	0	0	75	0	75	25	75	0	75	25
2030	-16	-30	-105	0	0	75	0	75	25	75	0	75	25

Financial Risk Analysis

The portfolios were input into the long-term financial model and which simulated the stochastic variables discussed in Chapter 8: Market Simulation. Outputs were entered in the financial model to produce a range of financial outcomes. The simulation subjected each portfolio to the 80 unique power price scenarios, along with the corresponding 80 scenarios of natural gas prices, regional hydro, and regional renewable generation.

Figure 86 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 86: Risk Drivers

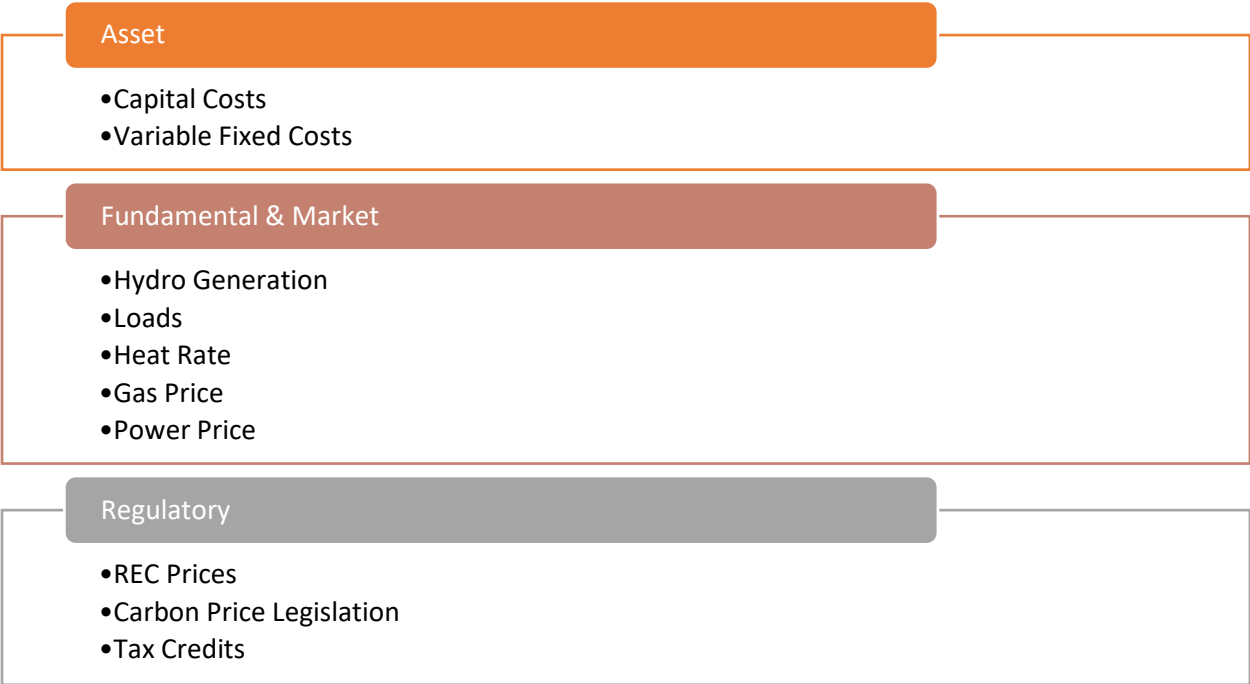
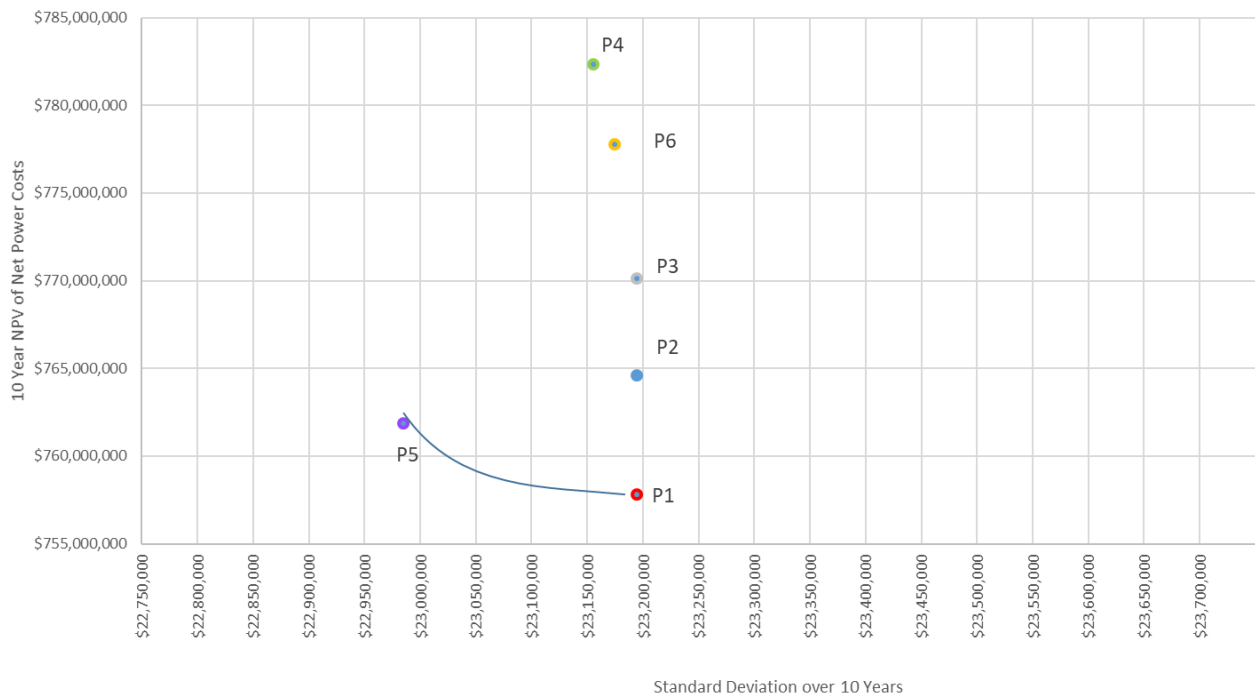


