2018 Integrated Resource Plan

Public Utility District No. 1 of Benton County

PREPARED IN COLLABORATION WITH

Resolution No. 2468

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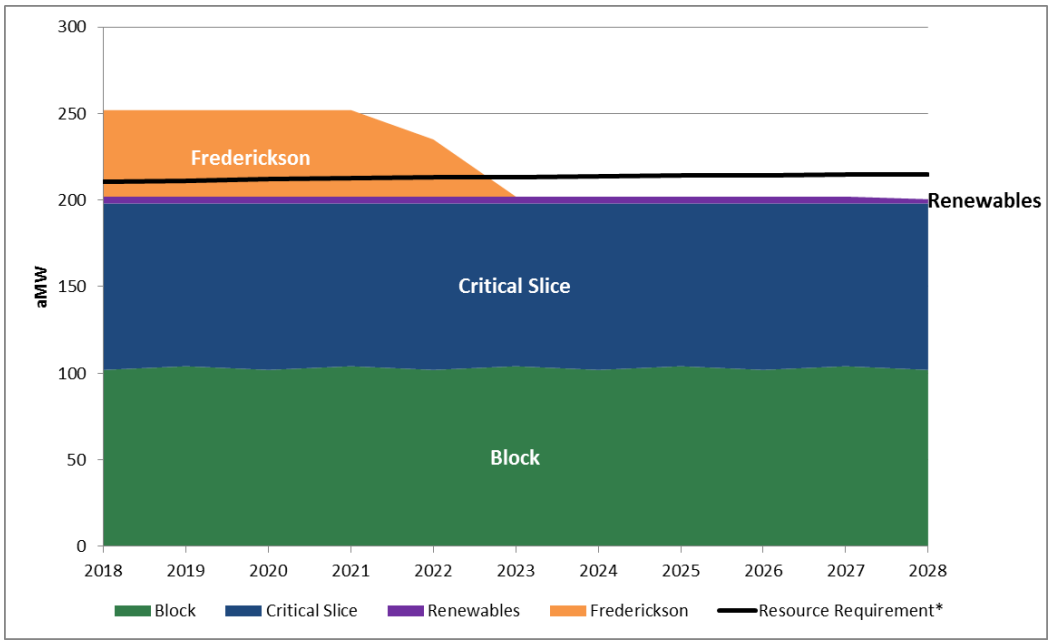
Chapter 1: Executive Summary

Benton PUD's (the District) 2018 Integrated Resource Plan (IRP) lays out a strategy for meeting its energy needs, capacity demand, and Washington State renewable portfolio standard (RPS) obligations over a 20 year planning horizon from 2019 through 2028. The goal of this IRP is to provide a framework for evaluating a wide array of supply resources, conservation, and renewable energy credits (REC). The IRP provides guidance towards strategies that will provide reliable, low cost electricity to the District's ratepayers at a reasonable level of risk.

Obligations and Resources

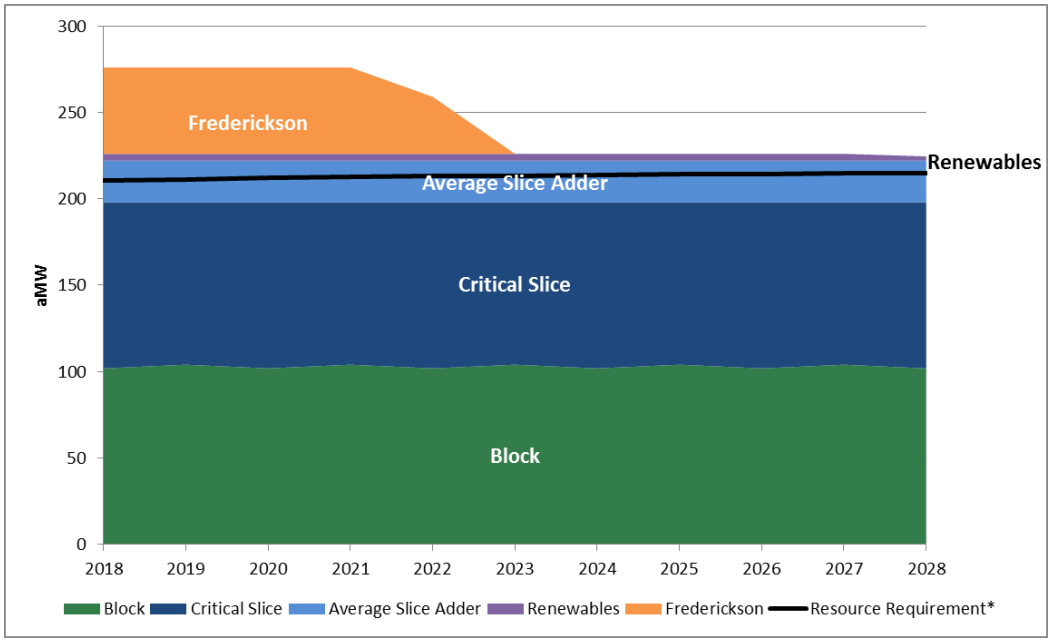
The majority of the District's wholesale electricity is supplied by the Bonneville Power Administration (BPA) under the "Slice of the system"/ Block contract, represented by the "Slice" and "Block" fields in the chart below. The Frederickson 1 Generating Station Combined Cycle Combustion Turbine also represents a sizable portion of the District's supply side resources. For planning purposes, each year represented is at critical hydro conditions – i.e. the lowest year on record at the time "critical" was defined, and assumes that Frederickson is always available for power generation. Critical hydro conditions represent a conservative supply scenario; the vast majority of the time, the District will have more generation than what is shown in the charts below. Planning to this level ensures adequate supply to meet demand. Benton PUD under critical hydro conditions is expected to supply enough energy to remain in load/resource balance on an average annual basis through August 2022, when the current Frederickson power purchase agreement expires (**Figure 1**).

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



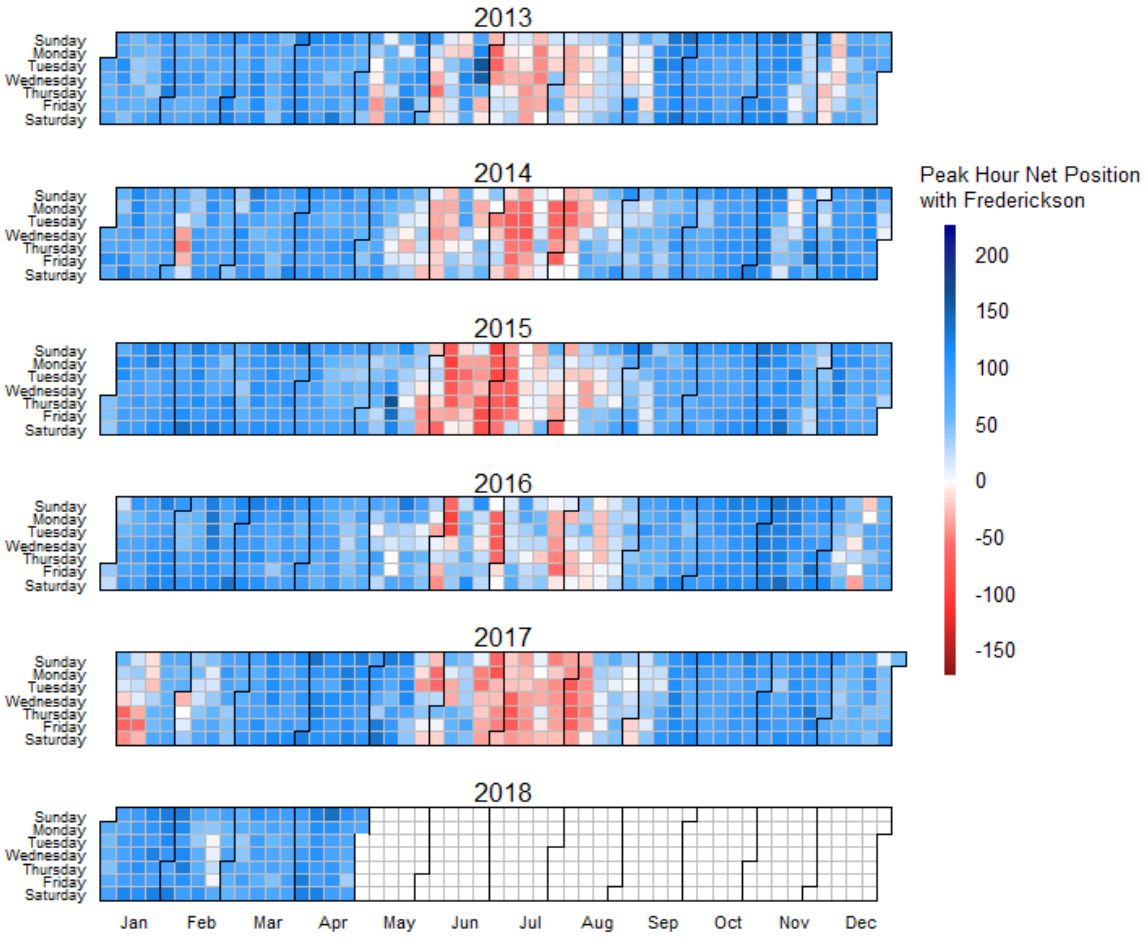
Most years, Slice generation will be greater than critical. **Figure 2** displays generation from the 80 year average hydro conditions showing the District is expected to supply enough energy to remain in load/resource balance on an average annual basis through August 2028.

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



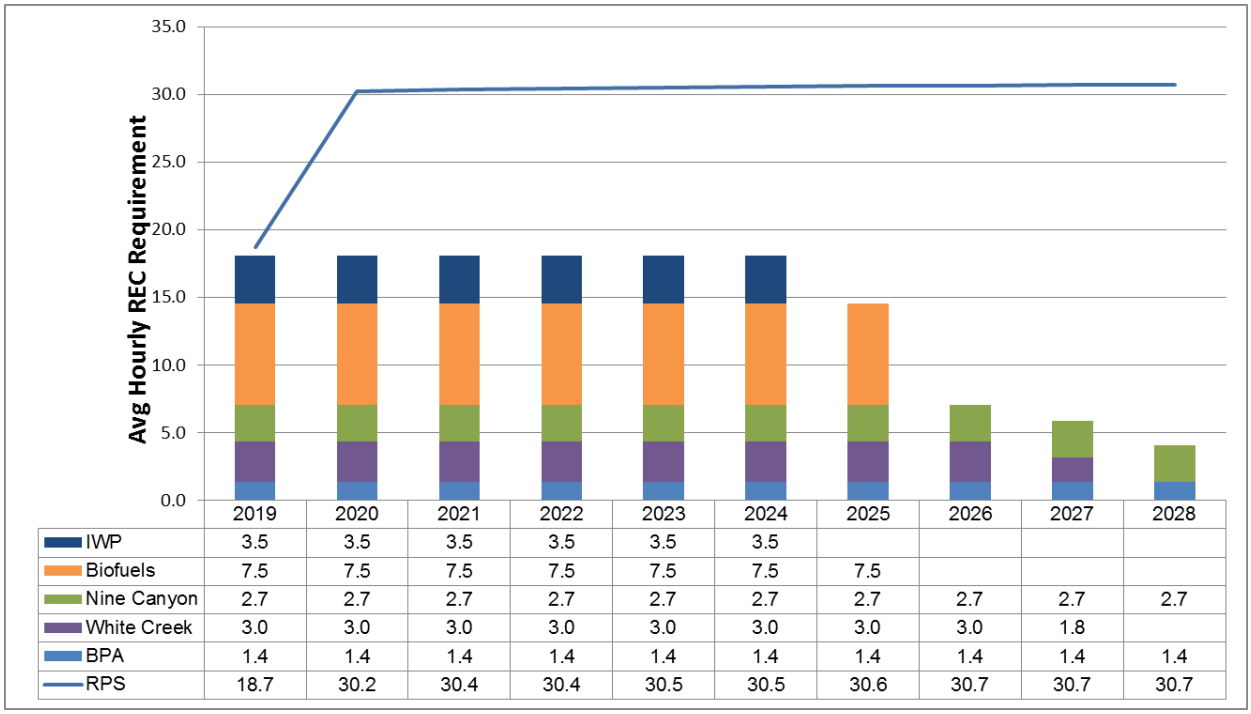
While the District has sufficient supply side resources to meet its annual average load obligations, there are certain times during the year when the fluctuations in hourly loads exceed the District's generating capacity. Maximum power demand usually occurs in the late afternoon/early evening during the summer when air conditioning and irrigation loads are at its highest. The District does not currently have the capacity to serve its load during these peak periods and relies on the wholesale market to make up the deficit. **Figure 3** below compares the daily peak demand to District contracted resources from 2013 to 2017 where surpluses are shown in blue and deficits are shown in red. The District sells into the regional energy market when it has a surplus and generally purchases from the regional energy market based on analysis and recommendations made by staff from The Energy Authority (TEA).

Figure 3: Daily Peak Demand Net Position by month



The District continues to closely monitor its load growth and evaluate supply side resource options leading up to 2020 as the Washington State Energy Independence Act renewable requirement ramps up from 9% to 15%. **Figure 4** displays the District's requirements under the Washington State Renewable Portfolio Standard (RPS). The black line represents Benton PUD's volume requirement under the law. Orange, blue, green, and purple represent existing Renewable Energy Credit (REC) contracts. The District has enough RECs based on current forecasts to comply through 2019. However, the District will need to acquire additional RECs in 2019 to maintain its RPS compliance.

Figure 4: Annual RPS Load/Resource Balance from 2019-2028

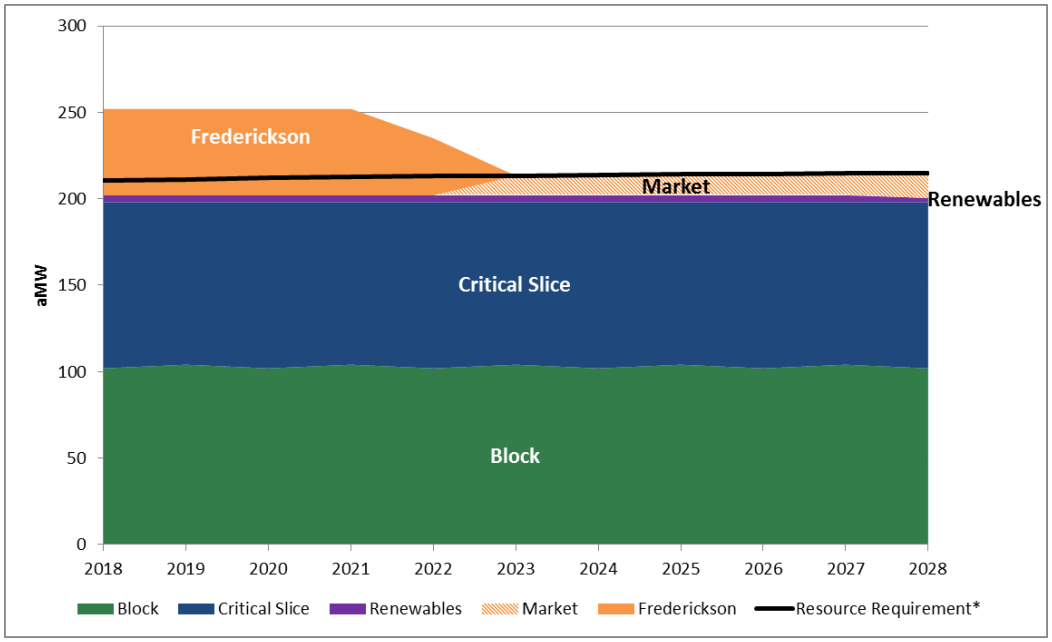


	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
IWP	3.5	3.5	3.5	3.5	3.5	3.5				
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5			
Nine Canyon	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
White Creek	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	1.8	
BPA	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
RPS	18.7	30.2	30.4	30.4	30.5	30.5	30.6	30.7	30.7	30.7

Preferred Portfolio

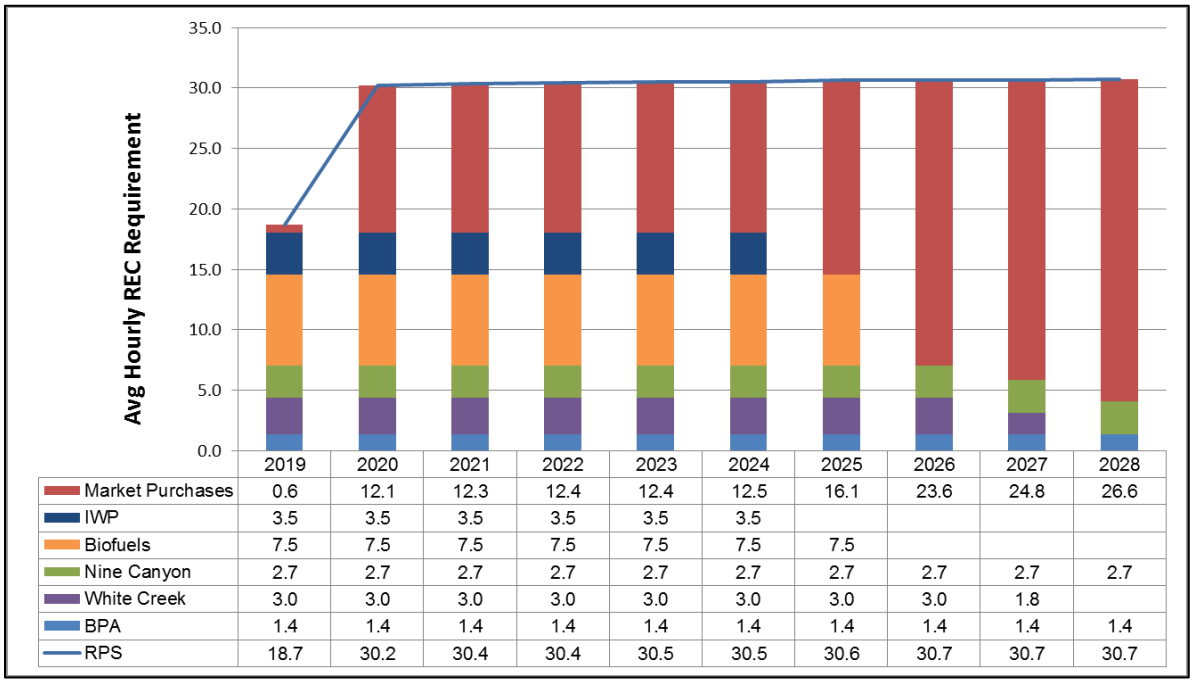
The District's preferred resource portfolio is illustrated in **Figure 5**. The current analysis concludes that the portfolio that will produce the lowest cost and risk (due to District hedging practice) consists of relying on the market to meet any future energy, capacity and REC deficits. Energy and RECs in the shorter term are projected to remain below the cost of acquiring a new resource. The energy deficits will be filled with short to medium term market purchases that allow the District to evaluate the relative risk associated with seasonal deficits without the additional burden associated with carrying costs of resources surplus to actual supply needs. Leaning on the market is currently the lowest cost and lowest risk (after applying District hedging practice to mitigate cost volatility) option for the District, but IRP staff will continue to systematically evaluate market conditions, emerging technologies, and resource availability. In particular, the next IRP will focus on the financial impact of capacity shortages that emerge after the expiration of the Frederickson Power Purchase Agreement (PPA).

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



The District's preferred resource plan to meet its REC requirements is listed below in **Figure 6**. Like energy and capacity, 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 6: Preferred Resource Plan REC Position

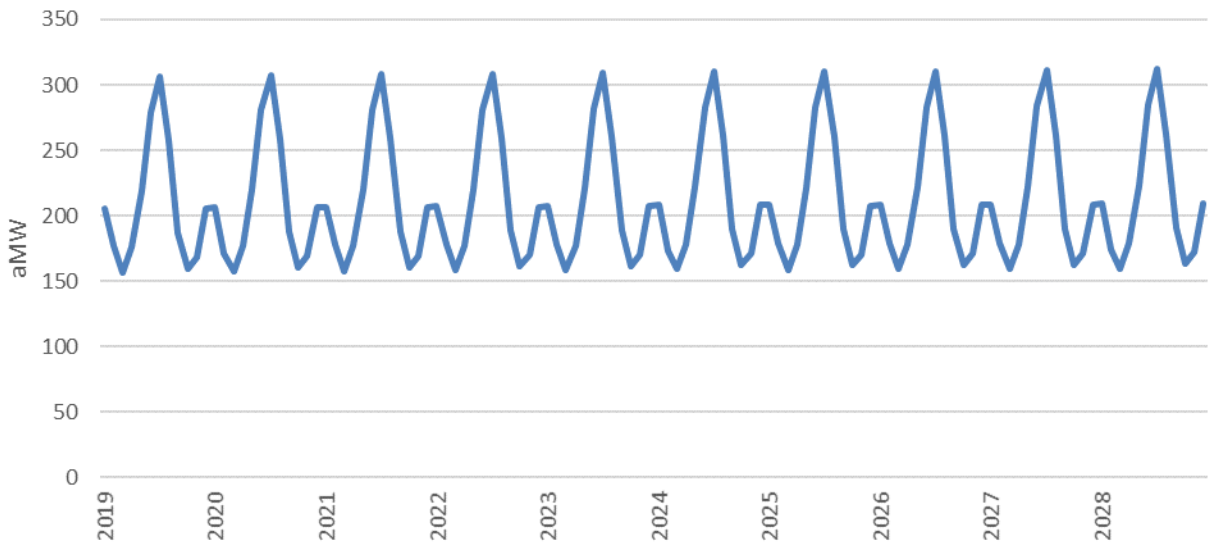


	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Market Purchases	0.6	12.1	12.3	12.4	12.4	12.5	16.1	23.6	24.8	26.6
IWP	3.5	3.5	3.5	3.5	3.5	3.5				
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5			
Nine Canyon	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
White Creek	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	1.8	
BPA	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
RPS	18.7	30.2	30.4	30.4	30.5	30.5	30.6	30.7	30.7	30.7

Chapter 2: Load Forecast

The 2018 ten year load and customer forecast base case scenario projects an average annual rate of growth (AARG) of 0.21%, a decrease from the 2016 forecast which expected a 0.41% AARG. The most recent ten-year load and customer forecast was adopted by the District in April 2018 (**Figure 7**).

Figure 7: 2019-2028 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 5 megawatts (aMW) over the 2018 load of 207.5 aMW at the Bonneville Power Administration (BPA) Points of Delivery (POD). The ten-year low, medium and high load and customer forecasts are each stand-alone forecasts 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. See **Appendix A: Ten Year Load & Customer Forecast** for more detail.

Chapter 3: Current Resources

The District sources its power requirements through purchases from BPA as well as from several non-federal sources of power. This section provides an overview of the District's existing resource portfolio and concludes with a description of the projected resource deficit beginning in August 2022 that will need to be filled from non-BPA sources of power.

Benton PUD's generation mix is made up of hydroelectric, wind, gas, and nuclear generation resources. In addition to this physical generation, Benton makes physical and financial purchases of power from the open market to help meet its load obligations. The hydroelectric resources, in descending order of electricity generation capacity, include a share of the Federal Columbia River Power System (FCRPS) through the Slice/Block product and the Packwood Hydroelectric Project. Wind resources include the White Creek and Nine Canyon projects. Benton PUD also receives a share of the output from the Columbia Generation Station nuclear reactor (part of the Slice contract) and Frederickson combined-cycle natural gas fired plant. Bonneville Power Administration (BPA) is the marketer and distributer of power generation provided by the 31 dams of the FCRPS and Columbia Generation Station.

Overview of Existing Long-term Purchased Power Agreements

Frederickson 1 Generating Station

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. Frederickson is an annual, diurnally shaped, source of power for the District.

Nine Canyon Wind

The District entered into a Nine Canyon Wind Project PPA 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 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 (2aMW of energy) from

the Phase III expansion of Nine Canyon. Nine Canyon Wind provides an intermittent source of energy for the District. There is no material difference in the amount of energy the District receives from month to month.

White Creek Wind Generation Project

In 2008, Benton PUD started purchasing renewable energy from the 205 MW White Creek Wind Generation 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 that produces environmental attributes which helps Benton PUD meet its I-937 renewable requirements. Benton PUD 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 2017.

Packwood Lake Hydro Project

The District is a 14% participant in Energy Northwest's 27.5 MW Packwood Lake Hydroelectric Project, located in the Cascade Mountains south of Mount Rainier. The Packwood Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an annual output of approximately 10 aMW. It is owned and operated by Energy Northwest. The Project's 50-year license has expired and the Project has satisfied all of the requirements for relicensing with the Federal Energy Regulatory Commission and is waiting for final issuance. Benton PUD receives about 0.91 aMW output from the project. The project does not qualify as a renewable resource toward Benton PUD meeting its EIA obligations.

Community Solar Projects

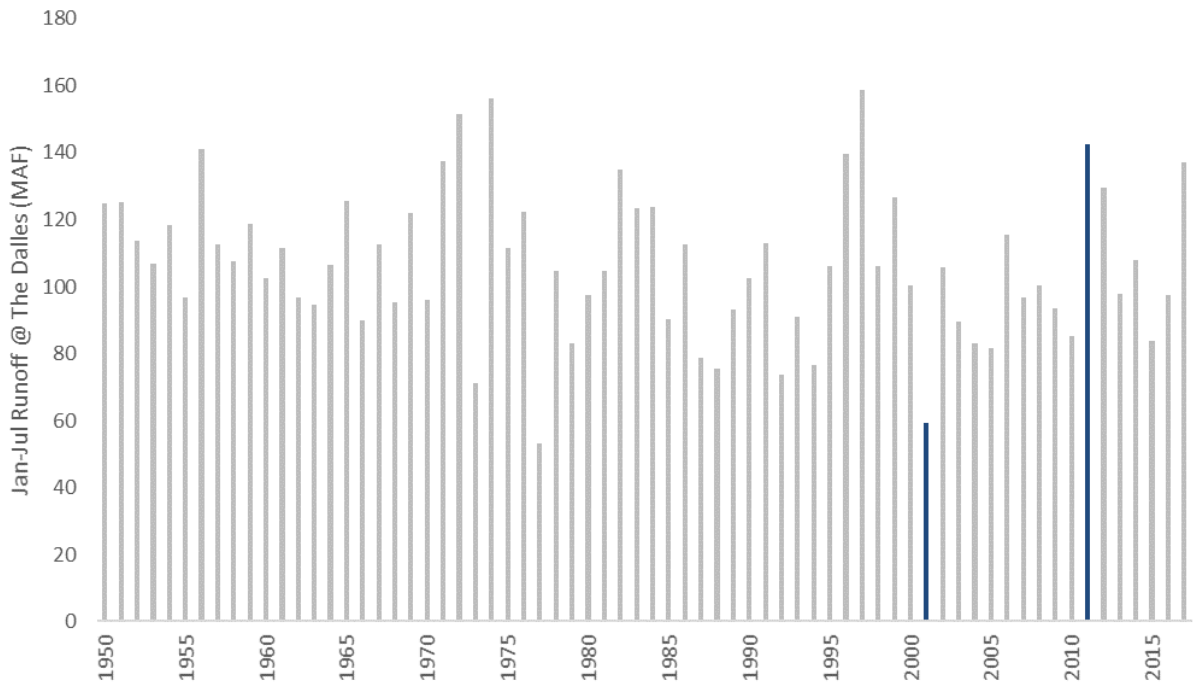
In early 2015, the Commissioners adopted a resolution authorizing the Solar Connections Program and a community solar project. The Solar Connections Program provides solar power information resources, supports customers who want to install their own solar power equipment, or participate in a community solar project. The program currently has two community solar projects that provide District customers an opportunity to participate in the 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.

Federal Resources

The Federal Columbia River Power System (FCRPS) is managed and operated by a joint collaboration of three federal agencies: the U.S. Army Corps of Engineers (Corps of Engineers), the Bonneville Power Administration (BPA), and the Bureau of Reclamation. It consists of 31 multipurpose dams which provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate

800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration). Due to the size of the system, up to 10,000 MW of generation capacity can be offline for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to overall hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period of time. BPA water years, which begin in October and end in September, are categorized by total water runoff in million acre-feet (MAF) at The Dalles between January and July. Hydrological conditions at The Dalles have been recorded since 1929. In that time period, total runoff has varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1950-2017) is illustrated in **Figure 8** below.

Figure 8: Historical Water Years (1950-2017)

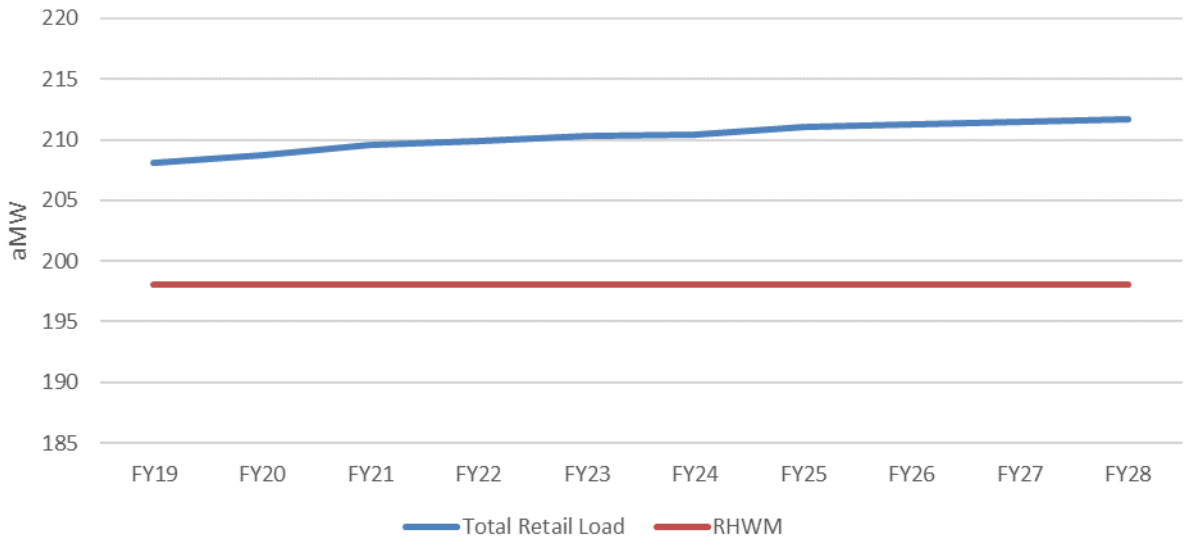


The 1937 water year streamflows represented the worst (lowest) on record at the time and was chosen as the benchmark "critical water" year. The significance of the critical water designation is that it represents baseline system capability – in other words, even in the worst hydrological conditions, the FCRPS will generate at the minimum critical level. BPA conservatively measures the system capability by determining its average annual energy output in critical water conditions. For the 2016 and 2017 water years, the system capability is 7,034 MW and 6,932 MW respectively (slightly lower due to refueling outage at CGS). System generation will exceed 7,034 MW and 6,932 MW in non-critical water years, which should occur the vast majority of the time.

As a Tier 1 Slice/Block customer, Benton PUD is allocated a certain portion of the system to manage and operate to serve their load. Each customer was initially allocated a certain portion of the system such

that on an annual average energy basis, and based on 2010 adjusted loads, the customer is in load/resource balance. In other words, for the first one or two years of the Slice/Block agreement energy supply is equal to energy demand on average for the year without any energy surpluses or deficits. Benton PUD can receive up to 2.85858% of the Slice/Block product. The quantity of power a utility is entitled to be known as its Contract High Water Mark (CHWM). The amount of power a Tier 1 customer is entitled to purchase is its Rate Period High Water Mark (RHWM), which is determined from the CHWM adjusted for any increases or decreases in the system capability.

Figure 9: Retail Load vs. BPA Contract High Water Mark



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

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

- ✓ Tier 1 priced at cost of existing system
- ✓ Tier 2 priced at marginal cost of new BPA purchases and/or acquisitions (i.e., equal to the cost of market or new resource)
- ✓ Public utilities can buy from BPA at Tier 2 rates, or acquire their own resources, to serve loads in excess of their HWM

The Slice/Block product is divided into two components: fixed and variable. The fixed component, or "Block," is a known and guaranteed quantity of power that Benton PUD receives from BPA, irrespective of the hydro conditions. Whether it is a critical water year or the highest on record, the quantity of Block power that BPA delivers to Benton PUD does not change. The power is shaped in advance into monthly blocks, which follows the District's monthly load profile. In other words, more Block power is

delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 9,539 MW for the two year rate period, but daily generation will fluctuate from between 4,000 MW to greater than 15,000 MW. The FCRPS is a multipurpose system and power generation achieves only one of system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. Benton PUD accepts these operational risks as a Slice customer. It accepts fluctuations in actual federal system output and takes responsibility for managing its percentage share of the federal system output to serve its load. There is no guarantee that the amount of Slice output made available, combined with the firm Block power, will be sufficient to meet load obligations, be it hourly, daily, weekly, monthly, or annually. Being a Slice customer requires Benton PUD to fulfill its load obligations with resources other than what is provided by BPA.

The District currently receives its full RHWM allocation from BPA from October 2016 through September 2017. Benton PUD's share of output is about 225 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 equal to its average annual energy needs, or 200 aMW. In water conditions greater than critical, total system output will be greater than 6,945 aMW. Based on a 70 year historical mean of hydrological conditions, the expected average system output is 8,916 aMW. Critical water is a rare event, and actual system generation will usually exceed critical output.

Columbia Generating Station

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

BPA Renewable Energy Resources

The new RD Slice contract also includes several resources with Western Renewable Energy Generation Information System (WREGIS) registered RECs. Those resources are the Foote Creek I & II Wind Projects, Stateline Wind Project, Condon 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 49.8MW.
- ✓ Foote Creek I & II are located in Carbon County, Wyoming and have a combined generation capacity of 43.2MW.
- ✓ Klondike I & III are located in Sherman County, Oregon with a combined generation capacity of 261.2MW. BPA has rights to 63.4MW of capacity from the project.

- ✓ The Stateline project straddles both Walla Walla County, WA and Umatilla County, OR. It has a nameplate capacity of 300MW. BPA has rights to 90MW of its total capacity.

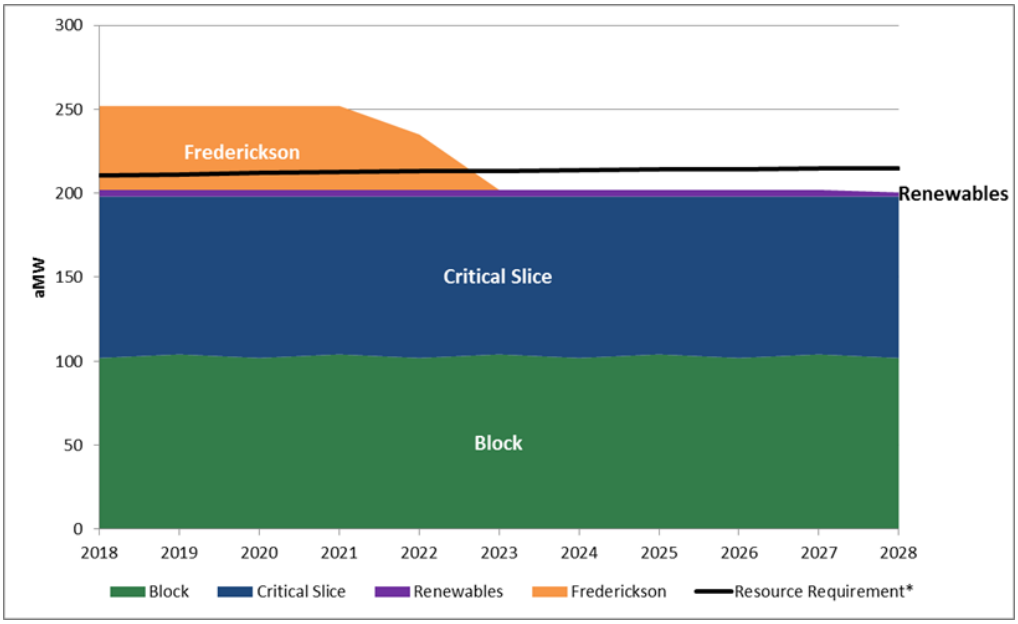
BPA has rights to 246.4MW of wind generating capacity in the WECC region. The energy and RECs associated with the wind resources are included in the BPA Tier 1 rate. Benton PUD's entitlement of those resources is approximately 6.4 MW of capacity. Assuming a capacity factor of 30 percent, the District receives an average of 1.25 Tier 1 RECs per hour or a range of 11,080-12,377 RECs over the last three years.

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

Load/Resource Balance with Existing Resources

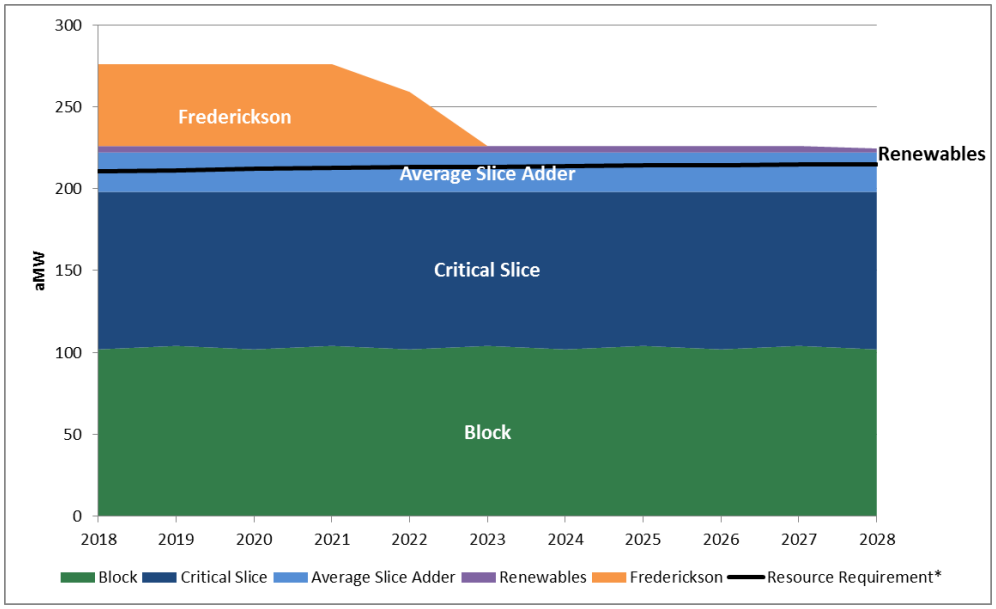
Figure 10 compares Benton's long-term load forecast under the expected load scenario to the District's projected BPA HWM plus already contracted for resources.

Figure 10: Annual Loads and Existing Resources in Critical Water Conditions



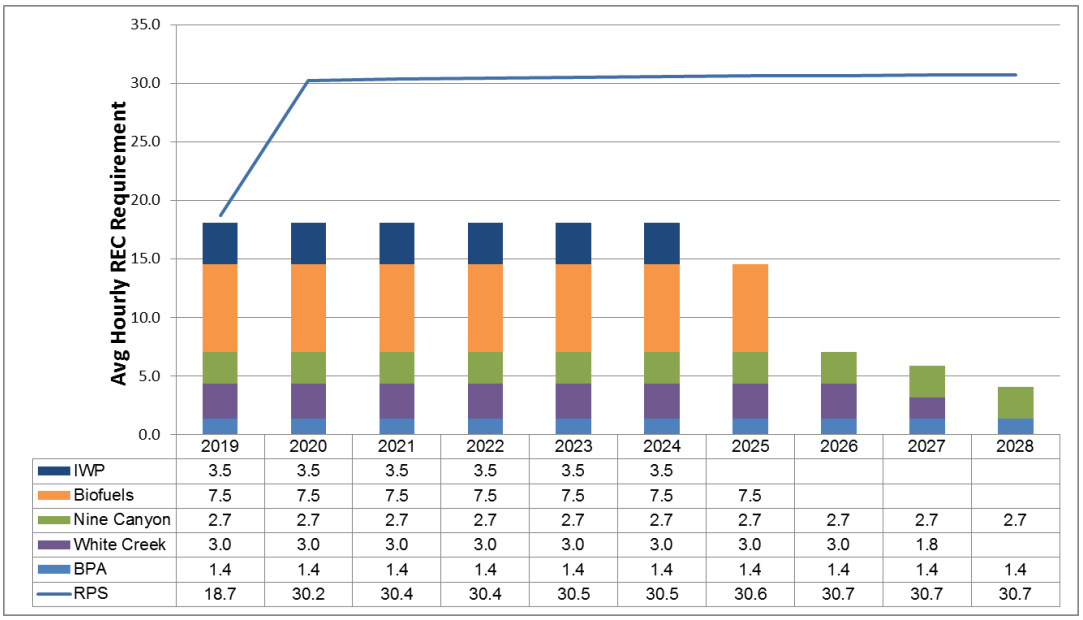
The District is in an energy surplus resource position under the expected load forecast through August 2022, when the Frederickson PPA expires, after which energy deficits appear on an average annual basis. **Figure 11** compares Benton's long-term load forecast under the expected load scenario and average hydro conditions to the District's projected BPA HWM plus already contracted for resources.

Figure 11: Annual Loads and Existing Resources in Average Water Conditions



In this scenario, the District is not expected to have any deficits in the expected load scenarios through the entire study period. Although the District is surplus energy on an annual load/resource view, the District does have hourly capacity shortages when the demand exceeds the District's supply. This is discussed in further detail in **Chapter 7: Capacity Requirements, Energy Storage, and Demand Response**. The EIA requires the District to supply the following amounts of its load requirements with renewable resources: 3 percent by 2012, 9 percent by 2016, and 15 percent by 2020. The EIA also requires the IRP process to develop a plan for acquiring renewable resources and all cost-effective conservation. The District's RPS requirements and resources to meet those requirements are depicted in **Figure 12** below. As discussed in **Chapter 1: Executive Summary** the District will continue to rely on purchases from the market when REC deficits occur starting in 2020.

Figure 12: REC Net Position



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
IWP	3.5	3.5	3.5	3.5	3.5	3.5				
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5			
Nine Canyon	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
White Creek	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	1.8	
BPA	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
RPS	18.7	30.2	30.4	30.4	30.5	30.5	30.6	30.7	30.7	30.7

Chapter 4: Policy & Regulation

Environmental policy continues to be a 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 expectations of federal carbon emission laws coming into effect. The District must meet its 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 legislation defines an IRP as an analysis describing the mix of generating resources, conservation, methods, technologies, and resources to integrate renewable resources and, where applicable, address over-generation events, and energy efficiency resources that will meet current and projected needs at the lowest reasonable cost to the utility and its ratepayers. Each electric utility must comply with the requirements specified in RCW 19.280.030(1) and develop a plan consistent with the following:

(a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage;

(b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

(c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources;

(d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;

(e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio;

(f) The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events, at the lowest reasonable cost and risk to the utility and its ratepayers; and

(g) A short-term plan identifying the specific actions to be taken by the utility consistent with the long-range integrated resource plan.

The District complied with the requirements of this legislation in September of 2008, 2010, 2012, 2014, and 2016. This IRP is designed to meet the biennial and update requirement.

Energy Independence Act (EIA)

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

The first phase of the renewable requirement of the EIA required the District to meet 3% of its retail loads with qualified renewable resources. The second phase of the renewable requirement is now in effect and requires the District to meet 9% of retail loads with qualified renewable resources. The third phase of the requirement will increase to 15% in 2020. If the District fails to meet the requirement, it will be assessed a penalty of $50/MWh, in 2007 dollars.

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 limit the impacts of the law on ratepayers. The law states:

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

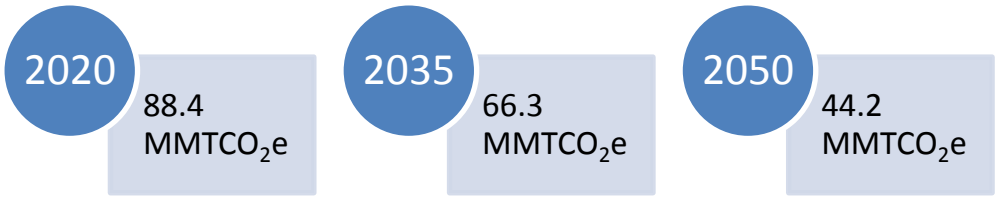
A principal driver of resource acquisition for the District is achieving compliance with the EIA. Based on updated analysis and current prices, the District does not believe that this mechanism could be a factor in the future but will continue to analyze the opportunity going forward.

The EIA also requires that the District implement all cost-effective conservation measures, using methodologies consistent with those used by the Pacific Northwest Power and Conservation Council in its most recently published regional power plan. Every two years, the District must identify its achievable cost-effective conservation potential for the next ten years as well as the next two year target, which the District must meet during the subsequent two-year period.

Washington State Green House Gas Legislation

In 2008, the Washington State Legislature enacted RCW 70.235.020, a law which aims to reduce the State's greenhouse gas (GHG) emissions in order to mitigate the impacts of climate change. The goal of the law is to lower GHG emissions to 1990 levels by 2020, 25% of 1990 levels by 2035 and 50% of 1990 levels by 2050 (**Figure 13**). In 2016, the Washington State Department of Ecology released a report that recommended the 2050 emission limit be strengthened to 80% below 1990 levels. While RCW 70.235.020 has not formally been updated, the recommended change to the 2050 emission limit has been implicitly supported and adopted. 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 or not 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 13: Target GHG Emissions



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

Clean Air Rule

The Department of Ecology proposed the Clean Air Rule (CAR) in January 2016, at the direction of Governor Jay Inslee. The Department of Ecology withdrew it after a public response period, and, based on the public input, released a second draft rule in June 2016. The proposed rule was intended to lower GHG emissions to 1990 levels by 2020, 25% below 1990 levels by 2035, and 50% below 1990 levels by 2050.

The CAR initially applies to power plants, natural-gas distributors, refineries and waste facilities that release at least 100,000 metric tons of carbon a year, and began in 2017 with 24 facilities. This included the Frederickson 1 Generating Station in Tacoma, of which the District has a Power Purchase Agreement through 2022 for a portion of its output. The 100,000 metric ton threshold for inclusion in the program decreases by 5,000 metric tons every three years until it reaches 70,000 metric tons in 2035, at which point it will remain constant, and approximately 60-70 participants are expected by 2035.

Ecology set a baseline emission level for each facility (based on average yearly emissions between 2012 and 2016), and the Rule mandates each facility to reduce its carbon emissions by 1.7% per year through 2035. The emissions reduction requirements can be met through a variety of ways, including efficiency gains that reduce emissions, creation of new projects that reduce carbon pollution in Washington, or the purchase of allowances from other established multi-sector carbon markets approved by Ecology. Allowance purchases, however, are capped at 50% starting in 2026, and 5% starting in 2035. Emission reduction units can be banked for later use or sale in future years, but expire after 10 years.
One major omission is that electricity wired in from outside of Washington is not covered under the Rule. This may have unintended consequences, such as an increase in out-of-state power purchases, including those from non-renewable resources. If the Rule does not trigger a change of the generation stack and result in the construction of more low or zero carbon resources, one of the results may be a shift in carbon pollution from Washington to nearby states. The CAR, if implemented, would apply to the Frederickson plant and would negatively impact the District's finances as long as it is under contract.

A Thurston County Superior Court judge orally invalidated major parts of the Rule in December 2017, maintaining that the executive order was unenforceable without legislative action. The ruling was finalized in March 2018. The Department of Ecology appealed the superior court's ruling to the Washington State Supreme Court in May 2018. The State is expected to drop its appeal if Initiative 1631 (defined below) wins approval from Washington State voters in the upcoming November elections.

Protect Washington Act (Initiative 1631)

On the upcoming November 2018 ballot is Initiative 1631 (I-1631), which would create a fee on carbon emissions, including those from the electricity generated by fossil fuels. Stakeholders crafted I-1631 in response to the defeat of Initiative 732 shortly after the completion of the 2016 IRP.

The Initiative would cover both electricity generated in the State of Washington and that which is imported into the State. The fee would start in 2020 at $15 per metric ton of carbon dioxide emissions, increasing at an annual rate of $2 per metric ton plus inflation per year. The annual increases would continue until the State reaches its stated 2035 carbon reduction goal of 20 million metric tons relative to the 2018 baseline and on a trajectory to meet its 2050 carbon reduction goal of 50 million metric tons relative to 2018. Receipts from the fee would be deposited in a "Clean Up Pollution Fund" and disbursed to communities such that 70 percent of the funds would go towards clean air and clean energy investments, 25 percent towards clean water and clean forest investments, and 5 percent towards healthy community investments. The District would also be eligible to claim a majority of the carbon fee it contributes to the fund.

> (6)(a) A qualifying light and power business or gas distribution business may claim credits for up to one hundred percent of the pollution fees for which it is liable under this chapter. Credits may be authorized for, and in advance of, investment in programs, activities, or projects consistent with a clean energy investment plan that has been approved by the utilities and transportation commission, for investor-owned utilities and gas distribution businesses, or the department of commerce, for consumer-owned utilities.

The District would be required to invest proceeds from the fund on clean energy investments, pending approval from the Washington State Department of Commerce. I-1631, if voted into law, would have many impacts on the District. The results include but are not limited to assessing a pollution fee on the District's BPA purchases, change the dispatch of the Frederickson plant resulting in decreased fixed cost recovery due to lost opportunity as well as assess a fee on market purchases from unspecified resources would also be subject to the carbon fee based on a default emission factor assigned by the State with the intent "to incentive utilities to specify the sources of electricity." All of these could result in an estimated impact ranging from $1.0 million to $1.5 million annually from 2020 to 2022.

Regardless of the result at the ballot box, it is likely that some form of a carbon tax will become Washington State law in the near future and will have a significant impact upon the energy sector. As such, in the Market Simulation chapter of this IRP, the default scenario includes a price on carbon applied to power plants in Washington State (see **Chapter 8: Market Simulation**).

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 lawmakers stated that another bill will be introduced and voiced confidence that it will ultimately pass in the 2019 session.

Oregon Clean Energy Program

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

Outside of Oregon, this law may set a precedent for other states like Washington to follow suit. California and Oregon both have 50% RPS mandates; more renewable buildout is expected, particularly 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 98 g/MJ in 2018. 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 0.5% of the utility's 1996 peak demand (1.89 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 the previous year will be granted to utilities without any compensation to the customer-generator on April 30 of the following year. In May 2018, the District's Commission approved increasing the District's Net Metering cap to 1.0% of its 1996 peak demand (3.78 MW) in an effort to provide more planning certainty for District customers who are considering installing renewable generation equipment and its minimal financial impact.

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. This is often referred to as green power. Benton PUD 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. There are no state mandated reporting requirements associated with RCW 19.29a.

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 incentivizes customers to build their own generation which reduces the District's energy loads.

Federal Policies & Regulations

Clean Power Plan

The EPA's Clean Power Plan (CPP) calls for a national carbon emission reduction of 32% by 2030 (and up to 44% in some states). This will have a significant impact on each state's resource mix, which will directly impact long-term price projections, and consequently affect utilities and their customers. The CPP requires all states to submit their final plan for emission reduction by September 2018 with the actual compliance period starting in 2022. Individual states may choose to create a statewide rate-based goal measured in pounds of CO2 per Megawatt hour (lbs/MWh) or a statewide mass-based goal measured in total short tons of CO2 emissions. Washington's specific CO2 emissions goals for 2030 are 983 pounds of CO2 per MWh or 10.7 million short tons of CO2 per year.

The CPP's impact on Washington, Oregon, and Idaho is projected to be relatively minimal given the reliance on zero-carbon hydropower in addition to the planned retirement of the remaining coal-fired generation in Washington and Oregon, Centralia and Boardman respectively. Other states, notably Montana and Wyoming, will have more significant hurdles towards achieving these emission reduction targets. Given these more demanding requirements on other states, many of these states have challenged the legislation.

Although it is still an active policy, the US EPA formally submitted a proposal to repeal the Clean Power Plan in October 2017. It is widely expected that the rule will eventually be repealed and thus is not included in the IRP market simulation modeling.

PURPA

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

PURPA established a new class of generating facilities known as qualifying facilities (QFs) which would receive special rate and regulatory treatment, including qualifying small power production facilities "of

80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources."

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

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

Renewable Electricity Production Tax Credit (PTC)

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

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

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

Renewable Energy Investment Tax Credit (ITC)

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

A taxpayer may claim a credit of 30% 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. 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 14.**

Figure 14: ITC Eligibility by Resource Type

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

The increase in wind and solar capacity from the PTC and the ITC has caused wholesale market prices to decrease, negatively impacting the District's sales for resale which in turn increases the District's Net Power Costs. These impacts are reflected in the analysis shown in the Power Price Simulation in **Chapter 8: Market Simulation.**

Chapter 5: Supply Side Resource Costs

The District analyzed a broad array of supply-side resource options in the IRP. Each technology has its own unique set of advantages and disadvantages, and therefore, a unique impact on the District's power supply costs. The resources considered in the plan are not a complete list of all possible generation types. Rather, the IRP reflects technologies that are deemed to be realistic candidates by the District's IRP team.

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

Resource Alternatives

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

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

Conventional Thermal Generation

Steam Units

Simple thermodynamic cycle steam turbine-generators (SC-STG) were the stalwart of electric generating units for many decades, with approximately 383 GW, over 32%, of total generating capacity currently operating in North America.[1] Until the last two decades, SC-STG units have been the primary choice for base load operation due to their reliability and

[1] Bloomberg New Energy Finance. US Power Plant Stack Data, April 3, 2018.

fuel flexibility (coal, oil, natural gas and nuclear). SC-STGs 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, SC-STGs have become less competitive than other alternatives such as combined cycle (CCCT) units due to higher thermal efficiencies realized by CCCTs and relatively low natural gas prices. The largest steam turbine units in the region are the Boardman, Centralia, and Colstrip units 1 and 2 coal fired power plants. These units combine for over 2500 MW of generating capacity and are all slated to retire by 2025.

Simple Cycle Gas Turbines (CT)

Simple cycle gas turbines began to penetrate the electric generation fleet in the 1960s. Early vintage gas turbines were relatively inexpensive to build on a $/kW basis, but were inefficient and generally limited to smaller size units. Because of their inefficiency, they were limited to serving load only during peak load or emergency operating conditions.

Unlike SC-STGs, fuel choices for CTs are generally limited to light fuel oil and natural gas and can generally be started with 30 minutes or less notice, thus providing significant operating flexibility. Currently there are about 172 GW, roughly 14%, of total generating capacity currently operating in North America.[2]

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.

Simple Cycle Gas Turbine with Intercooler

The addition of an "intercooler" to a simple cycle gas turbine can improve overall cycle power and efficiency ratings. As air is compressed, the CT heats up. Removing a

[2] Bloomberg New Energy Finance. US Power Plant Stack Data, April 3, 2018.

portion of this heat via an intercooler achieves a higher compression ratio which results in an increased thermal efficiency. General Electric's LMS100 is an example of a utility scale gas turbine in which intercooler technology is applied. This design retains much of the operational flexibility offered by a simple cycle gas turbine while improving heat rates to a level similar to that achieved with a RICE unit (see below).

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 STG. Thermal efficiencies are approaching or exceeding 60%, as compared to the 40% efficiency of SC-STGs. Today, there are 306 GW, (about 25%, of total generating capacity) of CCs operating in North America, excluding those permitted or under construction.[3]

Reciprocating Internal Combustion Engine (RICE)

Reciprocating internal combustion engines (RICE) are becoming an increasingly popular choice for utilities. These generally have higher thermal efficiencies than SC-CTs, and efficiency 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 wind and solar generation rapidly ramps up or down, these type of quick start units are able to quickly respond and balance the intermittent nature of wind and solar generation.

Small Modular Reactor (SMR)

Several companies are in the process of developing a commercially available small modular reactor (SMR), which are a new class of nuclear power plants that will be smaller in size and capacity than traditional nuclear plants. As the name implies, the units will be modular and offer more flexibility to

[3] Bloomberg New Energy Finance. US Power Plant Stack Data, April 3, 2018.

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

A 12 module, first of its kind plant built by NuScale at the Idaho National Laboratory for the Utah Associated Municipal Power Systems is currently in the planning stages. Energy Northwest, the current operator of the Columbia Generating Station, will also be the operator of this plant. Its expected completion date is in 2024.

Renewable Generation

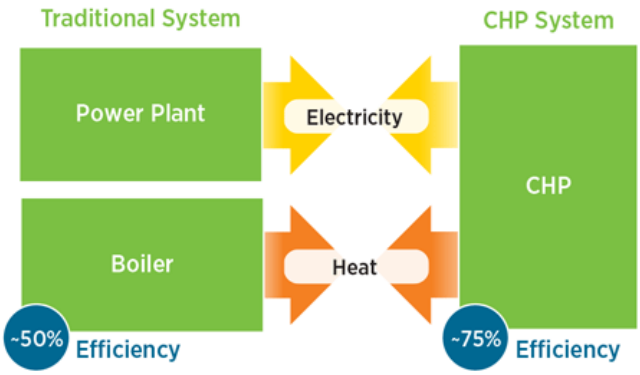
Electric generation using renewable energy resources is generally considered good public policy. As a result, state and federal lawmakers and regulatory authorities have placed considerable emphasis on increasing the amount of electricity which is produced by renewable energy resources through Renewable Portfolio Standards (RPS), tax breaks and other incentives.