Figure 87 is a plot of each portfolio's 10-year NPV net power cost on the y-axis vs. the standard deviation on the x-axis. Portfolio evaluation involves assessing cost vs. risk. The ideal portfolios can be isolated by fitting a hyperbola, known as the efficient frontier, through the points. Portfolios situated along the efficient frontier, represent the tradeoff between cost and risk. The ideal portfolio would have a low cost and low risk, but that is generally not achieved as there is usually a compromise between cost and risk. It is the District's opportunity to determine the best fit for the utility: lower expected cost with more risk or higher expected cost with less risk (Portfolio 1 vs. Portfolio 5).

Figure 87: Efficient Frontier and Preferred Portfolios



At first glance, the portfolio with the lowest risk is Portfolio 5, combining a capacity option with solar, though the risk profile amongst all of the portfolios examined are within about 1 percent of each other. The simulation also projected Portfolio 1, the all-market portfolio, as the least cost option. Again, the cost differences over a 10-year study period are relatively small, with all the portfolios falling within 3 percent of each other. Since the cost and risk profiles of the portfolios studied are all quantitatively similar, the District is comfortable with considering portfolios that may not lie on the efficient frontier.

Though the quantitative analysis was a result of several models that were created through a rigorous development process, these were not without their limitations. The primary limitation of the simulation results was that it was modeled on a monthly granularity, which means it is unable to evaluate the daily or hourly risk associated with peak load events. Aside from the quantitative results, the District also included qualitative analysis in its selection process. Second, the model also assumed unlimited market depth such that energy would always be available for purchase. While rare, the market can and has run out of energy to purchase in the past. And third, a point of emphasis was the dispatchability of a resource, namely its ability to generate electricity when it is needed most.

A solar-based portfolio (Portfolio 5) would be insufficient because of its intermittent nature. Summer hourly peaks typically occur in the early evening, when solar production is winding down. And winter hourly peaks occur both early in the morning and in the early evening, when solar production is low to begin with. A storage asset (Portfolio 3) could alleviate the dispatchability concern, however, there is the question as to whether battery would be unable to store enough energy to sustain the District's needs through the duration of a peak load event. Most storage systems discharge over a four-hour period, and it was decided that is insufficient to carry the District through the entire peak event.

The impetus behind the resource adequacy discussion is due to dwindling amount of available capacity to serve the region's load during a peak load event. The District will therefore not rely entirely on the market (Portfolio 1) to serve its peak loads. It became clear from the results of the risk simulation that the cost to dispatch new build fossil-fuel based generators (Portfolios 4 and 6) would be prohibitively expensive when including the societal cost of carbon in the analysis.

Preferred Portfolio

The District's preferred portfolio combines purchasing a capacity call option to reduce its reliance on the market during peak load events, while maintaining the District's flexibility (Portfolio 2). With CETA rulemaking ongoing, a wait-and-see approach to the final rulemaking was decided upon before committing to acquiring any physical assets. The District will continue to utilize market purchases to meet its average energy needs. The District also forecasts REC shortfalls within the study period. The REC market is expected to possess sufficient market depth to cover the District's REC needs through the study period. Financial risks will continue to be managed through the District's hedging program.

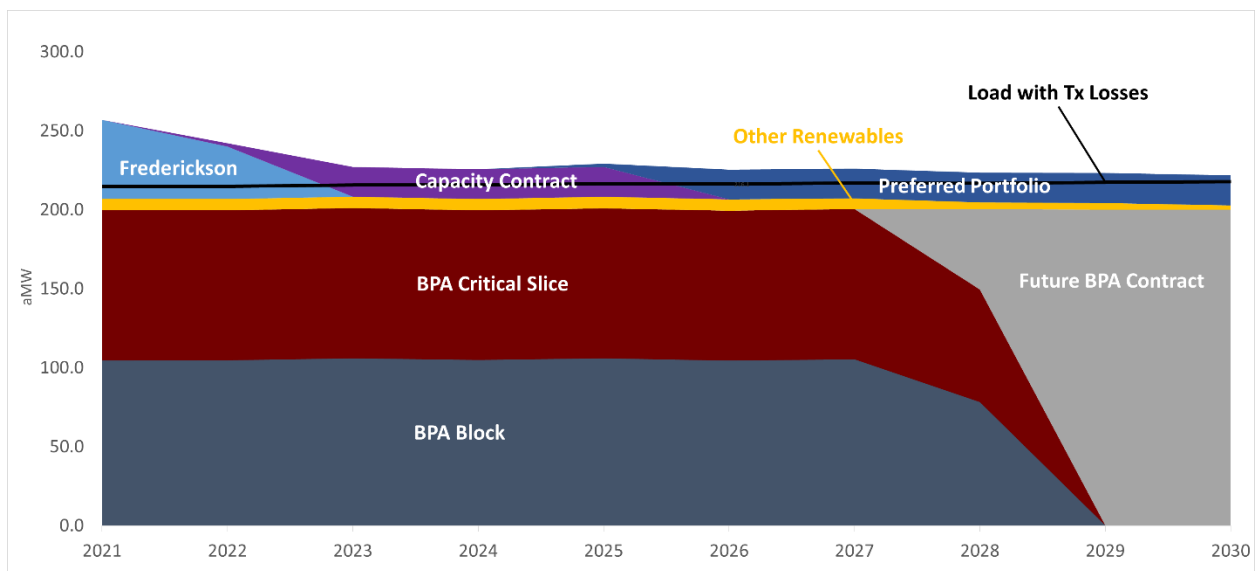
To summarize:

1. Gas prices remain in a persistent low price scenario. Additionally, regional load growth is in flux due to the global COVID-19 pandemic, the outcomes of which are yet to be determined. Inflation-adjusted power prices are expected to continue to remain as the lowest cost resource for the foreseeable future.
2. In addition to using the market for standard forward, daily, and hourly market purchases the District is planning to purchase physical capacity with existing assets in the market beginning 2025, after its existing capacity contracts expire. 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.
3. The full impact from CETA will remain unknown until rulemaking is finalized. With market purchases, the District maintains a high level of flexibility. Paradigm shifts, whether technological or political, can happen unexpectedly, thus flexibility is key.
4. The variability of Portfolio 2, 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 range of outcomes and thus narrows the range of cost variability.
5. Washington REC prices remained low through the first and second compliance periods from 2012-2018 despite RPS requirements increasing from 3% to 9% and have continued to be low with recent procurements to meet the 15% requirement. The continued build out of renewable generation may result in REC prices remaining low for the foreseeable future; however, it is difficult to forecast REC prices especially given the new carbon free resource requirements under CETA and the need for utilities to retain RECs for compliance.
6. The District will continue to monitor market conditions; any dramatic shift in the market may compel the District to revisit its preferred portfolio.