Wind and solar are variable resources which cannot necessarily be depended on for serving load at any particular time.

Energy Storage

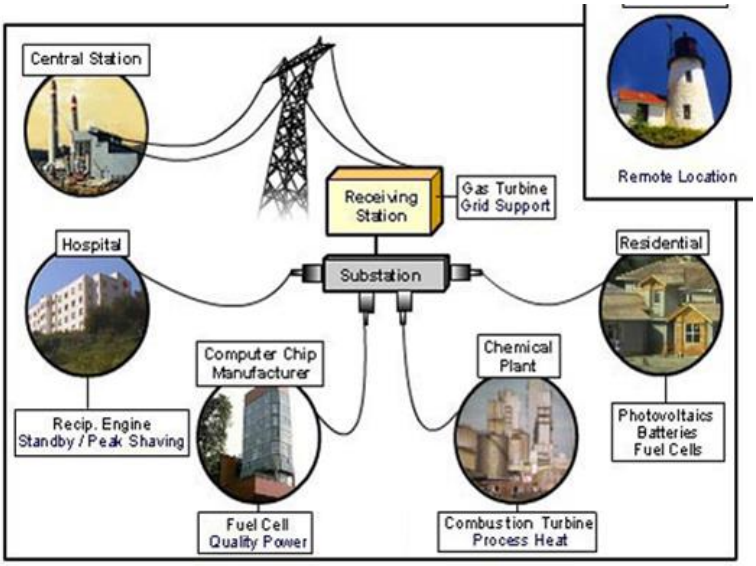
With increasing market penetration of variable resources such as wind and solar, managing the power grid around the variability of these renewable resources has become more challenging. Distributed and grid-scale energy storage resources have gained significant interest in the industry. Energy storage devices are distinguishable from other forms of generation in that they do not directly convert primary energy (such as wind and solar) into electricity. Instead, they store electricity produced from such resources when supply exceeds demand and discharge during periods when demand increases and/or the primary

energy is not available. Thus, these can level out the variable production from wind and solar generation.



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. A combination of maturing technology and financial incentives, many of these technologies 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 use at a later time.

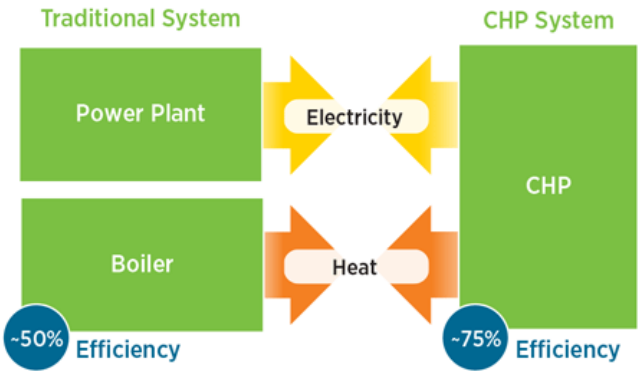


DER is typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. 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. 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.

Federal, State, and Local Tax Credits and Incentives

As mentioned in **Chapter 4**, there are two federal incentives available to renewable resources: the Production Tax Credit (PTC) and the Investment Tax Credit (ITC).[4,5] 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. Both programs received multi-year extensions at the end of 2015. The PTC provides a tax credit to eligible renewable generators for each kilowatt-hour of electricity produced for the first 10 years of operation. 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

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

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

beginning 2016 that gradually reduces the subsidy by 20 percent each year to wind generators until it phases out on December 31, 2019.

- 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

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

The subsidy schedule for the ITC varies significantly by generation resource gradually ramping down until its expiration. **Figure 15** below displays the credit provided by the ITC as a percent of capital expenditures.

Figure 15: 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%
Fuel Cells	30%	-	-	-	-	-	-	-
Geothermal	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. In recent news, the Internal Revenue Service ruled that renewable developers can claim a 30 percent tax credit for solar projects as long as they prove they've started construction by the end of 2019, according to an IRS notice Friday. That means breaking ground or investing at least 5 percent of the total expected costs of the installation, and they have until the end of 2023 to complete the power plants.

New Supply Side Resources

A variety of options for new supply side resources could be used to meet the District's future needs. The choices of new resources considered for this IRP were limited to those which are size-compatible with Benton PUD's requirements over the study period. 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 16 includes all supply-side resource options evaluated for this IRP. All costs are expressed in nominal dollars.

Figure 16: New Resource Cost Assumptions

Resource Type	Capital Cost ($/kW)	Fixed O&M ($/kW-Year)	Variable O&M ($/MWh)	Full Load Heat Rate (BTU/kWh)	Capacity Factor	Fuel Type
Aeroderivative Combustion Turbine	1,100	$25.00	$5.00	9,500	10%	Natural Gas
Reciprocating Internal Combustion Engine	$975	$9.30	$3.60	8,630	15%	Natural Gas
Combined Cycle Combustion Turbine	$1,125	$9.00	$1.70	7,450	50%	Natural Gas
Wind Turbine †	$1,695	$51.00	-	-	37%	Renewable
(South-Central WA)						
Single Axis-Tracking Solar	$1,100	$16.00	-	-	15%	Renewable
Photovoltaic (Western WA)‡						
Single Axis-Tracking Solar Photovoltaic (Eastern WA)‡	$1,100	$16.00	-	-	20%	Renewable
Small Modular Reactor	Unknown – levelized cost estimates made available by Energy Northwest					Uranium

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

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

Fuel and Cost Assumptions

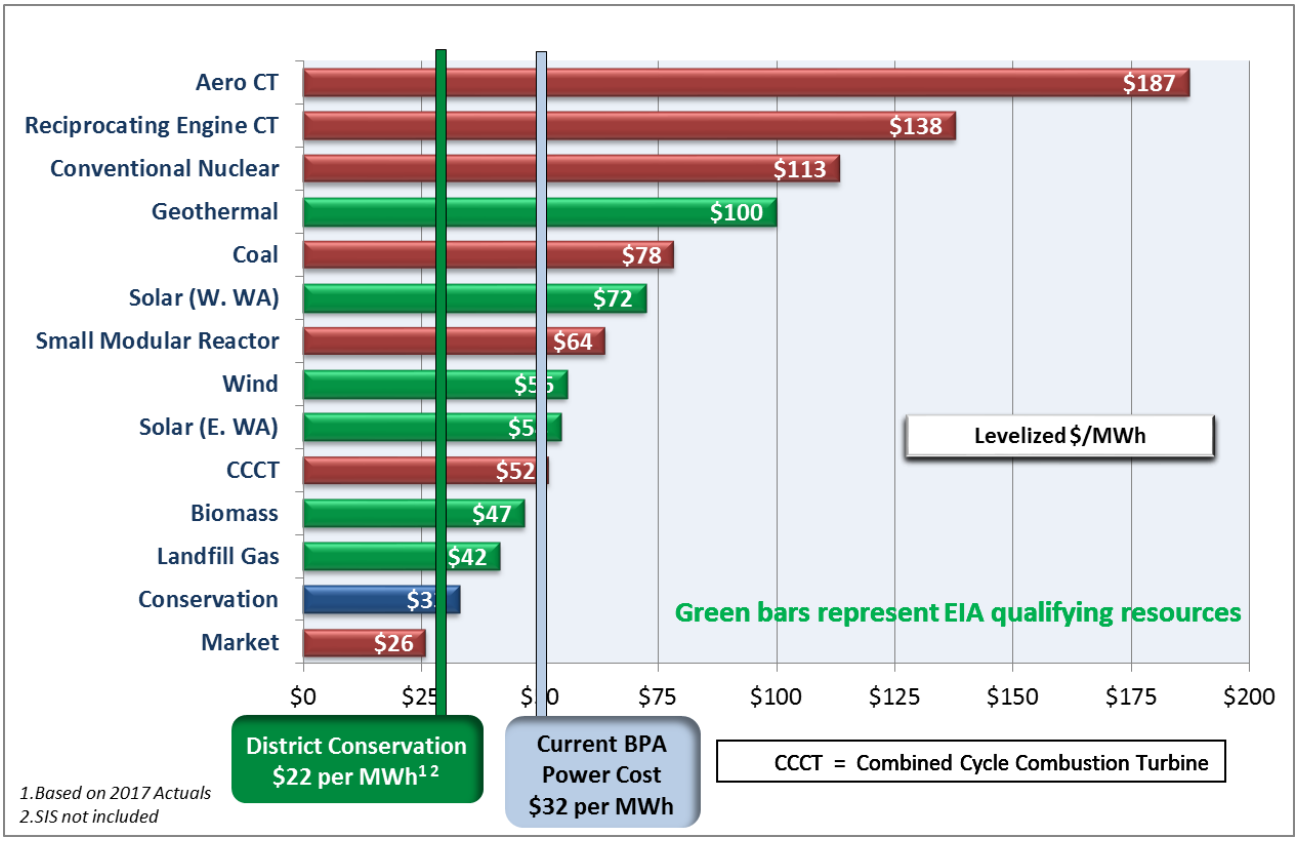
The fuel cost assumptions are equivalent to those described in **Chapter 8: Market Simulation.** Renewables costs are reported in both subsidized and unsubsidized figures to cover the range of possible outcomes as the subsidy decreases over time. The costs of thermal generators are calculated both with and without a carbon price. The carbon price regime was adapted from the Protect Washington Act, beginning at $15 per metric ton in 2020, escalating by $2 per ton per year until the 2035 greenhouse gas reduction goal is met and indicates the trajectory is likely to meet the 2050 greenhouse gas reduction goal. The model assumes that prices will level off in 2035 at $45 per metric ton.

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.

A project economics model was developed as a means 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 levelized cost of energy ($/MWh) metric. The cost of each resource examined in this IRP (**Figure 17**).

Figure 17: Levelized Cost of Energy for Resources Analyzed



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

This analysis did not consider wind from Eastern Montana despite its superior wind resources because it is not within the Bonneville Power Administration's balancing authority. Resources built there would require significant additional transmission infrastructure to interconnect to the Northwest region.

Resources Selected for Additional Analysis

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

Renewable resources:

- Wind
- Solar

Other resources:

- Combined Cycle Gas Turbines
- Simple Cycle Gas Turbines
- Reciprocating Internal Combustion Engines
- Small Modular Reactors

Coal was excluded from further analysis largely due to the extreme uncertainty in permitting such projects, as well as the fact that coal would violate the legal requirements mandated under RCW 80.80.

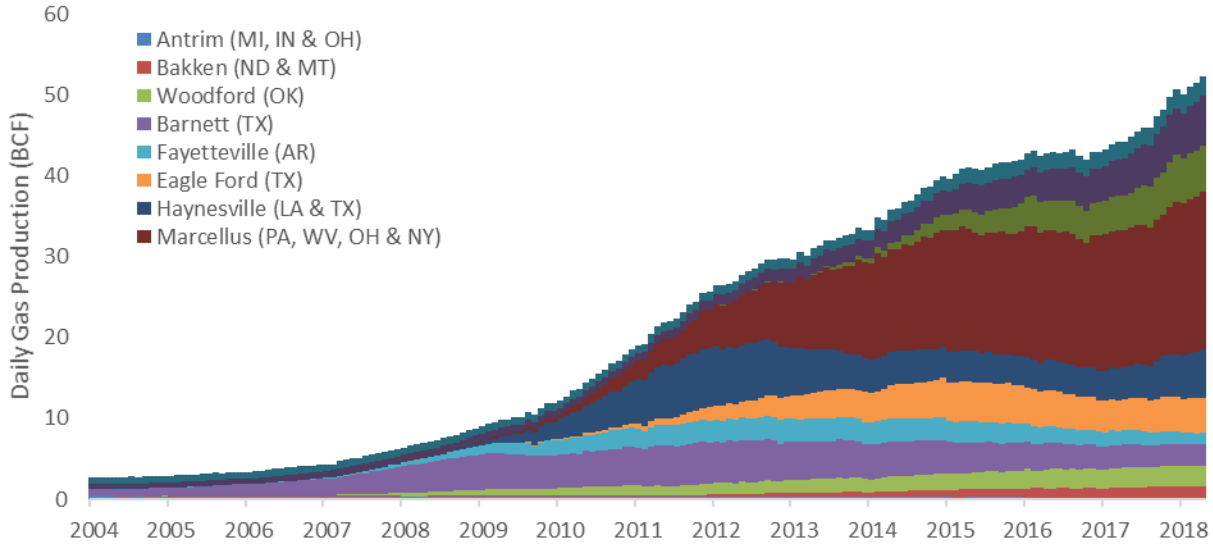
Chapter 6: Macro Utility Environment: The New Status Quo and Utility Industry Disruptions

The energy sphere is evolving as rapidly as any other industry. The industry has observed changes on all fronts since the 2016 IRP: market, regulatory, and technology. There are several technologies on the development front that have the potential to fundamentally alter the way that society generates and consumes electricity. This section delves into several of the areas that have observed changes on a particularly fast pace and how economics, politics, and science has impacted each of them.

Fracking

The natural gas industry is fundamentally different today with fracking technologies than it was just a decade ago. Fracking unlocked a vast, seemingly infinite supply of domestic natural gas that is well poised to serve the needs of the nation for years to come. The percentage of domestically produced natural gas from shale resources grew from roughly 5 percent in 2004 to about 60 percent in 2017.[6] On a volumetric basis, production grew roughly 18 fold since that period. Perhaps the most significant impact of prolific shale gas extraction was the significant decline in the commodity value of natural gas that followed (**Figure 18**).

Figure 18: Domestic Shale Gas Production by Formation (2004-2018)

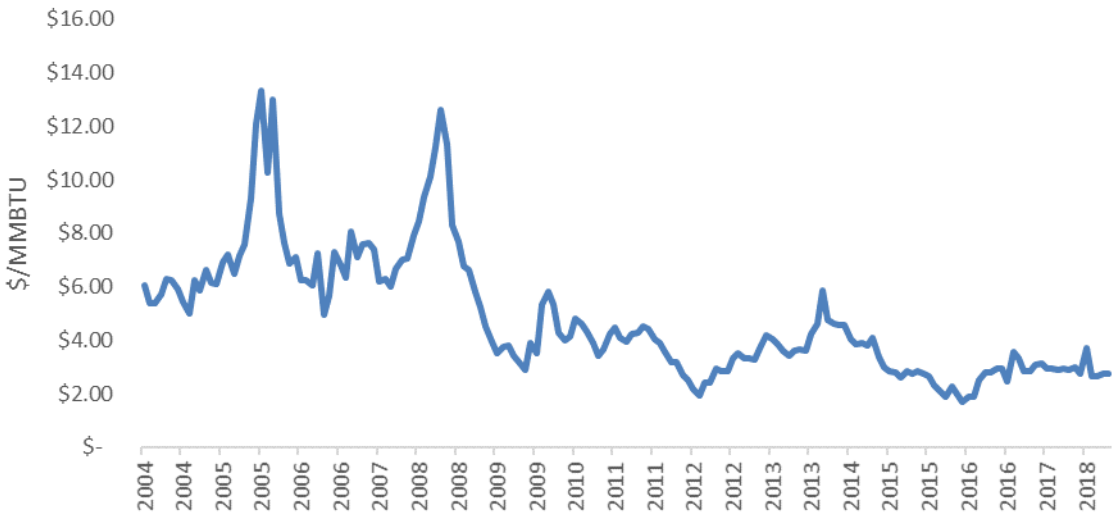


There are widespread consequences of a large quantity of cheap, abundant natural gas coming online. Most obviously, natural gas prices have declined significantly in recent years. Prices hovered in the $5-$9/MMBTU range between 2004 and 2008, prior to intensification of shale gas production (**Figure 19**). Current natural gas prices are between $2/MMBTU and $3/MMBTU, and expected to remain in that

[6] "How Much Shale Gas is Produced in the United States?" US Energy Information Administration. US Energy Information Administration, 08 March 2018. Web. 30 May 2018.

range for the next 5 years. Natural gas fueled power plants are competitive with coal plants at such price levels.

Figure 19: 2004 to Mid-2018 Henry Hub Natural Gas Prices



Fracking, however, is not without its controversies. There is evidence linking it to an ever increasing frequency of low-magnitude earthquakes in the Oklahoma region, as shale gas production intensifies. The Oklahoma Geological Survey determined that the increased seismic activity is likely caused by the injection of wastewater resulting from oil and gas production into disposal wells.

There are also questions of whether fracking results in groundwater contamination and the extent to which fugitive methane emissions, unaccounted natural gas leaks from the well, contribute to overall greenhouse gas emissions. It is unlikely that the Federal government will issue new regulations restricting fracking, however, regulations on the state level are possible. New York State, for example, enacted a 7 year fracking moratorium in 2015, heeding the requests of several activist groups and even prominent politicians to ban fracking.[7]

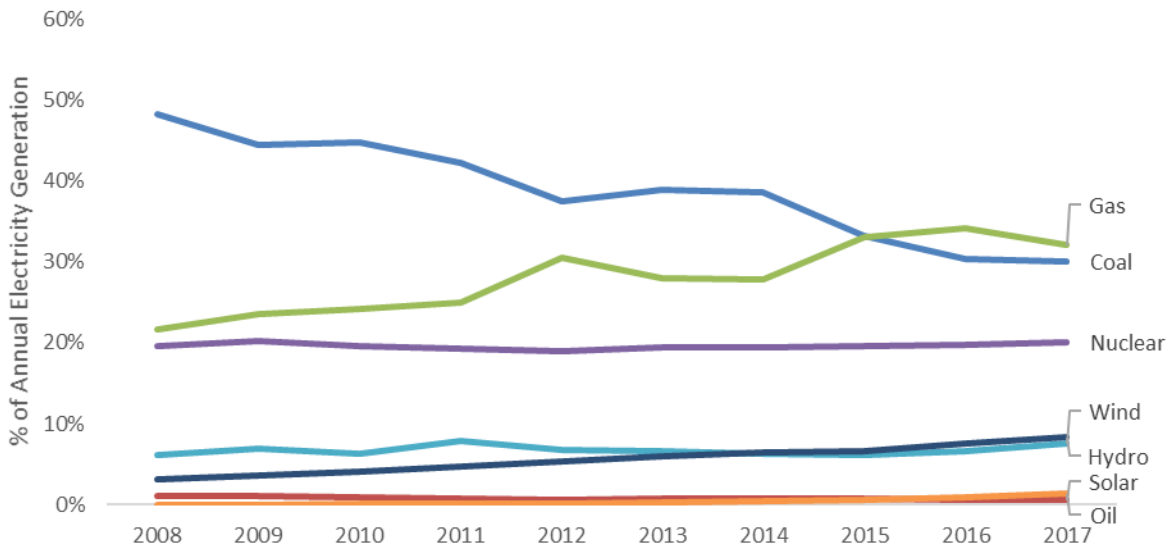
Coal

The dominant fuel for electricity generation since its advent was, until recently, coal (**Figure 20**). Electricity produced from coal decreased from over 50 percent in 2004 to 30 percent in 2017. In its place, natural gas, wind, and solar concurrently increased their respective generation shares.[8]

[7] Klopott, Freeman. "N.Y. Officially Bans Fracking With Release of Seven-Year Study." Bloomberg. 29 June 2015. Web. 26 May 2016.

[8] "Electric Power Monthly." US Energy Information Administration, 26 June 2018. Web. 30 May 2018.

Figure 20: Share of Annual US Electricity Generation by Resource



The trend of utilities diversifying away from coal towards natural gas and other resources is not expected to change in the foreseeable future. The current market conditions for coal generators is now less optimistic with market conditions favoring other generator types. There are regulatory reasons for the erosion of market share for coal in addition to the economic threat posed by natural gas. While regulations that primarily affect coal generation such as the Mercury Air Toxics Standard, the Cross State Air Pollution Rule, and California carbon cap-and-trade exist, the current Federal government signaled that loosening regulations to improve the viability of coal generation is a priority. Compliance to these rules oftentimes requires expensive upgrades to old plants – or abandoning coal and switching to a cleaner fuel. Scaling back these requirements would certainly enhance coal's economics. While the regulatory landscape may soon improve for coal generators, the primary challenge to the coal industry are the compelling economics of natural gas. With a lower carbon intensity and fewer pollution causing materials, natural gas can be an attractive alternative to coal, particularly with a cheap and abundant domestic supply available.

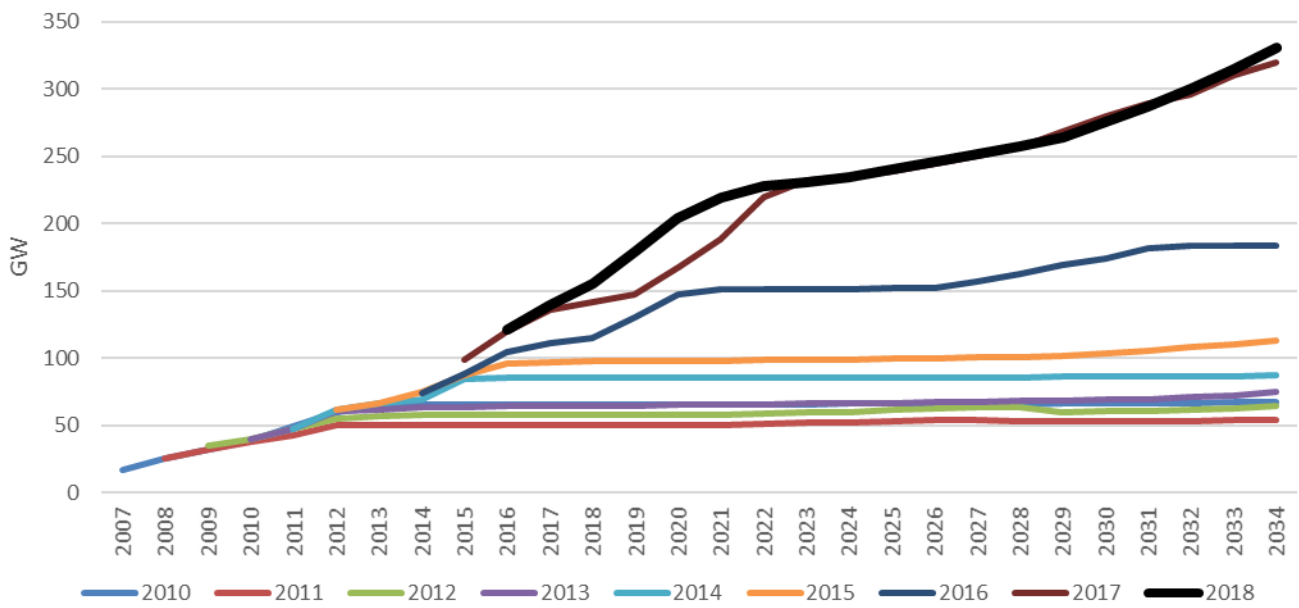
Irrespective of economics, Department of Energy signaled its desire to keep coal plants running. The DOE issued a notice of proposed rulemaking in September 2017 and directed the Federal Energy Regulatory Commission to consider rulemaking that would guarantee full cost recovery for power plants that possess, on-site, a 90-day fuel supply. The rationale behind this proposal was that generators which do no store fuel on-site can be susceptible to generation disruptions in the event that the fuel supply is cut off. The FERC unanimously rejected this proposal in January 2018.

Another proposal, which the DOE is currently considering, is Section 202(c) of the Federal Power Act for coal generators. Invoking Section 202(c) would mandates that companies purchase power from certain generators, which in this instance, would be coal and nuclear fueled power plants.

Renewable Resources

Renewable resources excluding large hydro generated about 9 percent of the electricity consumed in the US in 2017.[9] While the number is small relative to coal (30 percent) and natural gas (32 percent), the utilization of renewable resources continues to grow along with natural gas while the share of coal generated electricity declines. Wind, solar, and natural gas accounted for nearly all generation capacity additions in the US in 2017, with wind and solar making up a majority of those additions. The share of renewable energy is projected to increase by 50 percent to about 24 percent of total generation by 2034.[10] It is notable, however, that the rate of renewable energy adoption has historically been higher than forecasted, while the forecasted costs of renewable energy tend to come in lower than forecasts (**Figure 21**). There is a consistent trend where each new renewable generation capacity forecast projects a faster growth rate than the previous one.[11]

Figure 21: Evolving Wind and Solar Generation Capacity Forecasts by Year Through 2034



Wind

Wind remains the lowest cost available resource in certain regions of the US. The average levelized PPA price for wind projects in 2016 was about $20/MWh, inclusive of subsidies, but likely excludes

[9] Table 1.01. US Energy Information Administration, Web. 30 May 2018.

[10] "Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases." US Energy Information Administration. 17 May 2016. Web. 29 May 2016.

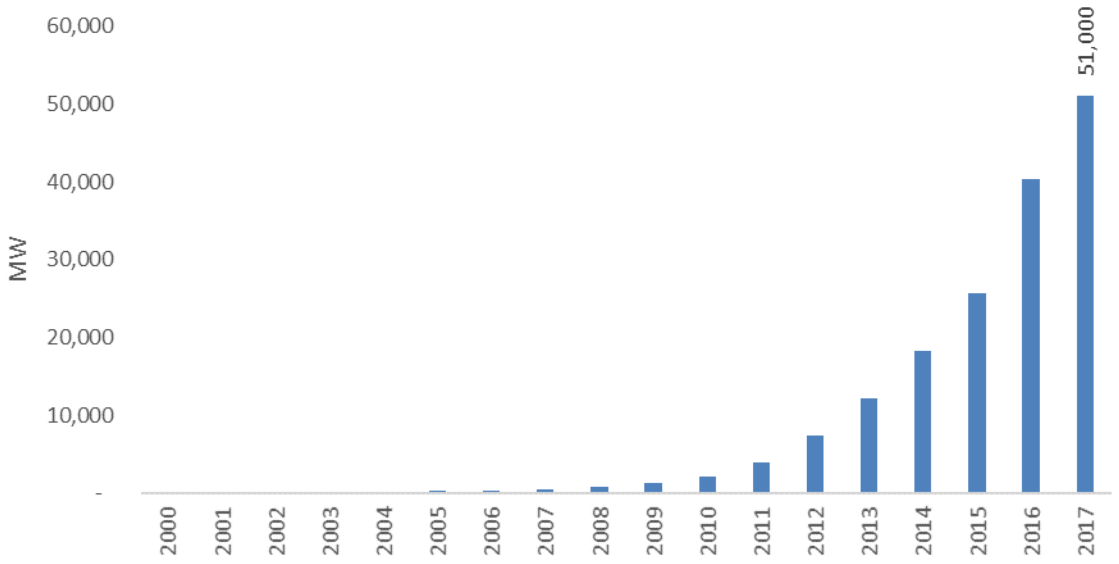
[11] "Annual Energy Outlook 2018: Table: Electricity Supply, Disposition, Prices, and Emissions." US Energy Information Administration. 06 Feb 2018. Web. 30 May 2018.

transmission costs.[12] These projects were likely built in the Great Plains or the panhandles of Texas/Oklahoma which all possess high-quality wind resources. Projects outside of these areas with lower wind potential will presumably have higher PPA costs. It is nonetheless significant that a resource that, just a few years ago was not economically viable, is now cost competitive even on an unsubsidized basis, in a low gas and power price environment.

Solar

Solar technology is advancing at a pace such that some of the information disseminated in this IRP will be outdated by the time the report is published. Domestic photovoltaic solar energy has grown an annualized rate of 51 percent since the turn of the century. Photovoltaic (PV) capacity (rooftop and utility scale) grew from 30 MW in 2000 to over 50,000 MW at the end of 2017 (**Figure 22**).[13]

Figure 22: Cumulative Annual US Solar Generation Capacity



PV solar is fundamentally different from all other generating resources in that it is completely modular and can be built to any size, from a system small enough to put on the rooftop of a household to a utility scale plant with an output comparable to a coal plant. Solar energy costs have declined by over an order of magnitude since the turn of the century and nearly 50 percent in the last five years alone.[14] This can be attributed partly to improved manufacturing processes as well as technological improvements which boost cell efficiency. As a result, utility scale solar energy, inclusive of subsidies, is now cost competitive

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[12] Wiser, Ryan & Bolinger, Mark, et. al. "2016 Wind Technologies Market Report" US Department of Energy Office of Energy Efficiency & Renewable Energy, August 2017. Web. 30 May 2018.

[13] "Capacity& Generation: Cumulative Installed Capacity by Technology" Bloomberg New Energy Finance. Web. 30 May 2018.

[14] "Solar Spot Price Index" Bloomberg New Energy Finance. Web. 30 May 2018. 2016.

with other resources in many geographic locations. Rooftop solar is also cost competitive with retail rates in sunnier locations with high retail electricity rates, such as California, the Desert Southwest, and Hawaii.

Customers can monetize rooftop solar primarily in two ways. The first approach is to offset consumption. Energy generated onsite at the time of consumption can directly offset electricity usage. Consumption is metered as zero when production equals consumption at any given time. The offsetting electricity in this case has a value equivalent to the retail rate. The second method is by utilizing net metering policies. Net metering nets the total amount of energy generated against the amount of energy consumed over a predetermined period of time, which is usually a year. Only the "net" energy consumption is billed. Nearly every state, including Washington, mandates that utilities allow net metering

The net metering remuneration mechanism has recently come under scrutiny as broad adoption of rooftop solar will impact utility finances. While net metering can produce economic benefits to customers with solar, it can also be detrimental to utilities if adopted on a broader scale. Utilities have both fixed and variable costs and depend on retail revenues to directly fund utility operations, including maintenance, power generation, and administrative functions. Utilities design rates to have mechanisms to recover both fixed and variable costs. However, the District's retail rates have historically been designed to have a low base charge which does not fully recover fixed costs with a higher volumetric charge which seeks to recover both the fixed and variable costs. If a customer is decreasing their consumption and avoiding the volumetric charge, the customer is not paying their full share of the fixed costs associated with the poles, wires, and other equipment needed for reliable electricity service. A decrease in revenue from volumetric charges from one customer results in shifting costs to other customers to make up the revenue gap. Simply increasing the volumetric charge thereby makes solar more cost competitive leading more customers to install rooftop solar. The crux of the case is that the progression of increasing rates to compensate for decreasing retail revenues leads to a downward spiral eventually rendering utility finances untenable. Designing rates to more fully recover fixed costs using the fixed cost rate components will help to mitigate the cost shifting and create more equity between customers with and without solar. Public utility commissions of many states were asked to weigh in on this issue, which did not result in a consensus opinion. The responses ranged from an effective affirmation of the status quo (California) to limiting remuneration to the energy offset and ending net metering (Hawaii).[15,16] One takeaway from these proceedings is that net metering is a complex issue. The intermittent nature of solar energy can also complicate grid management. The production profile of solar energy tracks closely to the daily and seasonal orientation of the sun; this is another way of stating that solar panels only generate energy when the sun is out. The solar fleet within each state tends to

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[15] Trabish, Herman K. "Inside the Decision: California Regulators Preserve Retail Rate Net Metering until 2019." Utility Dive, 01 Feb. 2016. Web. 25 Apr. 2016.

[16] Pyper, Julia. "Hawaii Regulators Shut Down HECO's Net Metering Program." Greentech Media, 15 Oct. 2015. Web. 25 Apr. 2016.

collectively come online and go offline. The implication is that there has to be enough dispatchable generation on standby to replace the solar generation when the sun sets or when clouds approach. Much of the backup generation is natural gas fueled. Therein lies the paradox of renewable energy: each kilowatt of renewable generation must be backed up with a dispatchable resource, which is almost universally fueled with natural gas.

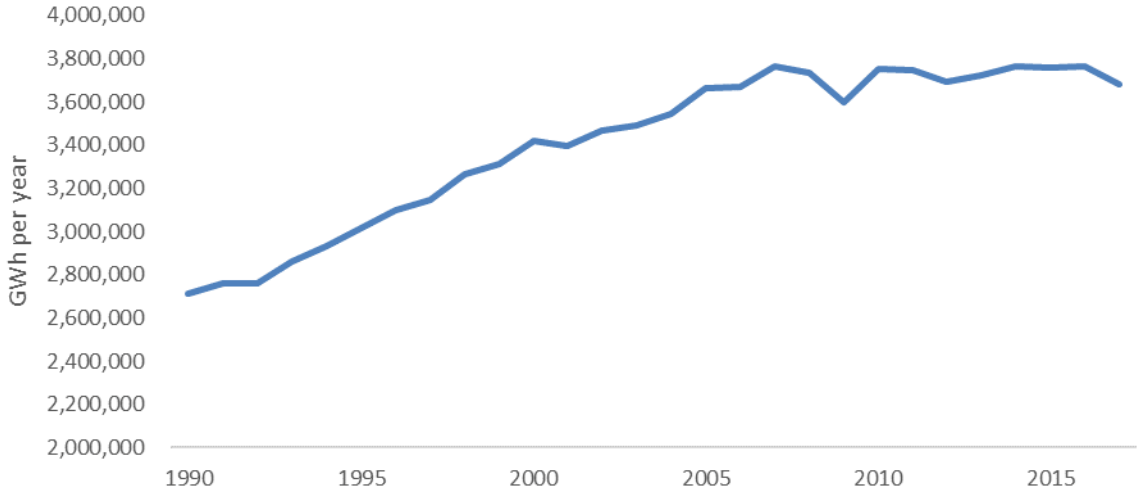
The dynamic of abundant, zero marginal cost electricity during the daytime hours, while the sharp ramp up of dispatchable non-zero marginal cost resources coinciding with the sun setting created a phenomenon in the market known as the duck curve. In areas with high rooftop solar penetration such as California, there are periods of the year when the midday net electricity demand (consumption less solar generation) is the lowest time of the day. Wholesale prices reflect this trend, with prices bottoming out when solar production is at its highest point, then sharply increasing as the sun sets.

The ability to shift load to periods with ample zero marginal cost supply would bolster wholesale market prices during depressed periods, encourage the use of carbon-free generation, and decrease the steep increase in market prices towards the end of the day.

Energy Efficiency

Since the Great Recession, both population and GDP per capita have increased nationwide, with no discernable impact on loads. Electricity consumption grew throughout the early 2000s, dipped during the Recession, recovered, and remained flat ever since (**Figure 23**).

Figure 23: US Annual Retail Electricity Consumption (non-Weather Normalized)



Part of this trend can be explained by implementing conservation measures such as adding insulation to homes. It can also partially be explained through increasing energy efficiency such as converting to LED bulbs or upgrading from electric resistance coil furnaces to heat pumps. The impact of energy efficiency cannot be understated. The estimated energy savings from LED lighting alone in the US in 2016 was 469 trillion BTUs, roughly 67 TWh (total national electricity consumption by comparison was about 3,500

TWh).[17] By 2035, LEDs are forecasted to reduce consumption by 5.1 quads by 2035 in the US, translating to a savings of over 700 TWh per year.[18]

Lighting is only a piece of the puzzle. Efficiency is increasing across all household appliances. Electric furnaces that utilize resistance heating, still commonly found in homes across Washington State, have a coefficient of performance (COP) of 1. For each unit of energy input, a single unit of heat is output. Heat pump systems, on the other hand, have COPs ranging between 2 and 4, meaning that they are between 2 and 4 times more efficient than electric furnaces. Rather than produce hot or cool air, heat pumps separate hot and cold air, injecting heat into the conditioned area and ejecting the cold exhaust into the atmosphere. Heat pump technology continues to improve as well, with newer heat pumps able to separate the air more efficiently and at lower temperatures. This technology is also applicable for water heaters, where the fluid being temperature conditioned is water, rather than air.

Heating/cooling (47%), water heating (14%), and lighting (12%) cumulatively make up roughly 73 percent of home energy consumption, excluding transportation. Technology that can reduce lighting loads by greater than 80 percent and conditioning loads by 50 to 75 percent is commercially available and viable today. There will be impacts to home energy consumption as more of the less efficient appliances are replaced with newer technology.

Electric Vehicles

The widespread adoption of electric vehicles has potential impacts on how and when energy is consumed and has the potential to at least partially offset two looming issues in the utility world. There was a strong historical correlation between load growth and population/GDP per capita, where they moved in lock-step. Electric vehicles present a unique opportunity and challenge for utilities going forward. While wide adoption has been slow due to concerns with earlier models of electric vehicles relating to the short range and concerns that the car would run out of charge before reaching their destination. For context, the Chevrolet Volt originally had a battery-only range of about 30 miles and the Nissan LEAF started with a range of roughly 70 miles per charge. The newest generation of electric vehicles starting with the Chevrolet Bolt are estimated to have a range of over 200 miles on a single charge – and roughly equal in cost to the earlier generation EVs. Along with range, consumer choice is also increasing. In 2010, there were 2 electric vehicle models available. That number is up to about 65 today, and it is projected that there will be about 100 different electric vehicle models commercially available by 2020.[19] .

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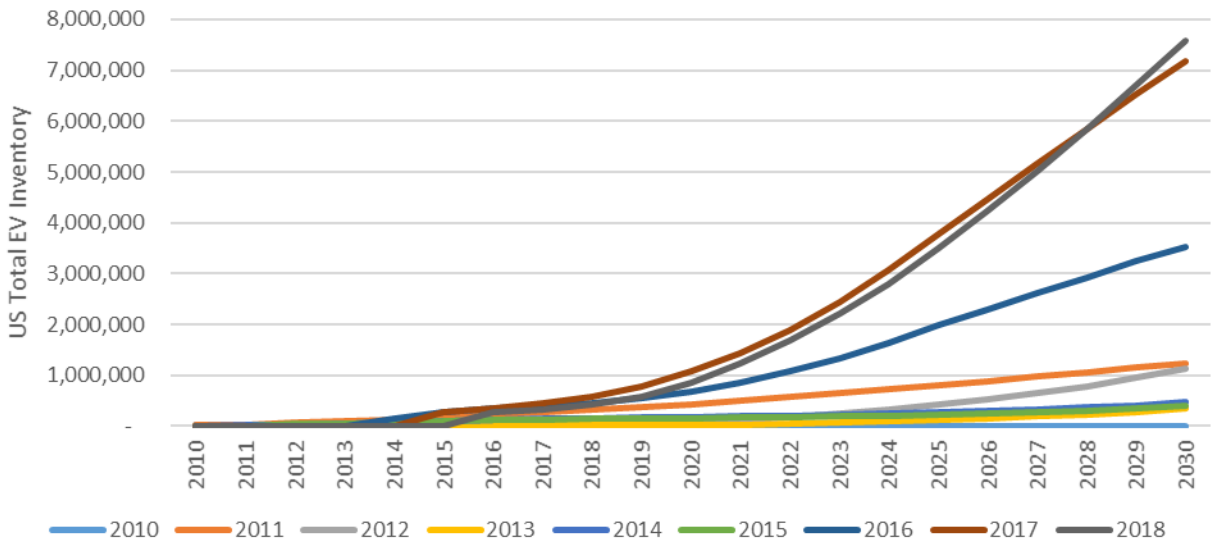
[17] "Adoption of Light-Emitting Diodes in Common Lighting Applications." US Department of Energy Office of Energy Efficiency & Renewable Energy, July 2017.

[18] "Solid-State Lighting 2017 Suggested Research Topics Supplement." US Department of Energy Office of Energy Efficiency & Renewable Energy, September 2017.

[19] "Electric Vehicles." Bloomberg New Energy Finance. Web. 30 May 2018.

The electric vehicle adoption forecast is similar to renewable energy as the succeeding forecasts continue to observe upward revisions. In 2010, the EIA forecasted a cumulative 2030 EV inventory at a paltry 3,500 vehicles.[20] The 2018 forecast revised that figure upwards to over 7.5 million vehicles (**Figure 24**).[21] If a continuation of this trend where each successive forecast is greater than the last (and sometimes significantly), the point at which EVs outnumber internal combustion engines will come sooner, and perhaps much sooner, than expected.

Figure 24: EV Inventory Forecast through Time (2010-2030)



Progress, however, is not without its setbacks. Tesla planned to build 500,000 electric vehicles per year by 2018, but it is reported that Tesla built fewer than 35,000 vehicles in Q1 2018, short of the mark required to hit its goal.[22,23] It's difficult to predict whether EVs will continue the trend of solar and batteries, with forecasters chronically underestimating consumer adoption or whether it is a trend that will eventually fizzle out.

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[20] "Fleet Vehicle Stock." Annual Energy Outlook 2010. US Energy Information Administration. Web. 30 May 2018

[21] "Fleet Vehicle Stock." Annual Energy Outlook 2018. US Energy Information Administration. Web. 30 May 2018

[22] Goliya, Kshitz, and Alexandria Sage. "Tesla Puts Pedal to the Metal, 500,000 Cars Planned in 2018." Reuters, 05 May 2016. Web. 30 May 2016.

[23] Lambert, Fred. "Tesla confirms record production of 34,494 vehicles last quarter, ~10,000 Model 3 vehicles." Electrek. 03 April 2018.

Cumulative EV sales as of the end of 2017 totaled about 1 million vehicles, less than 0.5 percent of the total passenger vehicle fleet.[24] Most forecasts, however, project EV adoption to follow along an "S-curve" trajectory, which is flat in the beginning and steeper in the middle. Following the theory, US adoption is currently at the beginning of the S-curve, and within the next decade will move towards a steeper part of the curve when EVs are forecasted to comprise over 10 percent of the vehicle fleet by 2030.[25] Norway is already leading the charge, where EVs made up 52 percent of new vehicle sales in December 2017.[26] This is a large jump from 2016, when the EV market share was about 23 percent.[27] Norway incentivizes the adoption of EVs by providing generous subsidies, along with already high gasoline prices which tilt the economics away from internal combustion engine vehicles. Though gasoline prices in the US have dropped since their 2014 highs, low, stable electricity prices bolster the economic case for EVs. Gasoline futures are hovering around $2.00/gallon, excluding state and federal gas taxes with oil prices between $60 and $70 per barrel. The average electricity price in Washington State is $0.077/kWh. A compact car that averages 30 miles per gallon would have a fuel cost of $0.07/mile. An equivalent sized electric car consumes about 0.3 kWh/mile, translating to a fuel cost of $0.023/mile, roughly 1/3 the cost of an internal combustion engine (**Figure 25**, **Figure 26**).[28]

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[24] "Long-Term Electric Vehicle Outlook 2018." Bloomberg New Energy Finance. 21 May 2018. Web. 31 May 2018.

[25] ibid

[26] Lambert, Fred. "Electric cars reach new 52% market share record in Norway thanks to Tesla's record deliveries." Electrek. 03 January 2018.

[27] McCarthy, Niall. "Norway Leads The World's Market For Electric Vehicles." Forbes. N.p., 23 July 2014. Web. 16 June 2016.

[28] Assumptions based on $2.00 wholesale gasoline which exclude state and federal gas taxes, a Washington State average electricity price of $0.77/kWh as published by the EIA, and an average EV consumption of 3 miles per kWh

Figure 25: Internal Combustion Engine Fuel Costs per Mile (excluding Federal and State gas taxes)

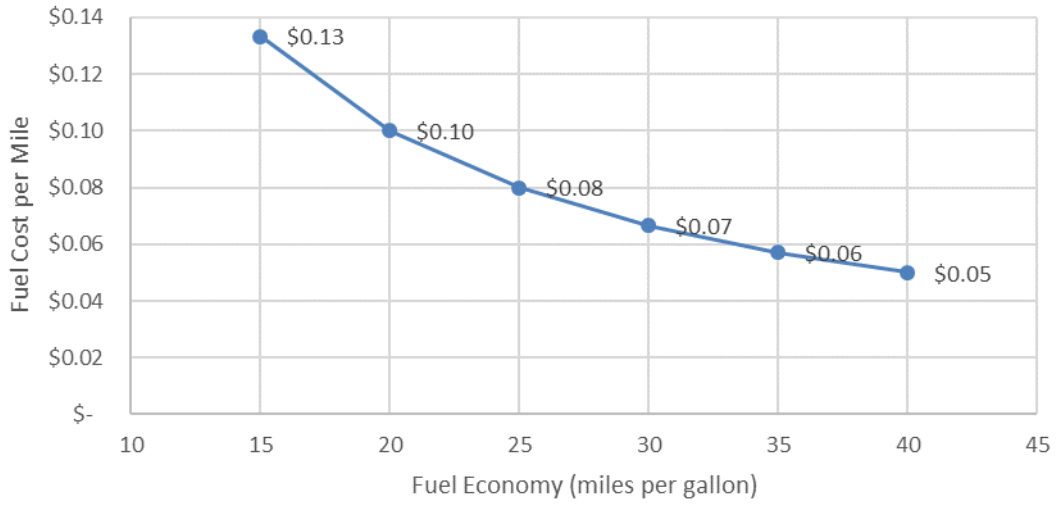
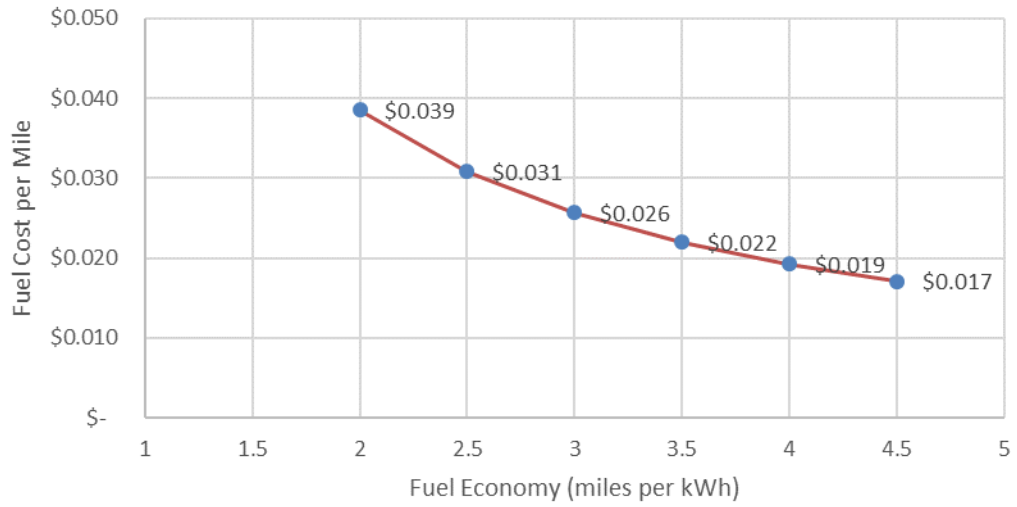


Figure 26: Electric Vehicle Fuel Costs per Mile (excluding taxes)



More aggressive forecasts suggest that by 2040, electric vehicles are forecasted to make up about 50 percent of the vehicle fleet.[29]

Envisioning a future where our current fleet of internal combustion engine vehicles is replaced by EVs still requires a bit of imagination, but it's a scenario with lasting, generally positive financial impacts on the utility.

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[29] EV Sales Forecast. Bloomberg New Energy Finance. Web. 06 June 2018.

Compact electric vehicles have a fuel economy of approximately 3 miles/kWh. The fuel efficiency for larger vehicles, such as minivans, decreases to 2 miles/kWh. Based on observed evidence, buses can achieve about 0.45 miles/kWh.

An average household that drives 2 vehicles 13,500 miles per year would consume about 9,000 kWh. Washington households, by comparison, consume about 12,500 kWh/year, slightly higher than the national average.[30] Back of the envelope math suggests that electrification can meaningfully increase electricity consumption.

While lower energy consumption generally has a positive societal impact, it necessarily harms utility finances. Switching cars to run on electricity rather than gasoline or diesel has the potential of increasing electricity consumption. The average US household has the potential of increasing its annual total retail load by 35 percent per electric vehicle.[31,32] At a minimum, that represents a significant portion of the demand lost to conservation and energy efficiency. The second problem that electric vehicles can solve, particularly if equipped with bidirectional chargers that can both draw energy from and inject energy to the grid, are potential grid stability issues as more non-dispatchable renewable resources come online. It is not difficult to imagine that well executed EV integration would treat as exactly what it is: a rolling battery that can be used as both an energy sink and source that draws electricity from the grid when it is available and supplies it when demand is higher. Improperly managed, EVs could easily exacerbate the situation if charging during periods of high demand when wholesale electricity prices are higher. Economic signals can strongly influence the EV integration path. With the correct incentives, EVs can increase demand when loads and wholesale prices are lower while simultaneously increasing retail sales.

The topics discussed in this chapter were not inclusive of all developments in the utility and energy sphere, however it was a brief screening of some well discussed subjects today. For evidence of the pace of change within the industry, we can look to the 2014 IRP. Solar was not expected to gain as much market share as it has, coal was still expected to remain as the dominant generating resource, and there was no discussion of batteries or electric vehicles. The growth renewables and electric vehicles outpaced their respective forecasts as recently as the 2016 IRP. It would not be surprising if in two years, some of the issues and technologies addressed in this chapter faded away while new ones appear and play an unexpectedly large role in our electric future.

Energy Storage

The topic of energy storage is explored in depth in **Chapter 7: Capacity Requirements, Energy Storage, and Demand Response**.

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[30] Residential Electricity Rates & Consumption in Washington. Electricity Local. Web. 06 June 2018

[31] "How Much Electricity Does an American Home Use?" US Energy Information Administration, 21 Oct. 2015. Web. 30 May 2016.

[32] Alternative Fuels Data Center. US Department of Energy. Web. 30 May 2016.

Corporate Renewable Procurement

Perhaps the greatest uncertainty in the generation landscape is what actions corporations will embark upon to meet their sustainability goals. In 2016, approximately 70 companies committed to becoming 100 percent renewable, including several Fortune 50 companies. The most current list has 135 companies committing to that goal.

Corporations are largely focused on building new renewable energy projects to meet their needs, rather than relying on the procurement of existing resources. Additionality and building incremental renewable generation capacity is part of the goal. Furthermore, the commitments are flexible in that the program is voluntary and timelines are set by each individual entity. And finally, the list of these commitments are growing – and it may not be all inclusive. Some companies may be pursuing this goal without being a part of the group. The challenge to resource planning is that the additional generation may not be being built out of need or even economics. 100 percent renewable energy is part of the corporate strategy. In other words, resource planners have little understanding as to when and how much of this new generation is slated to come online.

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

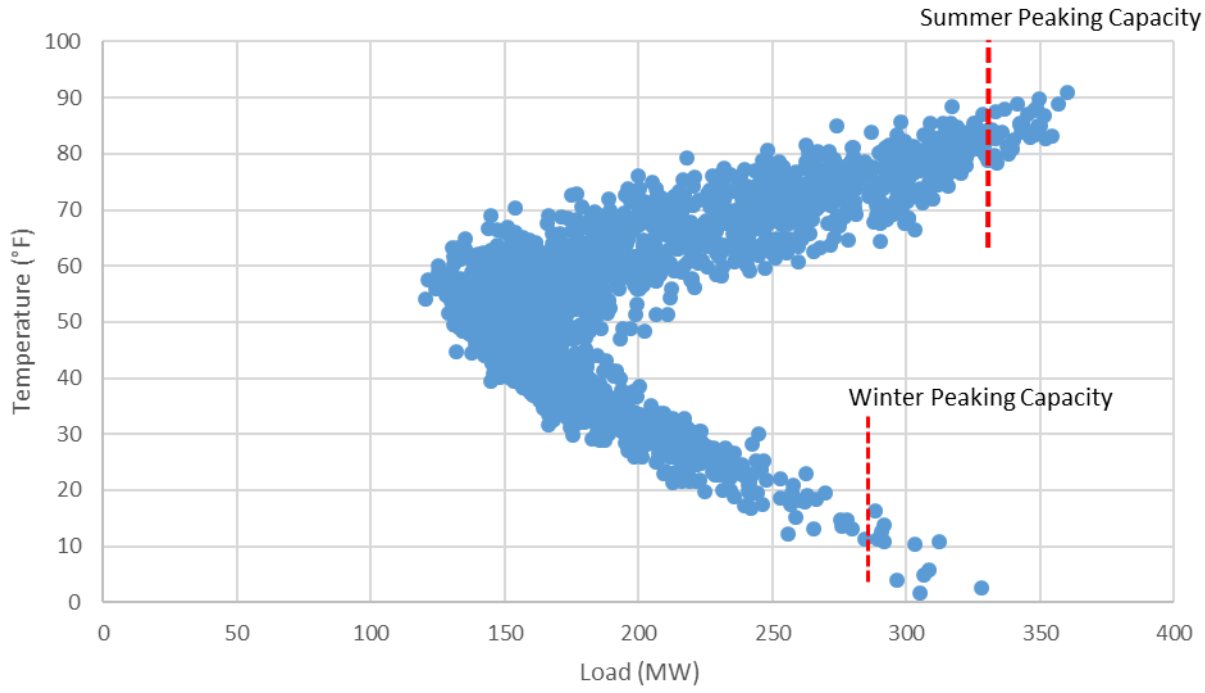
An important aspect of an IRP is an accurate forecast of peak load and a resource plan to meet this load. Legislation (EHB 1826) has been added requiring a stochastic look at Energy Storage (ES) and other capacity products to address the integration of variable resources. In the Power and Conservation Council's 7th Power Plan (Council or Council Plan), Demand Response (DR) was thoroughly reviewed and determined to be a cost effective resource to meet peak load.

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

Peak Load and Capacity Position

As discussed in **Chapter 3: Current Resources**, the District is surplus energy from an annual load/resource basis; however, the District does have hourly capacity shortages when the demand exceeds the District's supply. **Figure 27** charts the daily average temperature vs. the daily average load between 2011 and 2018. Loads are generally the lowest during periods when the temperature is between roughly 40°F and 60°F. While periods of extreme heat or cold are both accompanied by higher loads, higher load periods come more frequently during the summer rather than the winter.

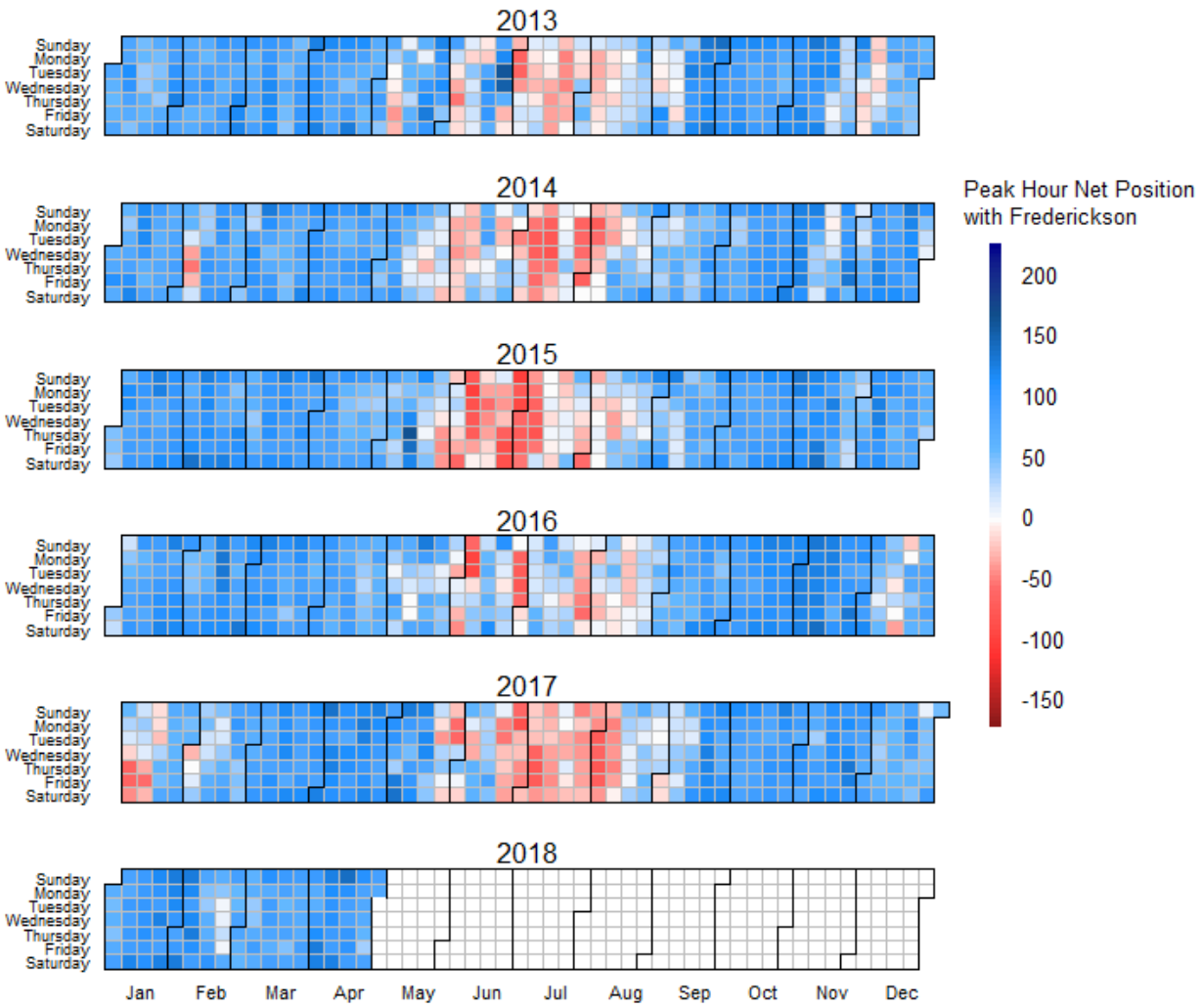
Figure 27: Daily Average Temperature vs. Daily Average Load



The highest load periods typically appear in June – August, though there are short periods of high loads during the winter months as well. The District currently has a summer peak generation capacity of 354 MW and 309 MW of peak winter generating capacity. This assumes a typical peak slice generation level of 10,900 MWs which can vary year by year and across seasons. Consistent with the BPA White Book analysis, this estimate excludes wind resources, which cannot be relied upon to generate electricity on demand. Compared to the highest peak demand and average heavy load hour loads observed in the last 5 years of 431 MW and 384 MW, respectively, the District's demand will exceed its supply during certain periods.