Energy and Capacity Strategy

Figure 88 below is the impact of Portfolio 2 on the District's net energy position. The district plans on conducting a Request for Proposal (RFP) to obtain a physical capacity call option of 75 MW in the summer and at least 25 MW in the winter. Additionally, the District will continue its practice of utilizing shorter-term power purchases and other instruments to provide additional capacity and financial protection where needed. 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 88: Preferred Resource Plan, Energy Position in Critical Water Conditions



The preferred plan is expected to cover a portion of the District’s seasonal capacity shortfalls as shown below for summer (Figure 89) and winter (Figure 90) peak events.

Figure 89: Preferred Resource Plan, Capacity Position in Summer

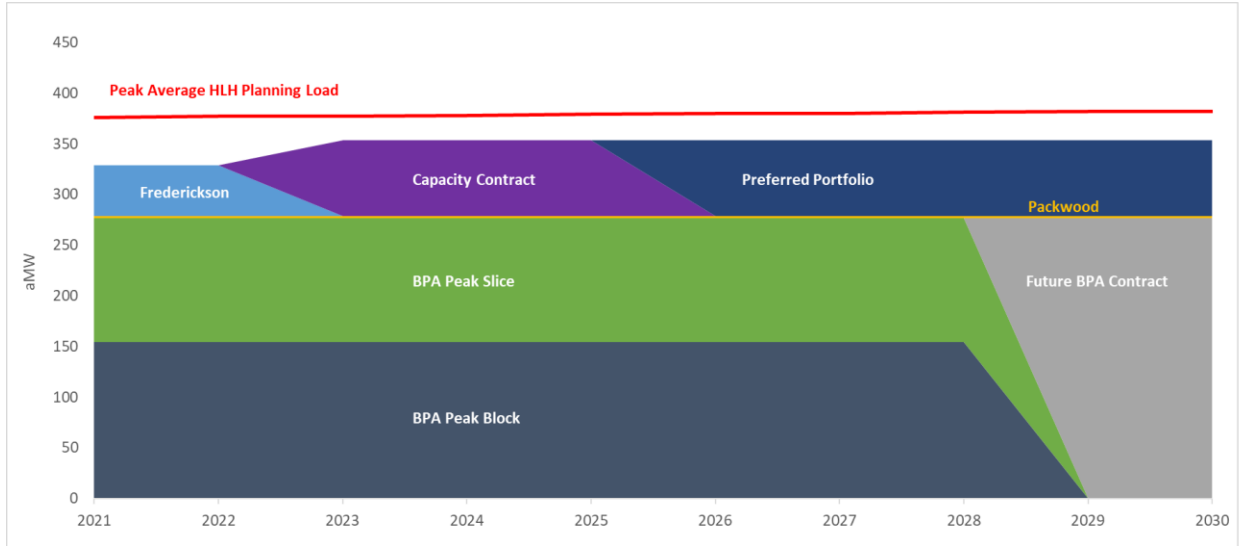
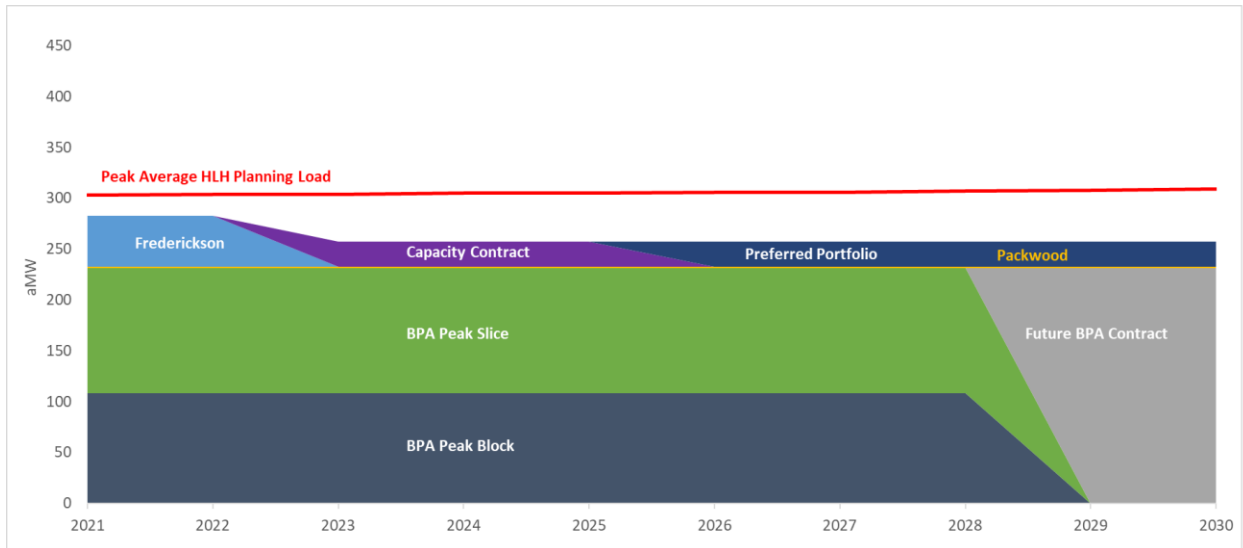