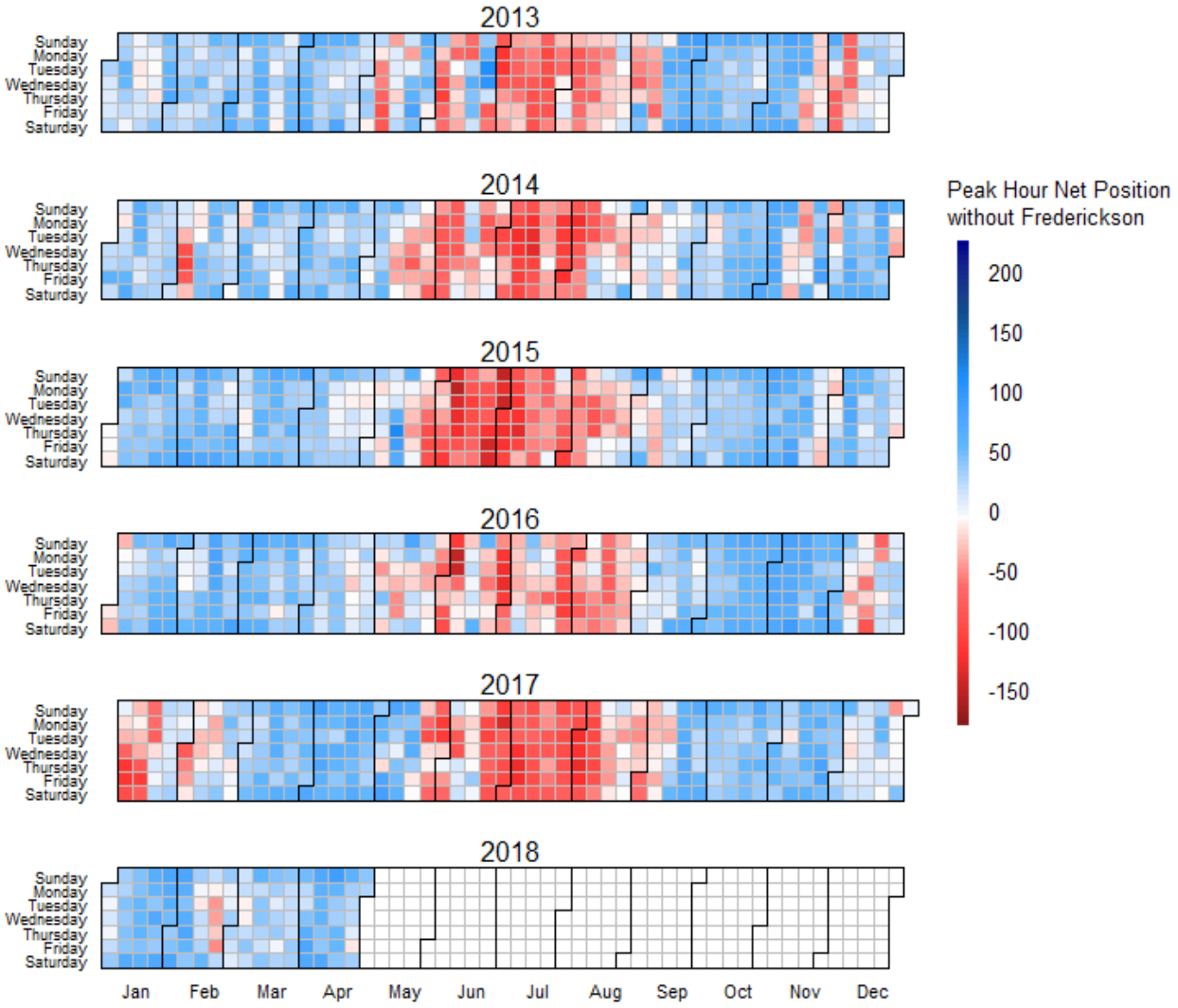
Figure 28 displays a theoretical net position of the daily peak demand hour that was calculated by applying the District's estimated peak generation capability to the actual loads observed between 2012 and 2018. Estimated peak generation capability is defined as the average peak generation available, by month, over the past seven years.

Figure 28: Daily Peak Demand Net Position by month



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 deficits occurred in July 2015 when the peak hourly deficit was over 100 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 also be evaluated in this IRP. When the Frederickson PPA expires in 2022, the District can expect more frequent capacity deficits of a higher magnitude. **Figure 29** replicates **Figure 28**, but does not count Frederickson as a resource.

Figure 29: Daily Peak Demand Net Position by month minus Frederickson



The costs and risks associated with a capacity shortage, along with available strategies to manage these situations are discussed later in **Chapter 9: Risk Analysis and Portfolio Selection**.

Peak Load Analysis

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

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

BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). By virtue 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. Impacts on the District are not known at this time.

Hourly peak load: This is the largest 60 minute load that historically occurs or is forecast to occur during a year, season, or month. It can be defined as the largest actual hourly load, the largest actual load that has occurred during a historical period, a forecast of the hourly load under extreme conditions, or the expected hourly load (i.e. hourly load expected to occur less than a given percentage of the time, for instance, less than 95% of the time). It is typical to identify the largest expected winter and summer hourly load for resource planning purposes (usually by choosing from actuals from a recent year, or a series of years or an extreme forecast). **Figure 30** displays the hourly load for the summer and winter peak days from November 2011 through February 2018. The highest hourly winter peak has been 371 MW and highest summer peak has been 431 MW.

Figure 30: Winter and Summer Loads

Season	Hourly Peak	HLH Peak
Winter11/12	288	260
Summer12	394	350
Winter12/13	265	243
Summer13	415	376
Winter13/14	338	303
Summer14	431	384
Winter14/15	291	256
Summer15	429	384
Winter15/16	285	270
Summer16	425	377
Winter16/17	371	338
Summer17	426	373
Winter17/18	292	239
All Data	431	384
Winter	371	338
Summer	431	384

Heavy load hour (HLH) peak load: This is the largest 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.

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. For a utility embedded within the BPAT BA, there is not currently a requirement to demonstrate Resource Sufficiency (RS) on a forecast 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.

Since there is not a 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.

A second question is whether to use extreme, expected, or expected with an adder in the determination of peak load. Many reliability organizations and organized markets have an RS requirement based on "expected" peak load times a multiplier. Another methodology is to use modeling techniques to determine a projection of the HLH and hourly peak load under expected and extreme weather conditions (**Figure 31**). Often times both approaches yield similar values.

Figure 31: Summer and Winter Peak Loads

Winter Peak loads as a Function of Temperature

Percentile	Temp	Peak Hour	aHLH
1%	58	159	135
5%	49	175	147
10%	45	182	156
15%	42	190	163
20%	41	194	169
25%	39	198	174
30%	37	203	178
35%	36	206	183
40%	35	210	188
45%	34	213	192
50%	33	217	196
55%	32	222	201
60%	31	227	206
65%	30	231	210
70%	29	236	216
75%	27	240	221
80%	26	247	227
85%	24	254	235
90%	21	266	246
95%	15	290	265
99%	4	335	309

Summer Peak Loads as a Function of Temperature

Percentile	Temp	Peak Hour	aHLH
1%	57	176	158
5%	70	228	199
10%	75	252	218
15%	78	268	231
20%	81	281	241
25%	82	290	250
30%	83	297	258
35%	85	305	265
40%	86	313	272
45%	87	319	279
50%	88	324	286
55%	89	330	293
60%	91	336	300
65%	92	343	307
70%	93	348	314
75%	94	356	322
80%	95	362	331
85%	97	373	342
90%	99	386	354
95%	101	399	373
99%	105	420	403

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 will contain 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): Contingency and Regulation 7-8%, additional or prolonged outages 3-10%, and 1-10% to cover temperature (assume about 5% for this portion), economics, new plant delays resulting in an 11-28% requirement.

- California Independent System Operator (CAISO): Forecasted hourly peak loads are increased by 15% (still unclear what peak condition to use for the forecasted peak). CASIO doesn't 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 to the Public Power Council (PPC) summarizing Resource Adequacy (RA) and Planning Reserve Margin (PRM) (**Figure 32**).

Figure 32: E3 Summary of Approaches to RA

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

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

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

E3 also provided recommendations for planning criteria:

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

Approach used for peak load determination:

1. Examine the Nov-Feb and June-August actual hourly and daily HLH load for 2012-2018 and determine the load associated with the 95th percentile temperature.
2. Establish this value as expected winter and summer hourly and HLH peak load for the 1st year of the IRP (2018/19).
3. Use the annual growth in energy load as the annual growth rate for future years.
4. As can be seen below, this will result in higher peak planning loads than the approach suggested by E3.

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

Figure 33 displays the Peak Load scenarios studied to assess the District's peak load/resource balance. The 2025 values were derived by escalating the 2018 values by 1.047, which is the District annual energy growth rate of .66% escalated for 7 years.

Figure 33: Peak Load Scenarios

	2018 Peak Load (aMW)		
	Load 50th	Load 50th * 1.16	Load 95th
July HLH	286	331	373
July Peak	324	376	399
Jan HLH	196	227	265
Jan Peak	217	252	290
	2025 Peak Load (aMW)		
Growth Rate	1.047	1.047	1.047
July HLH	299	347	391
July Peak	340	394	418
Jan HLH	205	238	277
Jan Peak	227	264	304

Figure 34 is the expected resource output during summer and winter hourly peak and HLH. The slice values were determined by TEA planning staff. The system values are 9400 aMW for HLH and 10,900 MW for the peak hour. Higher values may be achieved depending on water conditions. The New Capacity Resource is the amount needed to meet the HLH load:

Figure 34: Peak Resources

2018 Resources (aMW)						
	Slice	Block	Freddie	Other	New Capacity Resource	Total Existing Resource
July HLH	130	152	50	2	39	334
July Peak	150	152	50	2		354
Jan HLH	130	107	50	2	0	289
Jan Peak	150	107	50	2		309
2025 Resources (aMW)						
July HLH	130	152		2	107	284
July Peak	150	152		2		304
Jan HLH	130	107		2	38	239
Jan Peak	150	107		2		259

Figure 35 shows the resource outputs under the above conditions.

Figure 35: Peak Resources

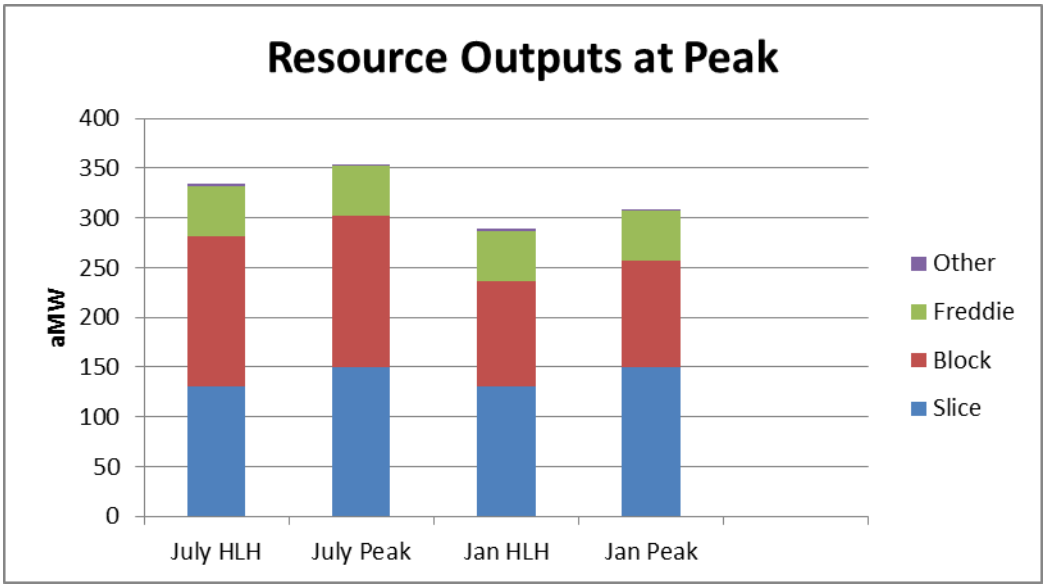


Figure 36 highlights the above data graphically. Note that peak resources meet the planning criteria in the winter, but not the summer. The HLH summer deficit is about 39 MW and the peak deficit is about 45 MW.

Figure 36: Peak Load/Resource Balance

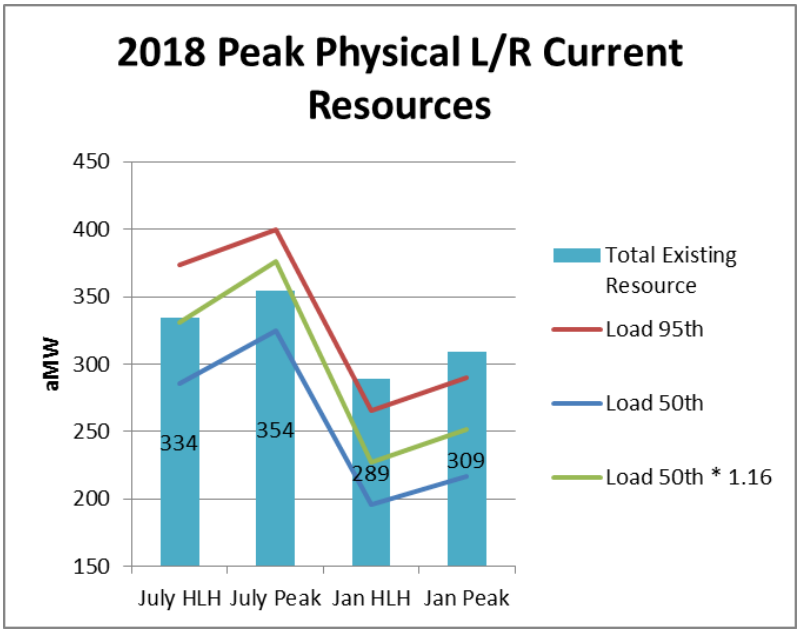
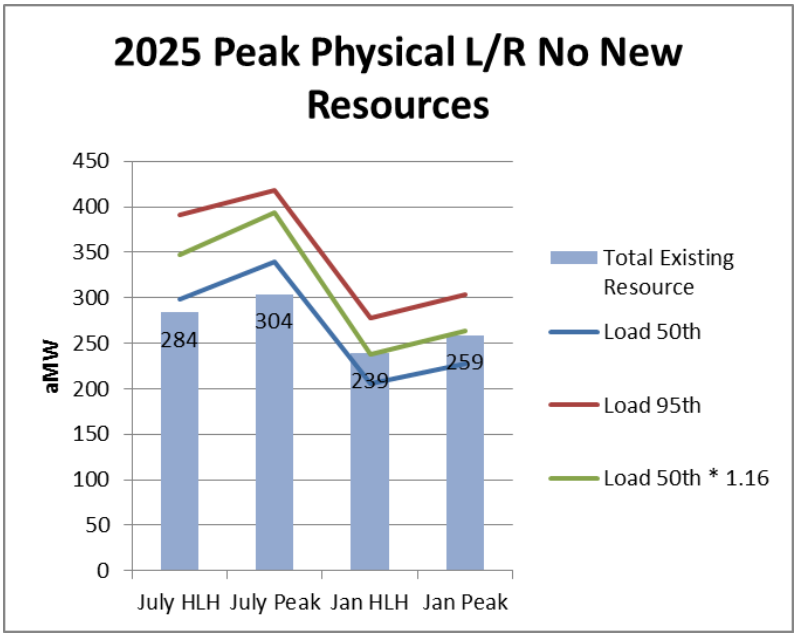


Figure 37 displays the load/resource balance in 2025 with .47% annual peak growth and no replacement for Frederickson. The HLH capacity deficit in summer in the 95th case is 107 MW and the capacity deficit in winter is 38 MW.

Figure 37: Peak Load/Resource Balance in 2025 with No Frederickson Replacement



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.

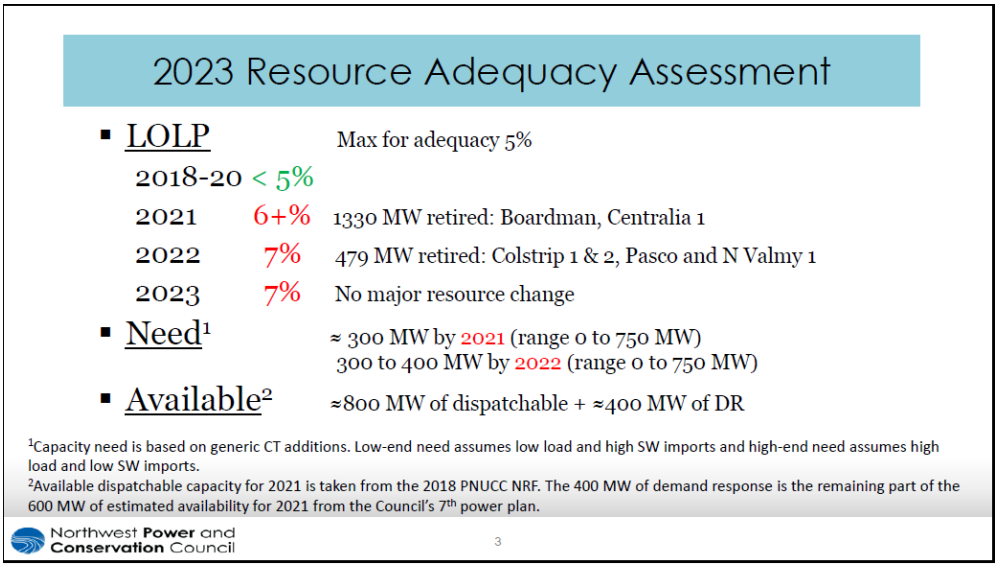
1. Market purchases above what is needed for energy in the IRP, including physical options with 1-5 year terms
2. Demand response and energy storage
3. Build a NG peaking resource (based on BPA's generic peaker in the rate case)

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. 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 7% in 2023, when several large coal plants are scheduled to shut down (**Figure 38**).

Figure 38: NWPPC LOLP Summary



The base case for the analysis allows 2500 MW of imports from CA. As seen below, the results are sensitive to the amount of imports and the load forecast. The Med Load forecast assumes a small amount of annual load loss for the region after accounting for conservation in the 7th Plan (**Figure 39**).

Figure 39: NWPPC LOLP Heat Map

2023 LOLP Heat Map (%)

SW Import (MW)	1500	2000	2500	3000[1]
High Load (+2%)	14.3	12.1	10.1	7.8
Med Load	11.0	8.6	6.9	5.1
Low Load (-2%)	8.0	6.4	4.9	3.5

The analysis provides LOLP for both summer and winter and includes some imports from California. As seen below, the monthly assessment is less than 3.3% in all months through 2023. The updated analysis shows virtually zero LOLP for the summer (**Figure 40**).

Figure 40: NWPPC Monthly LOLP Summary

Monthly Adequacy Assessments

Period	2022	2023	Diff
October	0.3	0.2	-0.01
November	0.1	0.1	0.0
December	0.3	2.0	1.7
January	2.0	3.3	1.3
February	0.7	1.5	0.8
June	0.0	0.0	0.0
July	0.0	0.0	0.0
August 1-15	1.9	0.0	-1.9
August 16-31	2.8	0.2	-2.6
September	0.2	0.1	-0.1

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 (through 2020), 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.

BPUD 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:

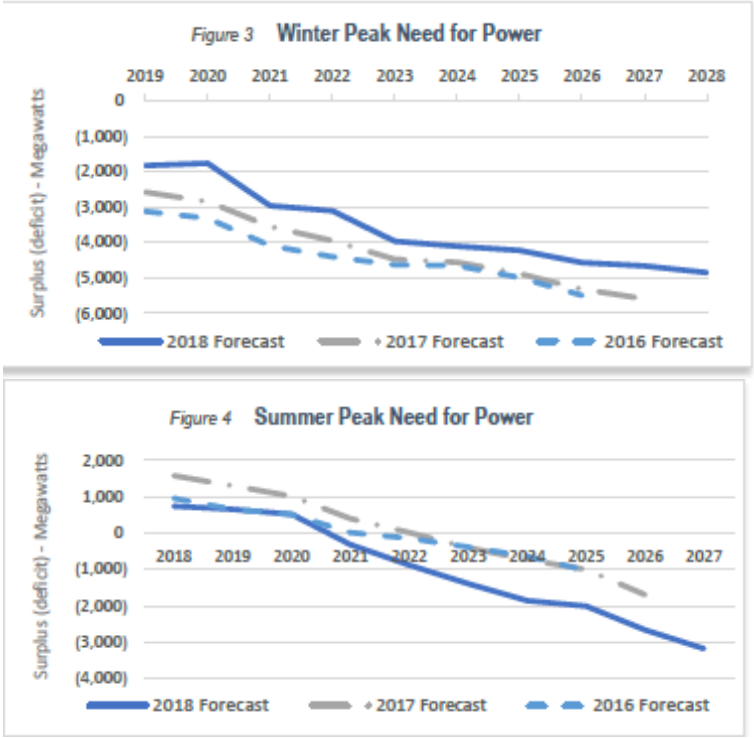
1. PNUCC NRF
2. BPA White Book
3. CA ramping needs to meet the solar ramp (duck curve)
4. NW IOU dispatchable resource build out plans from most recent IRP

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

The NRF[33] indicates in **Figure 41** a greater need for capacity in the winter months. As discussed below, capacity needs are more than covered by firm resources and Northwest Independent Power Providers (IPPs) through 2020, while market imports fully mitigate regional needs through 2021. 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 41** also indicates a potential summer capacity constraint starting in 2021 if average hydro conditions are not observed. While both potential capacity shortfalls are concerning, summer capacity issues present a greater risk to the District as a summer peaking utility due to its high concentration of irrigation loads and residential cooling loads. As discussed below, capacity needs are more than covered by firm resources and NW IPPs through 2026.

[33] http://www.pnucc.org/sites/default/files/file-uploads/2018%20NRF%20Final.pdf

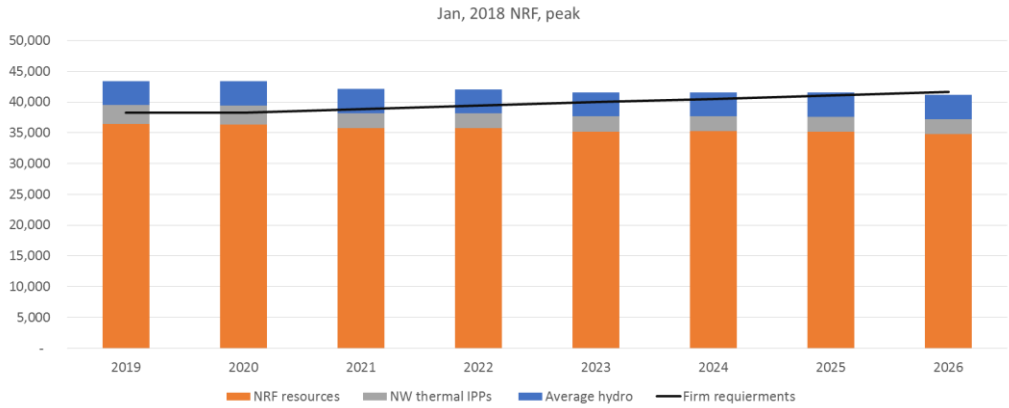
Figure 41: PNUCC Region-wide Winter and Summer Peak Capacity



Analysis of Regional Studies of Winter Loads and Resources

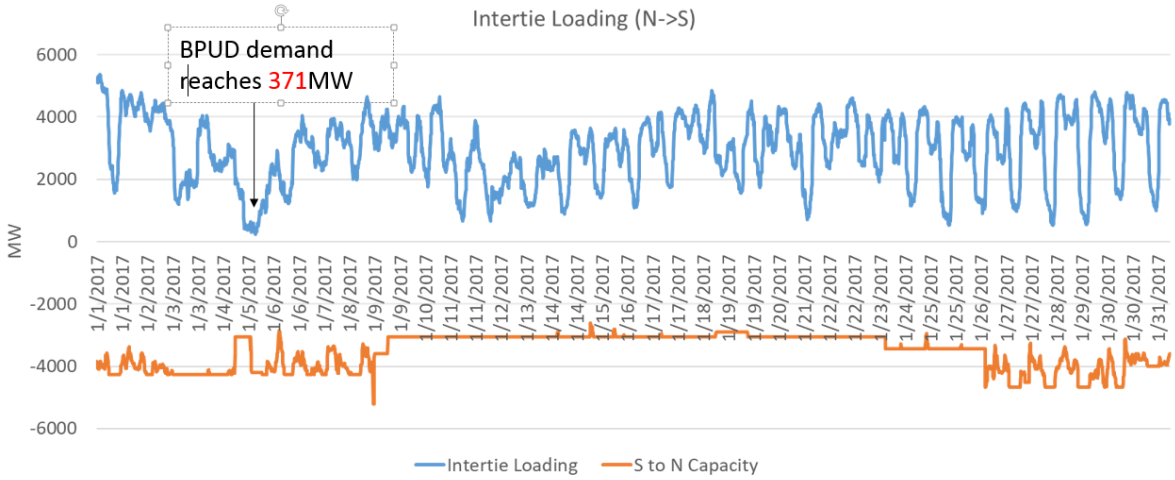
Since the NRF shows large deficits during winter peak events, additional analysis was performed to better understand the regional picture. IPP resources and average hydro are added to the NRF resources in **Figure 42**. As stated previously, the District is near Load/Resource (L/R) balance during a winter peaking event so the results of the NRF are less concerning.

Figure 42: 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 43**, significant import capability is available in the winter, even when the District load is peaking.

Figure 43: Pacific NW/SW Intertie Loading and BPUD hourly January Load

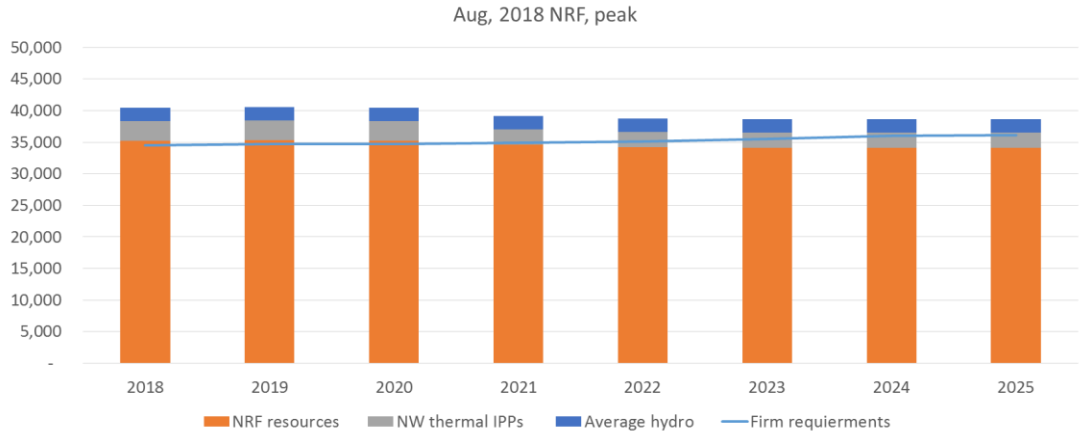


CAISO's winter peak is typically 30 GW, with 40 GW of thermal capacity (plus renewables). However, while the thermal capacity units are currently available, they are becoming uneconomical to operate due to policy decisions being made related to renewable buildout. Retirement of thermal units in CAISO 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 District is primarily concerned about summer peaking events, so further analysis is required. 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 these IPP resources are added to the analysis, the region shows a surplus during the summer peak through 2025 as can be observed in **Figure 44,** which also includes average hydro generation.

Figure 44: PNUCC NRF Summer Peak L/R Balance



As mentioned above, the NRF analysis does not include imports from CA. The Council's LOLP analysis includes small amounts of imports, as CA 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 CA from the NW. Although the District could be competing with CA entities on the price of power during peak summer days, **Figure 45** 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 45: Pacific NW/SW Intertie Loading North to South

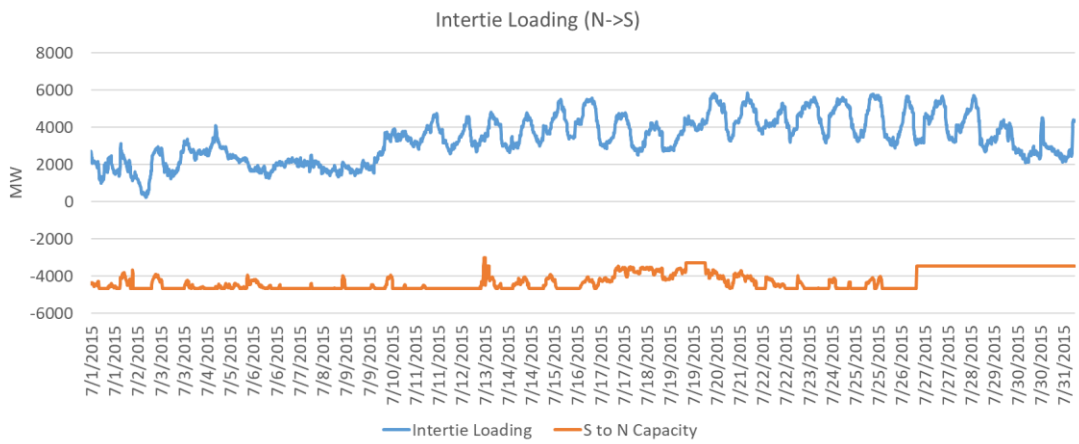
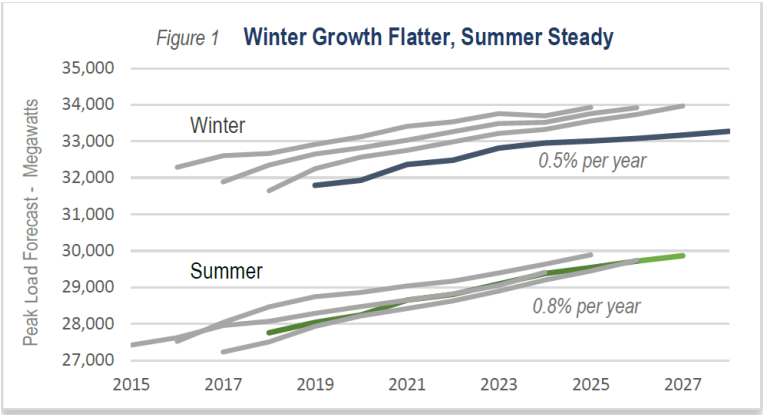


Figure 46 also notes that looking at past reports, firm annual energy (not pictured) and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply. This trend is not found in the summer peak forecasts which continue to trend as expected.

Figure 46: PNUCC 2018 NRF Region-wide Annual Energy Forecasts (Gray indicates previous forecasts)



BPA White Book

The "BPA 2017 Pacific NW Loads and Resources Study" also known as the White Book had the following key assumption changes from the 2016 version (**Figure 47**):

- Substantial increase in the average energy surplus each year
- Winter capacity surplus until 2021, with no imports assumed

Figure 47: BPA White Book Energy and Capacity Surplus/Deficit

Table 3-8

PNW Region
Annual Energy Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2019 through 2028
1937-Critical Water Conditions

Energy (aMW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2017 White Book	4088	4032	3017	2372	1721	1779	1347	918	505	465
2016 White Book	3839	3782	2707	2009	1323	1312	798	240	-293	n/a
Difference *(2017 WBK – 2016 WBK)*	*249*	*250*	311	363	399	467	548	678	798	n/a

Table 3-11

PNW Region
January 120-Hour Capacity Surplus/Deficit Comparison
Assuming 100% of Uncommitted IPP Generation is Available to the Region
OY 2019 through 2028
1937-Critical Water Conditions

January 120-Hour Capacity (MW)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
2017 White Book	41	308	-1185	-1666	-2331	-2599	-2840	-3765	-4019	-4175
2016 White Book	-198	-189	-1755	-2349	-3054	-3436	-3754	-4907	-5255	n/a
Difference *(2017 WBK – 2016 WBK)*	*239*	*497*	*570*	*684*	*723*	*837*	*914*	*1,143*	*1,235*	n/a

Summary of NW IOU Resource Procurement Plans in most Recent IRPs (Compiled by NWPPC and TEA)

- Could the LOLP continue to deteriorate if new resources are not built in the region in the future? While an IOU IRP is not a commitment to build, it does provide an indication of future resource plans. If the LOLP does continue to increase, there will be a justification for the IOUs to build some of the resources discussed in their plans. In the short term, the IOU's are primarily depending on energy efficiency and demand response as follows:

- Avista is not forecasting a capacity deficit until 2026, so they plan to do nothing until then

- PGE projecting capacity deficits beginning 2018
    - PGE will add about 500MW of energy efficiency and 200MW demand response resources
    - Identifies a need for "generic capacity" in 2018-2020
        - To be filled by "annual or seasonal" contracts
    - Proposed building of a 389MW CCCT in 2021
- PSE projecting capacity deficits by 2022
    - PSE plans to achieve 374MW of energy efficiency by 2023
    - Believes that "demand response and energy storage will be a reasonable, cost-effective resource that is sufficient to meet the capacity need that appears in 2022"
- Pacificorp just announced an amended IRP with no NG resources needed for the next 20 years

Figure 48: NWPPC Summary of Regional IOU IRP Resource Buildouts

Cumulative	2020	2025	2030	2036
Gas (MW)	335	1,222	2,701	5,113
Renewables (MW)	948	1,327	1,696	4,163

As displayed in **Figure 48**, there are plans for significant renewable and natural gas generation resource additions. **Figure 49** is a breakdown of the natural gas resources:

Figure 49: NWPPC Summary of Regional IOU IRP NG Buildouts

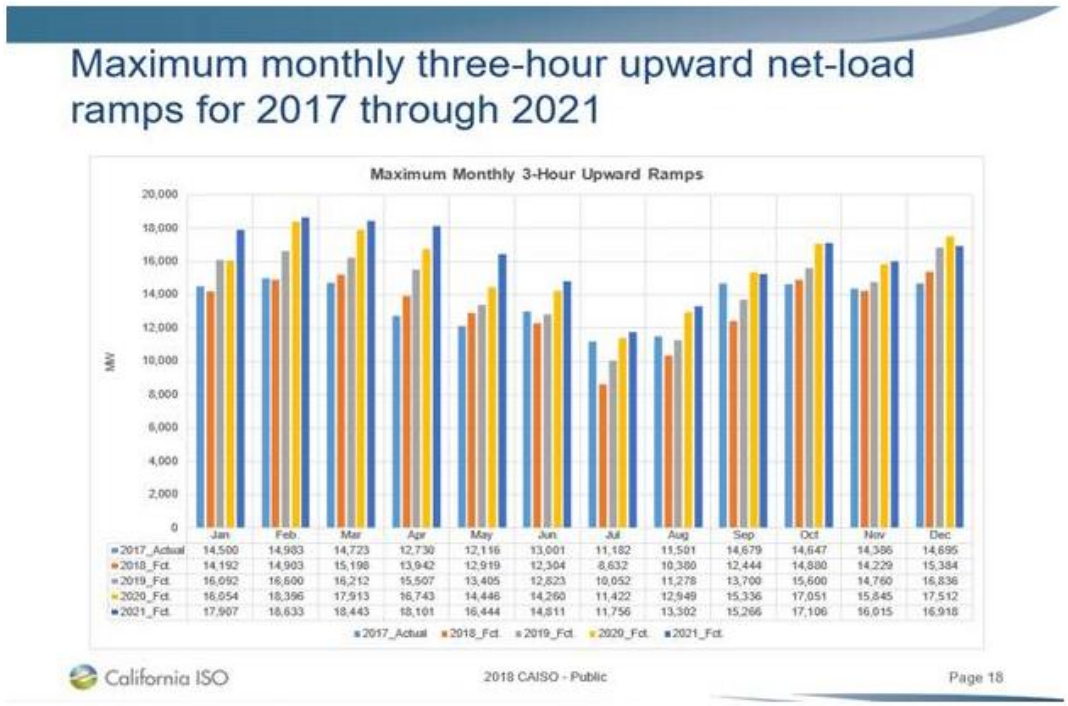
MW Installed	2020	2025	2030	2036
CCCT	0	497	166	481
Peaker	318	379	1,285	1751
Recip	17	11	28	180

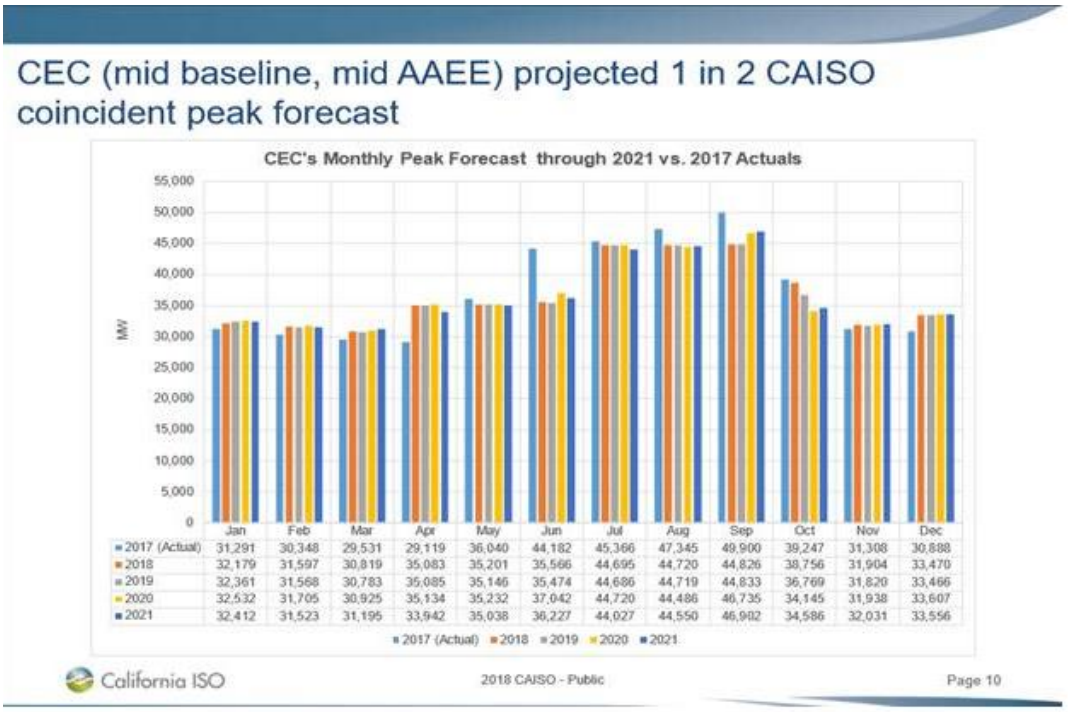
Summary of Impacts of CA need for Ramping due to Solar

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 50**).

Figure 50: CAISO Net Load Ramps and Peak Forecast





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

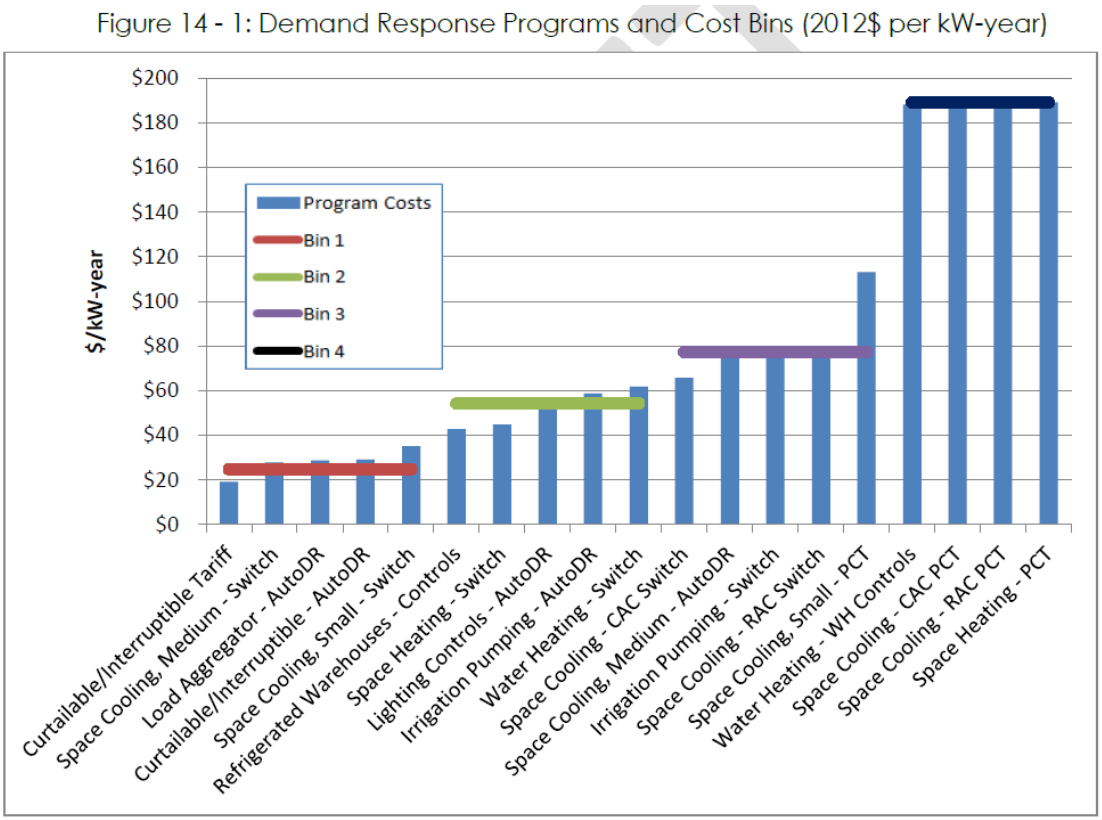
Based on the above discussion, the District's strategy of depending on market purchases to serve peak load is justified. The LOLP along with overall situational awareness of market availability will continue to

be monitored closely and longer term physical options will be considered if LOLP is projected to be above 5% in the 1-2 year time horizon. This will allow the District to have contract rights to the surplus IPP power available in the region**.**

Demand Response (DR)

DR is best suited for meeting the hourly peak load deficit. The Power Councils 7th Plan determined the following results for various DR programs. In 2016, Puget Sound Energy (PSE) released a Request for Proposal (RFP) to acquire 121 MW of winter peak capacity by 2021. The proposals submitted in response were ultimately all rejected due to not being cost effective. On March 29, 2018, PSE submitted a draft RFP to the Washington Utilities and Transportation Commission seeking bids to supply technology and implementation services for its Demand Response Program. The District will continue to monitor this development over the coming years. Since actual program implementation costs are unknown, it is assumed that DR could be implemented at the District for costs as displayed in **Figure 51**.

Figure 51: Seventh Northwest Power Plan's Estimated Cost of Demand Response



The District's implementation of a new Meter Data Management system in 2017 will assist in analyzing the DR potential available in its service territory. DR will continue to be evaluated and is addressed as an action item in **Chapter 10: Action Plan Summary**.

Energy Storage

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

Battery storage systems are not a one size fits all solution and the system design varies significantly depending on its desired function, whether it's for renewable integration, peaking, frequency regulation, or transmission congestion.[34] Building a battery storage system to absorb excess renewable generation for later use requires more infrastructure than a battery system used for short-term frequency response. Imagine an island grid powered only by solar and batteries. The battery bank will require a capacity that can store enough energy when the sun is shining to meet its demands at night. If that island grid also had backup generators on standby as a part of its generation mix, those could increase production when a cloud unexpectedly blocked the sun. The battery storage system then would be relied on for a much shorter burst of energy to maintain grid stability until the generators take over. The costs for the first option are greater, perhaps even significantly more than the second option. Battery technology, however, is evolving at a rapid pace. The development of battery packs in recent years can be attributed primarily due to investments into research and development from the automotive industry. The solar industry utilized technology from the semiconductor industry in its evolution earlier in the century and the energy storage sector is expected to leverage battery technology from other industries such as automotive development of electric vehicles.

The cost of battery packs declined from $1,000/kWh in 2010 to $350/kWh by 2015.[35] Battery capacity for the upcoming generation of electric vehicles dropped to $145/kWh as displayed in **Figure 52**, arriving at that price point 15 years ahead of current forecasts.[36,37] Energy storage will continue to be evaluated and is addressed as an action item in **Chapter 10: Action Plan Summary**.

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

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

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

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

Figure 52: Cost of EV Batteries

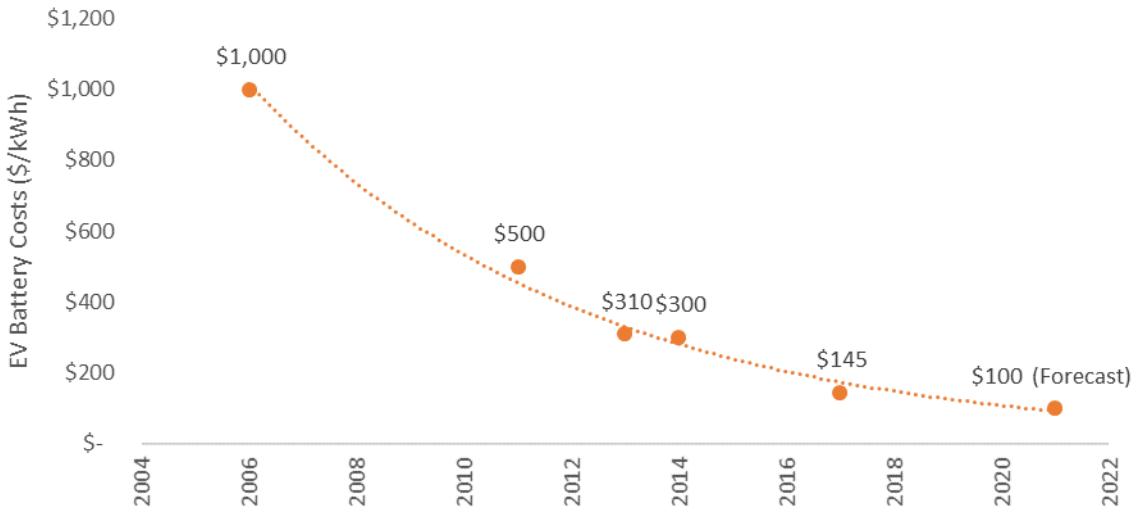


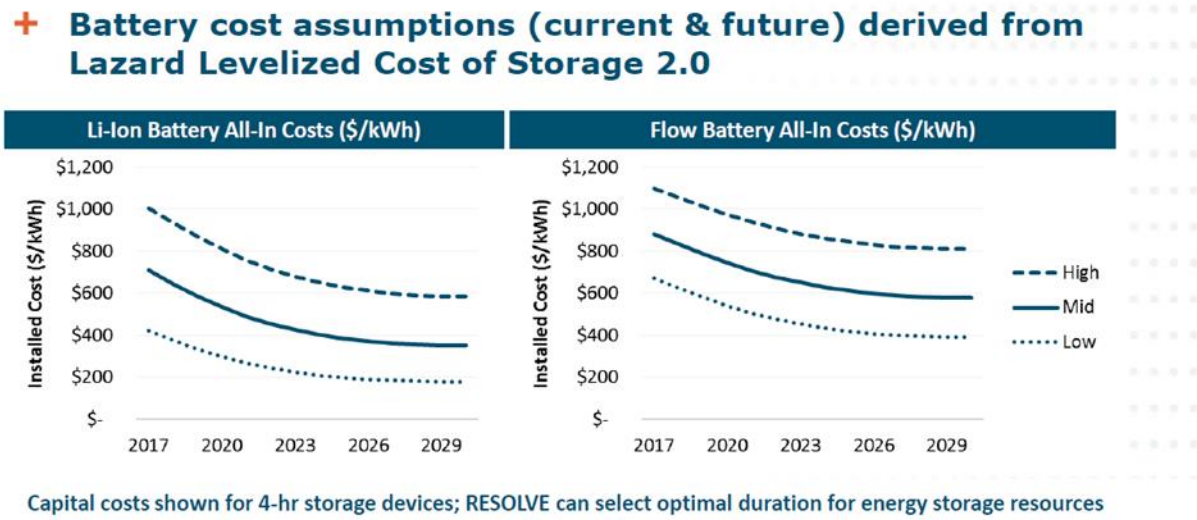
Figure 52 is a forecast of electric vehicle battery cost, which are forecasted to decline by 85 percent in six years, and seemingly follows a similar cost trajectory as wind and solar. Exponential cost declines continuously exceed the pace of forecasts along with higher than forecasted rates of adoption. 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.[38] Energy storage systems are costlier than the batteries alone due to balance of system costs that include bi-directional inverters that allow the two way flow of batteries, software, and other integration costs to ensure seamless operation regardless of energy source, whether it's from the grid, solar panels, or battery packs. There are few case studies available to determine the actual cost of battery storage systems. Puget Sound Energy's Glacier battery storage pilot project tied several thousand lithium ion batteries together and created a 4.4MWh system with a 2MW instantaneous power delivery rating. The total costs of the system are unclear, with at least $3.8 million funded through a grant from the Washington State Clean Energy Fund plus additional investments from PSE.

E3 provided estimates of battery storage system costs in their Carbon Markets analysis (**Figure 53**).

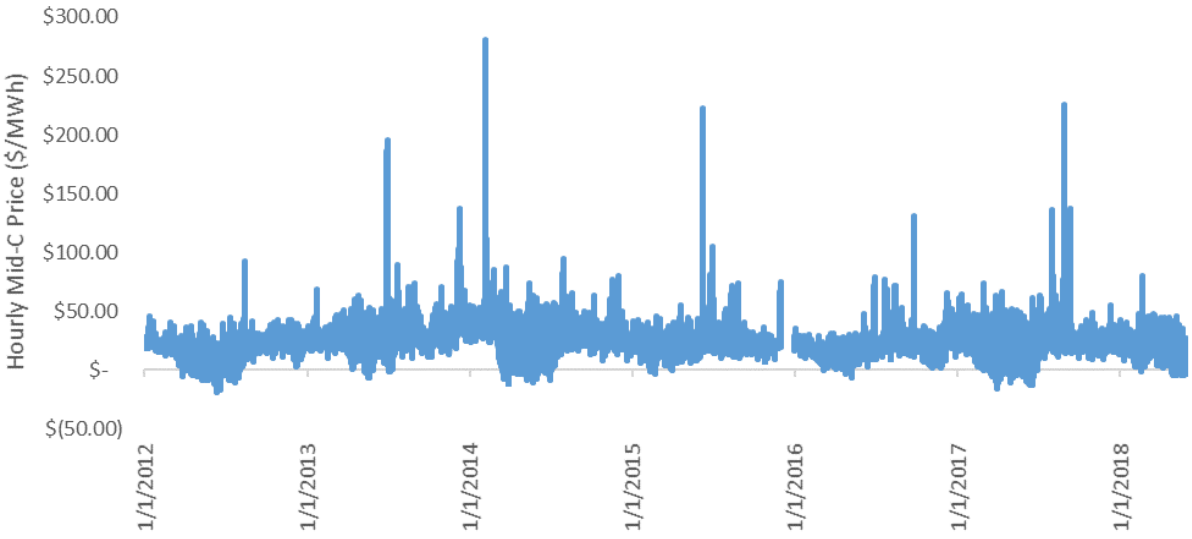
[38] Lambert, Fred. "Tesla Opens Direct Orders of up to 54 Powerpacks and Reveals Pricing." Electrek. N.p., 22 Apr. 2016. Web. 16 July 2016.

Figure 53: 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.[39] An analysis of five year historical wholesale market data (**Figure 54**) reveals that there are very few hours and even fewer days where batteries are cost competitive.

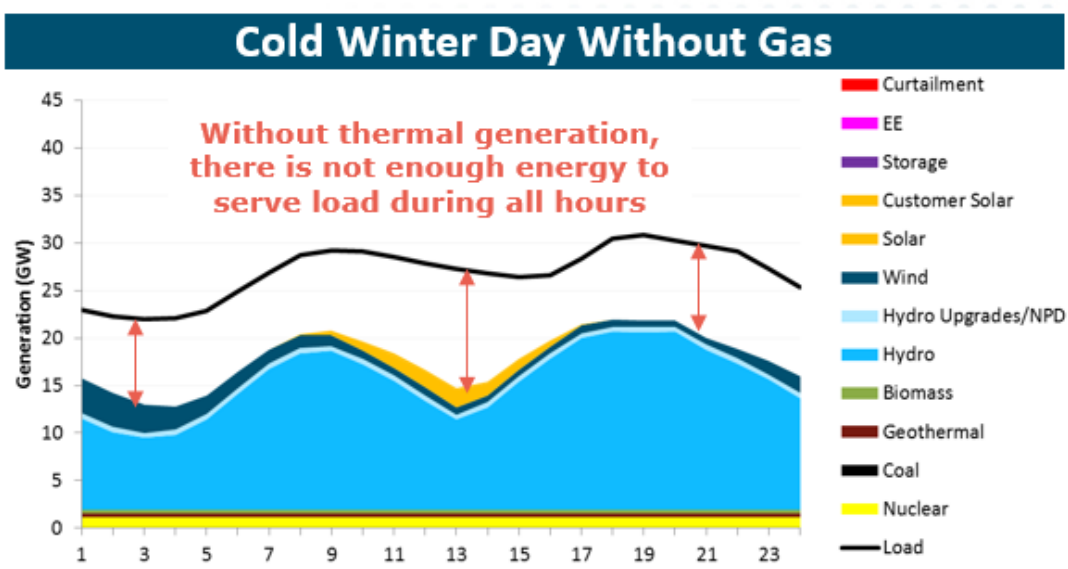
Figure 54: Hourly Mid-C Power Prices Through Time



[39] ibid

E3, in a presentation at the NW Power Markets Conference, performed analysis of using renewables plus battery storage to meet load in the Northwest. E3 concluded that renewables plus batteries alone is not sufficient to meet load on a cold winter day (**Figure 55**).

Figure 55: 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. If the reports are correct, costs will need to decline by nearly an order of magnitude 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 56**). Note the capacity cost is $117.44/kW/year. If 50 MW were desired from this resource, the annual cost would be about $6M/year. This is less than the current cost of Frederickson (approximately $7.7M/yr) due to a CT having a lower capital cost than a CCCT.

Figure 56: BPA Demand Rates

Table 4.1
Tier 1 Demand Rate

	A	B	C
1			
2	Start Year of Operation (FY)	2018	
3	Cost of Debt	3.80%	/1
4			
5	Inflation Rate	1.53%	
6	Insurance Rate	0.25%	/2
7			
8	Debt Finance Period (years)	30	/2
9	Plant Lifecycle (years)	30	/2
10			
11	Plant in service 2018 Vintaged Heat Rate Btu/kWh	8,541	/2
12			
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.17	/2
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 45.49	/2
15	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2018$	$ 45.09	
16	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2018$	$ 49.82	
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2018$	$ 47.46	
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2018$	$ 40.53	
19			
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,095.21	/3
21	Fixed O&M $/kW/yr 2018$	12.05	/4
22	Fixed Fuel $/kW/yr	$ 40.53	
23			
24			
25	/1 Source BPA FY 2017 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year		
26	/2 Source NWPCC 7th Power Plan Appendix H.		
27	/3 Source NWPCC Microfin Model with 100% PUD ownership at 3.80% with plant in service 2018. Version 15.2.1		
28	/4 Source NWPCC Microfin Model assumption of $11/kW/yr in 2012$		

D	E	F	G	H	I	J
Calendar Year	**Chained GDP IPD**		**Month**	**Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2011	103.31		Oct	26.74	8.90%	$ 10.45
2012	105.21		Nov	27.27	9.07%	$ 10.65
2013	106.91		Dec	30.28	10.07%	$ 11.83
2014	108.83		Jan	29.30	9.75%	$ 11.45
2015	110.00		Feb	28.54	9.49%	$ 11.15
2016	111.45		Mar	23.75	7.90%	$ 9.28
			Apr	19.67	6.54%	$ 7.68
	101.53%	5-year Ave.	May	16.63	5.53%	$ 6.49
			Jun	17.71	5.89%	$ 6.92
			Jul	24.66	8.20%	$ 9.63
Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2009 Base year)- Last Revised April 28, 2017			Aug	28.11	9.35%	$ 10.98
			Sep	27.94	9.29%	$ 10.91
					Average $/kW/mo	**$ 9.79**

End of Fiscal Year	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
2018	$ 1,076.96	$61.81	$ 12.05	$ 2.69	$ 40.53	$ 117.08
2019	$ 1,040.45	$61.81	$ 12.23	$ 2.60	$ 41.15	$ 117.79
					Rate Period Average Expense $/kW/year	**$ 117.44**

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Approach Considerations after Frederickson Contract

After the Frederickson contract expires, in future years where the LOLP exceeds 5%, the District will consider evaluating the below approaches for meeting capacity needs:

- Purchase 5 year forward electricity call option tied to a physical power plant (likely a CCCT) to cover the winter HLH shortfall. Due to regional planning entities predicting a 4,000 MW winter capacity deficit in 2023 under non-extreme situations after the Frederickson Contract expires, concerns are increasing about winter liquidity and how to meet the District's HLH shortfalls in the winter.
- Budget and plan to purchase Q3 electricity call options to cover the additional summer HLH shortfall.
- Demand response programs currently are not cost effective but the District will continue to monitor this development over the coming years. 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. Continue to monitor and evaluate emerging technologies.

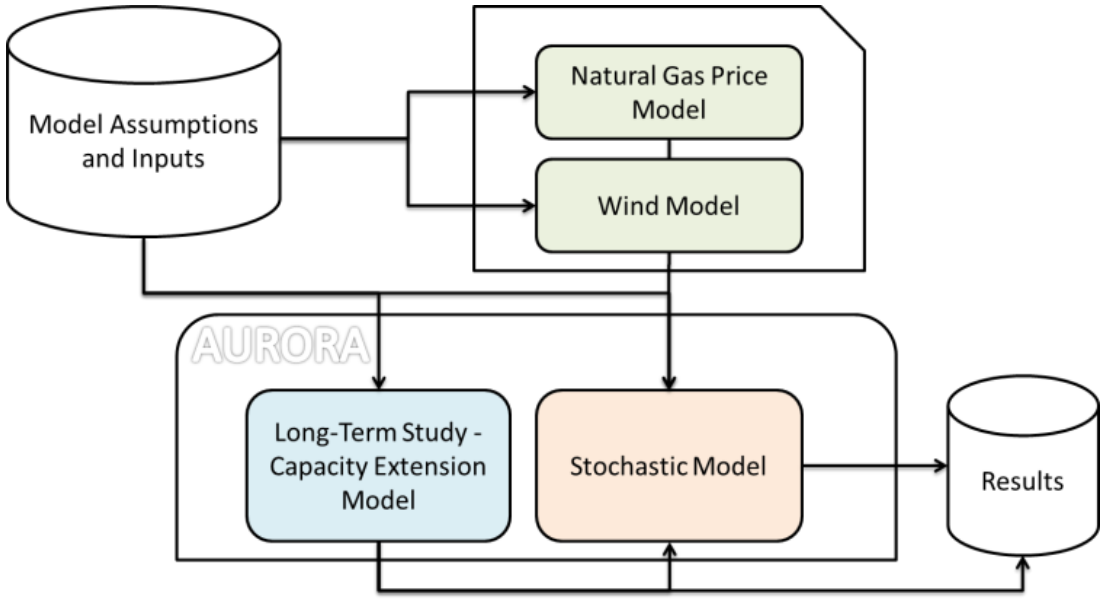
Chapter 8: Market Simulation

This chapter provides an overview of the methodology and assumptions used to create the long-term market simulation used in this project. The values produced are integral to the resource evaluation process as these inform the expected performance and risk of each candidate portfolio. Each potential resource is added to the District's existing portfolio and its cost is measured on a net present value basis over multiple simulations of electricity price.

Approach

The electricity price simulation is created by several fundamental models working in concert. **Figure** 57 provides an overview of the process used to create the price simulation. The progression can be broken down into three 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 part of the study uses the inputs from the first step to run a capacity expansion analysis. In this phase, market prices are simulated for all of the Western Interconnect utilizing a production cost methodology. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 10-year time horizon. In the final phase, the modified supply stack is integrated back into a stochastic simulation of price, fuel and hydro variables. This section will describe the price simulation in further detail.

Figure 57: Modeling Approach



Model Structure

The main tool used to determine the long-term market environment is Aurora. Developed by EPIS, Inc., 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
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 (wind and solar) 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 power plants 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 plants are built in the WECC. In the second step, Aurora progressively adds resources to meet expected load growth and renewable portfolio standards. The resources that are chosen are the best economic performers – i.e. the resources which provide the most regional benefit for the lowest price.

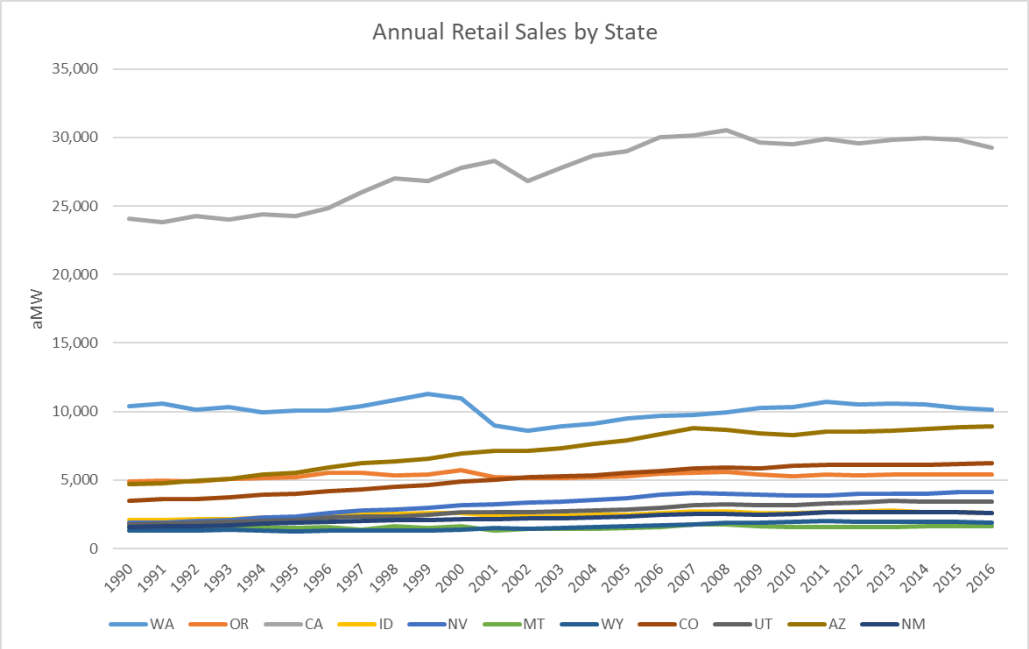
Principal Assumptions

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

WECC Load

Aurora's default demand escalation forecasts for zones in the WECC region are based on WECC's Transmission Expansion Policy and Procedure Study Report[40] and are provided in the Aurora database. However, based on recent observed retail load in the WECC and using the most recent forecast from the Northwest Power and Conservation Council's Seventh Power Plan, load is expected to decrease in the Pacific Northwest region, with an annual average of -0.67% growth.[41] Increases in energy efficiency, behind the meter generation, slower economic growth, and decreased population growth have contributed to flat or negative load growth when compared to the historical average. **Figure 58** below shows the clear flattening/declining trend to retail loads in nearly every state in the WECC over the past two decades.[42]

Figure 58: Historical WECC Retail Loads



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

[41] https://www.nwcouncil.org/media/7149940/7thplanfinal_allchapters.pdf

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

Because of this trend, the IRP team applied NWPCC's regional annual average load growth of -0.67% to the entire WECC for the Base Case of this study. For sensitivity studies, the lowest and highest load forecast projections from the Northwest Power and Conservation Council were used, summarized in **Figure 59** below.

Figure 59: NWPCC Load Projections

	Forecast of loads net of conservation targets (Annual average MW)		
Year	Lowest	Median	Highest
2019	18,422	19,873	21,315
2020	18,344	19,754	21,230
2021	17,726	19,605	21,447
2022	17,253	19,464	21,601
2023	17,010	19,320	21,736
2024	16,543	19,157	21,766
2025	16,513	19,049	21,790
2026	15,644	18,881	21,648
2027	15,630	18,805	21,909
2028	15,203	18,699	21,981
2019-2028 Average Annual Growth rate	-2.11%	-0.67%	0.34%

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 either extra generating capacity at already 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 planning reserve margins set by the North American Electric Reliability Corporation (NERC), in their 2017 Long-term Reliability Assessment, outlined below in **Figure 60**.[43]

[43] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf

Figure 60: WECC Regional Planning Reserve Margins

Assessment Area / Interconnection	2018 Reference Margin Level
WECC-AB	11.03%
WECC-BC	12.10%
WECC-CAMX	16.14%
WECC-NWPP-US	16.38%
WECC-RMRG	14.17%
WECC-SRSG	15.18%

WECC Renewable Portfolio Standards

Renewable portfolio standards (RPS) are requirements, set at the state level, 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 and economic needs.

Figure 61: WECC RPS Assumptions by State

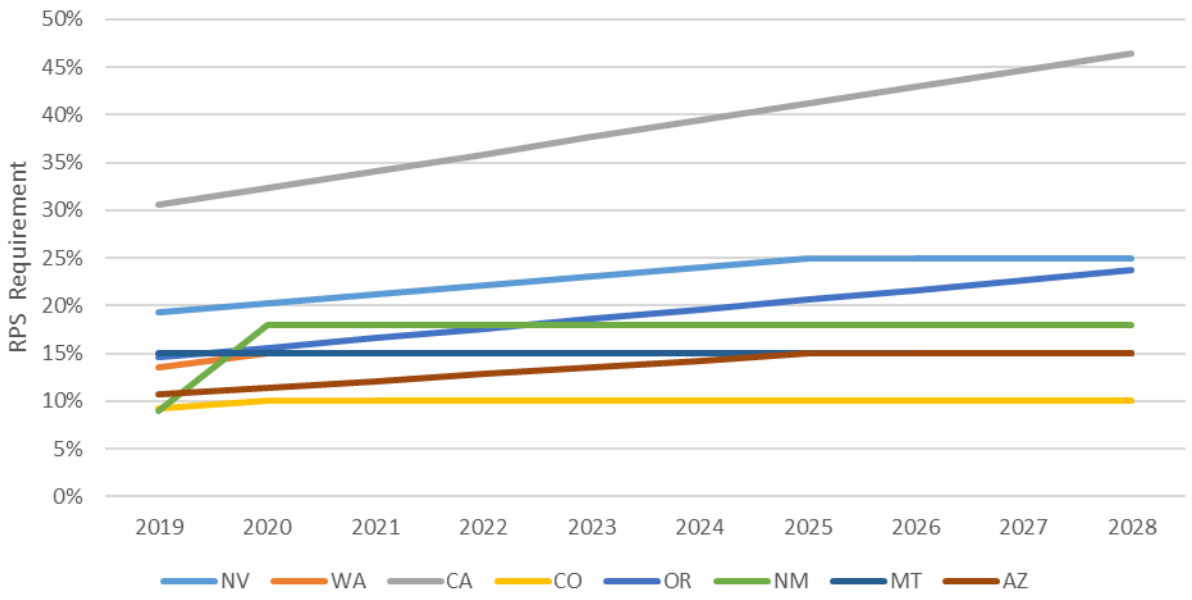


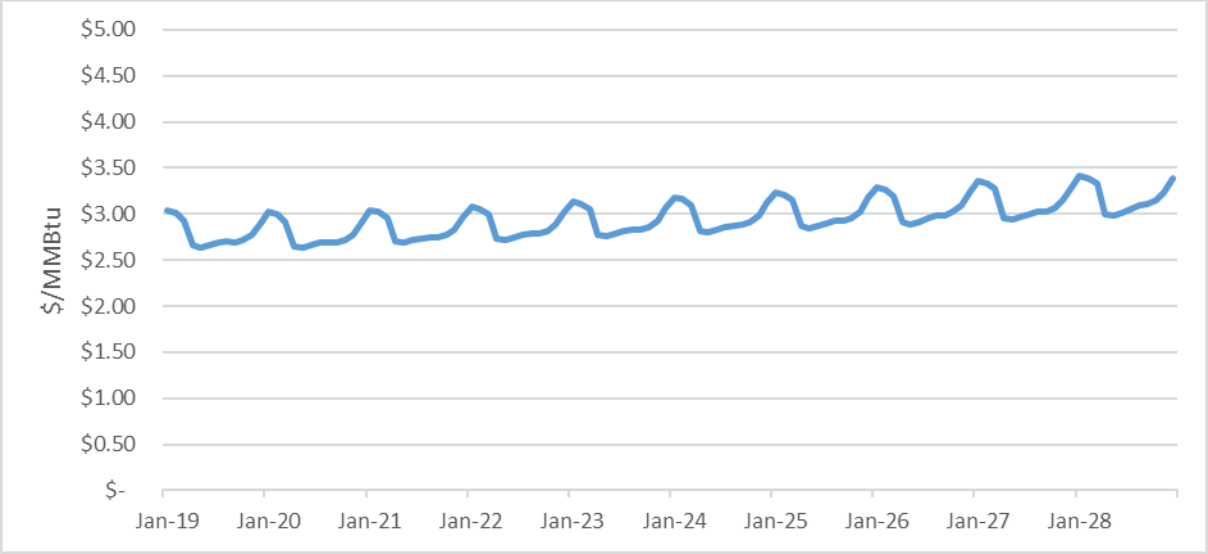
Figure 61 provides a summary of WECC states renewable standards. Currently 30 out of 50 US states have RPS requirements, including all WECC states except for Idaho and Wyoming. Utah has voluntary RPS guidelines, which were not included in this analysis. California has a higher RPS requirement at 50% by 2030, and Oregon has a 50% requirement for its IOUs by 2040. There is wide variability in the requirements between states in the region, which could have a sizeable effect on electricity pricing within the region. There is a long-term minimum constraint functionality built into the Aurora long-term capacity expansion model. This enables more consistent economic evaluation of different renewable resource additions.

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 62** uses Henry Hub forward pricing data from the New York Mercantile Exchange (NYMEX) through the year 2028. Prior IRPs have used a blend of NYMEX futures contract pricing for the near term and gradually transitioning to a long-term price forecast sourced from a reputable energy research firm. The rationale behind blending the two forecasts was that near-term NYMEX pricing reflects actual trading activity and should encompass all the collective information of the market. In short, it represents the most well-informed, consensus gauge of the value of the commodity. Outside of the short-term, though, trading activity is limited and the pricing ceases to exist beyond a 10-year outlook. The long-term forecast incorporates the fundamental factors of supply, demand, and variables that can cause those to change to develop a forecast.

The IRP team 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 IRP team believes NYMEX prices are the best representation of the expected future price of natural gas.

Figure 62: Natural Gas Price Assumptions



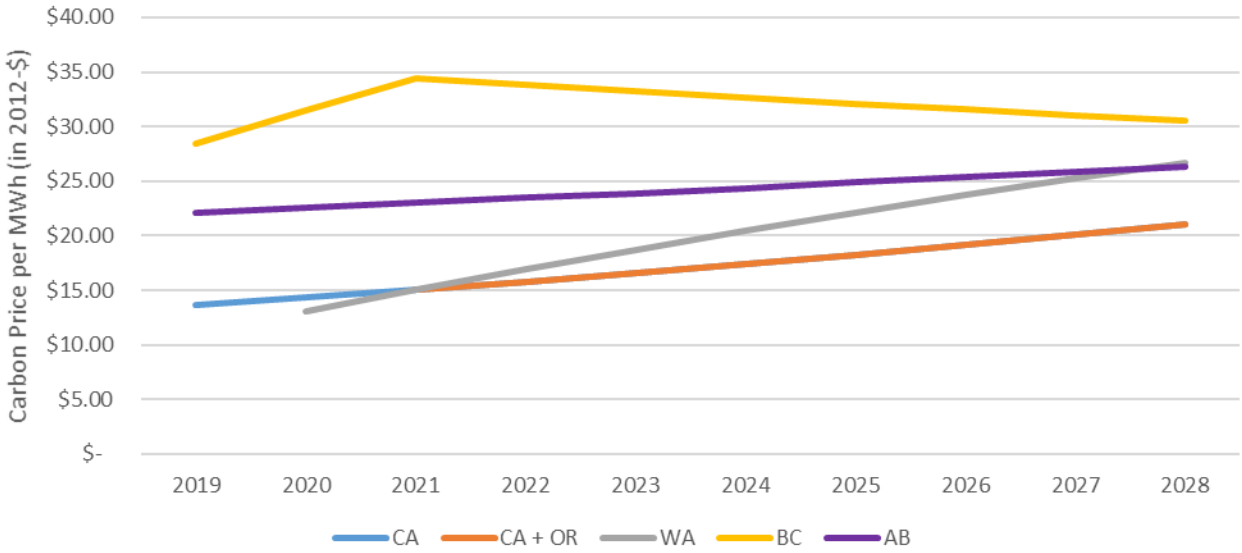
Carbon Pricing

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

Although Washington State does not have a carbon trading market, there has been a push in recent years to set one up. For example, the Clean Air Rule ("CAR") went into effect in 2016; this rule, however, was challenged in court and eventually ruled unconstitutional. In addition, a carbon tax initiative failed in 2016. However, a new carbon initiative is on the Washington ballot for the fall of 2018, and suggests a carbon tax in the future is likely. The base case assumes the pricing scheme of this 2018 initiative, I-1631, which starts at $15 per metric ton of carbon in 2020 and escalates at $2 plus inflation each year thereafter.

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, we modeled Oregon as having a carbon penalty equal to California's, starting in 2021. North of the border, British Columbia and Alberta already have carbon taxes in place, which are included in the market simulation and summarized in **Figure 63**.

Figure 63: Carbon Price Assumptions in WA, CA, BC, and AB



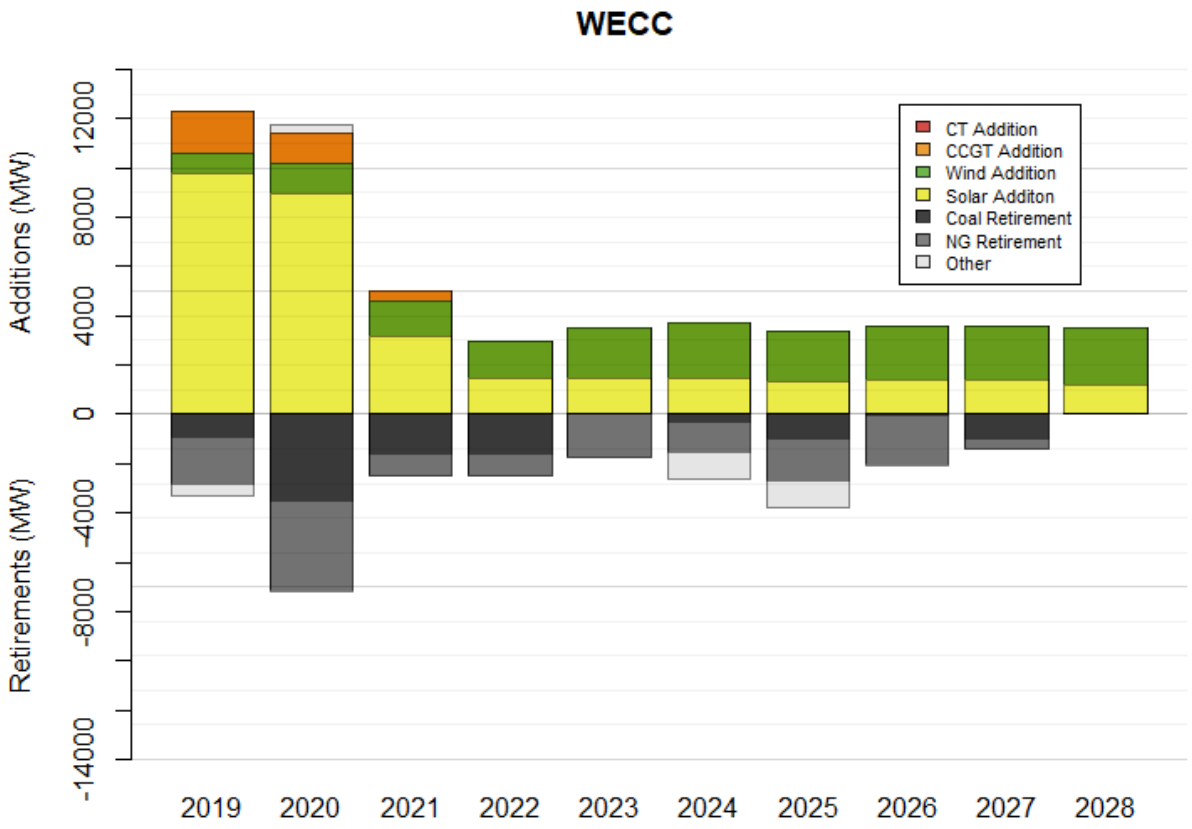
Capacity Expansion & Retirement

The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, 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. Based on the parameters outlined above, **Figure 64** illustrates the expected new resource expansion and retirement through 2028 throughout the entire Western Interconnect region.

RPS requirements are one of the main drivers of new resource expansion over the next decade. These renewable 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). As can be seen bellow in **Figure 64** below, solar generation expansion is significant through 2021,

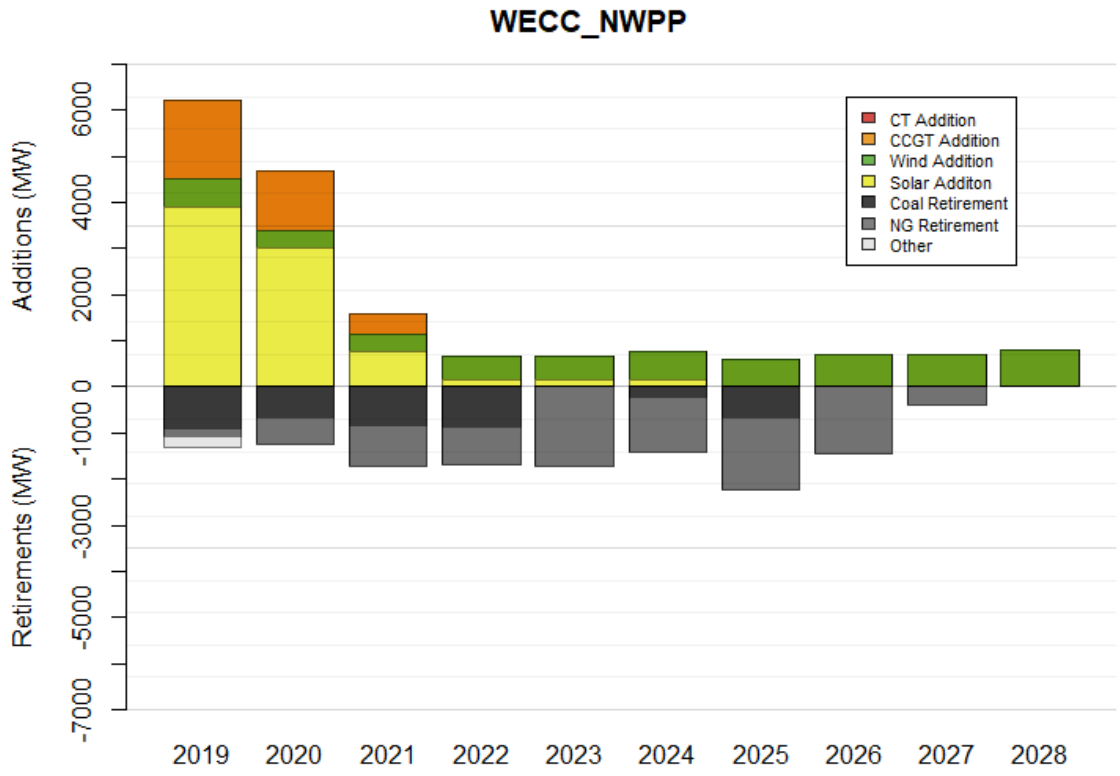
after which the ITC drops to 10 percent for commercial and utility projects and zero for residential projects.

Figure 64: Forecasted WECC Generation Capacity Additions through 2028



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 2028, more than 16,000 MW of coal capacity will be retired. Nuclear output will decline as aging units are taken off-line, and hydro output will stay the same. Future additions are expected to mainly be renewables to meet RPS mandates, with solar the preferred option for the first few years and wind the preferred option for the last years of the study period.

Figure 65: Forecasted Pacific Northwest Generation Capacity Additions through 2028

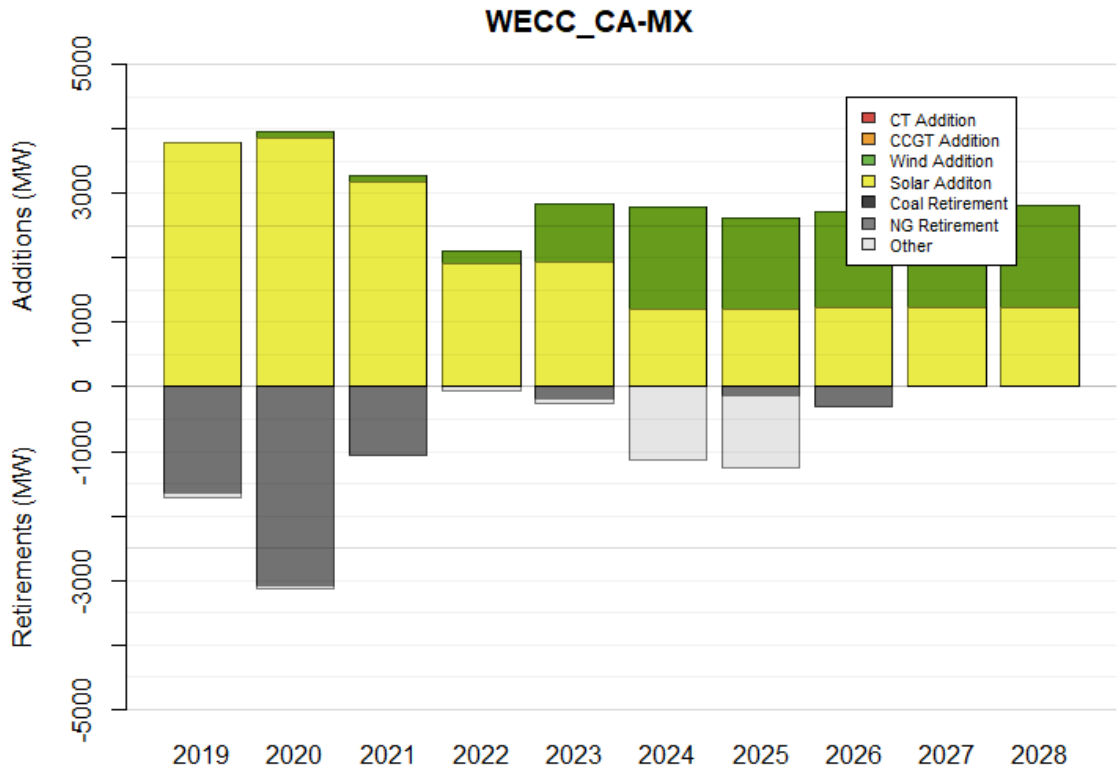


Within the Northwest Power Pool region, which includes the Canadian providences of British Columbia and Alberta, and the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, Utah, and a small portion of northern California, hydro will remain the largest single generating resource through the study period, with no projects being built or retired. All coal plants in the region are projected to retire by the end of 2025.

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. The majority of the renewables build out over the study period is to meet an increase in Oregon's RPS requirements, which targets 50% renewables by 2040 for the Investor Owned Utilities (IOUs) in the state.

In addition to a significant build out of solar in the region, just under 5,000 MW of CCGT generation is added. This addition over the study period largely offsets some of the lost capacity from retiring coal generation. Note, however, that due to the assumption of decreasing loads across the WECC, less capacity will be required to serve load, and therefore not all of the lost capacity due to coal and natural gas retirements is replaced with newly built CCGTs. Furthermore, the additional cost of carbon puts thermal resources at a disadvantage for meeting energy needs.

Figure 66: Forecasted California Generation Capacity Additions through 2028

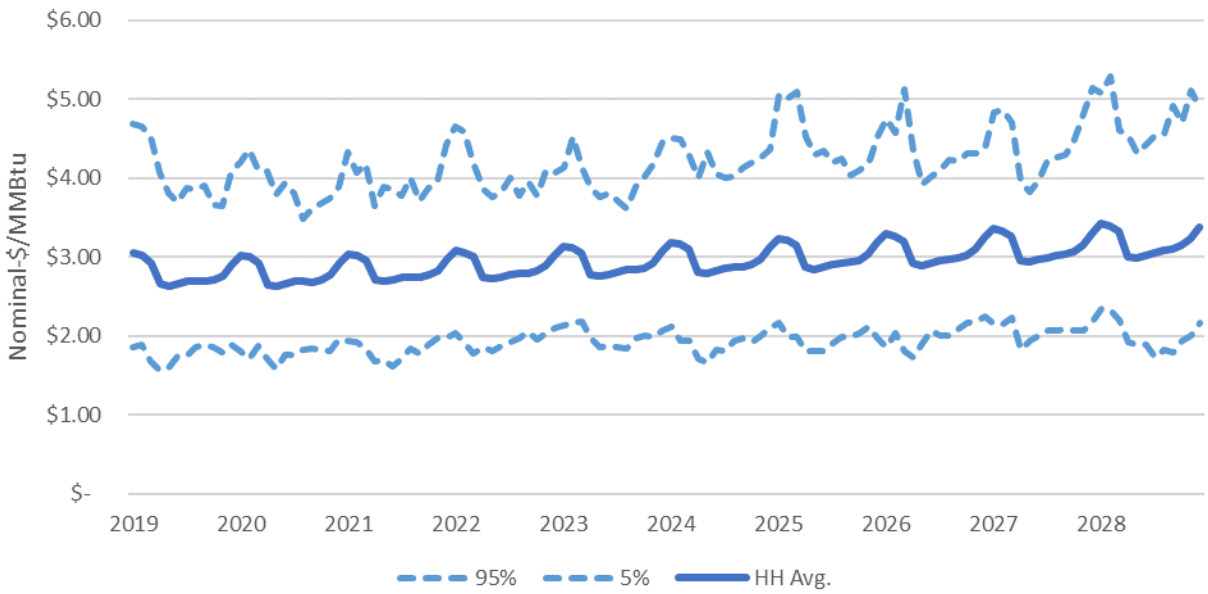


In California, although there are substantial natural gas unit retirements through 2021 (almost entirely made up of previously announced retirements of once-through-cooling units) and the retirement by 2025 of Diablo Canyon, the final nuclear facility in CAISO, the story is similar. Like the Northwest, the majority of renewables generation expansion is from solar. However, there is a significant amount of wind generation added later in the study period. This addition of wind generation later in the study period is because of the impact of increasing solar generation on deepening the duck-curve, which makes shoulder hours relatively more valuable. As such, wind generation becomes the preferred renewable resource by 2024.

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, which are shown below in **Figure 67**.

Figure 67: Henry Hub Gas Price Simulation

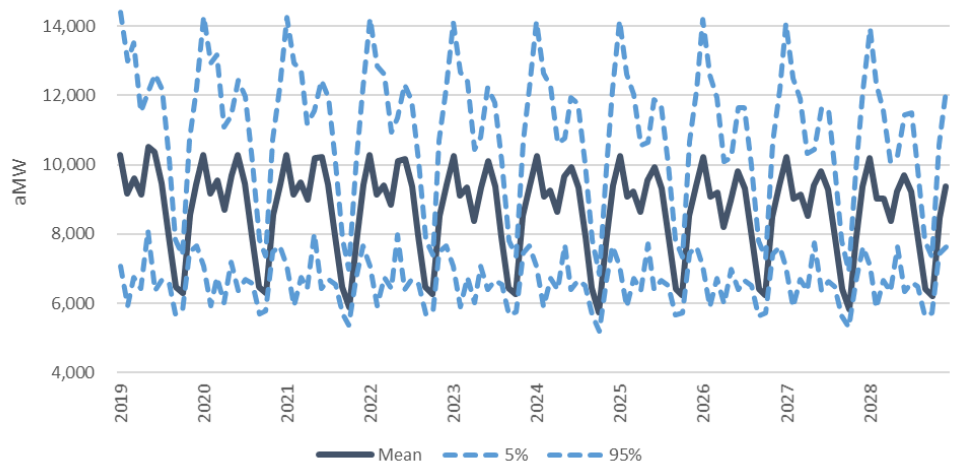


The middle line represents the average of all of the iterations, and the dashed lines represent the 5th and 95th percentiles. A multi-factor mean-reverting Monte Carlo process was used to simulate the volatility of daily spot gas prices, which is then used in a Heston Model to generate prices. The model 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 2028, which were then input into Aurora.

Hydroelectric Generation Simulation

Hydro power currently accounts for approximately two-thirds of electricity generated in the Northwest U.S., and one-quarter of generation in the WECC. One of the challenges of hydro generation is its 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 68** 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 68: 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 69** shows the expected Mid-C power prices from the long-term capacity expansion run, while **Figure 70** and **Figure 71** show the stochastic distributions for the range of potential outcomes. The solid dark blue lines represent the average of all of the iterations, while the dashed lines represent the 5th and 95th percentiles.

Figure 69: Mid-Columbia Prices

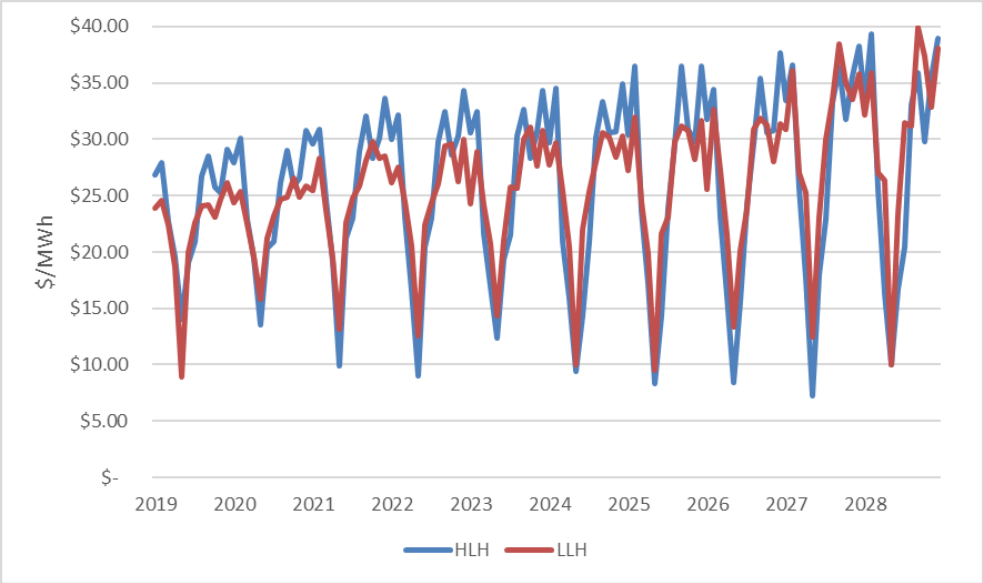


Figure 70: Mid-Columbia HLH Price Simulation

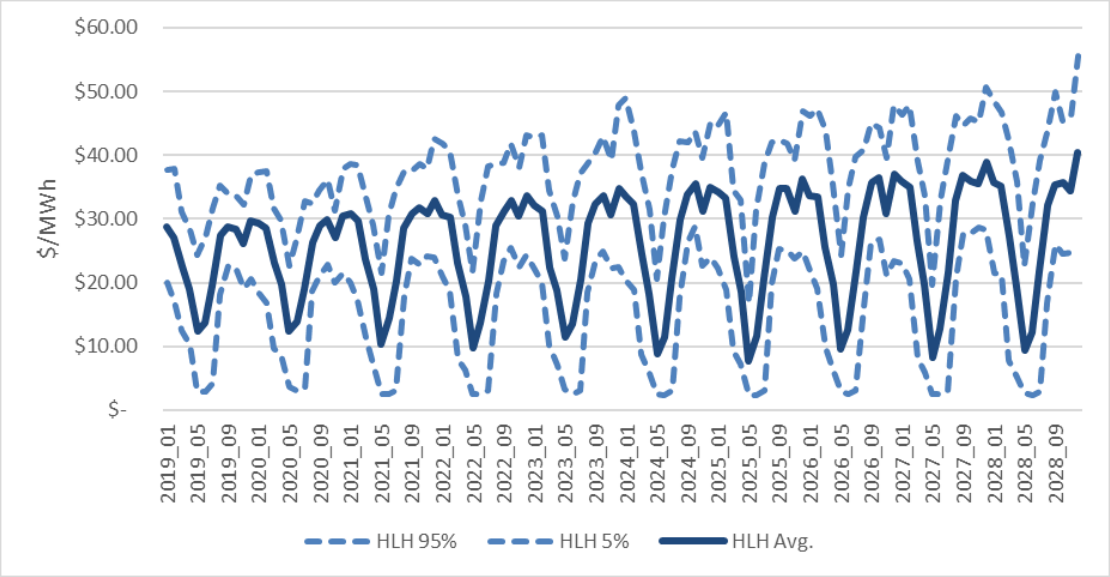
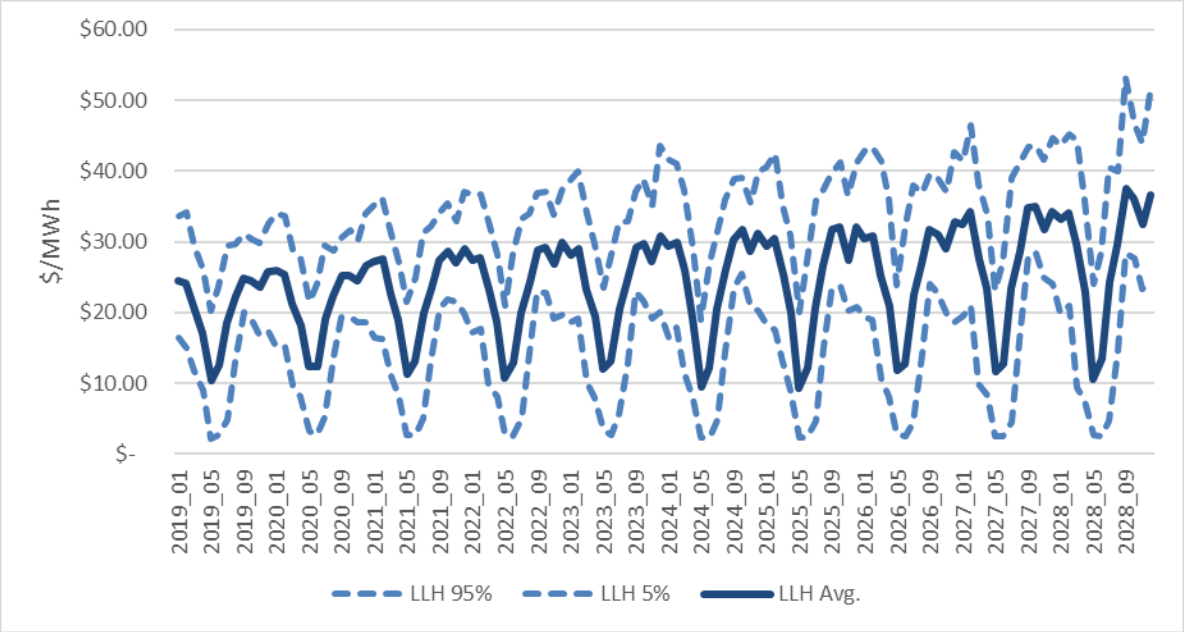


Figure 71: Mid-Columbia LLH Price Simulation



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 2020 for lower demand periods, LLH heat rates and power prices are higher than HLH heat rates and power prices. By the end of the study, LLH heat rates and power prices are higher than HLH heat rates and power prices for most time periods throughout the study period, as shown in **Figure 72**. This is a very notable change for the Northwest, and is attributable to decreasing loads, low natural gas prices, and the continued increase in solar generation through the entire WECC region. **Figure 73**, **Figure 74**, and **Figure 75** below are the average hourly profile of Mid-Columbia power prices for the months of April, August, and December in the years 2020,

2024, and 2028. As can be seen, there is an increase in the duck-curve phenomenon as we move through time and more solar generation comes online, particularly in the evening ramp.

Figure 72: Mid-C HLH/LLH Spread

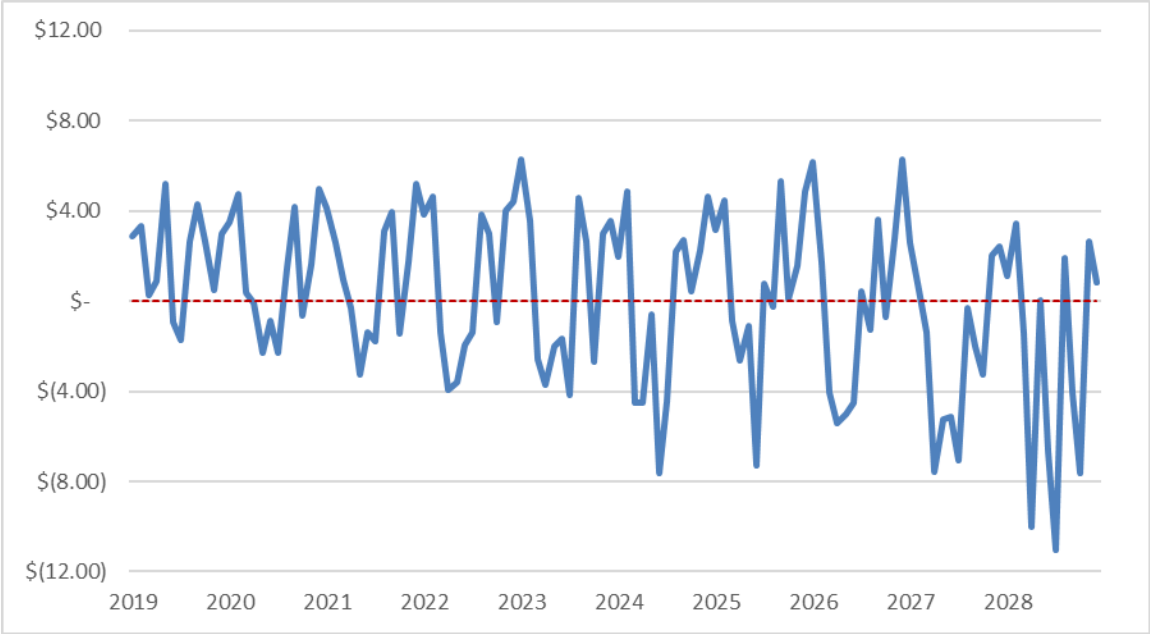


Figure 73: Mid-C Average Hourly Price Profile for April 2020, 2024, and 2028

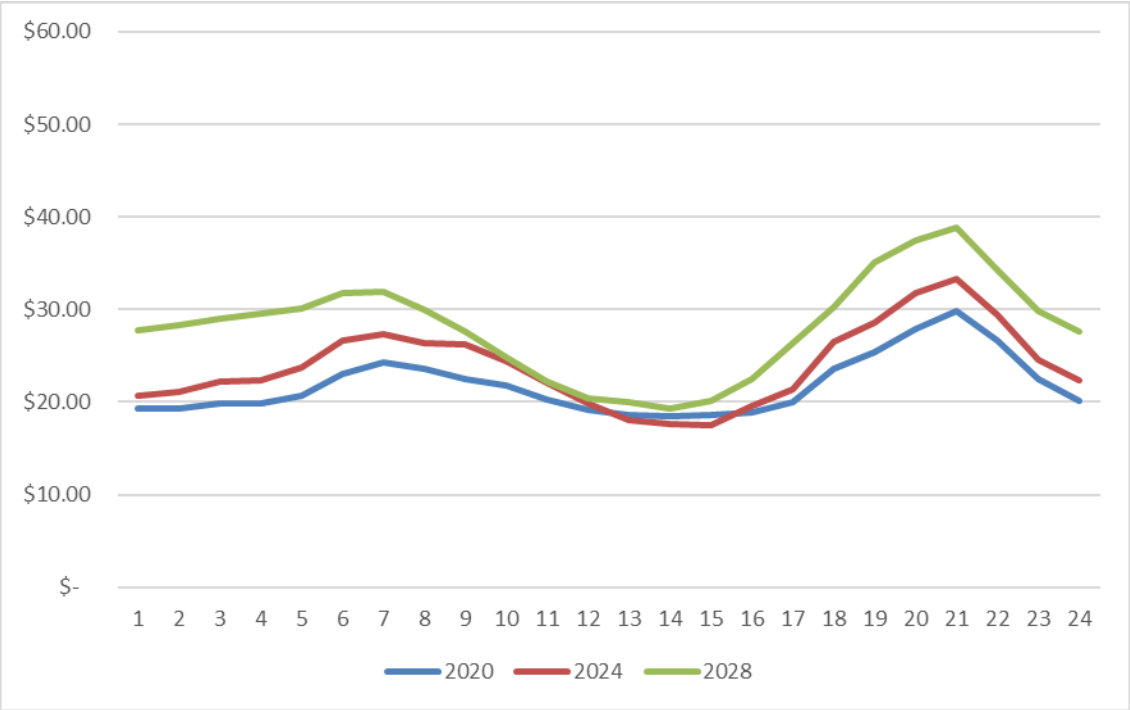


Figure 74: Mid-C Average Hourly Price Profile for August 2020, 2024, and 2028

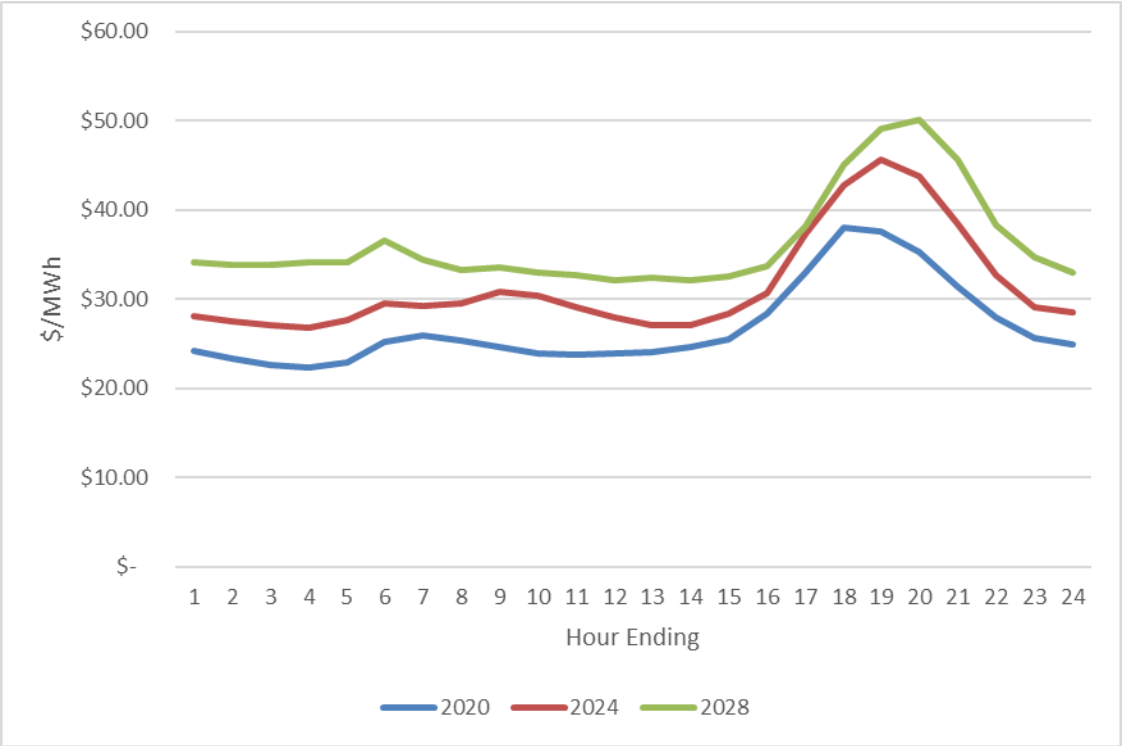
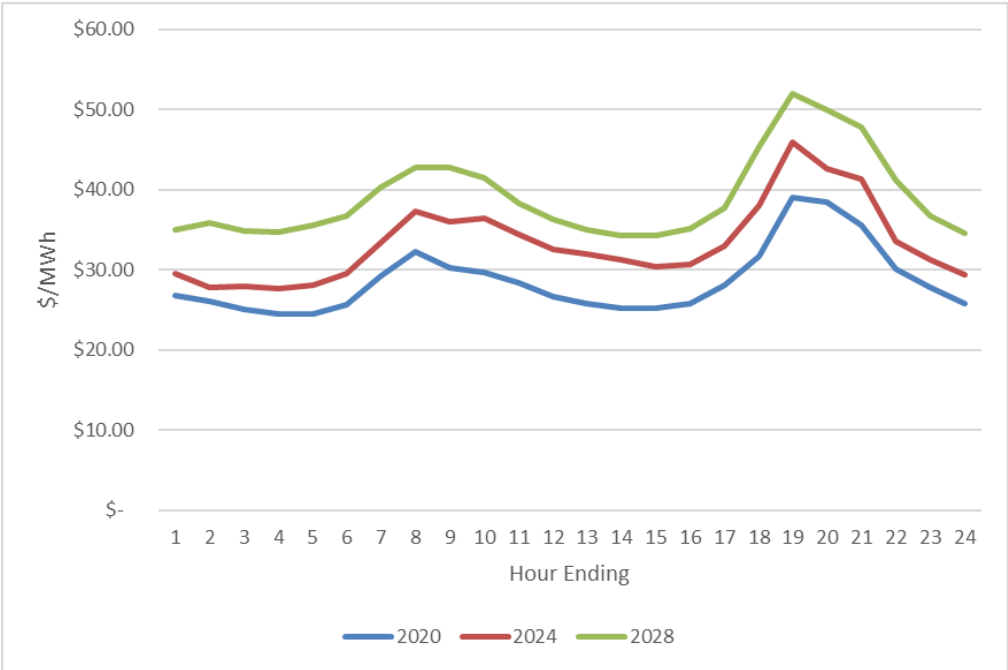


Figure 75: Mid-C Average Hourly Price Profile for December 2020, 2024, and 2028



Scenario Analysis

In addition to the above Base Case scenario, four other alternative hypothetical scenarios were considered. These were separate model runs intended to stress two 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 four 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 -2.11% year-over-year on average across the entire study, using the lowest load projection from the NWPCC described earlier. 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 0.34% year-over-year across the study, using the highest load projection from the NWPCC described earlier. This is intended to look at the impacts of increased population growth, manufacturing, and electrification of the transportation industry across the WECC.

3) *High West Coast Carbon Scenario*: A flat $100 per metric ton is applied to the states of Washington, Oregon, and California starting in 2020. This scenario picked an arbitrarily high carbon price to examine the potential impact of a unified high penalty along the west coast.

4) *No Washington Carbon Scenario*: This scenario assumes the status quo remains, and that Washington does not adopt a carbon tax or a carbon trading program.

Figure 76 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 1,300 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 76: Forecasted Resource Additions under the Low Load Growth Scenario

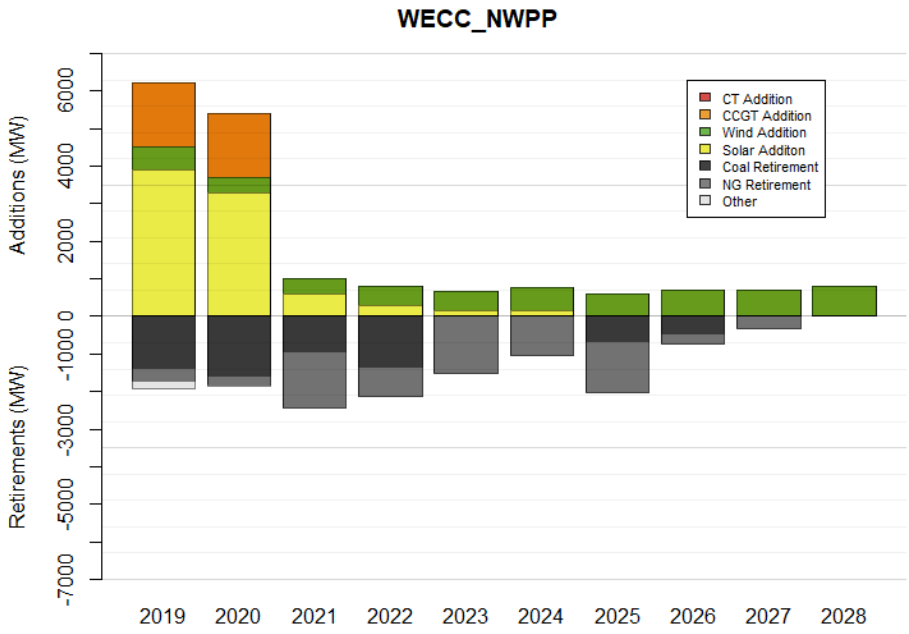


Figure 77 below is the projected resource additions in the Northwest through time for the High Load Growth scenario. Note that there are significant CCGT additions in 2021/22 to meet the higher load.

Figure 77: Forecasted Resource Additions under the High Load Growth Scenario

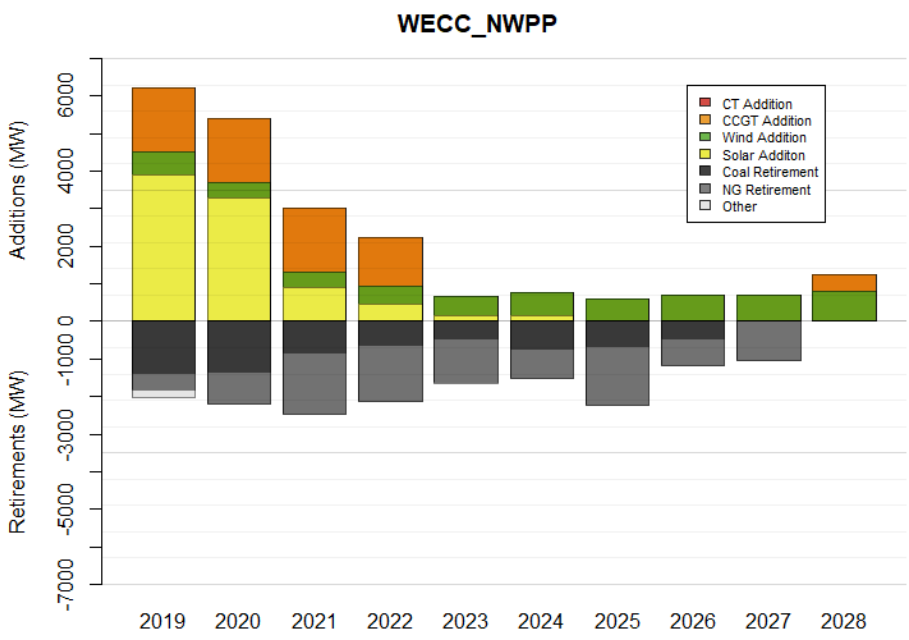


Figure 78 is the projected resource additions through time for the High Carbon scenario. Interestingly, there is little change in the resource stack from the Base Case, likely due to the fact that the new CCGT

builds in 2019-2021 are outside of the Washington-Oregon-California region with the higher carbon price of $100 per metric ton, and therefore not subject to the high carbon price in this scenario.