Figure 90: Preferred Resource Plan, Capacity Position in Winter

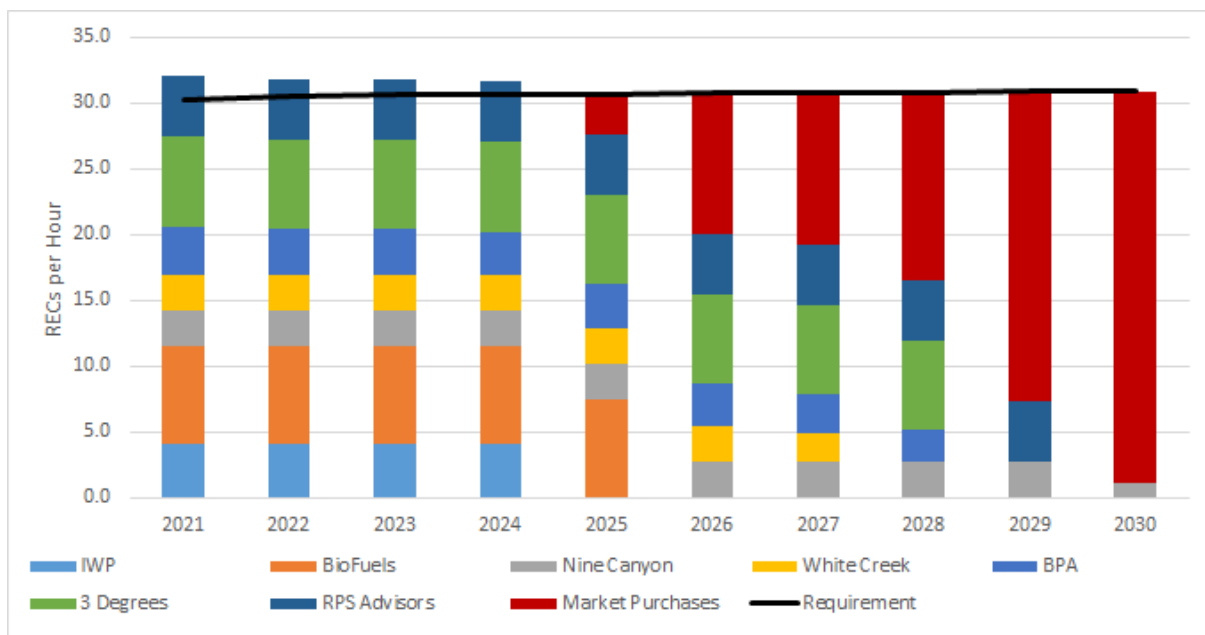


Renewable Portfolio Strategy

The District may fulfill its Renewable Portfolio Standard (RPS) requirements with a renewable resource acquisition or by purchasing only the renewable energy credits (RECs). 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 theoretically also augments the District's energy supply, which is helpful during the summer months when the District must 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, early in the evening on a hot or cold day. 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 the residual of the levelized cost of a new resource less the value of the brown power. With increasing REC requirements, the demand and cost of RECs should increase through time provided the market supply driven by new construction does not exceed the demand for RECs.