Figure 78: Forecasted Resource Additions under the High Carbon Scenario

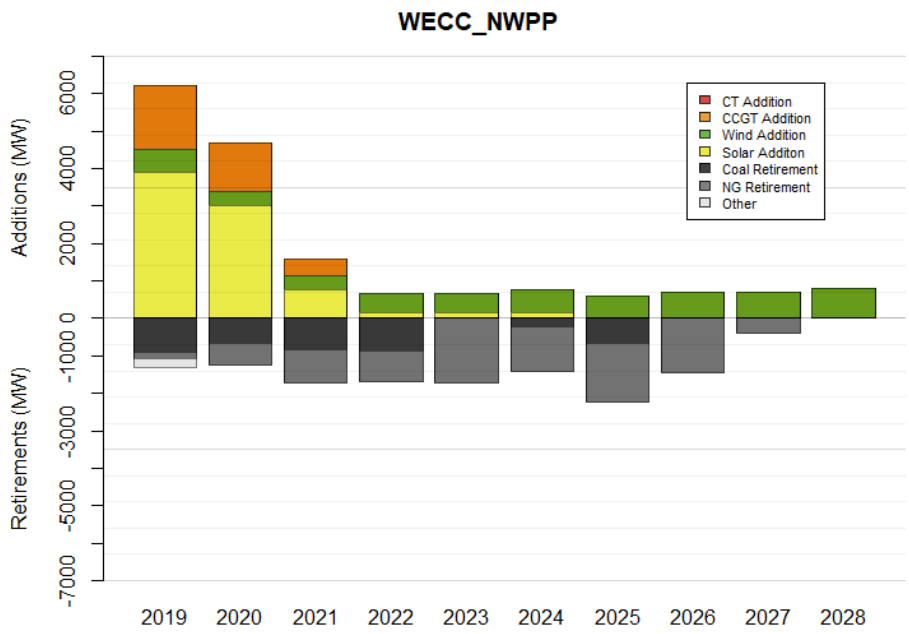
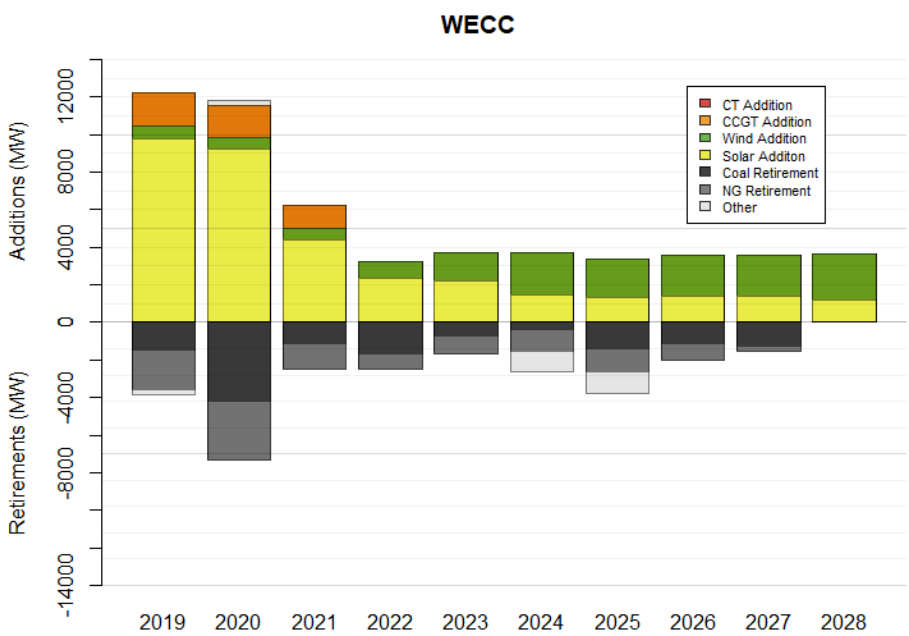


Figure 79 are the projected resource additions through time for the No Washington Carbon scenario, which is also very similar to the Base Case.

Figure 79: Forecasted Resource Additions under the No WA Carbon Scenario

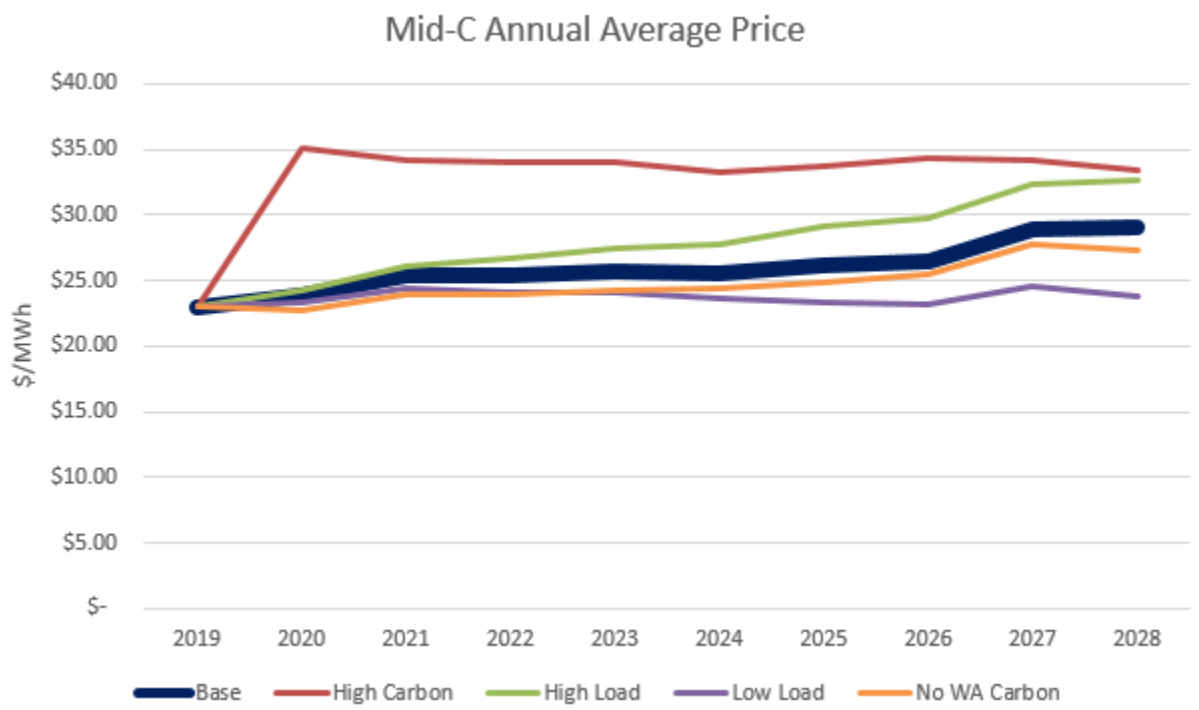


The effects on power prices are illustrated below in **Figure 80**. As expected, the High Carbon scenario has the largest impact on market prices, and increases the forecasted Mid-C market price by about $7.00/MWh on average over the study period. As discussed above, the resource stack is little changed between the Base Case and High Carbon scenario, so the increase in price is largely a result of marginal natural gas units paying the higher carbon tax and a significant amount of the heat rate stack not paying the tax (e.g. hydro, solar, and wind generation). Note that the price difference is highest in the first year of the higher tax in 2020, where the annual average is nearly $11.25/MWh higher than the Base Case, but is less than $4.50/MWh higher than the Base Case in 2028, as there are more carbon-free resources to call upon to meet load later in the study.

The Low Load Growth scenario also has a significant impact on power prices. The average power price for this scenario is about $2.25/MWh lower on average over the entire study period, with an annual average of approximately $23.75/MWh. As mentioned earlier, the Low Load Growth scenario alters the resource stack by displacing higher cost natural gas generation and meeting load growth with a continued build out of renewable generation due to RPS requirements.

Interestingly, of these four scenarios, the two with the least impact on Mid-C market prices are the High Load and No Washington Carbon scenarios. If one assumes a moderately positive annual average load growth of 0.34% in the WECC, Mid-C prices increase by just under $2.00/MWh on average over the study period. Similarly, in the status quo carbon pricing regime, Mid-C prices are forecasted to be on average slightly less than $1.25/MWh lower than the Base Case.

Figure 80: Projected Mid-C Power Prices Through Time



It should be noted 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 and a given carbon tax assumption, and by changing the load growth or including or excluding a carbon tax, we can observe the impact given changes in key assumptions.

Chapter 9: Risk Analysis and Portfolio Selection

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

Energy Net Position

Under the medium load forecast and critical hydro scenario, the District has sufficient resources to meet average annual energy needs until after the Frederickson PPA expires beginning in 2023 (**Figure 81**). The deficits will continue to increase commensurate with the District's load growth. The load/resource balance under average hydro conditions (**Figure 82**). In average water conditions, the District has sufficient resource on an average annual basis to meet energy needs through the end of the study period.

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

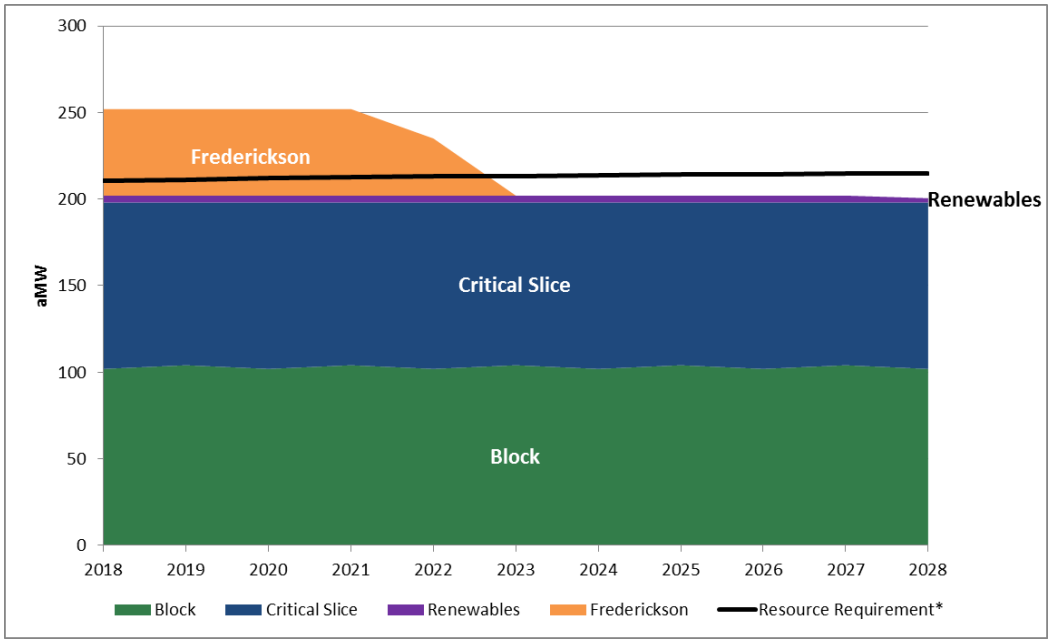
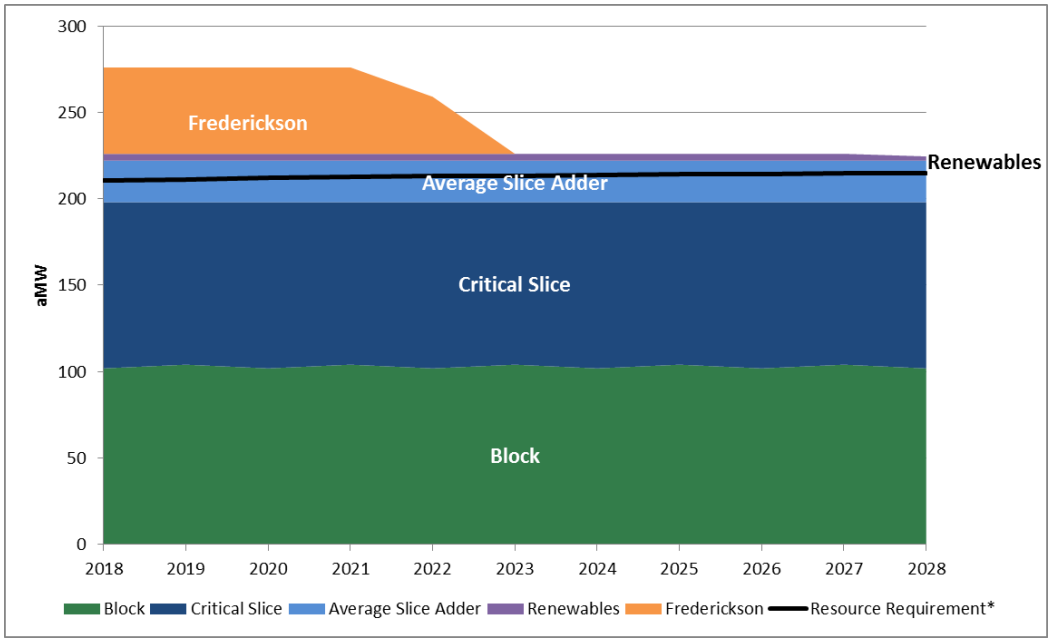


Figure 82: Energy Net Position - Medium Load Forecast and Average Hydro

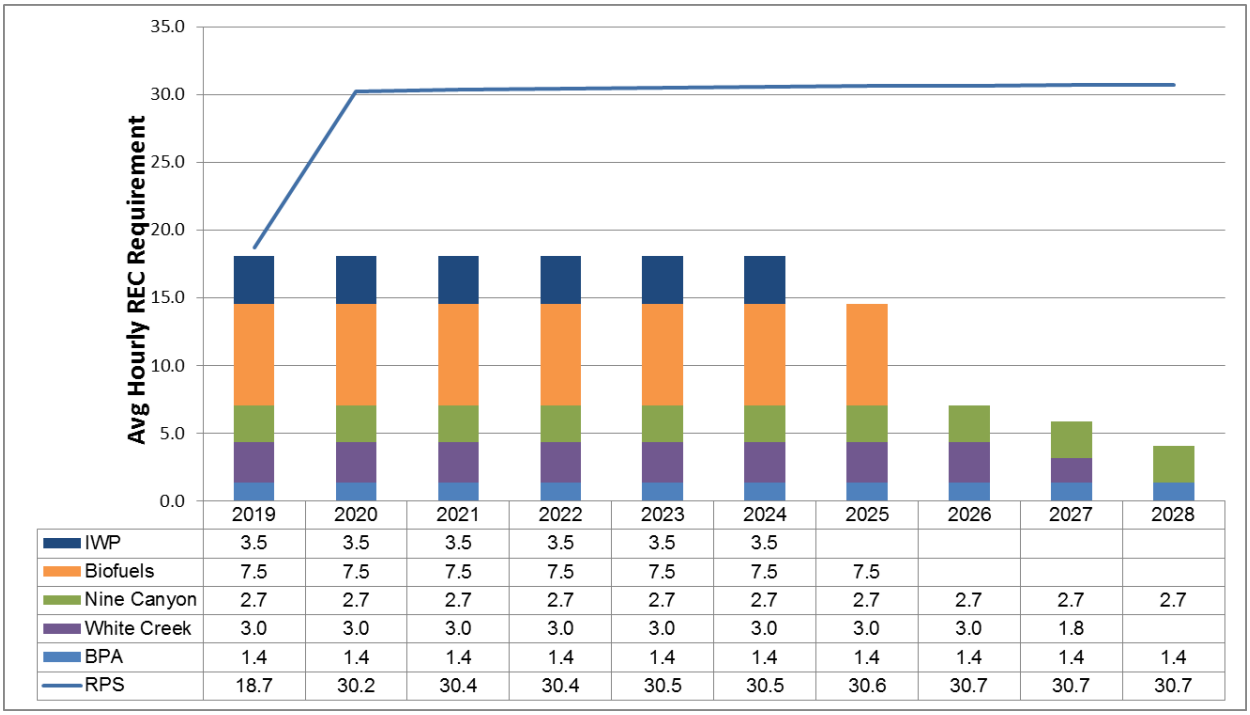


Renewable Portfolio Standard (RPS) / REC Net Position

The District may fulfill RPS requirements with a renewable resource acquisition or by purchasing only the renewable energy credits (RECs). With its current renewable assets, the District has sufficient resources to meet its forecasted RPS requirement through the end of 2019. That surplus turns into a deficit beginning in 2020 when the RPS increases from 9% to 15%. The REC deficit is projected to begin at 15 MW, and is expected to grow to almost 30 MW by the end of the study period (**Figure 83**). The growth of the deficit can be attributed primarily to the expiration of the REC generating wind resources, in addition to the shorter-term REC purchase contracts. Load growth also plays a small role in the expansion of the REC deficit.

Acquiring additional renewable resources to meet the RPS requirements has both benefits and drawbacks. Procuring a resource ensures that the District receives a steady supply of RECs at a known price and reduces exposure to the REC market. A generation resource also augments the District's energy supply, which is helpful during the summer months when the District has to manage its seasonal energy deficit. However, the most economical renewable resources, wind and solar, are not dispatchable and will not necessarily generate electricity when it is needed most, 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 residual of the levelized cost of a new resource less the value of the brown power. Because renewable resources continue to decline in costs, the cost of RECs should through time as well.

Figure 83: RPS Net Position – Medium Load Forecast and Existing Contracts



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
IWP	3.5	3.5	3.5	3.5	3.5	3.5				
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5			
Nine Canyon	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
White Creek	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	1.8	
BPA	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
RPS	18.7	30.2	30.4	30.4	30.5	30.5	30.6	30.7	30.7	30.7

Portfolio Strategies

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

1. Keep the status quo
   - Rely on the market to cover energy, capacity, and REC deficits

2. Acquire a 50 MW natural gas fired reciprocating engines in 2023 to meet a significant portion of seasonal and hourly energy and capacity deficits
   - The reciprocating engines allow for quick and efficient dispatching to balance hourly energy positions, particularly in response to a continued expansion of renewable generation and increased price volatility
   - The resource is sized to meet the majority of hourly energy and capacity deficits in summer months
   - Rely on market to cover REC deficits

3. Acquire a 25 MW combined cycle gas turbine beginning in 2023 to meet summer energy needs
   - Sized to meet average energy deficits in critical water conditions as the Frederickson contract expires
   - Will help to fill summer season energy deficits

- Capacity deficits in summer months would still be purchased from the market

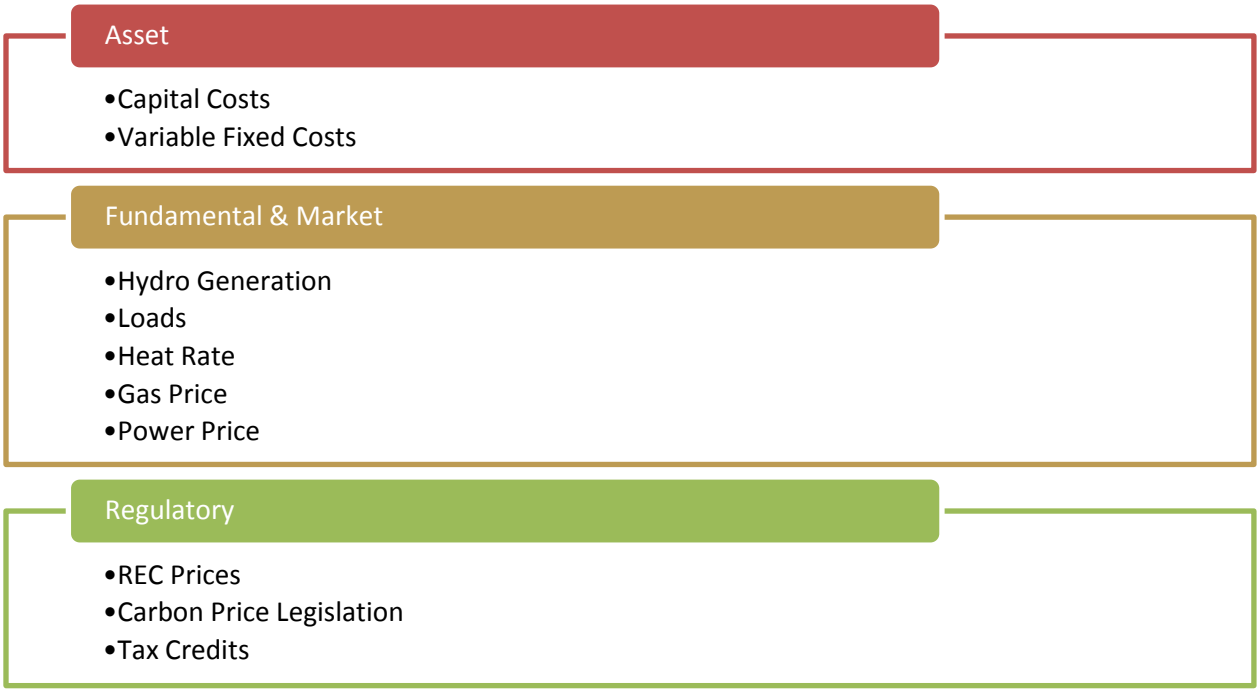
4. Acquire 20 MW solar and 30MW wind beginning 2020
    - This all renewables portfolio would purchase enough physical renewable generation to cover REC deficits throughout the study period
    - Energy produced from the renewable assets would partially offset some of the energy deficits in summer months
    - The solar generation profile coincides well with the District's peak load periods. Solar will also contribute RECs towards meeting the District's RPS requirements.
    - Wind energy will be used to meet the balance of RPS requirements as it is a more economically efficient resource in the Pacific Northwest.

5. Acquire 50 MW natural gas fueled reciprocating engines beginning 2023 plus 20MW solar and 30MW wind in 2020 (combined portfolios 2 and 4)
    - REC plus capacity portfolio will cover significant capacity deficits in addition to all renewable requirements

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

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

Figure 84: Risk Drivers



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

Other resources were considered on a qualitative basis but were not considered as part of this analysis as the impact of each could be predetermined. One example, is entering into a long-term hedge with an entity that already has a physical asset but does not need the energy or capacity. This could be a slice of hydro generation from a non-federal asset or a physical heat rate call option from a CCCT or CT/reciprocating engine. The advantage of these hedges are they are priced closer to market, which is a lower cost than acquiring a new asset, and have physical attributes such as physical supply and hourly shaping. The IRP team did not include any market-based hedges as it was assumed the results would be similar to Portfolio 1, which is based on market prices. The second example is small modular reactors, a brand-new nuclear technology, with is the first-of-a-kind power plant expected to enter commercial service in 2024. As is always the case with new technology, there is inherent cost and performance risk

associated with early models. The most current publicly available data suggests that the first-of-a-kind SMR will not be cost competitive with other commercially available resources. While costs are expected to decline over time, the timeframe is expected to fall outside of the study period. The District will continue to follow developments associated with the technology and reassess in the next IRP.

Figure 85: Resources Considered in Portfolio Construction

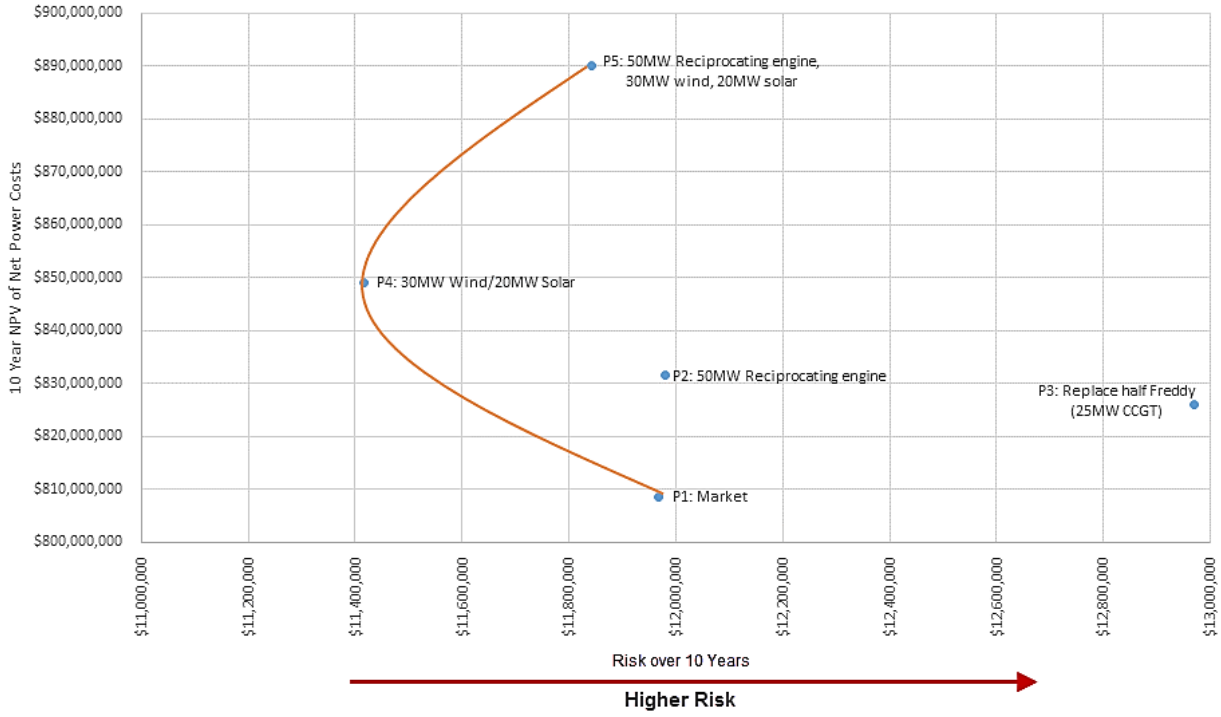
Portfolio >	P1		P2		P3		P4		P5	
Energy Source >	Market		Recip Engine		CCGT		Wind/Solar		Recip/Wind/Solar	
REC Source >		Market		Market		Market		Wind/Solar		Wind/Solar
Strategy >	Utilize wholesale market purchases for all energy and REC deficits		Acquire a reciprocating engine to meet capacity and seasonal summer energy needs; market purchases for REC deficits		Acquire a CCGT to replace a portion of the capacity and energy provided by Frederickson; market purchases for REC deficits		Acquire a wind and solar resource to meet energy and REC deficits		Acquire a wind, solar, and reciprocating engine to meet capacity and energy deficits; renewables will fill REC deficits	

			Cumulative New Installed Generation Capacity									
Year	**Energy Net Position (aMW)**	**REC Net Position (aMW)**	**Energy Resource**	**Renewable Resource**	**Energy Resource**	**Renewable Resource**	**Energy Resource**	**Renewable Resource**	**Energy Resource**	**Renewable Resource**	**Energy Resource**	**Renewable Resource**
2019	52	0	0	0	0	0	25	0	30/20	30/20	50/30/20	30/20
2020	50	-15	0	0	0	0	25	0	30/20	30/20	50/30/20	30/20
2021	50	-15	0	0	0	0	25	0	30/20	30/20	50/30/20	30/20
2022	32	-15	0	0	0	0	25	0	30/20	30/20	50/30/20	30/20
2023	1	-15	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2024	-1	-15	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2025	0	-18	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2026	-2	-26	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2027	-1	-26	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2028	-2	-26	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2029	-1	-26	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20
2030	-2	-26	0	0	50	0	25	0	30/20	30/20	50/30/20	30/20

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

Figure 86 is a plot of each portfolio's 10-year NPV net power cost on the y-axis vs. the standard deviation on the x-axis. Portfolio evaluation involves assessing cost vs. risk. The ideal portfolios can be isolated by fitting a hyperbola, known as the efficient frontier, through the points, as shown in **Figure 86**. Portfolios situated below the vertex, but still on the efficient frontier, have the least risk for a particular cost bucket. Portfolios that are high cost and high risk, such as Portfolio 5 (acquire a reciprocating engine, wind, and solar), have undesirable characteristics and can be quickly eliminated. The ideal portfolio would have a low cost and low risk, but that is generally not achieved as there is usually a tradeoff between cost and risk. It is up to the District to determine the best fit for the utility: lower expected cost with more risk or higher expected cost with less risk (Portfolio 1 vs. Portfolio 4).

Figure 86: Efficient Frontier and Preferred Portfolios



Preferred Portfolio

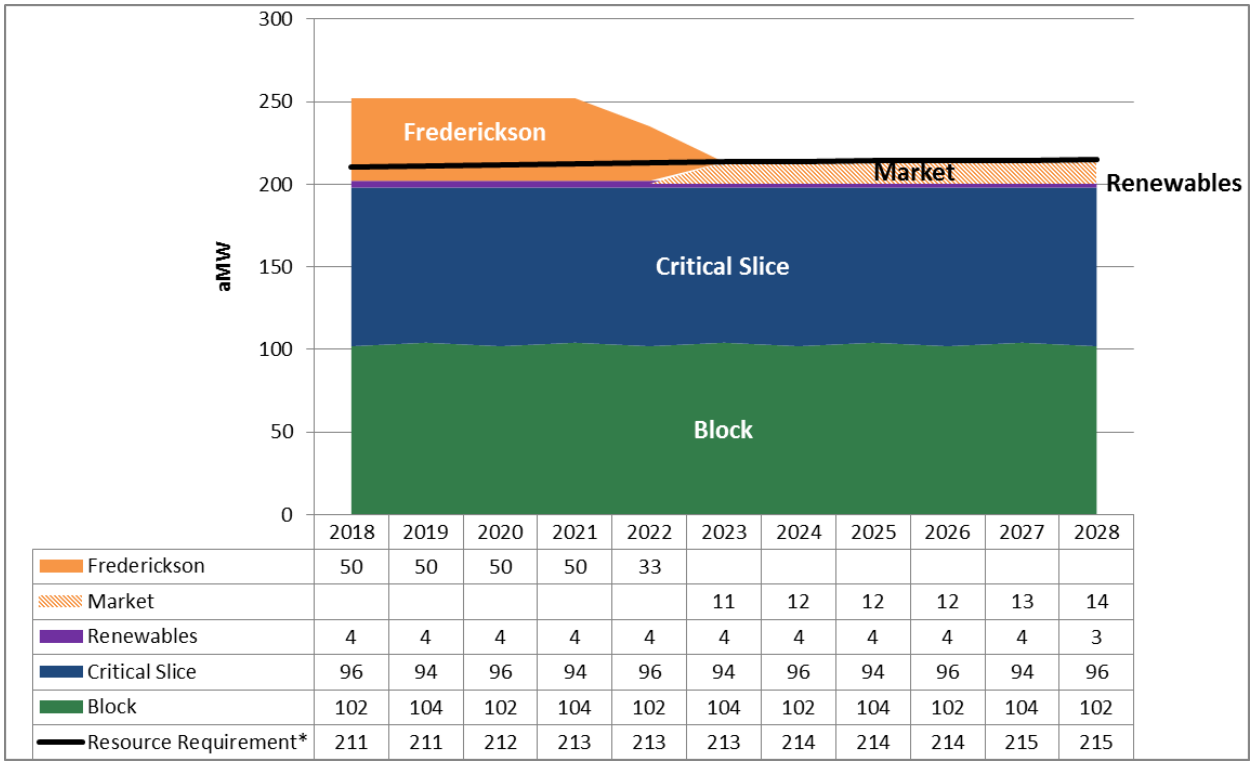
The results of the analysis suggest that the least cost versus least risk optimal portfolio is Portfolio 1. The cumulative 10 year costs are expected to be over $40 million lower, despite the slightly higher associated risk. Portfolio 1 continues to be the preferred portfolio at this point, as it has been for the last several IRPs for several reasons:

1. Gas prices remain in a persistent low price, low volatility scenario. Additionally, regional load growth is in a flat to declining pattern, thus inflation-adjusted power prices are expected to continue to remain as the lowest cost resource for the foreseeable future.
2. There are certain risks that the model is unable to capture which include site risks, regulatory risks, and construction risks, among others. With market purchases, the District maintains a high level of flexibility and can also reduce some of the risk it faces through purchases from other entities ahead of time and locking in a price for the energy.
3. The variability of Portfolio 1, which relies on the market for energy and REC purchases, can be significantly reduced with forward hedging. The District currently has a regimented hedging policy in place that it plans to continue indefinitely. By forward hedging, the District effectively reduces the standard deviation and thus narrows the range of cost variability.
4. In addition to using the market for standard forward, daily, and hourly market purchases the District could consider long-term off-take agreements with existing assets in the market. One example is entering into an agreement to take a slice of generation from non-Federal hydro projects in the region. Another example is entering into a physical heat rate call option with an owner of an existing natural gas fired asset. These alternative choices offer the same physical attributes such as providing capacity and flexibility as developing or acquiring a new resource, but without the development cost and long-term commitment.
5. Washington REC prices remained low through the first and second compliance periods from 2012-2018 despite RPS requirements increasing from 3% to 9%. The continued build out of renewable generation should, and although it is difficult to forecast, warrant that REC prices will remain low for the foreseeable future.
6. The District will continue to monitor market conditions; any dramatic shift in the market may compel the District to revisit its preferred portfolio.

While Portfolio 1 is the preferred portfolio at this point due to the reasons listed above, the District has concerns about it going forward as well. Knowing the District's large and growing capacity deficit that exists in the summer (up to 100 MW) after the Frederickson contract expires, and coupled with a projected regional summer capacity deficit along without guarantees of new thermal generation capacity coming online, the risk of being able to rely on the market to meet capacity deficits is growing. These dynamics will be closely monitored and appropriate actions are detailed in the action plan in **Chapter 10: Action Plan Summary**.

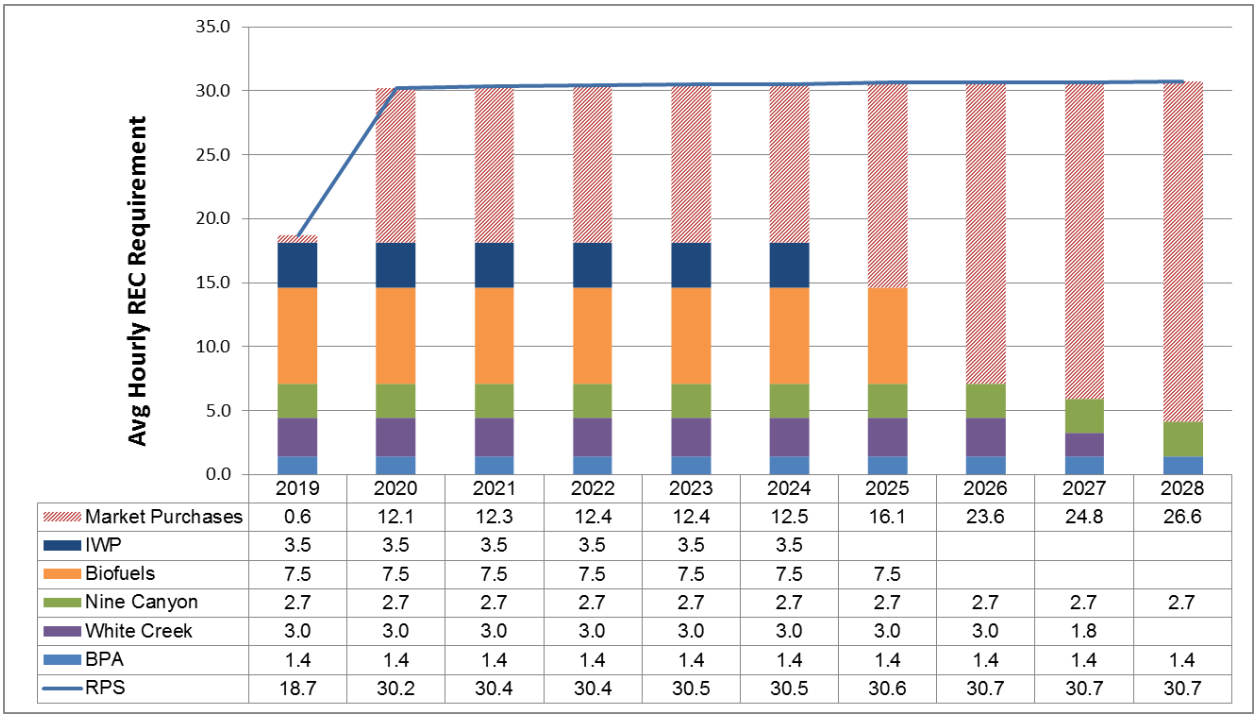
Figure 87 below is the impact of Portfolio 1 on the District's net energy position. **Figure 88** below is the impact of Portfolio 1 on the District's RPS position. The District will continue its practice of utilizing shorter-term power purchases and other instruments to provide additional capacity and financial protection. The benefit of this approach is that the District can target the parts of the year that present the most challenges (summer and winter) while avoiding the carrying costs of a physical asset during "lower risk" parts of the year (spring and fall), when loads are significantly lower. The District will regularly reevaluate this strategy. If there is a fundamental shift in the natural gas or power markets, the preferred portfolio could change.

Figure 87: Energy Net Position of the Preferred Portfolio



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Frederickson	50	50	50	50	33						
Market						11	12	12	12	13	14
Renewables	4	4	4	4	4	4	4	4	4	4	3
Critical Slice	96	94	96	94	96	94	96	94	96	94	96
Block	102	104	102	104	102	104	102	104	102	104	102
Resource Requirement*	211	211	212	213	213	213	214	214	214	215	215

Figure 88: RPS Position - Preferred Portfolio



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Market Purchases	0.6	12.1	12.3	12.4	12.4	12.5	16.1	23.6	24.8	26.6
IWP	3.5	3.5	3.5	3.5	3.5	3.5				
Biofuels	7.5	7.5	7.5	7.5	7.5	7.5	7.5			
Nine Canyon	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
White Creek	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	1.8	
BPA	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
RPS	18.7	30.2	30.4	30.4	30.5	30.5	30.6	30.7	30.7	30.7

Chapter 10: Action Plan Summary

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

- ✓ The preferred portfolio to meet energy, capacity, and REC requirements is to continue to make purchases from the market. The District will continue to monitor market conditions to track any significant changes in regional resource sufficiency.
    - The District will investigate potential medium to longer term market purchases from existing resources to lower the variability in market exposure.
    - The District will investigate alternative approaches for risk simulation analysis that take into account summer peak days.
    - 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, capacity and RECs needs.
    - If significant new industrial load (greater than 10 MW) commits to the District's service territory, prepare a report that analyzes the impacts on energy purchases and transmission infrastructure.
- ✓ The District will continue to monitor the regulatory environment and modify its resource strategy as necessary.
    - The District will closely monitor proposed Washington State carbon initiatives and/or legislation and develop an analysis of the timing, impacts, and magnitude of any resulting carbon regulation.
- ✓ The IRP continues to identify the District's summer capacity deficits as an item to closely monitor as the region's coal plants are retired.
    - Develop a tactical plan for the future purchase of capacity products from the market that addresses timelines, products, counterparties, etc.
    - Monitor the Council's LOLP studies and consider longer term (3-5 year capacity products) in periods where the LOLP increases above 5%. See **Chapter 7: Capacity Requirements, Energy Storage, and Demand Response** for more detail about the possible actions listed below:
        - Purchase of 5 year forward electricity call option tied to a physical power plant (likely a CCCT) to cover the District's winter HLH shortfall. Due to regional planning entities predicting a 4,000 MW winter capacity deficit in 2023 under non-extreme situations after the Frederickson Contract expires, concerns are increasing about winter liquidity and how to meet the District's HLH shortfalls in the winter.

        - Budget and plan to purchase Q3 electricity call options to cover the District's summer HLH capacity deficit.
        - 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.
    - Monitor regional utilities plans to construct dispatchable resources. If plans to build lag what is recommended in their current IRPs, consider longer term capacity products.
    - Prepare a report analyzing District market purchases from 2015-2018, showing Counterparties and source (Point of Receipt).
    - Closely monitor costs and applications of energy storage, or other emerging technologies, for indications it could become cost effective for the District or its customers to deploy.

✓ Implement all cost-effective conservation consistent with the requirements and any future amendments of the EIA.

✓ 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.

RESOLUTION NO. 2448

April 10, 2018

A RESOLUTION OF THE COMMISSION OF
PUBLIC UTILITY DISTRICT NO. 1 OF BENTON COUNTY, WASHINGTON
APPROVING THE TEN YEAR LOAD AND CUSTOMER FORECAST 2018-2027

WHEREAS, the Ten Year Load and Customer Forecast 2018-2027 (Forecast) has been prepared by District staff and reflects customer load information; AND

WHEREAS, information contained in the Forecast is updated annually and is necessary for the District's revenue forecasting, Pacific Northwest Utilities Conference Committee's (PNUCC) and the Bonneville Power Administration's (BPA) regional load forecasting; AND

WHEREAS, the Forecast is used in conjunction with other fiscal planning tools including, but not limited to, the Cost of Service Analysis (COSA), the Integrated Resource Plan (IRP), Rate Analysis, Budgeting, Power Requirements Planning, and Five-Year Capital Plan.

NOW, THEREFORE BE IT HEREBY RESOLVED that the Commission of Public Utility District No. 1 of Benton County approves and adopts the attached Ten Year Load and Customer Forecast 2018-2027.

BE IT FURTHER RESOLVED that this Resolution supersedes Resolution No. 2410 dated June 27, 2017.

APPROVED AND ADOPTED by the Commission of Public Utility District No. 1 of Benton County at an open public meeting as required by law, this 10th day of April, 2018.

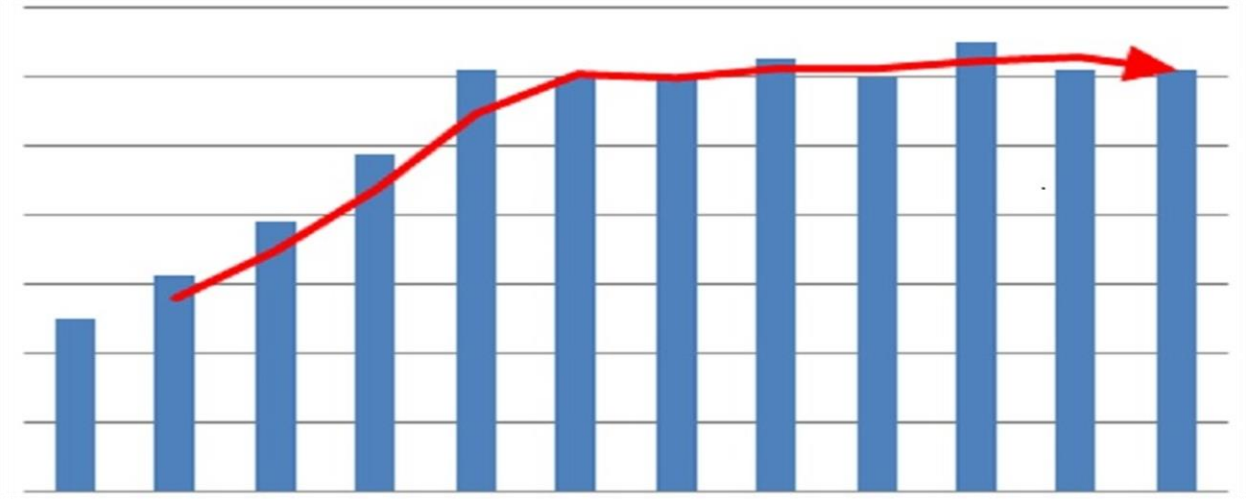
Jeffrey D. Hall, Vice-President

ATTEST:

Lori Kays-Sanders, Secretary

Appendix A: Ten Year Load & Customer Forecast

Ten Year Load & Customer Forecast 2018-2027



Public Utility District No. 1 of Benton County

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I. EXECUTIVE SUMMARY

The 2018 Ten Year Load and Customer Forecast (Forecast) is developed annually and used as critical input in a number of different analyses and processes including the Cost of Service Analysis (COSA), the Integrated Resource Plan (IRP), Rate Analysis, Budgeting, Power Requirements Planning, and Five-Year Capital Plan. Its utilization as an input in these decision making tools and future plans makes its accuracy important. Despite already being well into 2018, actual 2017 loads have an impact on the 2018 Forecast which was produced during the previous year. The District takes advantage of the opportunity to adjust the 2018 Forecast with the expectation of using the updated Forecast in future analyses.

Load Uncertainties

The District's Forecast projects moderate annual retail load growth over the five year and ten year planning periods with 2018 Retail Loads forecasted to be 201 average megawatts (aMW) at the Customer Meter. However, a number of factors can cause roughly 5% deviations from the Forecast such as weather variances, Large Irrigation customer crop rotations and unforeseen new loads or loss of loads.

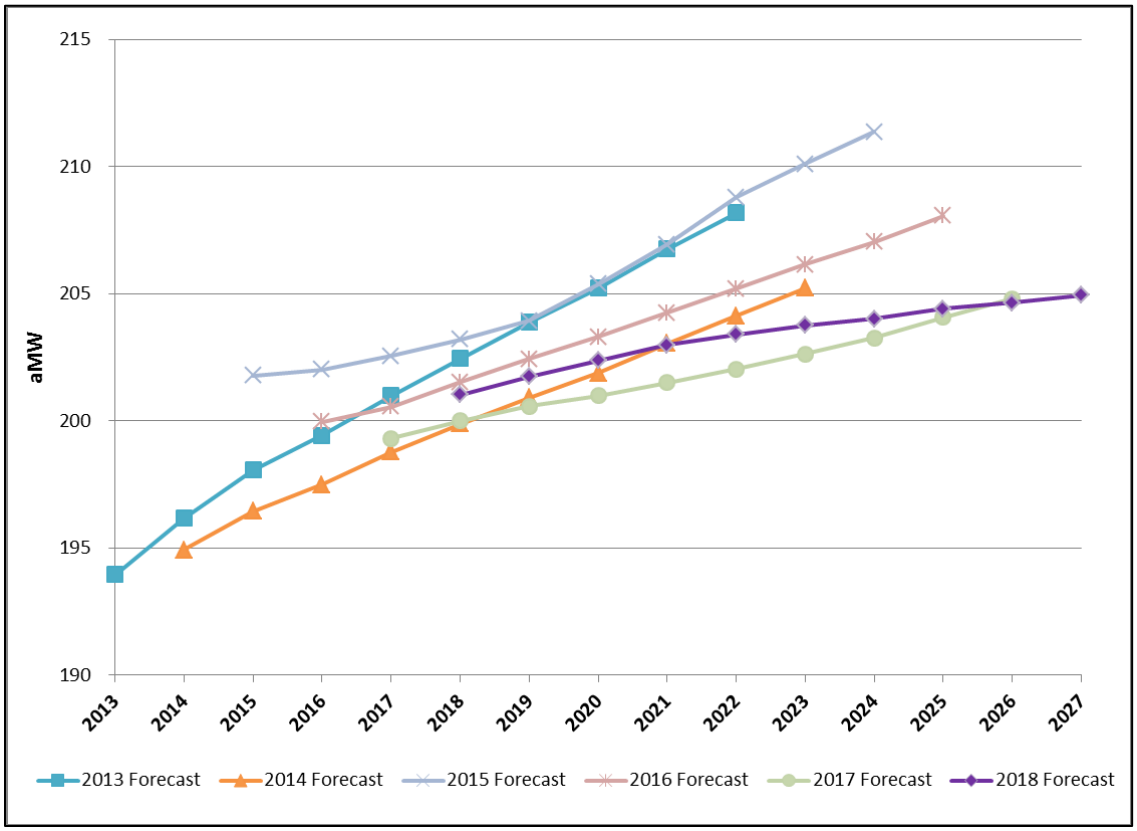

Figure 89 – Historical Ten Year Retail Load Forecasts (2013-2018)

Figure 89 above shows the historical ten year forecasts from 2013 to the current 2018 Forecast. As seen in the graph, the Forecasts have evolved over the last five years with the slope of each Forecast trending down. The Forecast's rate of load growth peaked in 2015 and has since trended downward similar to what has been observed regionally by the Pacific Northwest Utilities Conference Committee (PNUCC).

The 2018 Forecast is starting about 2 aMW higher than the previous Forecast. The higher starting point is largely due to an increase in expected Residential usage due to steady customer growth which has averaged 645 new customers per year for the last five years.

As can be seen in **Figure 2** below, the District has observed variances between past forecasts and actual loads observed. A 5% variance is equivalent to almost 10 aMW on an annual basis. While variances between forecasts and actual loads are expected, staff has used lessons learned and improved the forecasting methodology by analyzing modeling inputs used in the Forecast. The two biggest drivers of variances between the Forecast and what energy actually flows through the District's system are weather and conservation. In an effort to improve the Forecast's accuracy, last year staff adjusted how average weather is determined basing it on a shorter timeframe (last five years vs last 12 years) to reflect recent weather patterns which is also used in this year's Forecast. Last year, staff also adjusted how conservation is treated in the Forecast by calculating the energy savings that have been achieved historically versus what the incremental savings are projected to be in the future. The changes made last year to model weather and conservation were used again in this year's Forecast (See **III. MODELING ASSUMPTIONS** for more information).

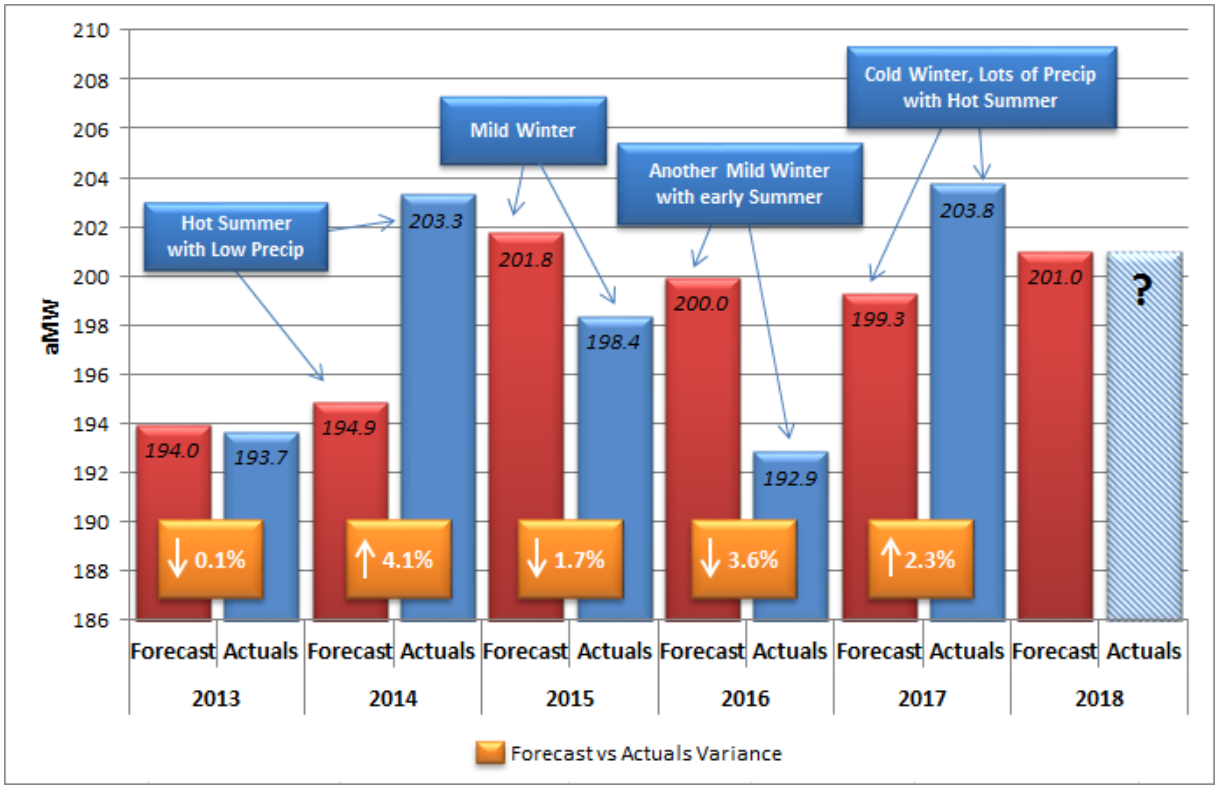

Figure 90 – Forecasts vs Actuals (2013-2018) – Retail Loads at Customer Meter

To account for some of the load uncertainties, the District developed three scenarios including a Low Case, Medium Case, and a High Case. For this year's Low Case and High Case, staff also adjusted the weather variables used to drive differences in each scenario. The District develops each scenario to establish a range of growth rates and adopts the Medium Case as the Base Case. Differences between the Low Case, Base Case and High Case can be found in **Appendix A**.

Forecast Conclusions

As highlighted in **Figure 1**, the District continues to see a flattening trend in Forecasts. The Average Annual Rate of Growth (AARG) is expected to be 0.21% for the ten year planning period which is down from last year's Forecast of 0.30%. Over the last five years, the District has achieved over eight aMW of conservation, and despite the Forecast including another 14 aMW of conservation to be achieved over the next ten years, the District expects four aMW of cumulative load growth. (More information on the impacts of conservation can be found in **III. MODELING ASSUMPTIONS**). **Figure 91** below shows the actual loads by customer class over the past five years along with the Forecast for the next five years.

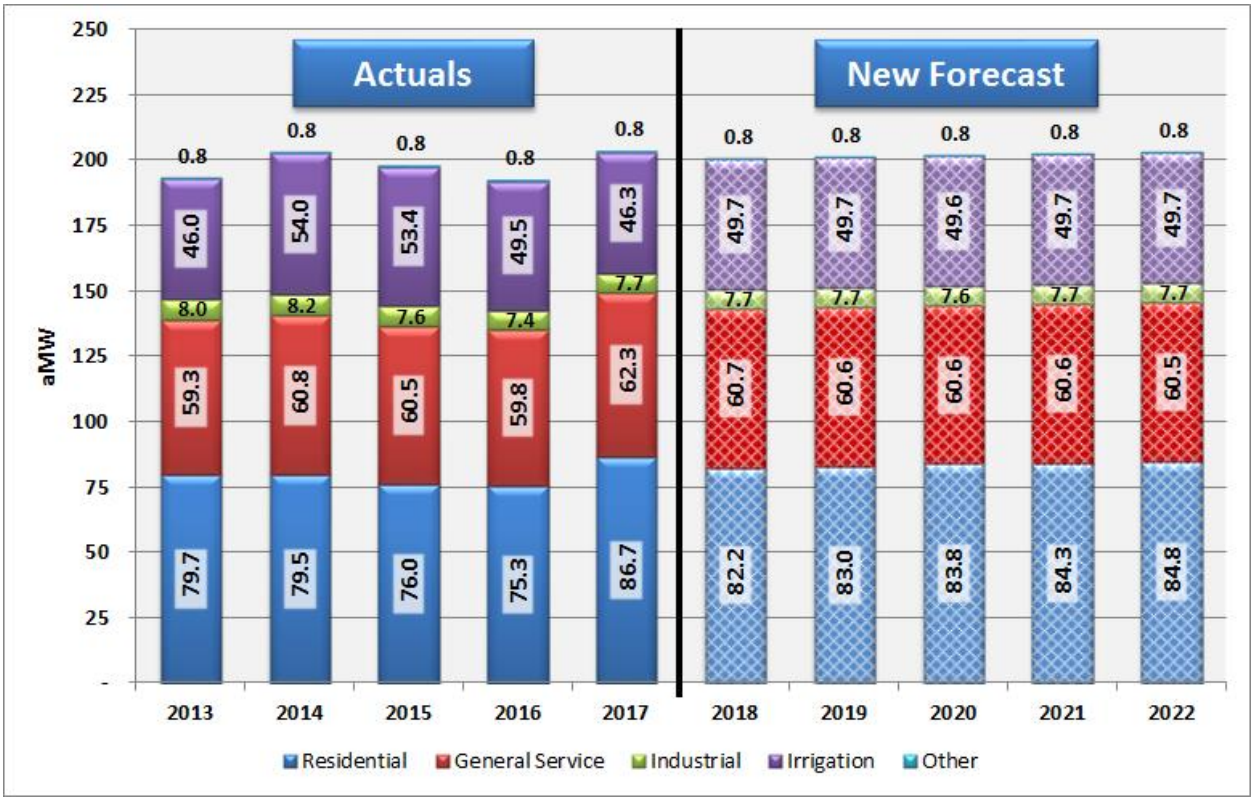

Figure 91 – Five Year Actuals vs. Five Year Forecast – Retail Loads at Customer Meter

As can be seen in **Figure 3** and highlighted in the Load Uncertainties section above, total system loads fluctuate with the largest changes observed in the Residential and Irrigation customer classes due to weather impacts on customer behaviors. In 2017, Irrigation usage was one of the lowest observed over the last five years due to the large amount of precipitation in the winter and springtime that "pre-charged" the land causing irrigators to pump less water. However, a very cold winter significantly increased Residential usage to the highest observed in the District's history at 86.7 aMW. The District total system Forecast under normal weather assumptions is not expected to surpass these loads again until 2027 (see **Table 1**).

Table 1 shows the difference between the District's Retail, BPA POD and Wholesale load forecasts. Retail loads include the District's aggregate metered customer load. BPA POD loads are measured at BPA meter points and include the District's aggregate metered customer load plus distribution losses.

Wholesale loads include the District's BPA POD loads plus regional power grid transmission losses. The District is not only responsible for procuring the energy necessary to serve our customer's load, but also the losses associated with the transport of electricity over equipment and power lines from regional generation resources to our customer loads. The District is using distribution losses and transmission losses observed in 2017 of 3.25% and 1.42% respectively in the Forecast.

2018 Load Forecast Overview			
(2017 Actual POD Load - 210)	Retail Loads	BPA POD Loads	Wholesale Loads
2022 Forecast aMW	203	210	213
2022 aMW change over 2017	0	0	0
2027 Forecast aMW	205	211	214
2027 aMW change over 2017	1	1	1

Table 1 – 2018 Average Annual Power Forecast Overview

Proactively Growing Loads

Many utilities are experiencing lower retail sales growth due to a number of factors which may include general economic activity, energy efficiency programs, or customer self-generation from rooftop solar installations and community solar installations. The District currently has 174 rooftop solar installations and two community solar installations accounting for ~0.22 aMW of load loss. Flattening or declining retail sales puts upward pressure on customer retail rates as general inflation causes costs to increase while sales remain stagnant (see **Figure 4** below). More importantly, about one-half of total utility costs are fixed costs such as poles, wires and substations to safely and reliably meet and serve customer loads. Fixed costs do not decrease as sales flatten or decrease.

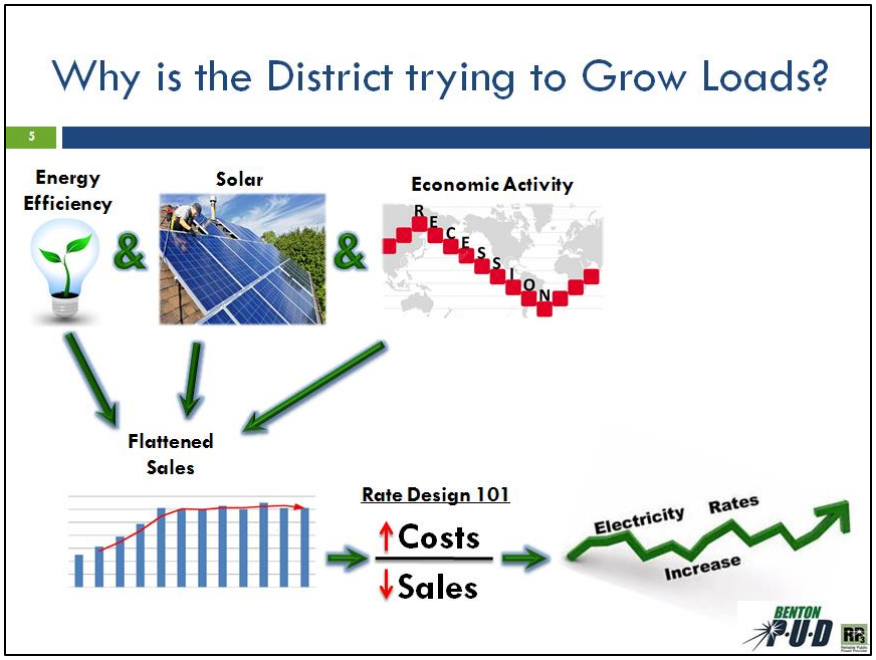

Figure 92 – Reasons for focus on load growth

Proactively growing loads has become a strategic focus for the District. This is primarily due to the fact that the District has surplus energy above what is required to meet loads ("long on resources") on an annual average basis. When the District has excess energy from its resources, it sells the energy on the wholesale market. Wholesale market prices have declined significantly in recent years due a number of different factors including overbuilding of renewable generation due to state mandated renewable energy policies and large increases in natural gas supplies due to fracking technologies. By growing loads and selling the District's energy at retail rather than wholesale, it will decrease pressure on customer retail rates. The District has partnered with TRIDEC and other local agencies to market and highlight areas within the District's service territory that have excess capacity and are ready to interconnect new loads. A lot of discussions are occurring about the development of the Vista Field area with new commercial related loads. One industry that is growing in interest is "blockchain" computing or "cryptocurrencies" such as Bitcoin.

Blockchain operations use relatively large amounts of electrical energy and present an opportunity the District is exploring cautiously due to the impacts it has had on other regional utilities distribution systems and financial risk profile. Due to the District's interest in growing loads, staff is currently working to develop a New Large Load (NLL) policy that will address loads that fall within the District's Industrial Rate Schedule of 3.5 megawatts (MW) to 10 MW of demand and loads in excess of 10 MW for which rates are subject to negotiations. The NLL policy will develop the process and procedure to facilitate the interconnection of a NLL while considering equity between the new customer and existing customers and possible economic benefit to our community.

Another possible source of load growth is electric vehicles (EVs). EVs present an opportunity for the District to offset the impact of flattening or declining retail sales as well by preserving and possibly growing loads. Similar to any new business that enters the community, EVs have the potential to

generate more energy sales over the long run that will help mitigate upward pressure on rates. There are currently 283 EVs registered in Benton County, but the Edison Electric Institute (EEI) recently released its *Plug-in Electric Vehicle Sales Forecast*. EEI estimates there will be more than 7 million EVs on the road by 2025, with approximately 1.2 million sold annually. The District is developing programs to educate customers about EVs and their potential benefits to help increase adoption in its service territory. The impacts of these various opportunities for load growth have not been modeled in the Forecast.

II. OVERVIEW

The District observed a 5.37% increase in actual energy sales for the year 2017 compared to 2016. This was the first increase in actual energy sales over the last three years due to one of the coldest winters on record that caused an increase in Residential energy usage. Total actual energy sales would have been even higher; however due above average precipitation, Large Irrigation energy usage did not materialize as previously forecasted. Residential, Small General Service, Medium General Service, Large General Service and Large Industrial customer classes experienced increased energy sales in 2017; whereas, Small Irrigation, Large Irrigation, Street Lights, Security Lights and Unmetered customer classes experienced decreased energy sales.

It should be noted the Forecast for 2018 shows an overall decrease of 1.34% over 2017 after accounting for the load reductions associated with expected conservation activities. The decrease is due largely to the Forecast using average weather rather than the extreme cold that caused the increased actual energy sales in 2017.

III. MODELING ASSUMPTIONS

Overview

The econometric load forecast model is a long-term model that forecasts total energy usage by customer class, number of customers by customer class and system peak demand. The model uses historical data and econometric data (*see below*) to establish a relationship between energy consumption and economic variables.

Model Inputs – Historical Load

Using the District's historical monthly load and customer data separated into customer classes: Residential, Small General Service, Medium General Service, Large General Service, Large Industrial, Small Irrigation, Large Irrigation, Street Lights, Security Lights, and Unmetered. Historical total system peak demand was also provided.

Model Inputs – Econometric Forecast

The Energy Authority subscribes to Woods & Poole Economic Forecasts, which are updated annually; most recently in April 2017. The Woods & Poole Economics, Inc. database contains more than 900 economic and demographic variables for every county in the United States for every year from 1970 to 2040.

The comprehensive database includes:

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

The Woods & Poole projection for each county in the United States is done simultaneously so that changes in one county will affect growth or decline in other counties. The specific economic projection

technique used by Woods & Poole to generate the employment, earnings, and income estimates for each county in the United States generally follow a standard economic "export-base" approach.

The model utilizes four variables for the Benton County region: total population, total employment, total number of households, and total retail sales including eating and drinking places. Values for the City of Richland and West Richland are gathered by various sources such as Washington State Office of Financial Management's (OFM) website and Google Public Data Explorer, and backed out of the Benton County data to more accurately represent the District's service territory.

According to Woods & Poole, the long-term outlook for the United States economy is one of steady and modest growth through the year 2040. Although periodic business cycles, such as the 2008-09 recession, will interrupt and change the growth trajectory, the nation's employment and income are expected to rise every year from 2018 to 2040. **Table 2** below highlights Benton County's historical and expected economic growth rates.

Woods & Poole Growth Rates				
Year	Population	Employment	Households	Retail Sales
2000	0.68%	0.16%	0.75%	4.21%
2001	1.25%	2.57%	5.53%	2.36%
2002	2.01%	2.07%	0.69%	3.60%
2003	1.54%	2.19%	2.60%	3.26%
2004	0.37%	0.96%	-0.66%	3.99%
2005	0.35%	0.86%	3.82%	3.33%
2006	1.75%	0.25%	-1.38%	1.91%
2007	1.74%	6.17%	2.21%	0.72%
2008	3.42%	2.40%	2.95%	-2.03%
2009	3.12%	2.31%	2.69%	-5.79%
2010	4.14%	4.31%	1.09%	5.91%
2011	0.61%	0.28%	3.81%	6.22%
2012	0.55%	-2.69%	1.50%	3.49%
2013	0.49%	-1.10%	2.35%	2.16%
2014	0.46%	1.39%	0.79%	2.90%
2015	1.84%	2.93%	1.53%	3.04%
2016	1.27%	2.08%	2.29%	2.83%
2017	1.38%	2.00%	2.02%	2.48%
2018	1.38%	1.86%	1.79%	2.25%
2019	1.37%	1.75%	1.64%	2.20%
2020	1.36%	1.72%	1.55%	2.12%
2025	1.34%	1.63%	1.18%	1.92%
2030	1.27%	1.42%	0.88%	1.77%
2035	1.12%	1.16%	0.65%	1.66%
2040	0.94%	0.92%	0.69%	1.66%

Table 2 – Benton PUD Service Territory Growth Rates

Model Inputs – Weather

The load forecast model normalizes historical energy usage for weather data from the Pasco, WA weather station. Heating degree days represent days where customers are forecasted to need heating services; whereas, cooling degree days represent days where customers are forecasted to need cooling

services. As the need for heating and cooling services increases, the District's energy usage increases as well. For the purposes of this forecast, heating and cooling degree days have been calculated using a 65 degree base.

Precipitation is also used to normalize the small irrigation and large irrigation customer classes. The load forecast model determines the proper correlation, or relationship, between historical loads, historical weather and historical economic indicators to produce a trend line for forecasted planning period. The model uses the last five years to determine average weather similar to last year's Forecast; whereas, in previous years the model used the last 12 years to determine average weather.

Conservation

In addition to natural energy saving effects due to electricity rate inflation and economic conditions, the District has an established conservation program in place to proactively assist our customers with efforts to reduce their energy consumption. In order to account for these extra efforts in the load forecast model, the District uses a Conservation Potential Assessment (CPA) prepared by EES Consulting that details both historical conservation savings and forecasted conservation savings by customer sector. In October 2017, the District's Commission passed Resolution 2427 to adopt a new CPA which increased the forecasted conservation savings by 28% (3 aMW higher than the previous ten year planning period). The forecasted cumulative savings from the CPA are subtracted from the forecasted loads to account for load reduction associated with conservation activities. District staff observed that approximately one aMW of conservation has been achieved annually since the year 2000. In order to account for the impact historical conservation activities had on the load forecast model's trend line, District staff subtracted the average annual achievement observed since 2000 from the annual conservation projection from the CPA. Therefore, the Forecast only includes the expected incremental conservation savings. See **Table 3** below for more detail on the forecasted incremental load reductions by customer class.

Cumulative Conservation Inputs					
Date	Residential	Small General	Medium General	Large General	Total
2018	0.03	0.01	0.01	0.02	0.08
2019	0.11	0.03	0.05	0.06	0.25
2020	0.21	0.06	0.09	0.12	0.48
2021	0.36	0.11	0.15	0.20	0.82
2022	0.57	0.17	0.24	0.31	1.29
2023	0.80	0.24	0.34	0.44	1.83
2024	1.05	0.31	0.44	0.58	2.38
2025	1.29	0.38	0.55	0.71	2.94
2026	1.55	0.46	0.66	0.86	3.53
2027	1.79	0.53	0.76	0.99	4.08
2028	2.02	0.60	0.86	1.11	4.59
2029	2.21	0.66	0.94	1.22	5.03
2030	2.38	0.71	1.01	1.31	5.41
2031	2.53	0.75	1.07	1.39	5.74
2032	2.65	0.79	1.12	1.46	6.02
2033	2.75	0.82	1.17	1.52	6.25
2034	2.82	0.84	1.20	1.56	6.42
2035	2.89	0.86	1.23	1.59	6.57

Table 3 – Forecasted Cumulative Incremental Conservation Acquisitions (aMW)

Methodology

The relationship between the normalized historical load data and the econometric variables is determined by partial least squares (PLS) 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. PLS regression is a technique that generalizes and combines features from principal component analysis and multiple regressions. It is particularly useful when it is necessary to predict a set of dependent variables from a (very) large set of independent variables. PLS regression tends to outperform multiple linear regressions when there are a large number of variables because it avoids over-fitting the data. An over fit model is one that is too complicated for the data set and can result in misleading forecasts of future behavior. The established relationship between load data and econometric variables is then used with the Woods & Poole Economic projections to create an energy consumption forecast.

Peak Forecast

To calculate a monthly peak forecast, a peak load factor was calculated using the historical relationship between total monthly load and the monthly peak demand. The calculated peak load factor was then applied to the monthly load forecast to generate peak demands for every month.

Scenarios Analysis

In the past, staff has only adjusted the econometric inputs to develop the Low Case and High Case. For this year's Low Case and High Case, staff also adjusted the weather variables used to drive differences in each scenario. The District develops each scenario to establish a range of growth rates and adopts the

Medium Case as the Base Case. **Figure 93** below shows the differences between the Low Case, Base Case and High Case scenarios. For the Low Case scenario, the Woods & Poole growth rates were decreased by 30% and the min HDD, min CDD, and max precipitation observed over the past 5 years were used for the expected weather to establish a lower boundary of potential outcomes. For the High Case scenario, the Woods & Poole growth rates were increased by 30% and the max HDD, max CDD, and min precipitation observed over the past 5 years were used for the expected weather to establish the upper boundary of potential outcomes. More information can be found in **Appendix A**.

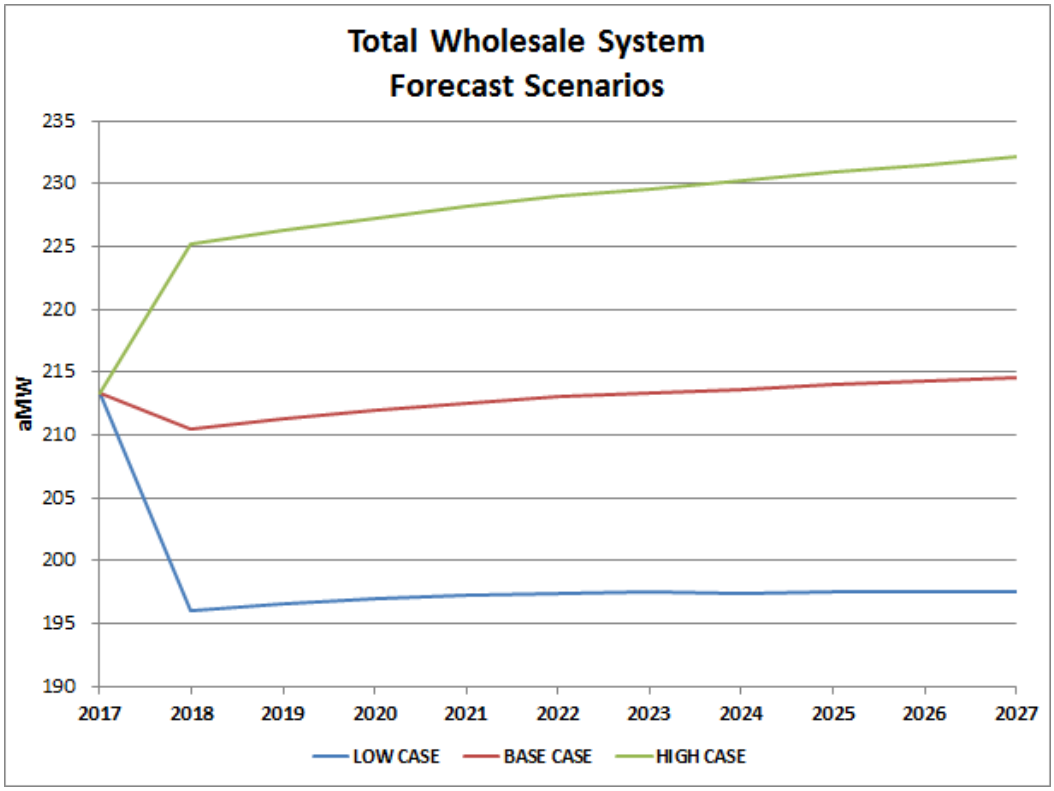

Figure 93 – Low, Base and High Case Scenarios

Other Factors affecting the Forecast

Currently, the District has 174 net metered customers who generate their own electricity from their renewable energy systems. It is projected that 40 new customers will be added in 2018. In addition to the net metered customers, 154 District customers fully funded the construction of two community solar projects, the Ely Community Solar Project and the OIE Community Solar Project. The estimated load reduction from the current net metered customers and community solar projects is approximately 0.22 aMW or 1,931 MWhs annually.

IV. DISTRIBUTION AND TRANSMISSION LOSSES

Table 1 shows the difference between the District's Retail, BPA POD and Wholesale load forecasts. In the past, the Forecast has strictly focused on the Retail load forecast as it is utilized to calculate the District's forecasted revenues. Retail loads include the District's aggregate metered customer load. BPA POD loads are the District's aggregate metered customer load plus distribution losses. Wholesale loads

include the District's metered customer load plus distribution losses plus regional power grid transmission losses. At a high level, the District is not only responsible for procuring the energy necessary to serve our customer's load, but also the losses associated with the transport of electricity over equipment and power lines from regional generation resources to our customer loads. To put this into context for the 2018 Base Case, the District is using 3.25% in distribution losses and 1.42% in transmission losses in the Forecast. The annual wholesale loads, the District's BPA POD loads and Retail loads are shown in **Appendix A – Table 1.**

V. RESIDENTIAL SALES

The District historically has experienced strong Residential energy usage and customer growth from 2013 to 2017. While the District averaged 591 new customers per year, the annual average energy usage decreased by 0.73%. The decoupling of customer growth and energy usage growth highlights the impacts from District conservation and new building codes and standards. Weather variations also can have significant impact. In 2017, the District observed 712 new Residential customers while seeing a 14.79% increase in energy usage. The increase in energy usage was driven by the coldest winter in the last 15 years and a hot summer. Looking forward the five year and ten year planning period shows customer growth increasing by 608 and 578 per year respectively. During the same planning period, the Residential energy usage is expected to see an AARG of 0.78% and 0.66% respectively. See **Table 4** and **Figure 6** for more detail.

Residential	
Load Growth	
Average Growth	Range
0.78%	2018-2022
0.66%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	636,952	72.51									
2001	617,763	70.52			-3.01%						
2002	622,196	71.03			0.72%						
2003	604,618	69.02			-2.83%						
2004	621,386	70.74			2.77%						
2005	622,639	71.08			0.20%			36,963		16.84	
2006	632,213	72.17			1.54%			37,418	455	16.90	0.30%
2007	644,392	73.56			1.93%			37,969	551	16.97	0.45%
2008	666,418	75.87			3.42%			38,855	886	17.15	1.06%
2009	721,719	82.39			8.30%			39,220	365	18.40	7.29%
2010	654,775	74.75			-9.28%			39,687	466	16.50	-10.34%
2011	687,953	78.53			5.07%			40,201	514	17.11	3.72%
2012	668,018	76.05			-2.90%			40,645	444	16.44	-3.96%
2013	697,887	79.67			4.47%			41,321	676	16.89	2.76%
2014	696,804	79.54			-0.16%			41,758	437	16.69	-1.20%
2015	665,505	75.97			-4.49%			42,375	617	15.71	-5.88%
2016	661,742	75.33			-0.57%			43,157	783	15.33	-2.37%
2017	759,634	86.72			14.79%			43,870	712	17.32	12.93%
2018			720,496	82.25	-5.15%	720,787	82.28	44,599	730	16.15	-6.70%
2019			727,029	82.99	0.91%	728,011	83.11	45,203	604	16.08	-0.44%
2020			735,923	83.78	1.22%	737,771	83.99	45,786	583	16.07	-0.07%
2021			738,389	84.29	0.34%	741,547	84.65	46,348	562	15.93	-0.88%
2022			743,159	84.84	0.65%	748,112	85.40	46,910	562	15.84	-0.56%
2023			747,643	85.35	0.60%	754,677	86.15	47,472	562	15.75	-0.59%
2024			754,934	85.94	0.98%	764,132	86.99	48,034	562	15.72	-0.21%
2025			756,465	86.35	0.20%	767,808	87.65	48,583	549	15.57	-0.93%
2026			760,401	86.80	0.52%	773,988	88.35	49,116	533	15.48	-0.57%
2027			764,446	87.27	0.53%	780,169	89.06	49,649	534	15.40	-0.55%

Table 4 – Residential History and Retail Load Forecast

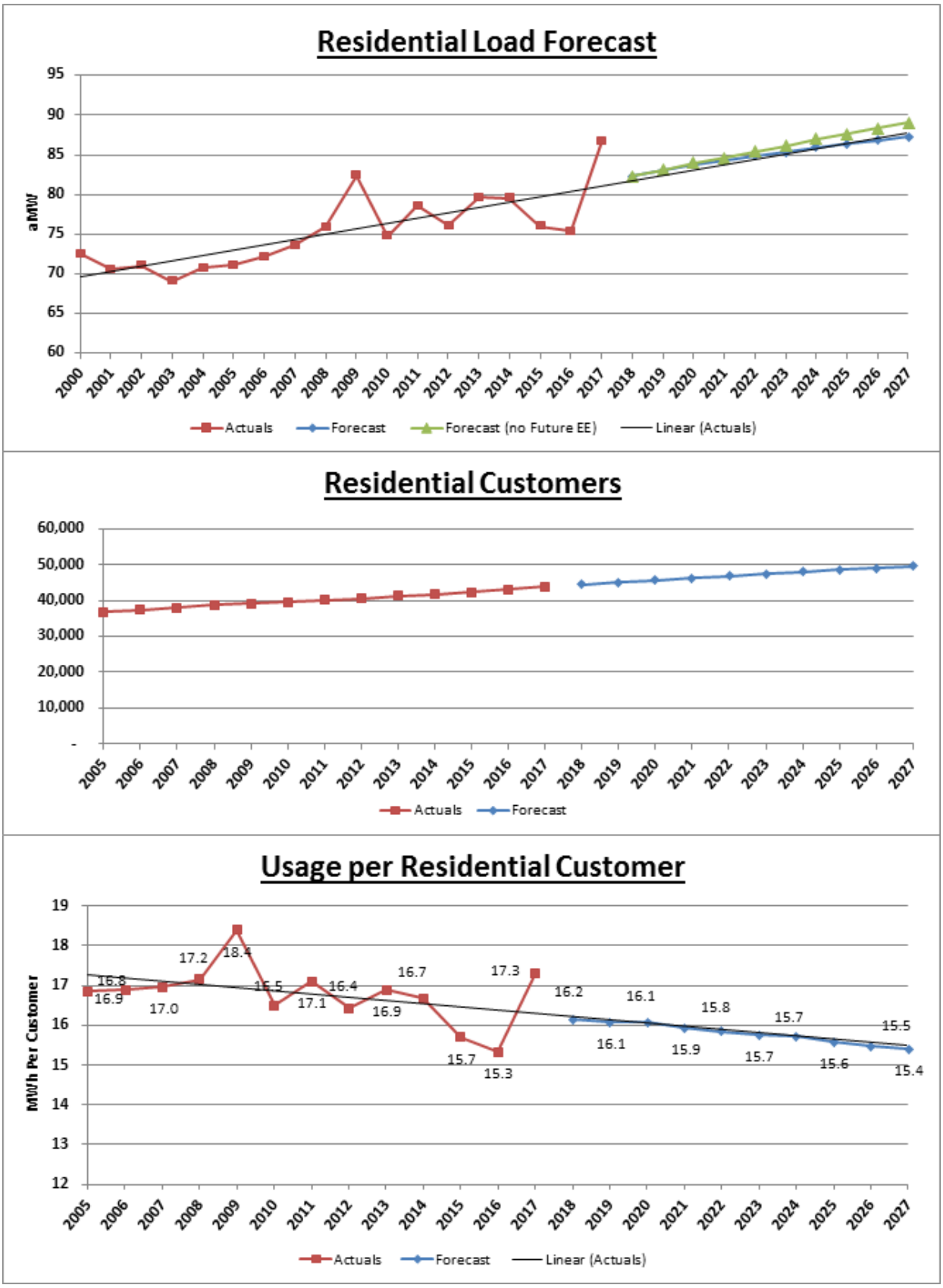

Figure 94 – Residential Load Forecast, Customer Forecast, Usage per Customer

VI. GENERAL SERVICE SALES

Customers with peak demand less than 50 kW are classified as Small General Service (SGS). There is wide range of different SGS customers including City of Kennewick and City of Prosser lighting, "box" stores in strip malls, and some churches. Medium General Service (MGS) customers have peak demand between 50 kW and 300 kW. When you think about a MGS customer, think of larger churches, irrigation and school districts. Large General Service (LGS) class is for customers with peak demand greater than 300 kW three times during the year and includes customers like Yokes, Costco or cold storage for commodity storage. As a customer's usage changes with time, it is possible for them to be reclassified into another customer class. Each General Service customer class is experiencing a decline in its AARG between the five year and ten year planning periods due the saturation of conservation activities including but not limited to the implementation of LED lighting.

The SGS class observed 1.22% of growth in energy usage from 2013 to 2017 with an average increase of 73 in customers. The SGS class is expected to see continued growth adding 71 and 69 new customers per year respectively over the five year and ten year planning period. During the same planning period, SGS's energy usage is expected to see an AARG of 0.30% and 0.17% respectively slightly lower than what was observed during the last five years. See **Table 5** and **Figure 95** for more detail on the SGS customer class.

Small General Service	
Load Growth	
Average Growth	Range
0.30%	2018-2022
0.17%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	115,604	13.16									
2001	113,104	12.91			-2.16%						
2002	113,127	12.91			0.02%						
2003	113,253	12.93			0.11%						
2004	115,574	13.16			2.05%						
2005	114,710	13.09			-0.75%			4,144		27.68	
2006	112,705	12.87			-1.75%			4,169	25	27.03	-2.34%
2007	115,049	13.13			2.08%			4,295	126	26.78	-0.92%
2008	115,616	13.16			0.49%			4,385	90	26.36	-1.57%
2009	121,580	13.88			5.16%			4,460	75	27.26	3.40%
2010	113,483	12.95			-6.66%			4,503	43	25.20	-7.55%
2011	118,338	13.51			4.28%			4,553	50	25.99	3.13%
2012	119,421	13.60			0.92%			4,610	57	25.90	-0.33%
2013	122,928	14.03			2.94%			4,682	72	26.26	1.36%
2014	124,285	14.19			1.10%			4,741	60	26.21	-0.16%
2015	121,498	13.87			-2.24%			4,828	87	25.17	-4.00%
2016	121,868	13.87			0.30%			4,915	87	24.80	-1.47%
2017	129,054	14.73			5.90%			4,977	62	25.93	4.59%
2018			124,893	14.26	-3.22%	124,979	14.27	5,051	75	24.73	-4.65%
2019			125,329	14.31	0.35%	125,621	14.34	5,125	74	24.45	-1.10%
2020			126,227	14.37	0.72%	126,776	14.43	5,196	71	24.29	-0.67%
2021			126,198	14.41	-0.02%	127,136	14.51	5,265	69	23.97	-1.33%
2022			126,397	14.43	0.16%	127,868	14.60	5,334	69	23.70	-1.13%
2023			126,511	14.44	0.09%	128,601	14.68	5,403	69	23.42	-1.18%
2024			126,983	14.46	0.37%	129,714	14.77	5,472	69	23.21	-0.89%
2025			126,697	14.46	-0.23%	130,065	14.85	5,539	67	22.87	-1.44%
2026			126,726	14.47	0.02%	130,761	14.93	5,604	65	22.61	-1.14%
2027			126,787	14.47	0.05%	131,457	15.01	5,669	65	22.36	-1.10%

Table 5 – Small General Service History and Retail Load Forecast

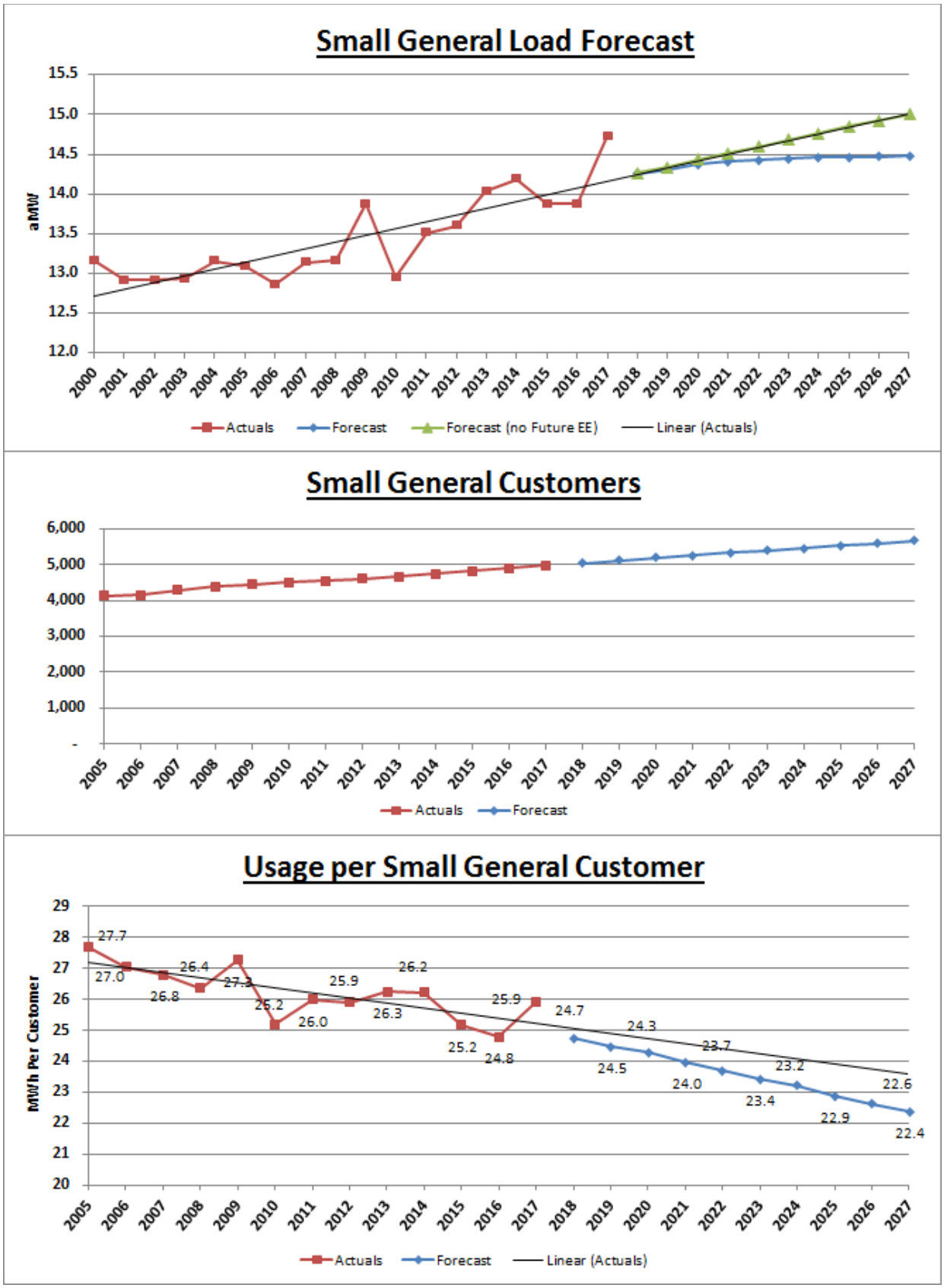

Figure 95 – Small General Service Load Forecast, Customer Forecast, Usage per Customer

The MGS class observed 1.23% of growth in energy usage from 2013 to 2017 with an average increase of seven customers annually. The MGS class is expected to see continued growth adding 13 new customers per year over the five year and ten year planning period. During the same planning periods, MGS's energy usage is expected to see an AARG of 0.41% and 0.27%. See **Table 6** and **Figure 96** for more detail on the MGS customer class.

Medium General Service	
Load Growth	
Average Growth	Range
0.41%	2018-2022
0.27%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	167,304	19.05									
2001	166,300	18.98			-0.60%						
2002	164,197	18.74			-1.26%						
2003	170,005	19.41			3.54%						
2004	167,622	19.08			-1.40%						
2005	164,043	18.73			-2.14%			637		257.46	
2006	160,440	18.32			-2.20%			636	(1)	252.20	-2.04%
2007	165,186	18.86			2.96%			654	18	252.45	0.10%
2008	169,571	19.30			2.66%			676	21	250.94	-0.60%
2009	175,265	20.01			3.36%			695	19	252.18	0.49%
2010	170,868	19.51			-2.51%			718	23	238.03	-5.61%
2011	175,463	20.03			2.69%			732	14	239.84	0.76%
2012	175,999	20.04			0.31%			747	15	235.71	-1.72%
2013	177,250	20.23			0.71%			746	(1)	237.60	0.80%
2014	182,044	20.78			2.70%			754	8	241.41	1.60%
2015	182,610	20.85			0.31%			758	4	240.99	-0.17%
2016	180,467	20.54			-1.17%			768	10	235.06	-2.46%
2017	186,155	21.25			3.15%			782	14	238.05	1.27%
2018			184,072	21.01	-1.12%	184,196	21.03	796	14	231.27	-2.85%
2019			184,987	21.12	0.50%	185,404	21.16	810	14	228.50	-1.20%
2020			186,450	21.23	0.79%	187,234	21.32	823	13	226.64	-0.81%
2021			186,622	21.30	0.09%	187,962	21.46	836	13	223.37	-1.44%
2022			187,098	21.36	0.26%	189,200	21.60	848	13	220.55	-1.26%
2023			187,453	21.40	0.19%	190,438	21.74	861	13	217.72	-1.28%
2024			188,297	21.44	0.45%	192,199	21.88	874	13	215.52	-1.01%
2025			188,101	21.47	-0.10%	192,914	22.02	887	13	212.18	-1.55%
2026			188,323	21.50	0.12%	194,087	22.16	899	12	209.60	-1.22%
2027			188,590	21.53	0.14%	195,260	22.29	911	12	207.13	-1.18%

Table 6 – Medium General Service History and Retail Load Forecast

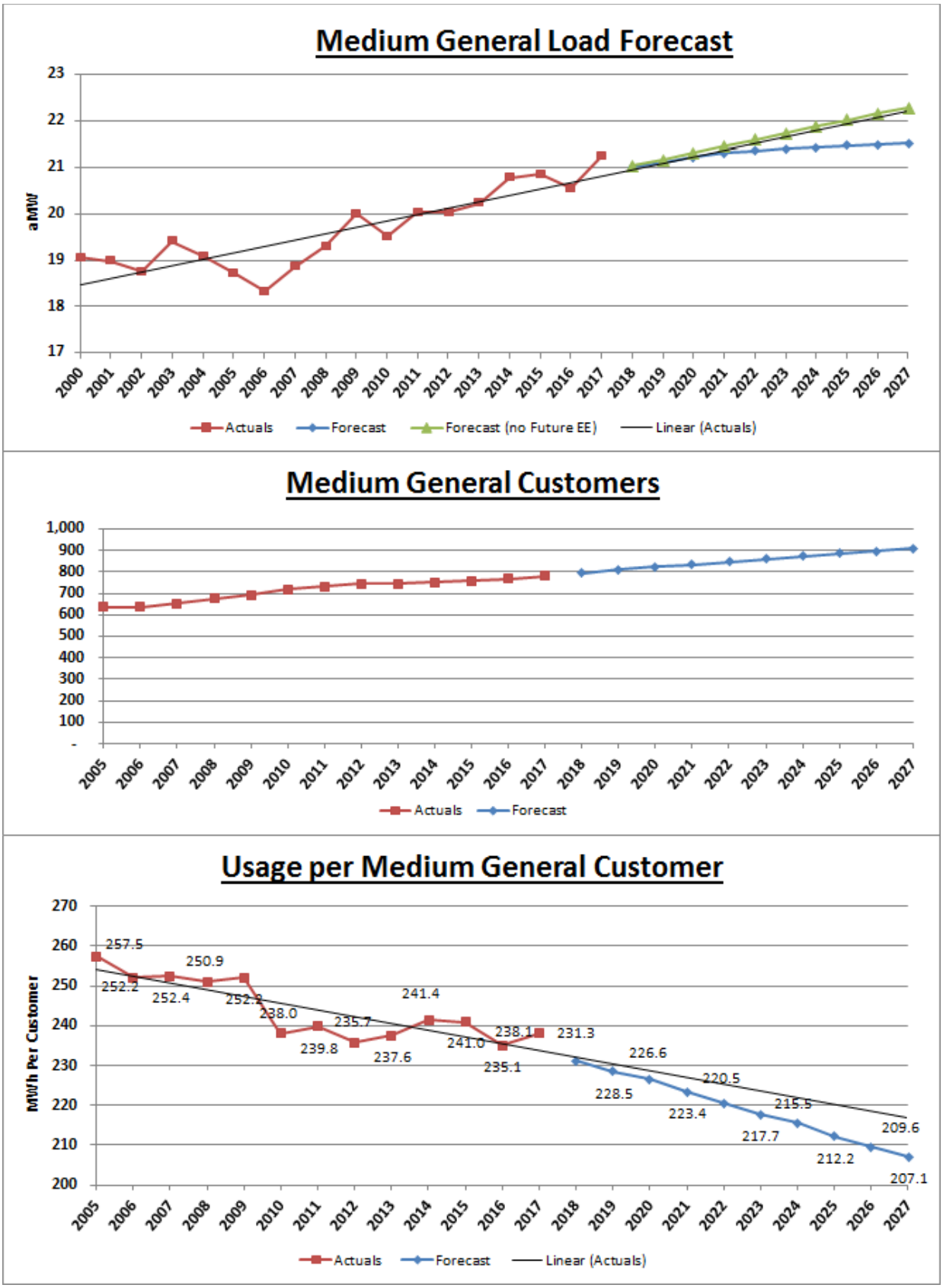

Figure 96 – Medium General Service Retail Load Forecast, Customer Forecast, Usage per Customer

The LGS has observed 1.27% of growth in energy usage from 2013 to 2017 with an average increase of three customers annually. However, the LGS class is not expected to experience any additional customer growth over the five year and ten year planning period. During the same planning period, LGS's energy usage is expected to see a decline of 0.71% and 0.81% respectively due to overall customer class trend decreasing since 2000 and an increase in conservation acquisitions for the LGS class. See **Table 7** and **Figure 97** for more detail on the LGS customer class.

Large General Service	
Load Growth	
Average Growth	Range
-0.71%	2018-2022
-0.81%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	247,522	28.18									
2001	220,952	25.22			-10.73%						
2002	219,625	25.07			-0.60%						
2003	225,799	25.78			2.81%						
2004	240,192	27.34			6.37%						
2005	242,555	27.69			0.98%			122		1,989.52	
2006	236,908	27.04			-2.33%			126	4	1,881.46	-5.43%
2007	223,317	25.49			-5.74%			128	2	1,742.39	-7.39%
2008	224,958	25.61			0.73%			131	3	1,715.05	-1.57%
2009	233,410	26.65			3.76%			134	2	1,747.30	1.88%
2010	218,686	24.96			-6.31%			135	2	1,618.90	-7.35%
2011	209,669	23.93			-4.12%			136	1	1,539.80	-4.89%
2012	217,377	24.75			3.68%			142	6	1,532.62	-0.47%
2013	219,315	25.04			0.89%			144	2	1,520.38	-0.80%
2014	226,679	25.88			3.36%			148	4	1,531.62	0.74%
2015	226,175	25.82			-0.22%			151	3	1,496.20	-2.31%
2016	223,268	25.42			-1.29%			157	6	1,421.33	-5.00%
2017	230,674	26.33			3.32%			160	3	1,443.22	1.54%
2018			222,518	25.40	-3.54%	222,678	25.42	160	0	1,390.73	-3.64%
2019			220,763	25.20	-0.79%	221,305	25.26	160	-	1,379.77	-0.79%
2020			220,056	25.05	-0.32%	221,075	25.17	160	-	1,375.35	-0.32%
2021			218,037	24.89	-0.92%	219,779	25.09	160	-	1,362.73	-0.92%
2022			216,307	24.69	-0.79%	219,038	25.00	160	-	1,351.92	-0.79%
2023			214,418	24.48	-0.87%	218,298	24.92	160	-	1,340.11	-0.87%
2024			213,033	24.25	-0.65%	218,105	24.83	160	-	1,331.45	-0.65%
2025			210,561	24.04	-1.16%	216,817	24.75	160	-	1,316.01	-1.16%
2026			208,631	23.82	-0.92%	216,124	24.67	160	-	1,303.94	-0.92%
2027			206,761	23.60	-0.90%	215,432	24.59	160	-	1,292.26	-0.90%

Table 7 – Large General Service History and Retail Load Forecast

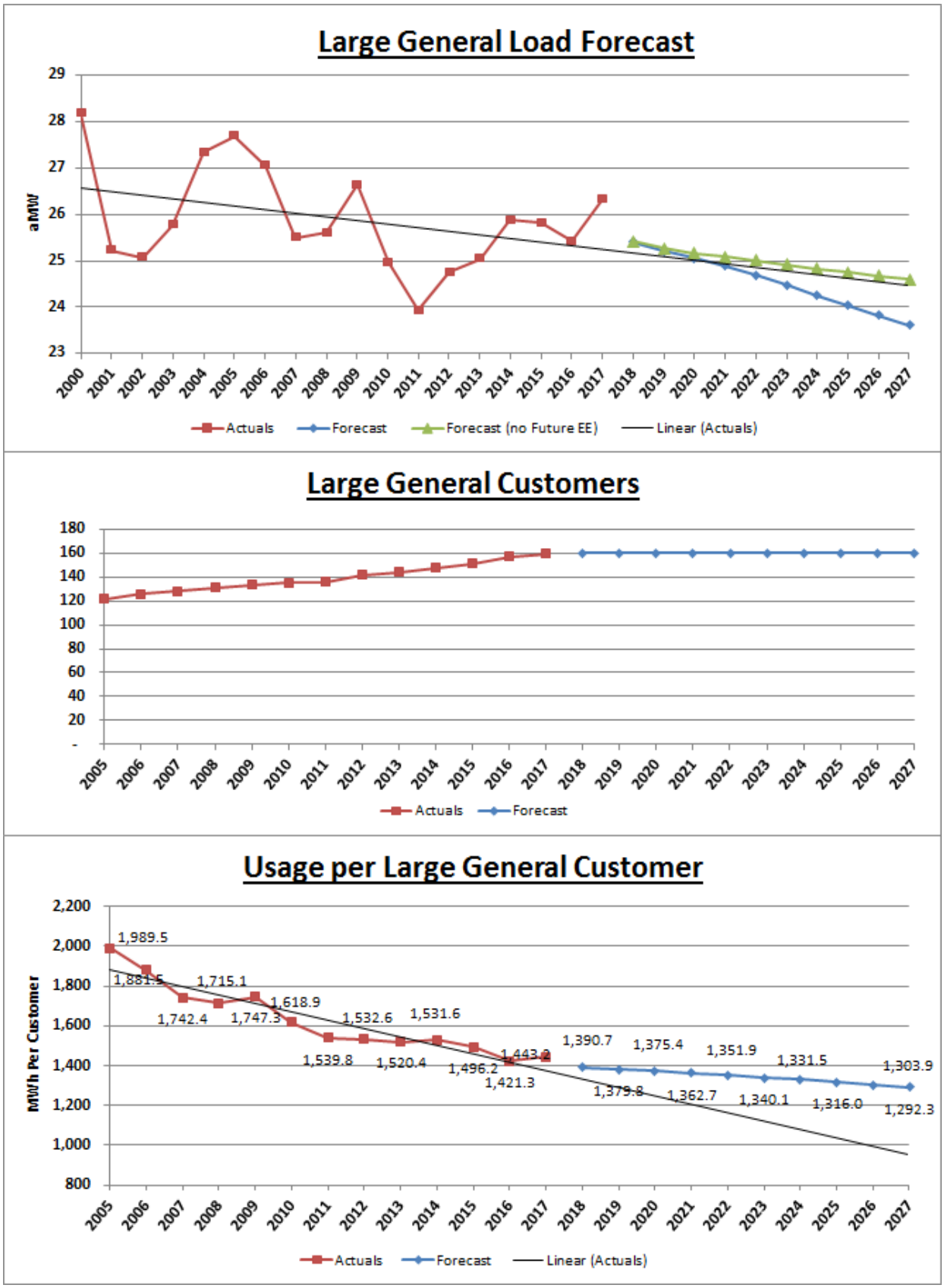

Figure 97 – Large General Service Retail Load Forecast, Customer Forecast, Usage per Customer

VII. LARGE INDUSTRIAL SALES

The District currently has only one large industrial customer. Historically, Large Industrial sales have fluctuated based on market demands for the plant's product and had an average annual decrease of 0.99% from 2013 to 2017. In 2017, energy sales reversed that trend and increased by 3.83% compared to 2016. The increase is attributed to the plant producing more of its product due to increased commodity prices.

During the five year and ten year planning period, the Large Industrial customer class is not expected to add any new customers with energy usage expected to remain flat as well. See **Table 8** and **Figure 98** below for more detail.

Large Industrial	
Load Growth	
Average Growth	Range
0.00%	2018-2022
0.00%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	220,913	25.15									
2001	70,897	8.09			-67.91%						
2002	80,551	9.20			13.62%						
2003	58,054	6.63			-27.93%						
2004	69,479	7.91			19.68%						
2005	53,286	6.08			-23.31%			3		17,761.93	
2006	37,456	4.28			-29.71%			3	-	12,485.31	-29.71%
2007	49,045	5.60			30.94%			3	-	16,348.38	30.94%
2008	47,760	5.44			-2.62%			3	-	15,920.10	-2.62%
2009	38,909	4.44			-18.53%			3	-	12,969.69	-18.53%
2010	55,365	6.32			42.29%			3	-	18,454.89	42.29%
2011	65,411	7.47			18.15%			3	-	21,803.60	18.15%
2012	70,575	8.03			7.90%			3	-	23,525.06	7.90%
2013	69,803	7.97			-1.09%			3	-	23,267.59	-1.09%
2014	71,869	8.20			2.96%			3	-	23,956.50	2.96%
2015	66,942	7.64			-6.86%			3	-	22,313.96	-6.86%
2016	64,612	7.36			-3.48%			5	2	12,922.45	-42.09%
2017	67,084	7.66			3.83%			5	-	13,416.82	3.83%
2018			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2019			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2020			67,084	7.64	0.00%	67,084	7.64	5	-	13,416.80	0.00%
2021			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2022			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2023			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2024			67,084	7.64	0.00%	67,084	7.64	5	-	13,416.80	0.00%
2025			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2026			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%
2027			67,084	7.66	0.00%	67,084	7.66	5	-	13,416.80	0.00%

Table 8 – Large Industrial History and Retail Load Forecast

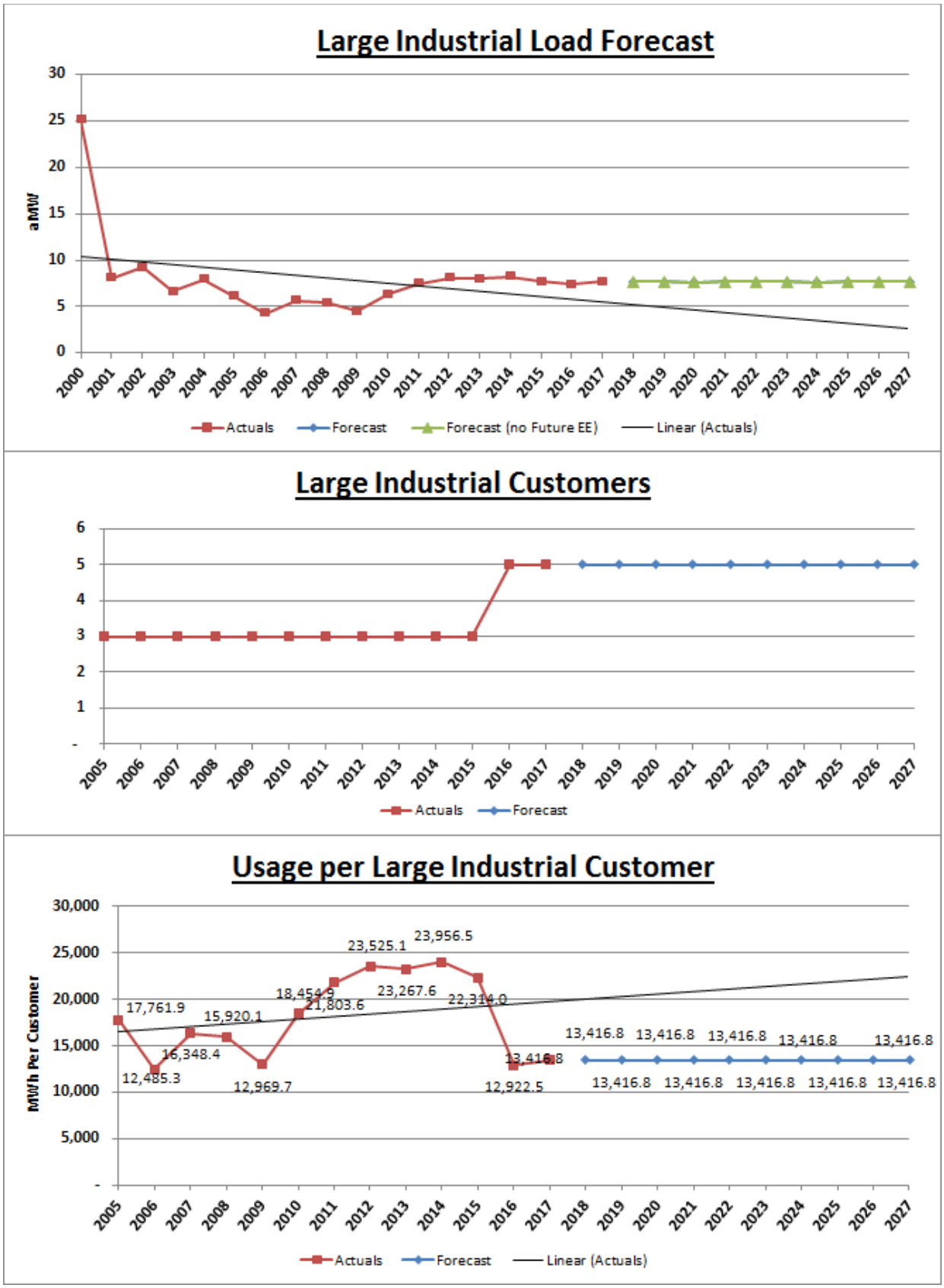

Figure 98 – Large Industrial Retail Load Forecast, Customer Forecast, Usage per Customer

VIII. IRRIGATION SALES

The Small Irrigation class has experienced a declining trend losing on average one customer annually since 2013. The Forecast continues the trend and predicts losing an additional six customers annually with the AARG decreasing by 0.21% and 0.23% per year during the five year and ten year planning periods. See **Table 9** and **Figure 11** for more detail.

Small Irrigation	
Load Growth	
Average Growth	Range
-0.21%	2018-2022
-0.23%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	16,917	1.93									
2001	15,951	1.82			-5.71%						
2002	16,119	1.84			1.05%						
2003	15,873	1.81			-1.52%						
2004	15,071	1.72			-5.05%						
2005	15,724	1.80			4.33%			622		25.27	
2006	14,305	1.63			-9.03%			614	(8)	23.30	-7.79%
2007	15,849	1.81			10.79%			607	(7)	26.10	11.99%
2008	16,043	1.83			1.22%			615	8	26.07	-0.11%
2009	16,884	1.93			5.24%			615	(1)	27.46	5.34%
2010	14,446	1.65			-14.44%			602	(13)	24.00	-12.61%
2011	14,607	1.67			1.11%			582	(20)	25.10	4.61%
2012	15,165	1.73			3.82%			563	(19)	26.95	7.34%
2013	15,211	1.74			0.31%			564	1	26.98	0.11%
2014	17,209	1.96			13.13%			563	(1)	30.59	13.38%
2015	16,425	1.87			-4.56%			560	(3)	29.33	-4.12%
2016	15,597	1.78			-5.04%			558	(3)	27.98	-4.61%
2017	13,754	1.57			-11.82%			557	(1)	24.71	-11.68%
2018			15,313	1.75	11.33%	-	-	547	(9)	27.98	13.25%
2019			15,305	1.75	-0.05%	-	-	542	(5)	28.25	0.95%
2020			15,264	1.74	-0.27%	-	-	536	(5)	28.46	0.74%
2021			15,225	1.74	-0.25%	-	-	531	(6)	28.68	0.80%
2022			15,187	1.73	-0.25%	-	-	525	(6)	28.91	0.81%
2023			15,148	1.73	-0.25%	-	-	520	(6)	29.15	0.82%
2024			15,109	1.72	-0.26%	-	-	514	(6)	29.39	0.81%
2025			15,070	1.72	-0.26%	-	-	509	(6)	29.64	0.85%
2026			15,034	1.72	-0.25%	-	-	503	(6)	29.89	0.85%
2027			14,996	1.71	-0.25%	-	-	497	(6)	30.15	0.87%

Table 9 – Small Irrigation History and Retail Load Forecast

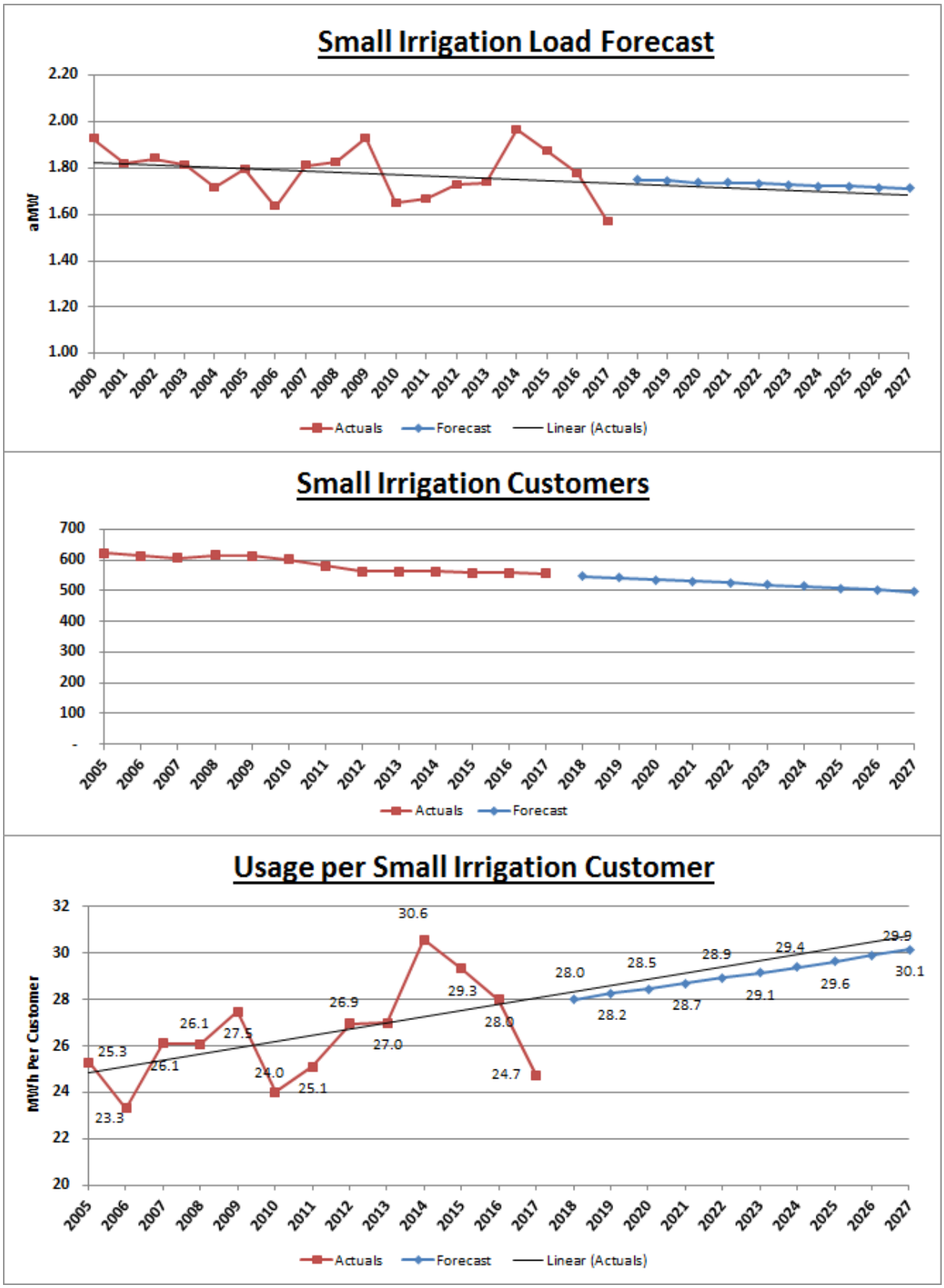

Figure 99 – Small Irrigation Retail Load Forecast, Customer Forecast, Usage per Customer

The Large Irrigation class tends to show strong yearly fluctuations due to weather and crop rotation. The 2017 actual energy sales decreased 6.56% compared to 2016. 2017 loads were severely depressed due to the large amount of precipitation in the winter and springtime that "pre-charged" the irrigated land causing large irrigators to not have to pump as much water in Q2. The Forecast has been set at approximately 48 aMW which are similar to loads observed in 2016. The Forecast for the Large Irrigation class is set to remain flat over the five year and ten year planning periods due to no new land being developed from a lack of water rights in the District's service territory. See **Table 10** and **Figure 12** for more detail.