Figure 91 shows the District's preferred resource plan to meet its RPS requirements.

Figure 91: RPS Position - Preferred Portfolio



Chapter 10: Action Plan Summary

Integrated Resource Plan Actions

The District's Integrated Resource Plan (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 Renewable Portfolio Standard (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. Issue a Request for Proposal (RFP) before the end of 2020 for seasonal capacity products to cover 75 MW of summer (July/August) capacity deficits and at least 25 MW of winter (December/January/February) capacity deficits for the term of December 2025 through August 2028. These are the same values used in a District RFP used to secure capacity for December 2022 through August 2025. RFP will include product definitions to meet the expected future Northwest Power Pool (NWPP) Resource Adequacy (RA) program requirements. Capacity purchases resulting from this RFP process are expected to cover a portion of the District's possible seasonal energy shortfalls based on historical data and the probability of similar future outcomes.
 - a. The District has significant seasonal capacity deficits that cannot be reliably addressed with renewable energy resources such as wind and solar due to the intermittent nature of these technologies, specifically during long duration summer heat and winter cold events that often occur within our service territory. Battery technology is not expected to be economic or operationally proven as a way to mitigate wind and solar intermittency through 2028 which is a key District planning milestone aligned with the beginning of the new Bonneville Power Administration contract term.
 - b. Regional generation resource adequacy is projected to continue to decline over the initial planning horizon due to the early retirement of coal-fired resources and the lack of firm plans by utilities to build new dispatchable capacity. The Northwest Power and Conservation Council projects the loss of load probability (LOLP) could increase to 26% by 2026 which is well above the 5% threshold used as a regional standard for adequacy.
 - c. The adoption of the Clean Energy Transformation Act (CETA) law in 2019 requires the elimination of coal-fired resources to serve retail load in Washington state and includes regulatory hurdles established to disincentivize new natural gas fired resources from being built in the region. The District believes the anti-fossil fuel bias of CETA will increase the demand for existing dispatchable capacity which is limited and already included in the LOLP calculations which show the region is short.
 - d. A limited number of independent power producers (IPP) with dispatchable capacity are available in the region which the District believes will be in high demand as utilities try and firm up their share of the capacity void left by coal-plant retirements

while also meeting new regional resource adequacy standards being developed by the NWPP.

2. Engage in the NWPP resource adequacy standard development and implementation processes with the intent of participating in the voluntary program. Procure additional capacity when needed to meet the District's compliance with the RA program's seasonal forward showing requirements, which is expected to include a planning reserve margin.
3. Seasonal energy deficits above the 75MW/25MW summer/winter capacity procurements identified previously (plus additional capacity subsequently acquired to meet NWPP RA standards) will be met through short-term wholesale market purchases hedged by financial products acquired in a 3-year purchase/sale window through the District's existing Risk Management Committee (RMC) process.
4. Implement all cost-effective conservation consistent with the requirements and any future amendments of the Energy Independence Act.
 - a. The most recent Conservation Potential Assessment (CPA) adopted by the Commission in September 2019 includes 11.62 aMW of cost-effective conservation over 10 years.
 - b. Targets in subsequent CPAs, conducted every two years, will continue to evolve as inputs change over time.
5. RPS requirements will be met by executing new Renewable Energy Credit (REC) purchase contracts as existing REC purchase contracts begin to expire in 2024.
6. Complete resource/market related analyses and studies to enhance the 2022 IRP process, inputs, and resource acquisition evaluations including the following:
 - a. 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.
 - 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 8/31/2021.
 - c. 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.
 - d. The District will monitor BPA's FY2022/2023 rate period high water mark process, analyze the impact of reduced BPA generation due to the change in hydro operations as outlined in the preferred portfolio identified in the Columbia River System Operations Final Environmental Impact Statement, and incorporate the results of the analysis into future power supply planning including the District's 2022 IRP update
 - e. Prepare a study about post-2028 BPA product offering in 2021 as additional information is available.
 - i. Evaluate scenarios of BPA supply of energy, capacity, and non-emitting attributes.
 - ii. Include various changes in the BPA resource, BPA augmentation, and regional loads placing Net Requirements on BPA.
 - f. If significant new industrial load (greater than 10 MW) commits to the District's service territory or the District experiences a sudden increase in commercial and