Large Irrigation	
Load Growth	
Average Growth	Range
0.00%	2018-2022
0.00%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	368,836	41.99									
2001	359,731	41.07			-2.47%						
2002	366,431	41.83			1.86%						
2003	385,995	44.06			5.34%						
2004	360,292	41.02			-6.66%						
2005	381,927	43.60			6.00%			96		3,978.41	
2006	353,743	40.38			-7.38%			99	3	3,588.26	-9.81%
2007	386,402	44.11			9.23%			110	11	3,526.10	-1.73%
2008	391,389	44.56			1.29%			121	12	3,223.52	-8.58%
2009	410,386	46.85			4.85%			131	10	3,132.72	-2.82%
2010	356,875	40.74			-13.04%			134	3	2,664.91	-14.93%
2011	367,393	41.94			2.95%			140	6	2,624.23	-1.53%
2012	370,573	42.19			0.87%			158	18	2,345.40	-10.63%
2013	387,408	44.22			4.54%			208	50	1,859.56	-20.71%
2014	455,435	51.99			17.56%			225	17	2,025.65	8.93%
2015	451,777	51.57			-0.80%			234	9	1,932.74	-4.59%
2016	419,588	47.77			-7.12%			233	(1)	1,801.45	-6.79%
2017	392,051	44.75			-6.56%			430	197	911.22	-49.42%
2018			420,000	47.95	7.13%	-	-	430	(0)	976.74	7.19%
2019			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%
2020			420,000	47.81	0.00%	-	-	430	-	976.74	0.00%
2021			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%
2022			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%
2023			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%
2024			420,000	47.81	0.00%	-	-	430	-	976.74	0.00%
2025			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%
2026			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%
2027			420,000	47.95	0.00%	-	-	430	-	976.74	0.00%

Table 10 – Large Irrigation History and Retail Load Forecast

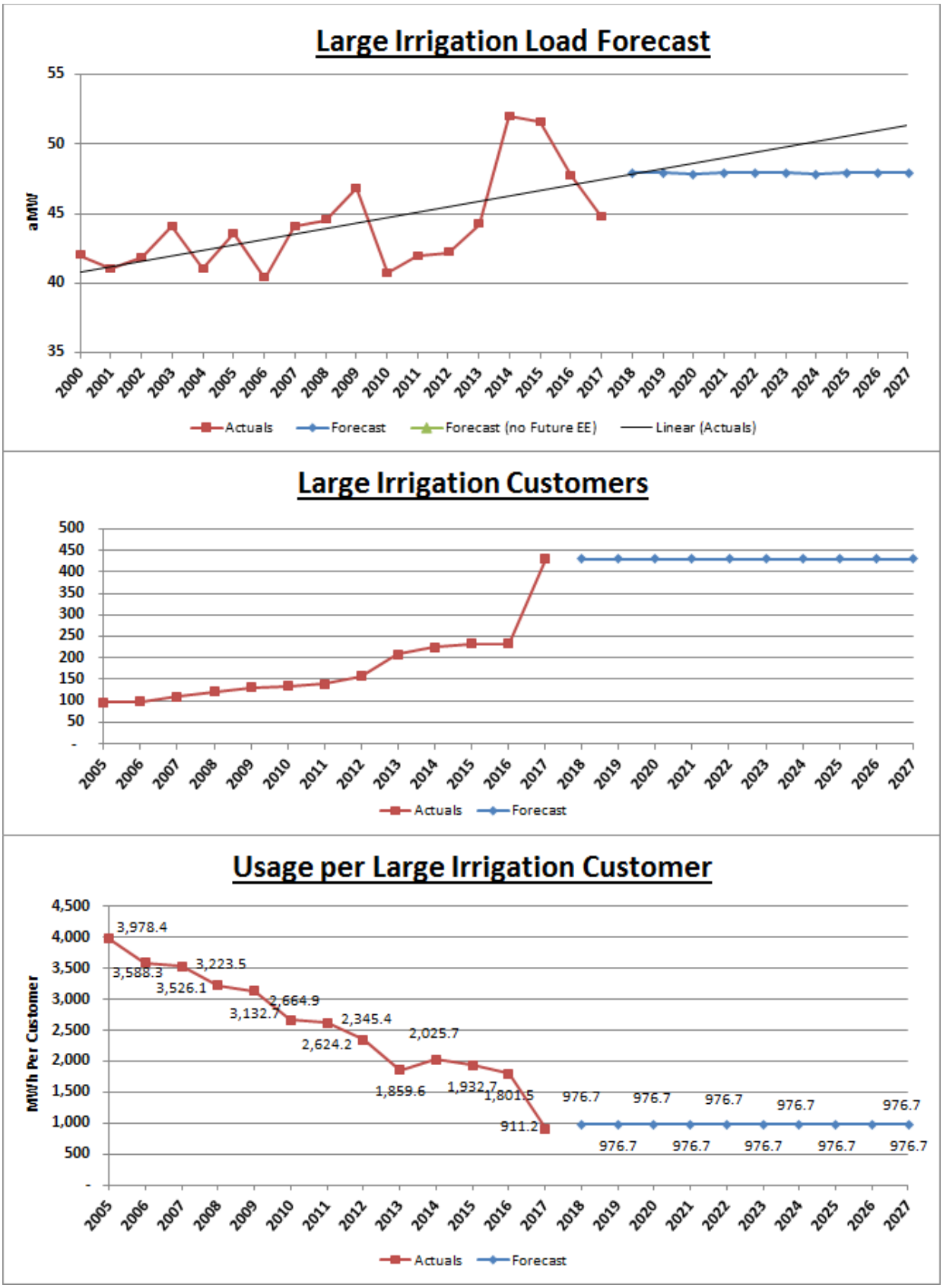

Figure 100 – Large Irrigation Retail Load Forecast, Customer Forecast, Usage per Customer

IX. STREET AND SECURITY LIGHTING

This category consists of street and security lights. Over the next ten years, Street Light energy sales are projected to decrease at an average rate of 1.98% annually. Over the same time period, Security Light energy sales are forecasted to grow at an average rate of 0.97% per year.

X. TOTAL SYSTEM

The Total System forecast is an aggregation of the forecasts of each customer class. During the past five years, the District observed an AARG of 1.28% while adding an average of 689 customers per year. Despite the observed growth, the Total System Forecast shows a decrease with an AARG of 0.29% during the five year planning period and 0.21% for the ten year planning period. While the District anticipates continuing to add a similar number of customers during the planning period, energy usage is not expected to grow at the pace as observed previously. As mentioned earlier, increases in energy efficiency, conservation and new building codes and standards are having a noticeable impact not only on the District, but also on the electric industry as a whole. See **Table 11** and **Figure 101** below for more detail.

Total System	
Load Growth	
Average Growth	Range
0.29%	2018-2022
0.21%	2018-2027

Year	Actuals		Forecast		% Change	Forecast - No Conservation		Cust Count	Change	Usage Per Customer	
	MWh	aMW	MWh	aMW		MWh	aMW			MWh	% Change
2000	1,779,257	202.56									
2001	1,569,982	179.22			-11.76%						
2002	1,587,678	181.24			1.13%						
2003	1,580,751	180.45			-0.44%						
2004	1,597,054	181.81			1.03%						
2005	1,602,508	182.93			0.34%			44,389		36.10	
2006	1,555,710	177.59			-2.92%			44,855	466	34.68	-3.93%
2007	1,607,265	183.48			3.31%			45,570	715	35.27	1.69%
2008	1,639,856	186.69			2.03%			46,601	1,031	35.19	-0.23%
2009	1,726,341	197.07			5.27%			47,074	473	36.67	4.22%
2010	1,592,802	181.83			-7.74%			47,616	542	33.45	-8.79%
2011	1,648,362	188.17			3.49%			48,197	581	34.20	2.24%
2012	1,645,277	187.30			-0.19%			48,710	513	33.78	-1.24%
2013	1,696,774	193.70			3.13%			49,519	809	34.26	1.44%
2014	1,781,322	203.35			4.98%			50,052	533	35.59	3.87%
2015	1,738,022	198.40			-2.43%			50,761	709	34.24	-3.79%
2016	1,694,078	192.86			-2.53%			51,642	881	32.80	-4.19%
2017	1,785,098	203.78			5.37%			53,109	1,467	33.61	2.46%
2018			1,761,097	201.04	-1.34%	1,761,757	201.11	53,925	816	32.66	-2.84%
2019			1,767,197	201.73	0.35%	1,769,431	201.99	54,616	691	32.36	-0.92%
2020			1,777,704	202.38	0.59%	1,781,903	202.86	55,284	667	32.16	-0.62%
2021			1,778,221	202.99	0.03%	1,785,399	203.81	55,927	644	31.80	-1.12%
2022			1,781,882	203.41	0.21%	1,793,139	204.70	56,570	643	31.50	-0.93%
2023			1,784,892	203.75	0.17%	1,800,880	205.58	57,213	643	31.20	-0.96%
2024			1,792,077	204.02	0.40%	1,812,979	206.40	57,856	643	30.97	-0.71%
2025			1,790,582	204.40	-0.08%	1,816,361	207.35	58,485	629	30.62	-1.16%
2026			1,792,788	204.66	0.12%	1,823,668	208.18	59,095	610	30.34	-0.91%
2027			1,795,242	204.94	0.14%	1,830,975	209.02	59,706	610	30.07	-0.89%

Table 11 – Total System History and Retail Load Forecast

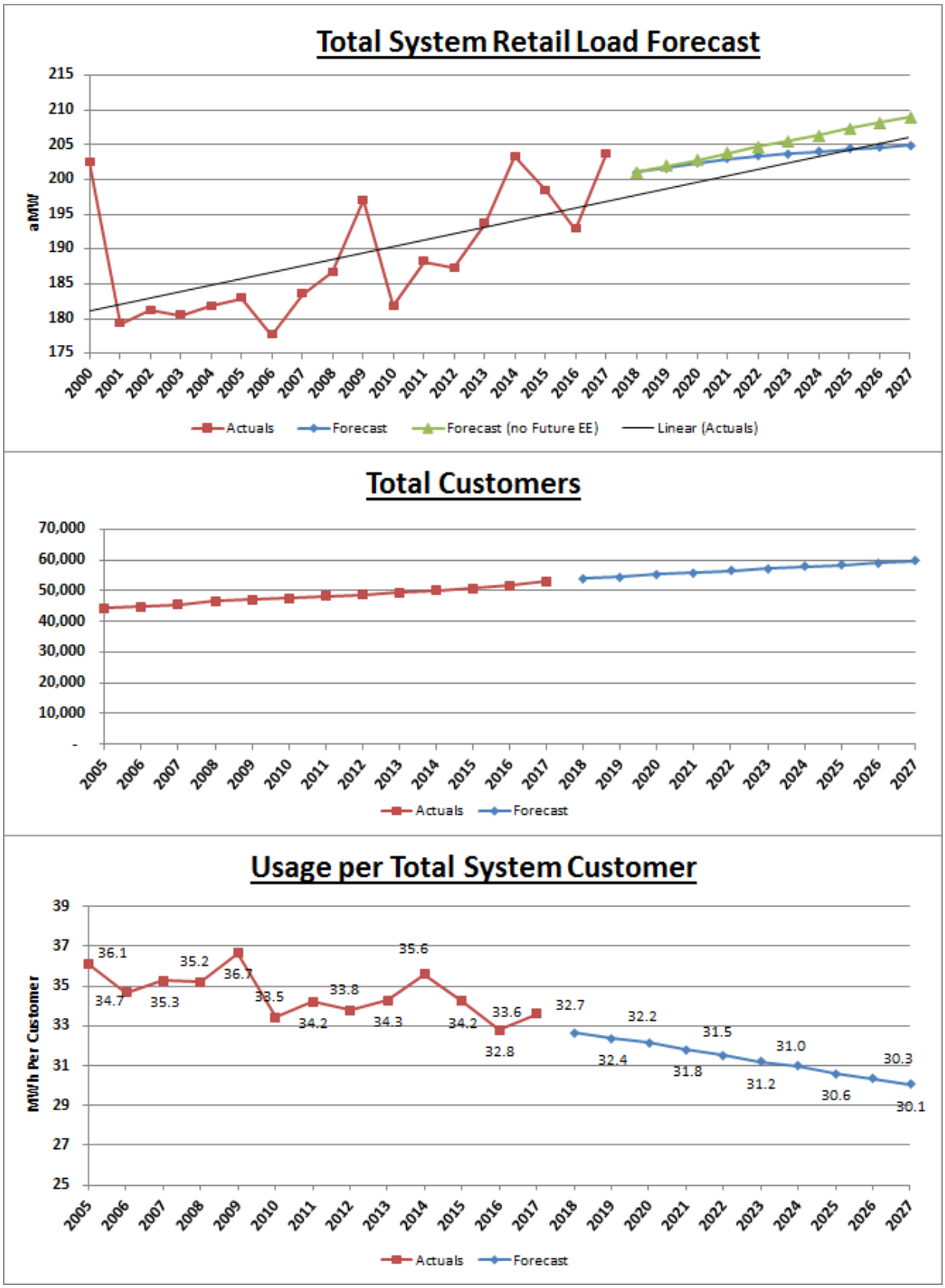

Figure 101 – Total System Retail Load Forecast, Customer Forecast, Usage per Customer

XI. 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 Case forecast being adopted as the most expected for current economic conditions and average weather.

XII. CONCLUSIONS

The 2018 Forecast's Base Case scenario expects an AARG of 0.21**%** for the ten year planning period which is down from 0.30% projected in last year's Forecast.

See **Table 12** a breakdown of the five year and ten year AARG by customer class.

	Residential	Sm Gen	Med Gen	Lrg General	Lrg Ind	Sm. Irr	Lrg Irr	Street Lights	Sec. Lights	Unmetered	Total System
Five Year AARG	0.78%	0.30%	0.41%	-0.71%	0.00%	-0.21%	0.00%	-1.94%	0.99%	0.62%	0.29%
Ten Year AARG	0.66%	0.17%	0.27%	-0.81%	0.00%	-0.23%	0.00%	-1.98%	0.97%	0.62%	0.21%

Table 12 – Average Annual Rates of Growth by Customer Class

XIII. TEN YEAR FORECAST TO 2027

Appendix A includes a breakdown of each load forecast scenario, customer counts and the District's normalized historical actuals compared to the Base Case forecast for the next ten years.

Included in **Appendix A** are the following five tables:

- **Table 1 – Load Forecast Summary (including Conservation)** shows the annual historical and forecasted summaries of the number of customers, Retail energy sales, peak demand, average annual loads at BPA POD and average annual Wholesale loads for each forecast scenario. All values shown are net of the load reductions associated with the District conservation activities.
- **Table 2 – Customer Metered Load – Historical and Forecasted (including Conservation) – Low Case** shows the annual historical and forecasted energy sales by customer class, the total BPA POD loads and total Wholesale loads for the Low Case. All values shown are net of the load reductions associated with the District conservation activities
- **Table 3 – Customer Metered Load – Historical and Forecasted (including Conservation) – Base Case** shows the annual historical and forecasted energy sales by customer class, the total BPA POD loads and total Wholesale loads for the Base Case. All values shown are net of the load reductions associated with the District conservation activities
- **Table 4 – Customer Metered Load – Historical and Forecasted (including Conservation) – High Case** shows the annual historical and forecasted energy sales by customer class, the total BPA POD loads and total Wholesale loads for the High Case. All values shown are net of the load reductions associated with the District conservation activities
- **Table 5 – Use per Customer in kWh – Historical and Forecasted (including Conservation) – Base Case** shows the annual historical and forecasted average use per customer in kWh for all classes. All values shown are net of the load reductions associated with the District conservation activities.

2018 LOAD FORECAST SUMMARY (INCLUDING CONSERVATION)

Table 1

YEAR	NUMBER OF CUSTOMERS			TOTAL RETAIL SALES aMW			PEAK SYSTEM DEMAND MW @ POD			TOTAL LOADS aMW @ POD			TOTAL WHOLESALE LOADS (aMW)		
	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE	LOW CASE	BASE CASE	HIGH CASE
2000	41,896	41,896	41,896	202.6	202.6	202.6	396	396	396	210.1	210.1	210.1	213.6	213.6	213.6
2001	42,491	42,491	42,491	179.2	179.2	179.2	352	352	352	187.8	187.8	187.8	190.9	190.9	190.9
2002	42,455	42,455	42,455	181.2	181.2	181.2	374	374	374	187.1	187.1	187.1	190.2	190.2	190.2
2003	43,459	43,459	43,459	180.5	180.5	180.5	384	384	384	186.7	186.7	186.7	189.7	189.7	189.7
2004	44,262	44,262	44,262	181.8	181.8	181.8	382	382	382	187.4	187.4	187.4	190.4	190.4	190.4
2005	44,628	44,628	44,628	182.9	182.9	182.9	366	366	366	187.5	187.5	187.5	190.6	190.6	190.6
2006	45,302	45,302	45,302	177.6	177.6	177.6	373	373	373	182.9	182.9	182.9	185.9	185.9	185.9
2007	45,930	45,930	45,930	183.5	183.5	183.5	374	374	374	190.2	190.2	190.2	193.3	193.3	193.3
2008	46,903	46,903	46,903	186.7	186.7	186.7	397	397	397	194.0	194.0	194.0	197.2	197.2	197.2
2009	47,328	47,328	47,328	197.1	197.1	197.1	401	401	401	203.6	203.6	203.6	206.9	206.9	206.9
2010	47,937	47,937	47,937	181.8	181.8	181.8	391	391	391	188.8	188.8	188.8	191.9	191.9	191.9
2011	48,455	48,455	48,455	188.2	188.2	188.2	380	380	380	194.3	194.3	194.3	197.5	197.5	197.5
2012	49,059	49,059	49,059	187.3	187.3	187.3	404	404	404	193.1	193.1	193.1	196.3	196.3	196.3
2013	49,816	49,816	49,816	193.7	193.7	193.7	422	422	422	202.3	202.3	202.3	205.6	205.6	205.6
2014	50,052	50,052	50,052	203.3	203.3	203.3	430	430	430	208.4	208.4	208.4	211.8	211.8	211.8
2015	50,762	50,762	50,762	198.4	198.4	198.4	429	429	429	205.5	205.5	205.5	208.9	208.9	208.9
2016	51,643	51,643	51,643	192.9	192.9	192.9	425	425	425	199.3	199.3	199.3	202.5	202.5	202.5
2017	53,109	53,109	53,109	203.8	203.8	203.8	426	426	426	210.4	210.4	210.4	213.4	213.4	213.4
2018	53,514	53,925	54,368	187.2	201.0	215.0	405	433	466	193.3	207.6	222.0	196.0	210.5	225.2
2019	54,010	54,616	55,313	187.7	201.7	216.1	406	436	468	193.8	208.3	223.1	196.5	211.2	226.3
2020	54,474	55,284	56,214	188.0	202.4	217.0	406	437	470	194.2	209.0	224.1	196.9	211.9	227.3
2021	54,932	55,927	57,112	188.4	203.0	217.9	407	438	471	194.5	209.6	225.0	197.3	212.6	228.2
2022	55,393	56,570	58,009	188.5	203.4	218.7	407	439	472	194.6	210.0	225.8	197.4	213.0	229.0
2023	55,850	57,213	58,906	188.6	203.8	219.3	407	439	473	194.7	210.4	226.4	197.5	213.4	229.6
2024	56,309	57,856	59,805	188.6	204.0	219.8	407	440	474	194.7	210.6	227.0	197.4	213.6	230.2
2025	56,738	58,485	60,679	188.7	204.4	220.5	407	440	475	194.8	211.0	227.7	197.6	214.0	230.9
2026	57,167	59,095	61,551	188.6	204.7	221.1	407	441	475	194.8	211.3	228.3	197.5	214.3	231.5
2027	57,592	59,706	62,424	188.6	204.9	221.7	407	441	476	194.8	211.6	228.9	197.5	214.6	232.1
AV RATE 2018-2022	0.87%	1.20%	1.63%	0.17%	0.29%	0.42%	0.12%	0.31%	0.28%	0.17%	0.29%	0.42%	0.17%	0.29%	0.42%
AV RATE 2018-2027	0.82%	1.14%	1.55%	0.08%	0.21%	0.34%	0.05%	0.21%	0.23%	0.08%	0.21%	0.34%	0.08%	0.21%	0.34%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION)
LOW CASE

Table 2

	RESIDENTIAL aMW SALES	SMALL GEN SERVICE aMW SALES	MEDIUM GEN SERVICE aMW SALES	LARGE GEN SERVICE aMW SALES	LARGE INDUSTRIAL aMW SALES	SMALL IRRIGATION aMW SALES	LARGE IRRIGATION aMW SALES	STREET LIGHTS aMW SALES	SECURITY LIGHTS aMW SALES	UNMETERED ACCOUNTS aMW SALES	TOTAL SALES aMW	ANNUAL CHANGE %	TOTAL @ BPA POD LOADS aMW	TOTAL WHOLESALE LOADS aMW
2000	72.5	13.2	19.0	28.2	25.1	1.9	42.0	0.4	0.1	0.1	202.6	3.3%	210.1	213.6
2001	70.5	12.9	19.0	25.2	8.1	1.8	41.1	0.4	0.1	0.1	179.2	-11.8%	187.8	190.9
2002	71.0	12.9	18.7	25.1	9.2	1.8	41.8	0.4	0.1	0.1	181.2	1.1%	187.1	190.2
2003	69.0	12.9	19.4	25.8	6.6	1.8	44.1	0.4	0.1	0.3	180.5	-0.4%	186.7	189.7
2004	70.7	13.2	19.1	27.3	7.9	1.7	41.0	0.5	0.1	0.3	181.8	1.0%	187.4	190.4
2005	71.1	13.1	18.7	27.7	6.1	1.8	43.6	0.5	0.1	0.3	182.9	0.3%	187.5	190.6
2006	72.2	12.9	18.3	27.0	4.3	1.6	40.4	0.5	0.1	0.3	177.6	-2.9%	182.9	185.9
2007	73.6	13.1	18.9	25.5	5.6	1.8	44.1	0.5	0.1	0.3	183.5	3.3%	190.2	193.3
2008	75.9	13.2	19.3	25.6	5.4	1.8	44.6	0.5	0.1	0.3	186.7	2.0%	194.0	197.2
2009	82.4	13.9	20.0	26.6	4.4	1.9	46.8	0.5	0.1	0.3	197.1	5.3%	203.6	206.9
2010	74.7	13.0	19.5	25.0	6.3	1.6	40.7	0.5	0.1	0.3	181.8	-7.7%	188.8	191.9
2011	78.5	13.5	20.0	23.9	7.5	1.7	41.9	0.6	0.1	0.3	188.2	3.5%	194.3	197.5
2012	76.0	13.6	20.0	24.7	8.0	1.7	42.2	0.5	0.1	0.3	187.3	-0.2%	193.1	196.3
2013	79.7	14.0	20.2	25.0	8.0	1.7	44.2	0.3	0.1	0.3	193.7	3.1%	202.3	205.6
2014	79.5	14.2	20.8	25.9	8.2	2.0	52.0	0.3	0.1	0.3	203.3	5.0%	208.4	211.8
2015	76.0	13.9	20.8	25.8	7.6	1.9	51.6	0.3	0.2	0.3	198.4	-2.4%	205.5	208.9
2016	75.3	13.9	20.5	25.4	7.4	1.8	47.8	0.3	0.1	0.4	192.9	-2.8%	199.3	202.6
2017	86.7	14.7	21.3	26.3	7.7	1.6	44.8	0.3	0.1	0.4	203.8	5.7%	210.4	213.4
2018	72.1	13.9	20.6	26.1	7.7	1.4	44.7	0.3	0.1	0.3	187.2	-8.1%	193.3	196.3
2019	72.6	13.9	20.7	26.0	7.7	1.4	44.7	0.3	0.1	0.3	187.7	0.3%	193.8	196.8
2020	73.1	13.9	20.7	25.9	7.6	1.4	44.6	0.3	0.1	0.4	188.0	0.2%	194.2	197.2
2021	73.4	14.0	20.8	25.7	7.7	1.4	44.7	0.3	0.1	0.4	188.4	0.2%	194.5	197.5
2022	73.7	14.0	20.8	25.6	7.7	1.4	44.7	0.3	0.1	0.4	188.5	0.1%	194.6	197.7
2023	74.0	13.9	20.8	25.4	7.7	1.4	44.7	0.3	0.1	0.4	188.6	0.0%	194.7	197.7
2024	74.3	13.9	20.7	25.2	7.6	1.4	44.6	0.3	0.1	0.4	188.6	0.0%	194.7	197.7
2025	74.5	13.9	20.7	25.0	7.7	1.4	44.7	0.3	0.1	0.4	188.7	0.1%	194.8	197.8
2026	74.7	13.9	20.7	24.8	7.7	1.4	44.7	0.3	0.1	0.4	188.6	0.0%	194.8	197.8
2027	74.9	13.9	20.7	24.6	7.7	1.4	44.7	0.3	0.1	0.4	188.6	0.0%	194.8	197.8
AV RATE 2018-2022	0.55%	0.15%	0.21%	-0.52%	0.00%	-0.23%	0.00%	-1.38%	0.69%	0.43%	0.17%		0.17%	0.17%
AV RATE 2018-2027	0.43%	-0.01%	0.07%	-0.65%	0.00%	-0.22%	0.00%	-1.37%	0.68%	0.43%	0.08%		0.08%	0.08%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION)

Table 3

BASE CASE

	RESIDENTIAL aMW SALES	SMALL GEN SERVICE aMW SALES	MEDIUM GEN SERVICE aMW SALES	LARGE GEN SERVICE aMW SALES	LARGE INDUSTRIAL aMW SALES	SMALL IRRIGATION aMW SALES	LARGE IRRIGATION aMW SALES	STREET LIGHTS aMW SALES	SECURITY LIGHTS aMW SALES	UNMETERED ACCOUNTS aMW SALES	TOTAL SALES aMW	ANNUAL CHANGE %	TOTAL @ BPA POD LOADS aMW	TOTAL WHOLESALE LOADS aMW
2000	72.5	13.2	19.0	28.2	25.1	1.9	42.0	0.4	0.1	0.1	202.6	3.3%	210.1	213.6
2001	70.5	12.9	19.0	25.2	8.1	1.8	41.1	0.4	0.1	0.1	179.2	-11.5%	187.8	190.9
2002	71.0	12.9	18.7	25.1	9.2	1.8	41.8	0.4	0.1	0.1	181.2	1.1%	187.1	190.2
2003	69.0	12.9	19.4	25.8	6.6	1.8	44.1	0.4	0.1	0.3	180.5	-0.4%	186.7	189.7
2004	70.7	13.2	19.1	27.3	7.9	1.7	41.0	0.5	0.1	0.3	181.8	0.8%	187.4	190.4
2005	71.1	13.1	18.7	27.7	6.1	1.8	43.6	0.5	0.1	0.3	182.9	0.6%	187.5	190.6
2006	72.2	12.9	18.3	27.0	4.3	1.6	40.4	0.5	0.1	0.3	177.6	-2.9%	182.9	185.9
2007	73.6	13.1	18.9	25.5	5.6	1.8	44.1	0.5	0.1	0.3	183.5	3.3%	190.2	193.3
2008	75.9	13.2	19.3	25.6	5.4	1.8	44.6	0.5	0.1	0.3	186.7	1.8%	194.0	197.2
2009	82.4	13.9	20.0	26.6	4.4	1.9	46.8	0.5	0.1	0.3	197.1	5.6%	203.6	206.9
2010	74.7	13.0	19.5	25.0	6.3	1.6	40.7	0.5	0.1	0.3	181.8	-7.7%	188.8	191.9
2011	78.5	13.5	20.0	23.9	7.5	1.7	41.9	0.6	0.1	0.3	188.2	3.5%	194.3	197.5
2012	76.0	13.6	20.0	24.7	8.0	1.7	42.2	0.5	0.1	0.3	187.3	-0.5%	193.1	196.3
2013	79.7	14.0	20.2	25.0	8.0	1.7	44.2	0.3	0.1	0.3	193.7	3.4%	202.3	205.6
2014	79.5	14.2	20.8	25.9	8.2	2.0	52.0	0.3	0.1	0.3	203.3	5.0%	208.4	211.8
2015	76.0	13.9	20.8	25.8	7.6	1.9	51.6	0.3	0.2	0.3	198.4	-2.4%	205.5	208.9
2016	75.3	13.9	20.5	25.4	7.4	1.8	47.8	0.3	0.1	0.4	192.9	-2.8%	199.3	202.6
2017	86.7	14.7	21.3	26.3	7.7	1.6	44.8	0.3	0.1	0.4	203.8	5.7%	210.4	213.4
2018	82.2	14.3	21.0	25.4	7.7	1.7	47.9	0.3	0.1	0.3	201.0	-1.3%	207.6	210.5
2019	83.0	14.3	21.1	25.2	7.7	1.7	47.9	0.3	0.1	0.4	201.7	0.3%	208.3	211.5
2020	83.8	14.4	21.2	25.1	7.6	1.7	47.8	0.3	0.1	0.4	202.4	0.3%	209.0	212.2
2021	84.3	14.4	21.3	24.9	7.7	1.7	47.9	0.3	0.1	0.4	203.0	0.3%	209.6	212.9
2022	84.8	14.4	21.4	24.7	7.7	1.7	47.9	0.3	0.1	0.4	203.4	0.2%	210.0	213.3
2023	85.3	14.4	21.4	24.5	7.7	1.7	47.9	0.3	0.1	0.4	203.8	0.2%	210.4	213.7
2024	85.9	14.5	21.4	24.3	7.6	1.7	47.8	0.3	0.1	0.4	204.0	0.1%	210.6	213.9
2025	86.4	14.5	21.5	24.0	7.7	1.7	47.9	0.3	0.1	0.4	204.4	0.2%	211.0	214.3
2026	86.8	14.5	21.5	23.8	7.7	1.7	47.9	0.2	0.1	0.4	204.7	0.1%	211.3	214.6
2027	87.3	14.5	21.5	23.6	7.7	1.7	47.9	0.2	0.1	0.4	204.9	0.1%	211.6	214.9
AV RATE 2018-2022	0.78%	0.30%	0.41%	-0.71%	0.00%	-0.21%	0.00%	-1.94%	0.99%	0.62%	0.29%		0.29%	0.33%
AV RATE 2018-2027	0.66%	0.17%	0.27%	-0.81%	0.00%	-0.23%	0.00%	-1.98%	0.97%	0.62%	0.21%		0.21%	0.23%

CUSTOMER METERED LOAD - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION)

Table 4

HIGH CASE

	RESIDENTIAL aMW SALES	SMALL GEN SERVICE aMW SALES	MEDIUM GEN SERVICE aMW SALES	LARGE GEN SERVICE aMW SALES	LARGE INDUSTRIAL aMW SALES	SMALL IRRIGATION aMW SALES	LARGE IRRIGATION aMW SALES	STREET LIGHTS aMW SALES	SECURITY LIGHTS aMW SALES	UNMETERED ACCOUNTS aMW SALES	TOTAL SALES aMW	ANNUAL CHANGE %	TOTAL @ BPA POD LOADS aMW	TOTAL WHOLESALE LOADS aMW
2000	72.5	13.2	19.0	28.2	25.1	1.9	42.0	0.4	0.1	0.1	202.6	3.3%	210.1	213.6
2001	70.5	12.9	19.0	25.2	8.1	1.8	41.1	0.4	0.1	0.1	179.2	-11.5%	187.8	190.9
2002	71.0	12.9	18.7	25.1	9.2	1.8	41.8	0.4	0.1	0.1	181.2	1.1%	187.1	190.2
2003	69.0	12.9	19.4	25.8	6.6	1.8	44.1	0.4	0.1	0.3	180.5	-0.4%	186.7	189.7
2004	70.7	13.2	19.1	27.3	7.9	1.7	41.0	0.5	0.1	0.3	181.8	0.8%	187.4	190.4
2005	71.1	13.1	18.7	27.7	6.1	1.8	43.6	0.5	0.1	0.3	182.9	0.6%	187.5	190.6
2006	72.2	12.9	18.3	27.0	4.3	1.6	40.4	0.5	0.1	0.3	177.6	-2.9%	182.9	185.9
2007	73.6	13.1	18.9	25.5	5.6	1.8	44.1	0.5	0.1	0.3	183.5	3.3%	190.2	193.3
2008	75.9	13.2	19.3	25.6	5.4	1.8	44.6	0.5	0.1	0.3	186.7	1.8%	194.0	197.2
2009	82.4	13.9	20.0	26.6	4.4	1.9	46.8	0.5	0.1	0.3	197.1	5.6%	203.6	206.9
2010	74.7	13.0	19.5	25.0	6.3	1.6	40.7	0.5	0.1	0.3	181.8	-7.7%	188.8	191.9
2011	78.5	13.5	20.0	23.9	7.5	1.7	41.9	0.6	0.1	0.3	188.2	3.5%	194.3	197.5
2012	76.0	13.6	20.0	24.7	8.0	1.7	42.2	0.5	0.1	0.3	187.3	-0.5%	193.1	196.3
2013	79.7	14.0	20.2	25.0	8.0	1.7	44.2	0.3	0.1	0.3	193.7	3.4%	202.3	205.6
2014	79.5	14.2	20.8	25.9	8.2	2.0	52.0	0.3	0.1	0.3	203.3	5.0%	208.4	211.8
2015	76.0	13.9	20.8	25.8	7.6	1.9	51.6	0.3	0.2	0.3	198.4	-2.4%	205.5	208.9
2016	75.3	13.9	20.5	25.4	7.4	1.8	47.8	0.3	0.1	0.4	192.9	-2.8%	199.3	202.6
2017	86.8	14.6	21.3	25.2	7.4	2.1	49.8	0.3	0.1	0.3	207.8	7.8%	210.4	213.7
2018	91.1	14.8	21.6	25.2	7.7	2.0	51.9	0.3	0.1	0.3	215.0	3.5%	222.0	225.2
2019	92.0	14.9	21.7	25.0	7.7	2.0	51.9	0.3	0.1	0.4	216.1	0.5%	223.1	226.3
2020	93.1	15.0	21.9	24.9	7.6	2.0	51.8	0.3	0.1	0.4	217.0	0.4%	224.1	227.3
2021	93.8	15.0	22.0	24.7	7.7	2.0	51.9	0.3	0.1	0.4	217.9	0.4%	225.0	228.2
2022	94.6	15.1	22.1	24.5	7.7	2.0	51.9	0.3	0.1	0.4	218.7	0.3%	225.8	229.0
2023	95.4	15.1	22.2	24.2	7.7	2.0	51.9	0.3	0.1	0.4	219.3	0.3%	226.4	229.6
2024	96.2	15.2	22.3	24.0	7.6	2.0	51.8	0.2	0.1	0.4	219.8	0.3%	227.0	230.2
2025	96.9	15.2	22.4	23.7	7.7	2.0	51.9	0.2	0.1	0.4	220.5	0.3%	227.7	230.9
2026	97.6	15.2	22.4	23.5	7.7	2.0	51.9	0.2	0.1	0.4	221.1	0.3%	228.3	231.5
2027	98.3	15.3	22.5	23.2	7.7	2.0	51.9	0.2	0.1	0.4	221.7	0.3%	228.9	232.1
AV RATE 2018-2022	0.96%	0.50%	0.63%	-0.76%	0.00%	-0.30%	0.00%	-2.48%	1.29%	0.81%	0.42%		0.42%	0.42%
AV RATE 2018-2027	0.85%	0.36%	0.48%	-0.91%	0.00%	-0.29%	0.00%	-2.59%	1.28%	0.81%	0.34%		0.34%	0.34%

USAGE PER CUSTOMER IN KWH - HISTORICAL AND FORECASTED (INCLUDING CONSERVATION) Table 5
BASE CASE

	RESIDENTIAL USE PER CUSTOMER	SMALL GEN USE PER CUSTOMER	MEDIUM GEN USE PER CUSTOMER	LARGE GEN USE PER CUSTOMER	LARGE IND USE PER CUSTOMER	SMALL IRR USE PER CUSTOMER	LARGE IRR USE PER CUSTOMER	STREET LIGHT USE PER CUSTOMER	SECURITY USE PER CUSTOMER	UNMETERED USE PER ACCOUNT	OVERALL USE PER CUSTOMER
2000	18,207	29,934	284,530	2,426,689	73,637,600	26,269	4,610,455	500,431	699	6,569	42,468
2001	17,724	28,787	248,952	1,545,119	23,632,237	23,933	2,587,995	506,783	525	59,191	36,949
2002	17,644	28,517	265,262	2,014,909	26,850,190	25,069	3,777,644	399,277	752	2,284	37,397
2003	16,764	27,690	274,201	1,998,214	19,351,268	24,725	4,020,780	422,990	744	6,421	36,373
2004	16,878	27,822	264,389	1,968,784	23,159,528	24,037	3,753,041	439,687	753	6,788	36,082
2005	16,721	27,788	261,631	1,971,996	17,761,932	25,403	3,978,407	508,368	743	7,059	35,908
2006	16,724	26,632	250,296	1,865,415	12,485,305	23,762	3,502,406	453,740	716	8,003	34,341
2007	16,831	26,607	248,399	1,704,706	16,348,383	26,024	3,512,746	453,740	712	8,041	34,992
2008	17,046	26,010	248,274	1,704,225	15,920,098	26,086	3,156,362	468,669	719	8,046	34,963
2009	18,304	27,114	247,899	1,728,966	12,969,692	27,678	3,085,607	474,203	715	8,099	36,476
2010	16,380	25,062	235,680	1,619,899	18,454,887	24,320	2,745,195	482,159	723	7,999	33,227
2011	17,015	25,861	234,891	1,487,012	21,803,603	25,491	2,587,273	614,671	734	8,288	34,018
2012	16,311	25,671	237,195	1,520,121	23,525,055	27,324	2,273,457	459,597	731	8,270	33,537
2013	16,792	26,105	236,333	1,502,161	23,267,593	27,018	1,777,101	305,647	838	8,301	34,061
2014	16,724	25,741	239,681	1,504,273	23,657,100	25,352	1,749,526	308,703	840	8,301	33,775
2015	15,705	25,165	240,990	1,496,196	22,313,962	29,330	1,932,736	300,405	921	8,352	34,239
2016	16,225	25,299	236,393	1,461,506	23,170,994	28,294	1,748,300	302,560	924	8,311	34,172
2017	17,316	25,933	238,050	1,443,218	13,416,822	24,708	911,216	281,642	573	8,054	33,612
2018	16,155	24,726	231,271	1,390,735	13,416,800	27,981	976,744	283,169	576	8,041	32,658
2019	16,084	24,454	228,496	1,379,769	13,416,800	28,247	976,744	277,606	581	8,073	32,357
2020	16,073	24,292	226,641	1,375,351	13,416,800	28,456	976,744	272,864	587	8,125	32,156
2021	15,931	23,968	223,366	1,362,734	13,416,800	28,682	976,744	266,949	589	8,133	31,795
2022	15,842	23,697	220,548	1,351,917	13,416,800	28,913	976,744	261,783	594	8,165	31,499
2023	15,749	23,416	217,716	1,340,113	13,416,800	29,149	976,744	256,625	598	8,196	31,197
2024	15,717	23,208	215,525	1,331,454	13,416,800	29,386	976,744	252,141	605	8,250	30,975
2025	15,571	22,875	212,184	1,316,006	13,416,800	29,637	976,744	246,276	607	8,259	30,616
2026	15,482	22,614	209,597	1,303,942	13,416,800	29,888	976,744	241,353	612	8,290	30,337
2027	15,397	22,364	207,128	1,292,256	13,416,800	30,149	976,744	236,454	616	8,322	30,068
AV RATE 2018-2022	-0.49%	-1.06%	-1.18%	-0.71%	0.00%	0.82%	0.00%	-1.94%	0.76%	0.38%	-0.90%
AV RATE 2018-2027	-0.53%	-1.11%	-1.22%	-0.81%	0.00%	0.83%	0.00%	-1.98%	0.75%	0.38%	-0.91%

Appendix B: 2018-2037 Conservation Potential Assessment

Conservation Potential Assessment

Final Report

October 1, 2015

Prepared by:

EES Consulting
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Kirkland, Washington 98033
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Kirkland, WA and Portland, OR
Telephone: (425) 889-2700 Facsimile: (425) 889-2725

October 7, 2017

Mr. Chris Johnson
Benton PUD
P.O. Box 6270
2721 W. 10th Avenue
Kennewick, WA 99336

SUBJECT: 2017 Conservation Potential Assessment –Final Report

Dear Chris:

Please find attached the report summarizing the 2017 Benton Public Utility District Conservation Potential Assessment (CPA). This report covers the 20-year time period from 2018 through 2037. The measures and information used to develop Benton PUD's preliminary conservation potential incorporate the most current information available for Energy Independence Act (EIA) reporting. The potential has increased from the 2015 CPA, largely due to increased avoided costs and improvements in LED technology and its increasing acceptance and adoption in the market.

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

Best Regards,

Amber Nyquist
Senior Project Manager

Executive Summary

This report describes the methodology and results of the 2017 Conservation Potential Assessment (CPA) for Public Utility District No. 1 of Benton County (Benton PUD). This assessment provides estimates of energy savings by sector for the period 2018 to 2037. The assessment considers a wide range of conservation resources that are reliable, available and cost-effective within the 20-year planning period.

Background

Benton PUD provides electricity service to over 53,000 customers located in Benton County, Washington, excluding the City of Richland and Benton Rural Electric Association's service territory. Benton PUD's territory covers 939 square miles and includes 1,700 miles of transmission and distribution lines. In addition, Benton PUD's service territory includes an estimated 109,000 acres of irrigated agriculture.

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

The EIA sets forth specific requirements for setting, pursuing and reporting on conservation targets. The methodology used in this assessment complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Seventh Power Plan. Thus, this Conservation Potential Assessment will support Benton PUD's compliance with EIA requirements.

This assessment was built on a new model based on the completed Seventh Power Plan, but utilizes the same methodology as previous Conservation Potential Assessments. However, the model was further updated to reflect changes and developments since the completion of the Seventh Power Plan. These model updates included the following:

- Updated avoided cost – recent forecast of power market prices, a value for avoided generation capacity costs, and a social cost of carbon
- Updated financial parameters – including a Benton PUD-specific peak hour definition
- Updated customer characteristics data
  - New residential home counts
  - Updated commercial floor area
  - Updated industrial sector consumption

- Measure updates
  - Updated approximately 20 measures based on updates from the Regional Technical Forum (RTF) subsequent to the development of the Seventh Power Plan. Examples include heat pump water heaters, duct sealing, advanced power strips, and others.
  - Updated measure saturation data from the Council
- Improved modeling methodology that allows for measure opportunities not captured early in the study period to be achieved in subsequent replacement cycles
- Accounting for recent achievements
  - Internal programs
  - NEEA programs

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

Results

Table ES-1 shows the high-level results of this assessment. The economically achievable potential by sector in 2, 6, 10, and 20-year increments is included. The total 20-year energy efficiency potential is 26.8 aMW. The most important numbers per the EIA are the 10-year potential of 14.08 aMW, and the two-year potential of 2.25 aMW.

Table ES-1
Cost Effective Potential - Base Case (aMW)

	2-Year*	6-Year	10-Year	20-Year
Residential	1.03	3.43	6.16	12.17
Commercial	0.52	2.17	4.26	9.20
Industrial	0.46	1.35	2.18	2.73
Agricultural	0.22	0.69	1.05	1.51
Distribution Efficiency	0.03	0.19	0.43	1.19
Total	**2.25**	**7.83**	**14.08**	**26.80**

**2018 and 2019*

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

These estimates include energy efficiency achieved through Benton PUD's own utility programs and through its share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. Some of the potential may be achieved through code and standards changes, especially in the later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA. While not quantified at a utility-specific level, the Momentum Savings quantified by BPA will also be claimed against the Seventh Plan conservation targets.

Energy efficiency also has the potential to reduce peak demands. Estimates of peak demand savings are calculated for each measure using the Council's ProCost tool, which uses hourly load profiles developed for the Seventh Power Plan and a Benton PUD-specific definition of when peak demand occurs. These

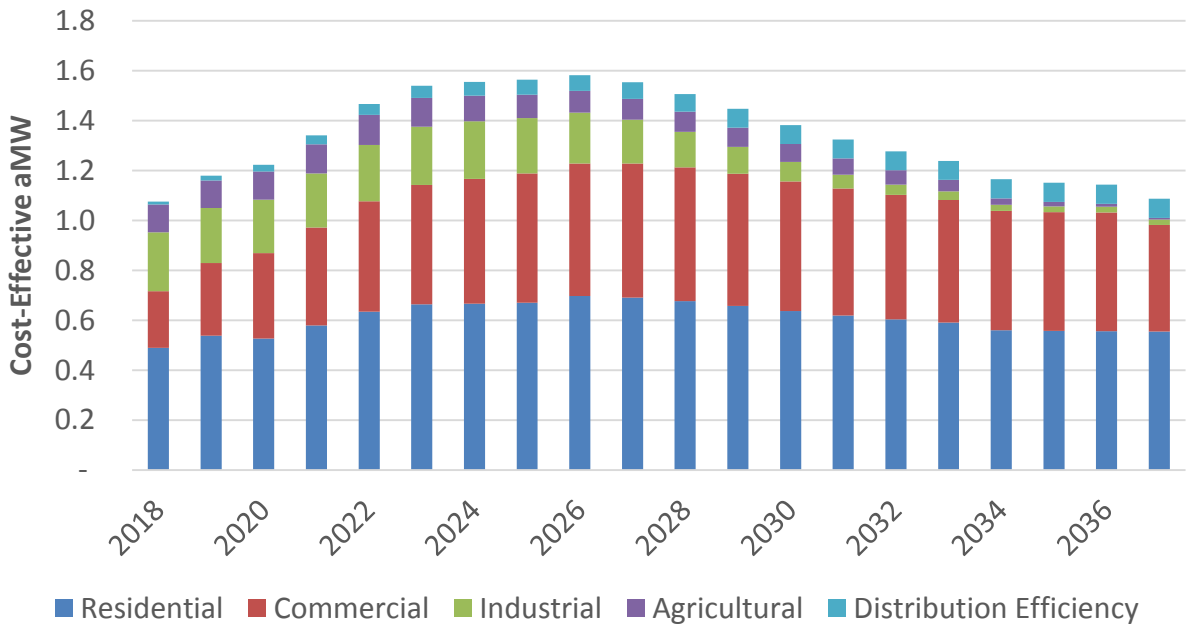
unit-level estimates are then aggregated across sectors and years in the same way that energy efficiency measure savings potential is calculated. The reductions in peak demand provided by energy efficiency are summarized in Table ES-2 below. Benton PUD's annual peak occurs most frequently in summer evenings, between 4 and 6 PM. In addition to these peak demand savings, demand savings would occur throughout the year.

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

	2-Year	6-Year	10-Year	20-Year
Residential	1.33	4.49	7.94	15.34
Commercial	0.56	2.33	4.66	9.65
Industrial	0.61	1.83	2.99	3.71
Agricultural	0.56	1.76	2.72	3.93
Distribution Efficiency	0.03	0.18	0.43	1.17
Total	**3.09**	**10.60**	**18.74**	**33.81**

The 20-year energy efficiency potential is shown on an annual basis in Figure ES-1. This assessment shows potential starting around 1.08 aMW in 2018 and ramping up to 1.58 aMW per year in 2026. Potential is gradually ramped down through the remaining years of the planning period as the remaining retrofit measure opportunities diminish over time based on the ramp rate assumptions.

Figure ES-1
Annual Cost-Effective Energy Efficiency Potential Estimates – Base Case Scenario



As Figure ES-1 shows, the majority of the potential is in the residential sector. The conservation potential in this sector falls among the major end uses of lighting, HVAC, and water heating. The areas of notable potential include:

- LED lighting
- Weatherization measures like windows and insulation
- Water Heating – including heat pump water heaters and low-flow showerheads
- Consumer electronics such as advanced power strips

Second to the residential sector, a large share of conservation is available in Benton PUD's commercial sector. The potential in this sector is higher compared with the potential estimated in the 2015 CPA. With the 2017 CPA, acquisition rates for commercial lighting were updated to more accurately reflect the success of commercial lighting programs and the broad market acceptance of LED products. Outside of lighting, there were smaller changes to the potential in several end uses. Measures relating to food preparation and water heating increased, while the potential from HVAC measures decreased. Notable areas of commercial sector potential include:

- Lighting – including interior and exterior LED lighting, controls, and street lighting
- Commercial energy management
- HVAC measures like rooftop equipment controls and economizer retrofits
- Refrigeration – including grocery refrigeration measures

Another significant area of consideration for Benton PUD is the agriculture sector. Based on the most recent census of agriculture, it is estimated that Benton PUD has 109,000 irrigated acres in its service area.[44] While Scientific Irrigation Scheduling (SIS) has long been an important conservation area for the utility, a recent study conducted by BPA has called the energy savings of SIS into question and SIS will likely no longer be offered as a BPA measure. As such, SIS has been excluded from this CPA. There remain conservation opportunities in irrigation hardware and Low Elevation Spray Application (LESA).

Comparison to Previous Assessment

Table ES-3 shows a comparison of the 2, 10, and 20-year Base Case conservation potential by customer sector for this assessment and the results of Benton PUD's 2015 CPA.

[44] Based on updated figures from the US Department of Agriculture's 2012 Census of Agriculture.

Table ES-3 Comparison of 2015 CPA and 2017 CPA Cost-Effective Potential									
	2-Year			10-Year			20-Year		
	2015	2017	% Change	2015	2017	% Change	2015	2017	% Change
Residential	1.07	1.03	-4%	5.75	6.16	7%	10.06	12.17	21%
Commercial	0.41	0.52	27%	2.13	4.26	100%	3.37	9.20	173%
Industrial	0.26	0.46	75%	1.17	2.18	86%	1.58	2.73	73%
Agricultural	0.19	0.22	17%	1.49	1.05	-29%	2.53	1.51	-40%
Distribution Efficiency	0.03	0.03	5%	0.46	0.43	-6%	2.53	1.19	-53%
Total	**1.97**	**2.25**	**15%**	**11.00**	**14.08**	**28%**	**20.07**	**26.80**	**34%**

*Note that the 2015 columns refer to the CPA completed in 2015 for the time period of 2016 through 2035. The 2017 assessment is for the timeframe: 2018 through 2037.

The change in conservation potential estimated since the 2015 study is the result of several changes to the input assumptions, including measure data and avoided cost assumptions. These are discussed below.

Measure Data

Substantial changes were made to energy efficiency measures which significantly affected overall conservation potential:

- Commercial LED Lighting – Due to the program success and broad market acceptance of LED fixtures of all types, the projected annual acquisition rate of LED lighting has increased from the 2015 CPA. LED prices have declined and product availability has increased for a variety of applications. The current projections are in line with recent program accomplishments.
- Residential Lighting Measures – The total possible savings per home increased in 2017 by 40%, due in large part to the continued evolution of LED performance and cost. To account for the federal EISA standard, a set of measures in the model account for savings that are only available through the end of 2019.
- Industrial Potential – Updated potential based upon new load forecast and growth rate
- Agricultural Measures – As previously discussed, the removal of SIS measures from the potential resulted in a decline in agricultural potential.

Avoided Cost

In addition to measure changes, changes in the financial assumptions used to model cost-effective conservation potential impacted the amount of economic achievable potential estimated in this assessment. Revised EIA rules required the inclusion a social cost of carbon as well as a generation capacity value, which were not explicitly included as avoided cost inputs in previous CPAs. The higher avoided costs increased the cost-effectiveness of the energy efficiency measures resulting in greater estimated potential over the study period.

Modeling Methodology

New to the Seventh Power Plan was some additional modelling that allowed for lost opportunity conservation measures not acquired at the first opportunity to be acquired later in the study period. For example, the model assumes that approximately 4 percent of all heat pumps being replaced in 2018 will be replaced with an efficient model. The remaining 96 percent now become available again 15 years later, when it is assumed that the heat pump will be replaced again. At that point in the study period, nearly all of the heat pumps being replaced are assumed to be replaced with an efficient model.

Market Prices

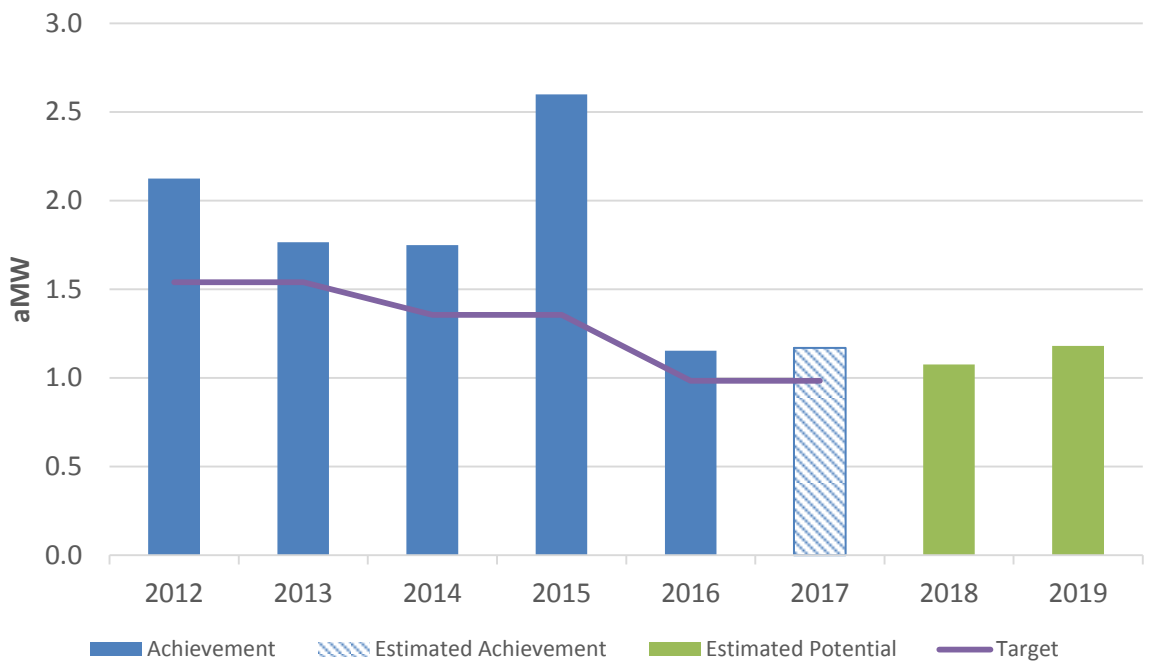
The EIA requires that utilities use a forecast of market prices in the Conservation Potential Assessment cost-effectiveness test for energy efficiency measures. The 2017 price forecast is 26 percent lower compared with the forecast used in Benton PUD's 2015 CPA due to changes in market conditions. This lower electricity price forecast is a result of multiple factors including an abundance of renewable wind energy and low natural gas prices. The effect of using a lower market price forecast is that fewer measures are considered cost-effective when compared with the alternative resource–market power purchases, although this was offset to some extent by the inclusion of values for the social cost of carbon and generation capacity described above. Additional information regarding the avoided cost forecast is included in Appendix IV.

Targets and Achievement

Figure ES-2 compares historic achievement with Benton PUD's targets. The figure shows that Benton PUD has consistently met its energy efficiency targets, and that the potential estimates presented in this report are achievable through Benton PUDs various programs and Benton PUD's share of NEEA savings.

Figure ES-2

Historic Achievement and Targets



Conclusion

This report summarizes the CPA conducted for Benton PUD for the 2018 to 2037 timeframe. Many components of the CPA are updated from previous CPA models including items such as energy market price forecast, code and standard changes, recent conservation achievements, revised savings values for RTF and Council measures, and multiple scenario analyses. Additionally, new requirements from EIA November 2016 rulemaking changes to WAC 194-37-070 require inclusion of deferred generation benefits and social cost of carbon.