- light industrial load (greater than 5 aMW), prepare a report that analyzes the impacts on energy purchases and transmission infrastructure.
- g. Monitor the cost and availability of regional developments of pumped hydro storage, solar plus storage, and standalone battery storage
 - h. 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. The District is concerned EDAM could reduce market liquidity for bi-lateral transactions in northwest wholesale electricity markets
 - i. The District will continue to monitor the regulatory environment and modify its resource strategy as necessary, including reviewing PURPA regulation changes and closely monitoring CETA rulemaking for impacts to this action plan.
 - j. 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 REC s may require changes to the District's plan.
 - k. The District will assess the 2021 White Creek Wind purchase option.

Clean Energy Action Plan

The District will continue to take steps to ensure compliance with CETA requirements outlined in RCW 19.405.030 through 19.405.050 consistent with prudent utility planning practices. As required under RCW 19.280.030, the following is the District's Clean Energy Action Plan including the actions that will be taken to meet the CETA requirements.

1. RCW 19.405.030 – Elimination of coal-fired resources by 12/31/2025
 - a. The District will continue its practice of making market purchases to meet its day ahead and real-time power needs. These transactions are unspecified resource purchases, which could include coal-fired resources; however, per the definition of coal-fired resource in RCW 19.405.020, these transactions are exempt from the requirement because they are a limited duration wholesale power purchase that does not exceed one month. The District will ensure any longer duration wholesale power purchase transactions do not include coal-fired resources by either having these transactions be specified source purchases or develop another means within the rules of the statute to determine the source of the purchase does not contain coal-fired resources.
2. RCW 19.405.040 – Greenhouse gas neutral by 1/1/2030 (first compliance period 2030-2033)
 - a. The District will continue to monitor the CETA rulemaking process for this section and develop a plan to comply with those rules once adopted.
 - b. Assuming the District's BPA contract renewal in 2028 is similarly structured as its existing BPA contract, the District will have sufficient electricity from renewable resources and non-emitting electric generation to meet, and exceed, the 80% portion of the requirement.
 - c. The District will procure RECs to address the remaining need to comply with the 20% portion of the requirement, which will also satisfy its Energy Independence Act renewable requirement per RCW 19.285.040.
 - d. Future evaluations of the District's energy/capacity needs and associated potential resource acquisition in future integrated resource plans will consider this requirement.
3. RCW 19.405.050 – 100% carbon free by 1/1/2045
 - a. Continue to monitor carbon free resource development and new technology (energy storage, small modular reactors (SMR), etc.) that may assist in meeting this requirement. Meeting the District's capacity needs with renewable resources and non-emitting generation is anticipated to be challenging during peak winter and summer events with existing technology; however, the District will assess the need to contract for a baseload non-emitting resource, such as SMRs, in excess of its energy needs in order to meet its capacity needs.
 - b. The District plans to explore developing a demand response potential assessment to better understand what cost-effective demand response could be deployed in our service territory that would contribute toward meeting our peak capacity needs.

- c. Future evaluations of the District's energy/capacity needs and associated potential resource acquisition in future integrated resource plans will consider this requirement.

Appendix A: Ten Year Load & Customer Forecast

Copy available on District's website:

<https://www.bentonpud.org/About/Planning-Performance/Integrated-Resources-Plan>

Appendix B: 2019 Conservation Potential Assessment

Copy available on District's website:

<https://www.bentonpud.org/About/Planning-Performance/Integrated-Resources-Plan>