The results of this assessment are higher than the previous assessment due to both changes in commercial and residential LED lighting technology, as well as increases to the avoided cost estimates. First, continued improvements have allowed LED technology to be used in more applications, resulting in greater potential savings. Further, improvements in LED costs have led to broad market adoption and higher acquisition rates. Second, while market prices for wholesale electricity have decreased, the decrease in energy value was offset by the addition of the following two avoided cost adders that were defined explicitly in this study: the social cost of carbon and the value of deferred generation capacity investments. These changes result in a total 10-year cost effective potential of 14.08 aMW and a two-year potential of 2.25 aMW for the 2018-19 biennium, which is a 15% increase over the target for the 2016-17 biennium.

Introduction

Objectives

The objective of this report is to describe the results of the Benton Public Utility District (Benton PUD) 2017 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2018 to 2037, with the primary focus on 2018 to 2027 (10 years). This analysis has been conducted in a manner consistent with requirements set forth in RCW 19.285 (EIA) and 194-37 WAC (EIA implementation) and is part of Benton PUD's compliance documentation. The results and guidance presented in this report will also assist Benton PUD in strategic planning for its conservation programs in the near future. Finally, the resulting conservation supply curves can be used in Benton PUD's Integrated Resource Plan (IRP).

The conservation measures used in this analysis are based on the measures that were used in the Council's Seventh Power Plan, along with any subsequent updates by the Regional Technical Forum (RTF). The assessment considered a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

Electric Utility Resource Plan Requirements

According to Chapter RCW 19.280, utilities with at least 25,000 customers are required to develop IRPs by September 2008 and biennially thereafter. The legislation mandates that these resource plans include assessments of commercially available conservation and efficiency measures This CPA is designed to assist in meeting these requirements for conservation analyses. The results of this CPA may be used in the next IRP due to the state by September 2018. More background information is provided below.

Energy Independence Act

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

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the Pacific Northwest Power and Conservation Council's (Council) latest power planning document.
- Beginning January 2010, each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent ten years.
- On or before June 1, 2012, each utility shall submit an annual conservation report to the department (the Department of Commerce or its successor). The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.
- Beginning on January 1, 2014, cost-effective conservation achieved by a qualifying utility in excess of its biennial acquisition target may be used to help meet the immediately subsequent two biennial acquisition targets, such that no more than twenty percent of any biennial target may be met with excess conservation savings.

- Beginning January 1, 2014, a qualifying utility may use conservation savings in excess of its biennial target from a single large facility to meet up to an additional five percent of the immediately subsequent two biennial acquisition targets.[45]

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

Study Uncertainties

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

- Customer characteristic data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that Benton PUD's service area is similar to that of the region, or that the regional survey data represents the population.
- Measure data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Council and RTF, will vary across the region. In some cases, measure applicability or other attributes have been estimated by the Council or the RTF based on professional judgment or limited market research.
- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, different avoided cost scenarios are included in the analysis to consider the sensitivity of the results to fluctuating market prices over the study period.
- Utility System Assumptions – Credits have been included in this analysis to account for the avoided costs of bulk transmission and distribution system expansion and local distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits to be representative estimates of these avoided costs.
- Discount Rate – The Council develops a real discount rate as well as a finance rate for each power plan. The finance rate is based on the relative share of the cost of conservation and the cost of capital for the various program sponsors. The Council has estimated these figures using the most current available information. This study reflects the current borrowing market although changes in borrowing rates will likely vary over the study period.

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[45] The EIA requires that the savings must be cost effective and achieved within a single biennial period at a facility whose average annual load before conservation exceeded 5 aMW. In addition, the law requires that no more than 25% of a biennial target may be met with excess conservation savings, inclusive of provisions listed in this section.

- Forecasted Load and Customer Growth – The CPA bases the 20-year potential estimates on forecasted loads and customer growth as approved by Resolution 2410. Each of these forecasts includes a level of uncertainty.
- Load Shape Data – The Council provides conservation load shapes for evaluating the timing of energy savings. In practice, load shapes will vary by utility based on weather, customer types, and other factors. This assessment uses the hourly load shapes used in the Seventh Plan to estimate peak demand savings over the planning period, based on shaped energy savings. Since the load shapes are a mix of older Northwest and California data, peak demand savings presented in this report may vary from actual peak demand savings.
- Frozen Efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. The Seventh Plan did, however, include the effects of a highly impactful lighting standard set to take effect in 2020. This assessment also includes that consideration. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

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

Report Organization

The main report is organized with the following main sections:

- Methodology – CPA methodology along with some of the overarching assumptions
- Recent Conservation Achievement – Benton PUD's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions
- Results – Energy Savings and Costs – Primary base case results
- Scenario Results – Results of all scenarios
- Summary
- Appendices

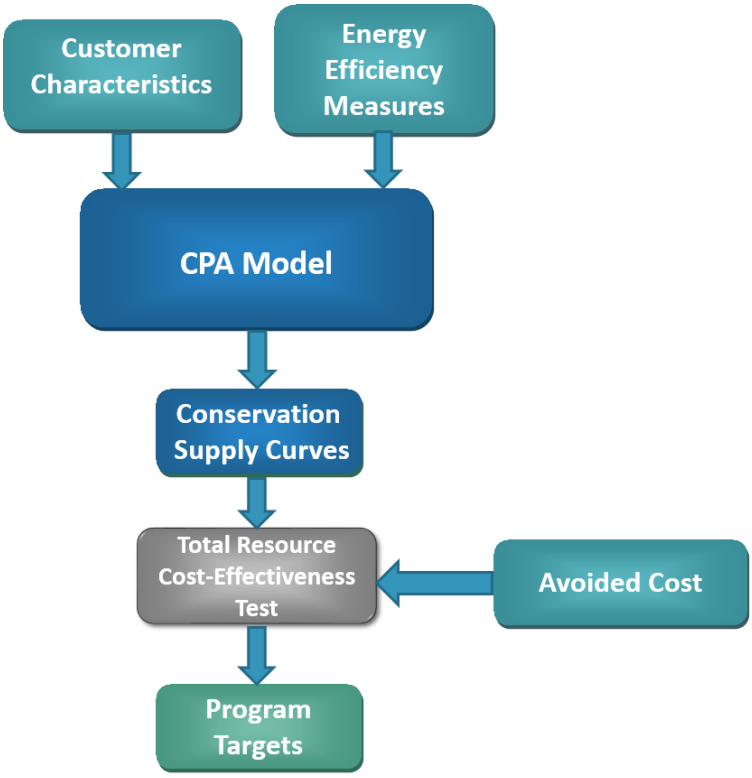
CPA Methodology

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

Basic Modeling Methodology

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

Figure 1
Conservation Potential Assessment Process



Customer Characteristic Data

The quantification of energy efficiency begins with compiling customer characteristics, baseline measure saturation data, and appliance saturation. For this analysis, the characterization of Benton PUD's

baseline was determined using data provided by Benton PUD customer surveys, NEEA's commercial and residential building stock assessments, and county assessor data. Details of data sources and assumptions are described for each sector later in the report.

This assessment primarily sourced baseline measure saturation data from the Council's Seventh Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources, and the Council has updated baselines for regional conservation achievement as part of the Seventh Power Plan. Historic conservation achievement data are often used to update measure saturation levels when current market data is unavailable. EES adjusted measure baselines using Benton PUD's customer surveys. For measures not accounted for in the customer surveys, conservation achievement was used to adjust baselines that have not been updated since the 2011 Residential Building Stock Assessment. Benton PUD's historic achievement is discussed in detail in the next section.

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings (kWh), demand savings (kW), measure costs ($), and measure life (years). Other features, such as measure savings shape, operation and maintenance costs, and non-energy benefits are also important components of the measures. The Council's Seventh Power Plan is the primary source for conservation measure data. Where appropriate, the Council's Seventh Plan supply curve workbooks, have been updated to include any subsequent updates from the RTF.

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

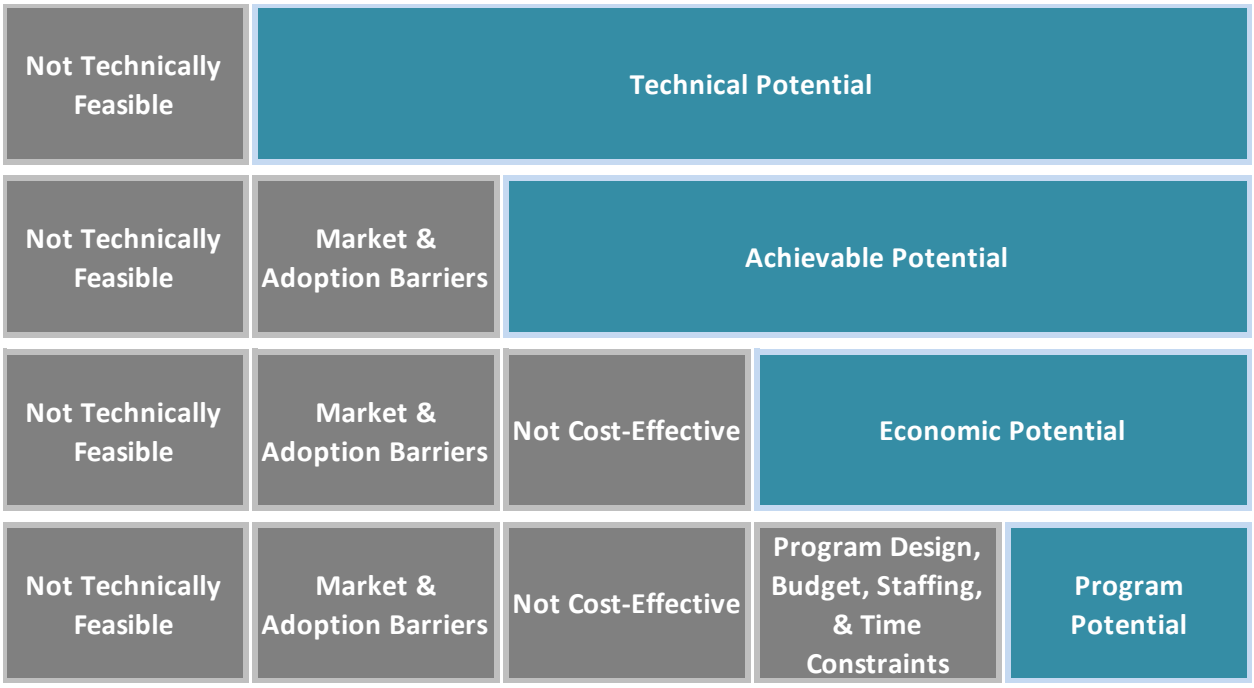
A list of measures by end-use is included in this CPA is included in Appendix VI.

Types of Potential

Once the customer characteristics and energy efficiency measures are fully described, energy efficiency potential can be quantified. Three types of potential are used in this study: technical, achievable, and economic potential. Technical potential is the theoretical maximum efficiency in the service territory if cost and achievability barriers are excluded. There are physical barriers, market conditions, and other consumer acceptance constraints that reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the technical-achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 2 illustrates the four types of potential followed by more detailed explanations.

Figure 2

Types of Energy Efficiency Potential[46]



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

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Then, the number of "applicable units" must be estimated. "Applicable units" refers to the number of units that could technically be installed in a service territory. This includes accounting for units that may already be in place. The "applicability" value is highly dependent on the measure and the housing stock. For example, a duct sealing measure can only be completed in homes with ducts as part of the HVAC system. A "saturation" factor accounts for measures that have already been completed.

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

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

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

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

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

For this potential assessment, the Council's ProCost models are used to determine cost-effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2017 CPA evaluates measure savings on an hourly basis, but ultimately values the energy savings during two segments covering high and low load hour time periods.

Program – Program potential is the amount of potential that can be achieved through utility administered programs. The program achievable potential excludes savings estimates that are achieved through future code changes and market transformation. The program potential is not the emphasis of this assessment, but understanding the sources of achievement is an important reporting requirement.

Avoided Cost

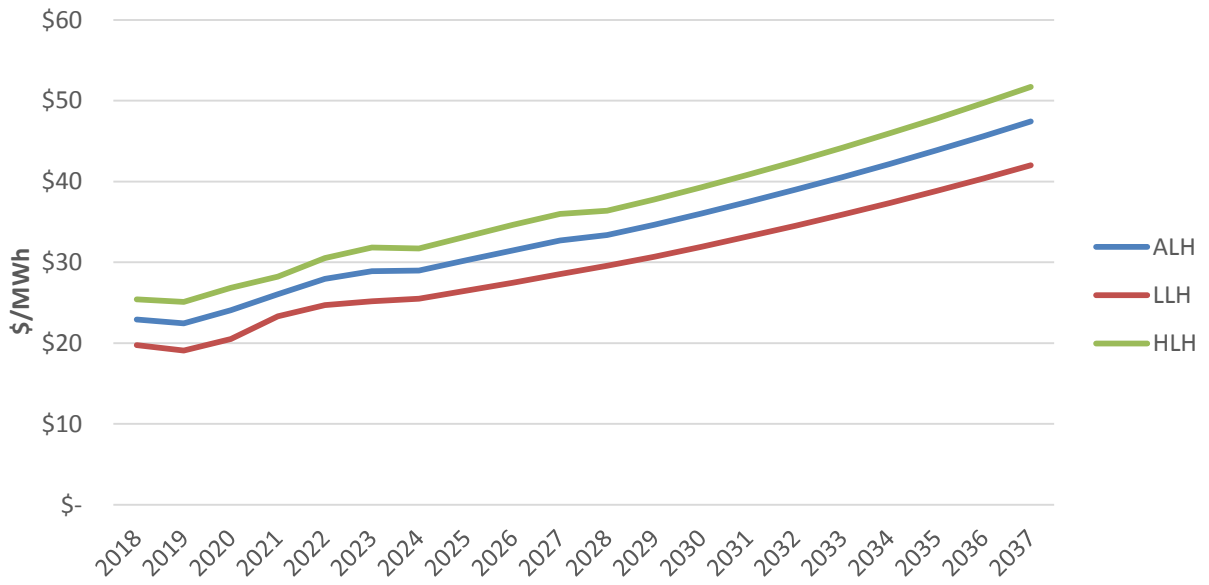
Each component of the avoided cost of energy efficiency measure savings is described below. Additional information regarding the avoided cost forecast is included in Appendix IV.

Energy

The avoided cost of energy is represented as a dollar value per MWh of conservation. Avoided costs are used to value energy savings benefits when conducting cost effectiveness tests and are included in the numerator in a benefit-cost test. These energy benefits are often based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the IRP process. Figure 3 shows the price forecast used as the primary avoided cost component for the planning period. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (ALH).

Figure 3

20-Year Market Price Forecast (Mid-Columbia)



The EIA requires that utilities "…set avoided costs equal to a forecast of market prices." As discussed in Appendix IV, Benton PUD relies on market purchases to meet peak energy demands. Therefore, the market price forecast shown in Figure 3 is appropriate for modeling the value of avoided energy.

Social Cost of Carbon

In addition to the avoided cost of energy, energy efficiency provides the benefit of reducing carbon emissions and lowering Benton PUD's Renewable Portfolio Standard (RPS) requirements. The revised EIA rules require the inclusion of the social cost of carbon. Because uncertainty exists around this value, a range of values was considered. These included a forecast of prices from Benton PUD's most recent IRP, as well as the federal interagency workgroup values that were considered in the Seventh Plan.

Renewable Energy Portfolio Cost

By reducing Benton PUD's overall load, energy efficiency provides a benefit of reducing the RPS requirement. Benton PUD purchases Renewable Energy Credits (RECs) to fulfill a requirement of sourcing 9% of its energy from renewable energy sources. Therefore, for every 100 units of conservation achieved, the RPS requirement is reduced by 9 units. A RPS with higher requirements was considered in the high-case, to account for the possibility of higher RPS requirements or higher Renewable Energy Certificate (REC) prices.

Transmission and Distribution System

The EIA also requires that deferred capacity expansion benefits for transmission and distribution systems be included in the cost-effectiveness analysis. To account for the value of deferred bulk transmission and local distribution system expansion, a distribution system credit value of $31/kW-year and a transmission system credit of $26/kw-year were applied to peak savings from conservation measures, at the time of the regional transmission and local distribution system peaks. These credits are taken from the Council's Seventh Plan supporting documents.

Generation Capacity

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

Benton PUD's IRP concluded peak demands will be met through market purchases of energy. Thus, the District does not currently avoid any capital expenses associated with generation resources by reducing peak demands. The region may face capacity shortfalls in 2021 when several large coal plants in the Northwest are scheduled to be decommissioned. Further, the District's need for generation capacity will further increase when its Power Purchase Agreement with the Frederickson 1 Generating Station expires in 2022.

To be conservative, EES has included a value for generation capacity deferral beginning in 2021. EES used BPA's monthly demand charges as a proxy value for the monthly value of generation capacity, as those charges were based upon the cost of a generating unit. By assuming a monthly shape to the Benton PUD's peak demand reductions due to conservation, the generation capacity costs were converted into a value of $86.26/kW-year. For the base case, it was assumed that this cost would increase in real terms by 3% annually. In the low avoided cost scenario, it was assumed that market purchases would continue to be available to meet peak demands. The Council's value of $115 was used in the high scenario.

Risk

With the generation capacity value explicitly defined, the Council's analysis found that a risk credit did not need to be defined as part of its cost-effectiveness test. In this CPA, risk was modeled by varying the base case input assumptions. In doing so, this CPA addresses the uncertainty of the inputs and looks at the sensitivity of the results. The avoided cost components that were varied included the energy prices,

generation capacity value, REC prices, and the social cost of carbon. Through the variance of these components, implied risk credits of up to $71/MWh and $32/kW-year were included in the avoided cost.

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

Power Planning Act Credit

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

Discount and Finance Rate

The Council develops a real discount rate and finance rate for each of its Power Plans. The most recent real discount rate assumption developed by the Council is 4%. The 4% discount rate was developed to model conservation potential for the Seventh Power Plan. The discount rate is used to convert future cost and benefit streams into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives. The Council's 4% discount rate is used in this analysis.

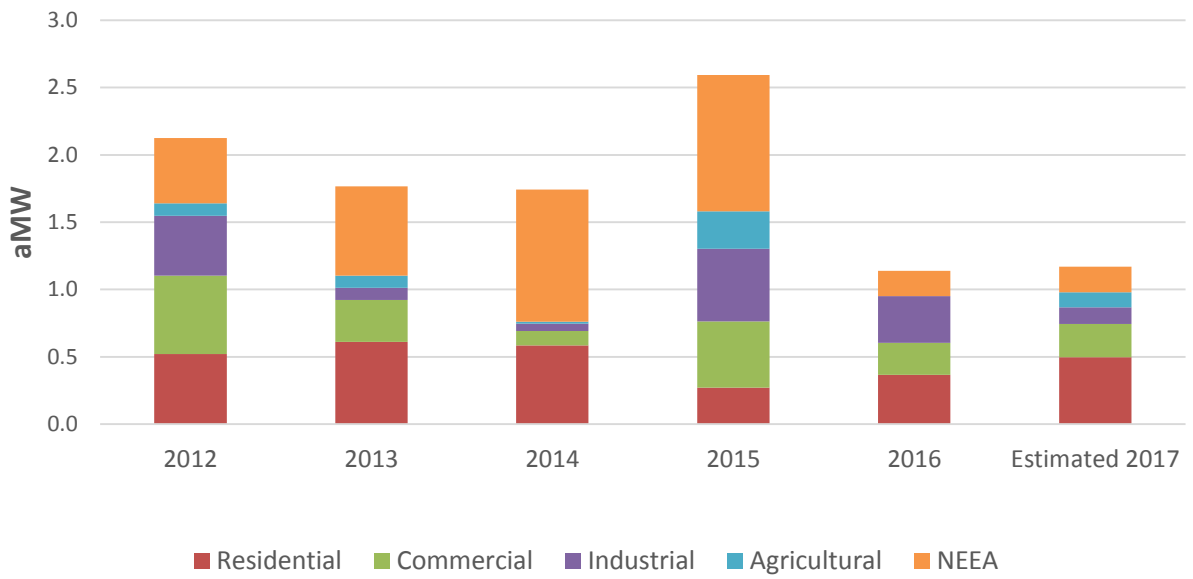
The finance rate is developed from two sets of assumptions. The first set of assumptions describes the relative shares of the cost of conservation distributed to various sponsors. Conservation is funded by the Bonneville Power Administration (BPA), utilities, and customers. The second set of assumptions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

Recent Conservation Achievement

Benton PUD has pursued conservation and energy efficiency resources for many years. Currently, the utility offers several rebate programs for both residential and non-residential applications. These include, residential weatherization, Energy Star® appliance rebates, new construction programs for commercial customers, and energy-efficiency audits. In addition to utility programs, Benton PUD receives credit for market-transformation activities that are accomplished by the Northwest Energy Efficiency Alliance (NEEA) in its service territory. While they have contributed as much as 1 aMW in recent years, recent savings and near term savings projections have decreased significantly due to a change in baselines related to the adoption of the Seventh Power Plan. Figure 4 shows Benton PUD's conservation achievement from 2012 through projections for 2017. More detail for these savings are provided below for each sector.

Figure 4

Benton PUD's Recent Conservation History by Sector

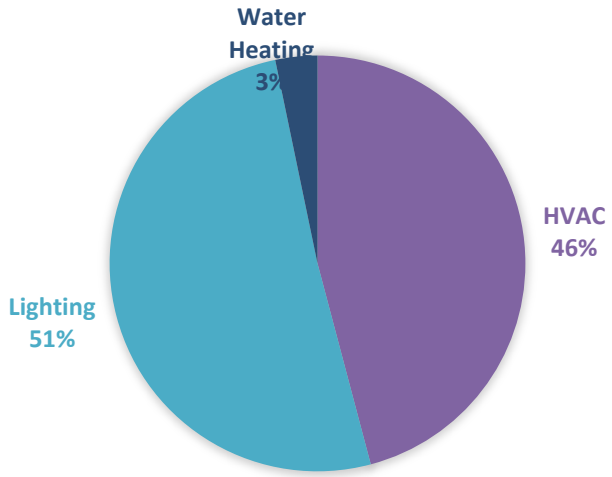


Residential

Figure 5 shows historic conservation achievement by end use in the residential sector. Savings from lighting measures account for just over half of the total. Due to the large share of electric heat in Benton PUD's service area, heat pumps and weatherization measures also make up a significant share of savings (HVAC).

Figure 5

2015-2016 Residential Savings

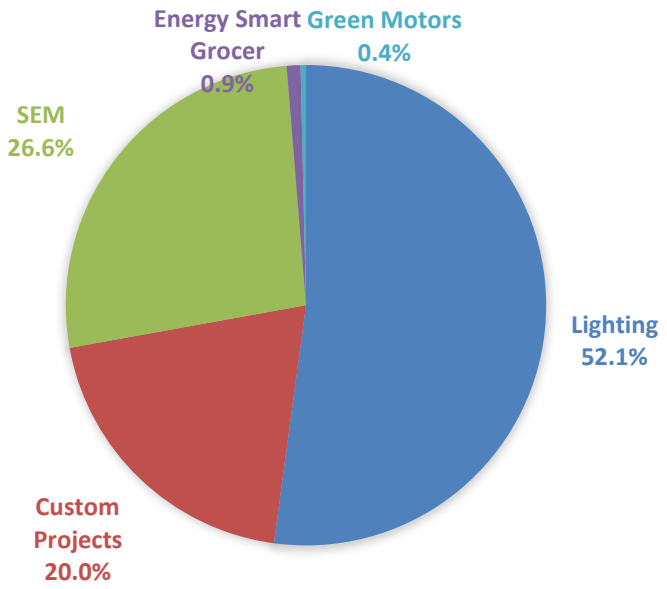


Commercial & Industrial

Historic achievement in the commercial and industrial sectors is primarily due to lighting, SEM, and custom projects. Figure 6 shows the breakdown of total savings from 2016 and projections for 2017.

Figure 6

2016-2017 Commercial & Industrial Savings



Agriculture

Savings in the agriculture sector have largely been due to scientific irrigation scheduling (SIS), irrigation hardware updates, and efficient pumps and motors. Benton PUD has helped farmers implement SIS on more than 55,000 acres annually.

Current Conservation Programs

Benton PUD offers a wide range of diverse conservation programs to its customers. These programs include many types of deemed conservation rebates, energy audits, net metering, commercial custom projects, and agricultural custom projects. The current programs offered by Benton PUD are detailed below and Benton PUD's board resolution detailing the utility's conservation rebate policy is included as Appendix VII.

Residential

- *Energy Star Rebates* – Benton PUD offers a number of rebates for Energy Star appliances. These include $20 for Energy Star clothes washers and $50 for clothes dryers
- *Heat Pump Water Heater* – Rebates are available for heat pump water heaters based on capacity. Rebates include $300 for 50-75 gallon tanks and $500 for tanks over 75 gallons.
- *Weatherization* – This program provides insulation rebates from $0.02 to $0.70 per square foot, depending on location and home type. Benton PUD offers window replacement rebates of $3 per square foot. Finally, qualified energy efficient doors are eligible for a $40 rebate.

- *HVAC Rebates* – This program provides rebates for a variety of space conditioning upgrades including: a heat-pump and ductless heat-pump rebates ($500 to $1,000), and duct- sealing rebates up to $250.
- *Energy Star Homes and Manufactured Homes Program* – Benton PUD provides rebates of $1,000 to Northwest Energy Efficient Manufactured (NEEM) certified homes.

Commercial

- *Lighting Energy Efficiency Program (LEEP)* – Owners of commercial buildings can apply for a lighting energy audit. Applicable rebate amounts are determined upon completion of the audit.
- *Custom Projects Rebates* – Benton PUD offers rebates for special projects that improve efficiency or process related systems including, but not limited to, compressed air, variable frequency drives, industrial lighting interactive with HVAC systems, and refrigeration. Rebates for this program vary.

Agriculture

- *Agricultural Rebate Program* – This program offers incentives for sprinklers, nozzles, replacement of 25 to 500 horsepower pump motors and variable frequency drives installed in onion and potato sheds. Rebate amounts vary and an application form must be completed to qualify.

Summary

Benton PUD plans to continue to invest in energy efficiency by offering incentives to all sectors. The results of this CPA will help Benton PUD program managers to structure energy efficiency program offerings, establish appropriate incentive levels, comply with the EIA requirements, and maintain the District's status as our customer's Trusted Energy Partner.

Customer Characteristics Data

Benton PUD serves over 50,000 electric customers in Benton County, Washington, with a service area population of approximately 123,299. A key component of an energy efficiency assessment is to understand the characteristics of these customers – primarily the building and end-use characteristics. These characteristics for each customer class are described below.

Residential

For the residential sector, the key characteristics include house type, heat fuel type, and water heating. Tables 1, 2 and 3 show relevant residential data for single family, multi-family and manufactured homes in Benton PUD's service territory. The data is based on surveys conducted by Benton PUD as well as the 2011 Residential Building Stock Assessment (RBSA), developed by NEEA. The surveys were conducted by Robinson Research for the 2015 CPA, but are still considered relevant and useful information.

Table 1
Residential Building Characteristics

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	41,862	123,299

Table 2 Existing Homes - Heating / Cooling System Saturations				
	Single Family	**Multifamily - Low Rise**	**Multifamily - High Rise**	**Manufactured**
Existing Homes				
Electric Forced Air Furnace (FAF)	45%	36%	36%	56%
Heat Pump (HP)	42%	5%	5%	40%
Ductless HP (DHP)	0%	0%	0%	0%
Electric Zonal (Baseboard)	11%	57%	57%	4%
Central AC	42%	43%	43%	52%
Room AC	16%	38%	38%	6%
New Homes				
Electric Forced Air Furnace (FAF)	45%	36%	36%	56%
Heat Pump (HP)	42%	5%	5%	40%
Ductless HP (DHP)	0%	0%	0%	0%
Electric Zonal (Baseboard)	11%	57%	57%	4%
Central AC	42%	43%	43%	52%
Room AC	16%	38%	38%	6%

Table 3 Appliance Saturations				
	Single Family	Multifamily - Low Rise	Multifamily - High Rise	Manufactured
Existing Homes				
Electric WH	80%	88%	88%	100%
Refrigerator	140%	102%	102%	121%
Freezer	61%	61%	61%	61%
Clothes Washer	94%	94%	94%	94%
Clothes Dryer	91%	91%	91%	91%
Dishwasher	79%	79%	79%	79%
Electric Oven	95%	95%	95%	95%
Desktop	96%	44%	44%	71%
Laptop	68%	26%	26%	42%
Monitor	102%	45%	45%	72%
New Homes				
Electric WH	80%	88%	88%	100%
Refrigerator	140%	102%	102%	121%
Freezer	61%	61%	61%	61%
Clothes Washer	94%	94%	94%	94%
Clothes Dryer	91%	91%	91%	91%
Dishwasher	79%	79%	79%	79%
Electric Oven	95%	95%	95%	95%
Desktop	96%	44%	44%	71%
Laptop	68%	26%	26%	42%
Monitor	102%	45%	45%	72%

Commercial

Building square footage is the key parameter in determining conservation potential for the commercial sector, as many of the measures are based on savings as a function of building area (kWh/sf). Commercial building floor area data in the 2017 CPA is based upon the data developed for the 2015 CPA, with the addition of new service orders provided by Benton PUD. The 2015 data was based on 2011 county assessor data and average building size (square feet) from Benton PUD's commercial customer surveys. Benton PUD conducted commercial customer surveys both in 2010 and 2015 and requested that customers submit commercial building square footage. The building sizes for commercial building types are then averaged between the two surveys. The result is average building sizes that represent a larger sample size (800 buildings in total between the two surveys). The number of buildings was estimated based on county assessor data (2011 data) escalated using a 0.6 percent growth rate. Total commercial square footage by building type is the product of the number of buildings and average building size calculated from the surveys.

Table 4 shows estimated 2016 commercial square footage in each of the 18 building categories. Estimates of commercial floor area by building type are slightly higher than 2015 CPA estimates (22,523,065 square feet).

Benton PUD provided a load forecast by rate class that was used to develop a sector-wide growth rate of 0.73% after embedded energy efficiency impacts were added back in. The growth rates by segment from the 2015 CPA were then scaled to match this overall growth rate. A regional demolition rate, based on the Council's Seventh Plan assumptions is also used. Energy use intensity (EUI) values from the most recent Commercial Building Stock Assessment (CBSA)[47] were used for comparison purposes and are provided in Table 4.

Table 4
Commercial Building Square Footage by Segment

Segment	EUI[1]	Area (Square Feet)	Growth Rate
Large Office	15.6	327,870	0.64%
Medium Office	20.2	2,825,184	0.64%
Small Office	14.1	3,071,940	0.64%
Extra Large Retail	13.9	1,265,579	0.63%
Large Retail	13	2,131,774	0.63%
Medium Retail	14.4	423,180	0.63%
Small Retail	13.9	32220	0.63%
School (K-12)	9	111,327	0.63%
University	16.9	216,049	0.66%
Warehouse	7.3	5,989,721	0.91%
Supermarket	53.4	851,368	0.88%
Mini Mart	80.9	162,999	0.67%
Restaurant	50.7	642,258	0.71%
Lodging	14.6	1,668,139	0.44%
Hospital	27.4	153,847	0.50%
Residential Care	14.9	552,786	0.64%
Assembly	10.5	780,771	0.73%
Other Commercial	12.5	2,098,712	0.88%
Total		**23,305,723**	**0.73%**

1. Navigant Consulting. 2014. *Northwest Commercial Building Stock Assessment: Final Report.* Portland, OR: Northwest Energy Efficiency Alliance.

To benchmark the estimated commercial square footage for this assessment, EES took the resulting floor area for each commercial segment described above and applied energy use intensity numbers from NEEA's 2014 Commercial Building Stock Assessment to develop an estimated commercial load. Doing this resulted in an estimated load of approximately 339 GWh.

This value was compared with an estimate of Benton PUD's actual commercial load, which was approximately 381 GWh. The actual commercial load is somewhat difficult to determine as load forecasting is done by rate class, which does not align with the sector definitions used in this

[47] Navigant Consulting. 2014. *Northwest Commercial Building Stock Assessment: Final Report.* Portland, OR: Northwest Energy Efficiency Alliance.

assessment. The difference between the floor area based load forecast and rate class based forecast is 11%, which is considered to be reasonable given the uncertainties of rate classes aligning to the sector definitions and the fact that regional EUI numbers may not accurately represent Benton PUD's commercial building stock. The saturation of natural gas is lower in Benton PUD's service area, which would mean that Benton PUD's commercial EUI values would be higher as more buildings are heated with electricity.

The commercial square footage shown in Table 4 was used to estimate commercial potential for this assessment.

Industrial

The methodology for estimating industrial potential is different than that of the residential and commercial sectors primarily because most energy efficiency opportunities are unique to specific industrial segments. The Council and this study use a "top-down" methodology that utilizes annual consumption by industrial segment and then disaggregates total usage by end-use shares. Estimated measure savings are applied to each sector's end-use shares.

Benton PUD provided 2016 energy use for its industrial customers. Individual industrial customer usage is summed by industrial segment in Table 5. Similar to the commercial sector, the industrial growth rate used in Benton PUD's medium load growth scenario was calculated from the industrial load forecast after accounting for embedded energy efficiency and applied across all sectors. The 2016 industrial consumption totaled 189,697 MWh.

Table 5
Industrial Sector Load by Segment

Industrial Segment	2016 Sales (MWh)	Annual Growth Rate
Frozen Food	4,321	0.1%
Other Food	88,650	0.1%
Metal Fabrication	1,247	0.1%
Equipment	894.24	0.1%
Cold Storage	9,024	0.1%
Fruit Storage	489	0.1%
Refinery	1,275	0.1%
Chemical	67,660	0.1%
Miscellaneous Manufacturing	16,137	0.1%
Total	**189,697**	**0.1%**

Agriculture

To determine agriculture sector characteristics in Benton PUD's service territory, EES utilized data provided by the United States Department of Agriculture (USDA). The USDA conducts a census of farms and ranches in the U.S. every five years. The most recent available data for this analysis is from the 2012 census, which was published in 2014. This data was used in both the 2015 and 2017 CPAs.

Benton PUD provides electric service to agriculture customers in Benton County; however, Benton REA and the City of Richland also provide electric service to agriculture customers in Benton County. Because the USDA reports census data by county, the 2012 data for Benton County was adjusted to reflect Benton PUD's service area. Irrigated acreage and the number of farms were taken from the 2012 census, then weighted based on Benton PUD's service area size (square miles) and the total area of Benton County.

Irrigated acreage is estimated at 108,982 acres, based on 2012 census data. Irrigated acreage is used to estimate savings from energy efficient irrigation hardware upgrades.

The number of farms in Benton PUD's service territory (834) is estimated based on 2012 USDA census data for Benton County and has been adjusted to reflect Benton PUD's service area. The number of farms is used to estimate agriculture sector area lighting potential. Finally, Benton PUD provided the number of dairy farms and head of dairy cattle. This data is summarized in Table 6 below and was used to estimate dairy measure potential.

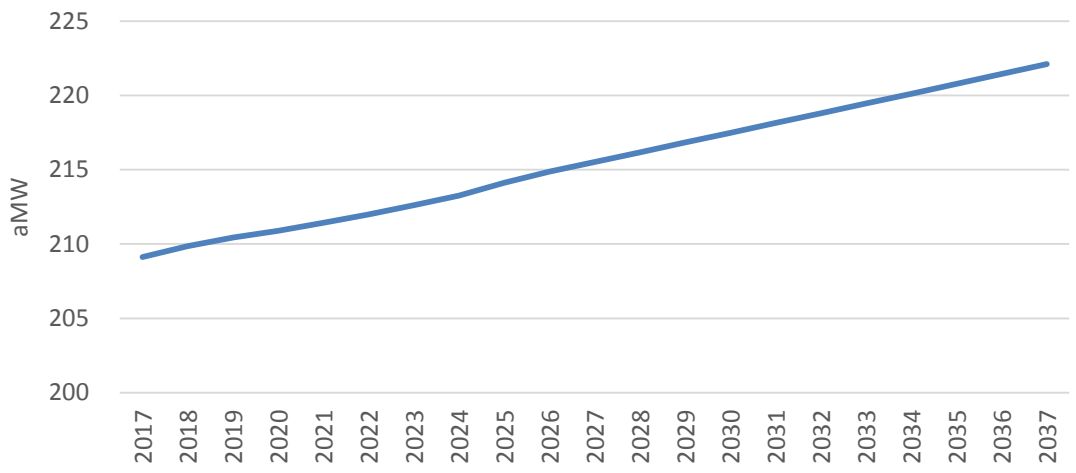
Table 6
Agricultural Inputs

Number of Dairy Farms	17
Total Irrigated Acreage	108,982
Total Number of Pumps	1,076
Total Number of Farms	834

Distribution Efficiency (DE)

For this analysis, EES developed an estimate of distribution system conservation potential using the Council's Seventh Plan approach. The Seventh Plan estimates distribution potential for five measures as a fraction of end system sales ranging from 0.1 to 3.9 kWh per MWh. Benton PUD provided a load forecast through 2026. The forecast is extended through 2037, assuming a 0.3 percent annual growth rate. This growth rate is based on compound average growth rate for the utility-provided forecast. Benton PUD's load forecast is graphed in Figure 7 and distribution system conservation is discussed in detail in the next section.

Figure 7
20-year End System Load Forecast



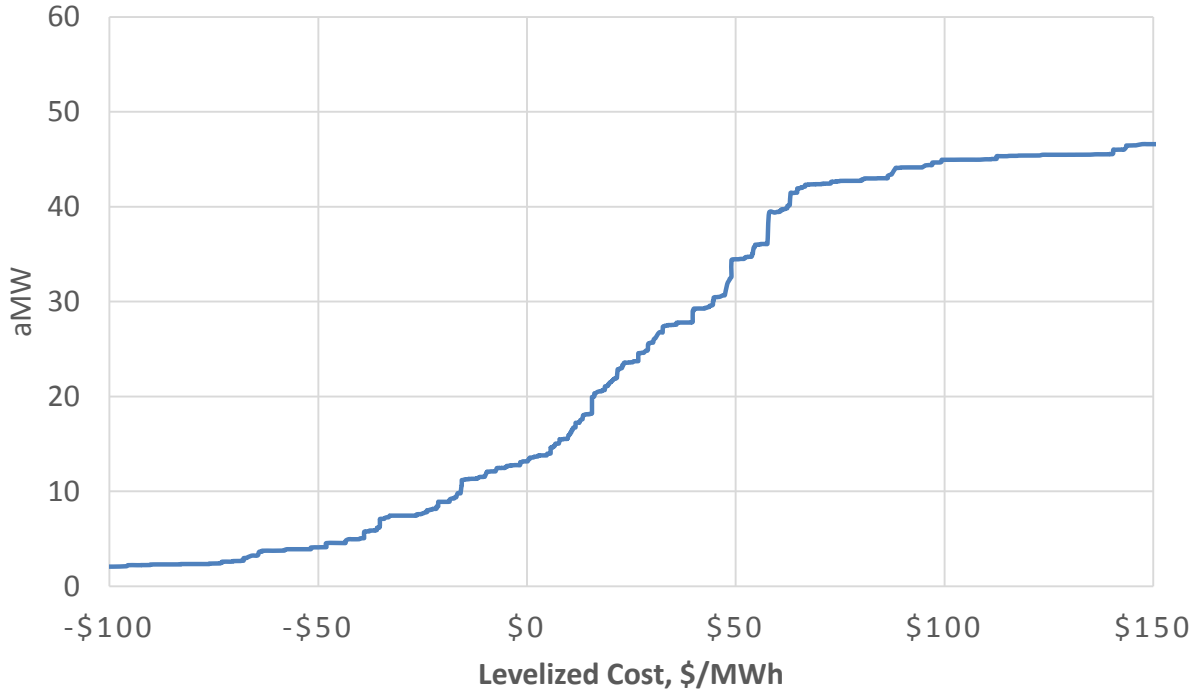
Results – Energy Savings and Costs

Technical Achievable Conservation Potential

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

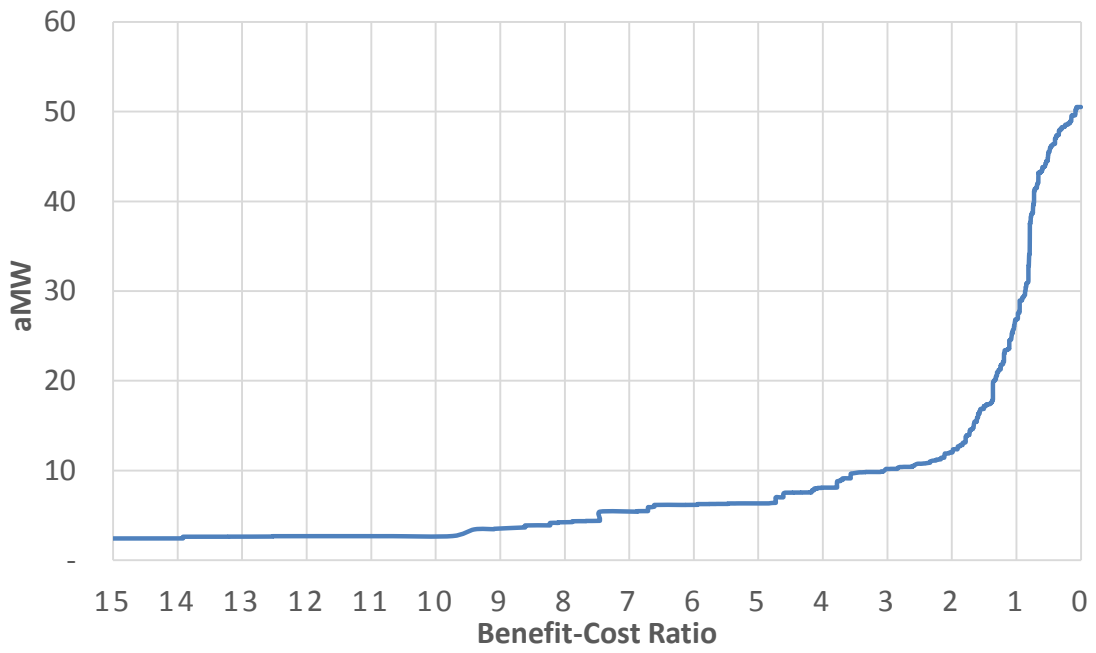
Figure 8, below, shows a supply curve of 20-year, technical-achievable potential. A supply curve is developed by plotting energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the conservation. The technical potential has not been screened for cost effectiveness. Costs are standardized (levelized), allowing for the comparison of measures with different lives. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with integrated resource plans (IRPs). Figure 8 shows that approximately 25 aMW of saving potential are available for less than $30/MWh and over 42 aMW are available for under $80/MWh. Total technical-achievable potential for Benton PUD is approximately 50 aMW over the 20-year study period.

Figure 8
20-Year Technical-Achievable Potential Supply Curve



While useful for considering the costs of conservation measures, supply curves based on levelized cost are limited in that not all energy savings are equally valued. Another way to depict a supply curve is based on the benefit-cost ratio, as shown in Figure 9 below. This figure repeats the overall finding that 26.8 aMW of potential is cost-effective with a benefit-cost ratio greater than or equal to 1.0. The line is steep at the point where the benefit-cost ratio is equal to 1.0, suggesting that small changes in avoided cost assumptions would lead to large changes in potential.

Figure 9
20-Year Technical-Achievable Potential Benefit-Cost Ratio Supply Curve



Economic Achievable Conservation Potential

Economic potential is the amount of potential that passes the Total Resource Cost (TRC) test. This means that the present value of the benefits attributed to the conservation measure exceeds the present value of the measure costs over its lifetime.

Table 7 shows aMW of economically achievable potential by sector in 2, 6, 10 and 20-year increments. Compared with the technical and achievable potential, it shows that 26.8 aMW of the total 50.5 aMW is cost effective for Benton PUD. The last section of this report discusses how these values could be used for setting targets.

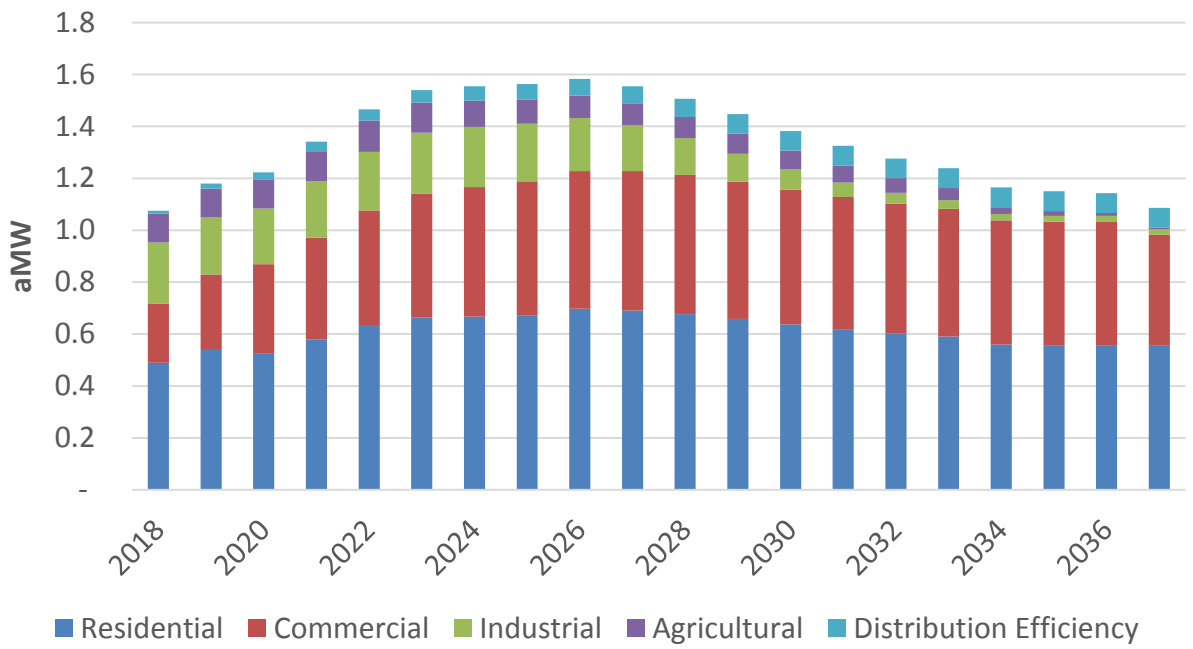
Table 7
Cost Effective Achievable Potential - Base Case (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	1.03	3.43	6.16	12.17
Commercial	0.52	2.17	4.26	9.20
Industrial	0.46	1.35	2.18	2.73
Agricultural	0.22	0.69	1.05	1.51
Distribution Efficiency	0.03	0.19	0.43	1.19
Total	**2.25**	**7.83**	**14.08**	**26.80**

Sector Summary

Figure 10 shows economic achievable potential by sector on an annual basis.

Figure 10
Annual Achievable Potential by Sector

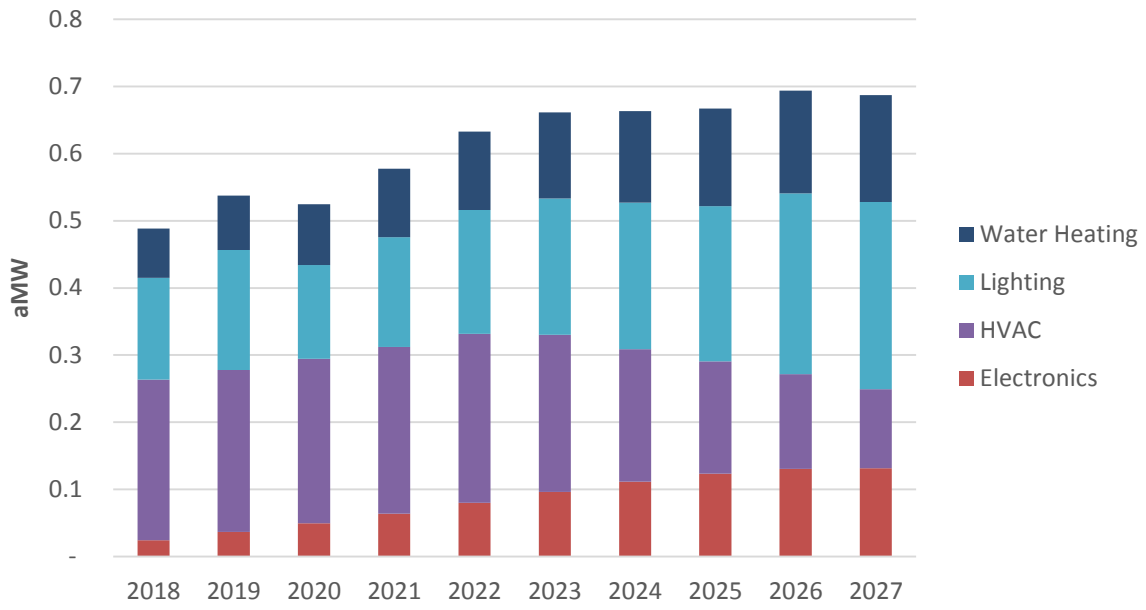


The largest share of the potential is in the residential sector followed by substantial savings potential in the commercial sector. Ramp rates are used to establish reasonable conservation achievement levels. Achievement levels are affected by factors including timing and availability of measure installation (lost opportunity), program (technological) maturity, non-programmatic savings, and current utility staffing and funding. In this analysis, the ramp rates used in the Seventh Plan were found to be a good fit for Benton PUD's current level of achievement. Figure 10 shows that savings estimates are ramped up over the first half of the study period. The ramp rates reflect both resource availability and Benton PUD's current program levels and achievements.

Residential

Within the residential sector, lighting measures make up the largest share of savings. The availability of a broad array of LED products and their widespread adoption has led to an increase in lighting savings potential. Weatherization measures—included in the HVAC category—also account for a significant amount of cost-effective conservation. This is due, in part, to the fact that Benton PUD's residential customers rely mostly on electricity for heating (Figure 11). Similar to weatherization measures, the large amount of electric water heating in Benton PUD's service area provides significant potential savings through heat pump water heaters, showerheads, and faucet aerators.

Figure 11
Annual Residential Potential by End Use

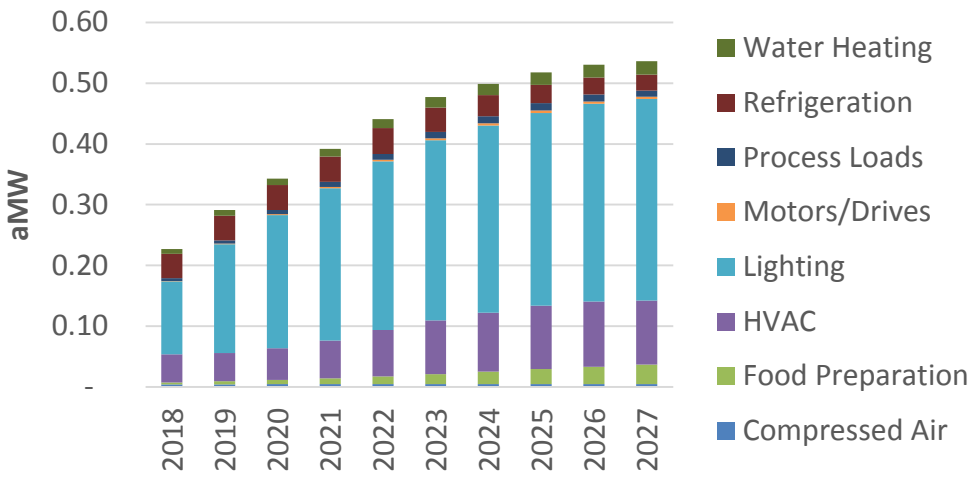


Commercial

Commercial lighting measures remain the largest contributors to commercial conservation potential (Figure 12). Lighting savings are higher in this assessment after ramp rates were adjusted to account for the success of commercial lighting programs and the broad acceptance of new LED products for a variety of applications and fixture types. These products have been easy to adopt in existing commercial lighting programs and trade ally networks, which are already well established. As a result, savings from lighting have been and will continue to be a foundation of commercial efficiency programs.

After lighting, commercial HVAC is the next largest source of potential for this assessment. The measures driving savings in this category include advanced rooftop controllers, ductless heat pumps, and commercial energy management. The custom nature of commercial building energy efficiency is reflected in the variety of end-uses and corresponding measures.

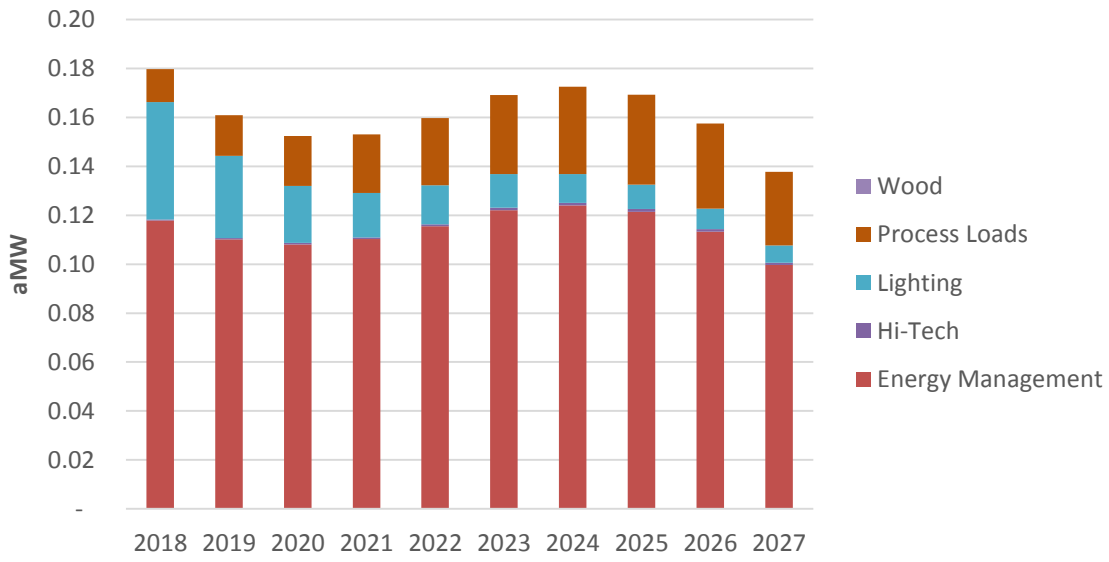
Figure 12
Annual Commercial Potential by End Use



Industrial

Much of Benton PUD's industrial load is composed of food and chemical facilities. Refrigerated storage and fruit storage load is also substantial. These segments contribute significantly to end-use savings in the energy management measures (Figure 13). Energy management measures include both Strategic Energy Management and improved management of motor-driven systems. Benton PUD's recent industrial sector achievement was used to adjust the 20-year technical industrial sector potential to estimate the remaining applicable potential available for future conservation programs. Because most industrial measures are thought to be retrofit measures, they are considered to be available from the beginning of the study period and generally decline over time as they are acquired.

Figure 13
Annual Industrial Potential by End Use

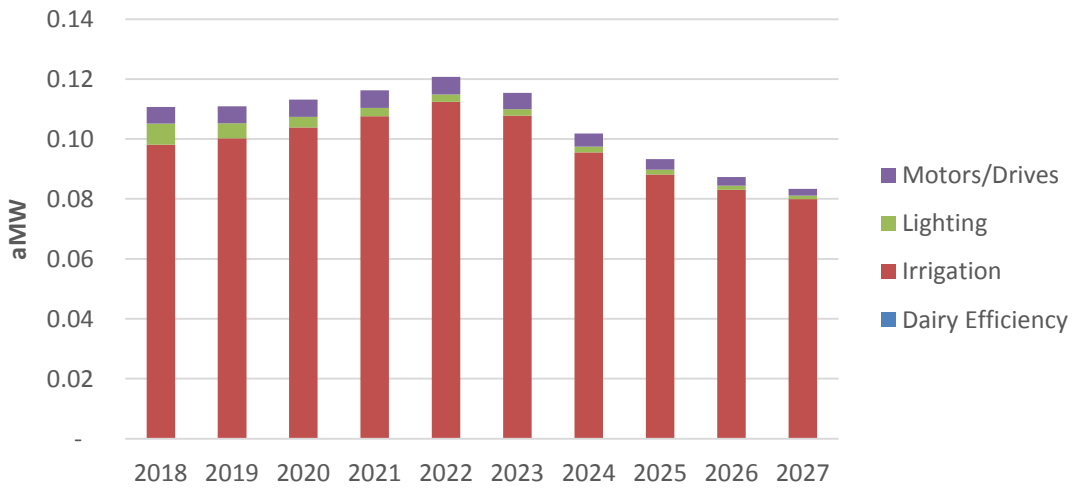


Agriculture

Potential in agriculture is a product of total acres under irrigation in Benton PUD's service territory, number of pumps (well or river), and the number of farms (applied to lighting measures and dairy). As mentioned above, SIS measures were not considered in this assessment, as a study recently completed by BPA indicates that SIS may no longer result in energy savings. While Benton PUD may continue to offer SIS for other reasons, it will likely no longer provide energy savings. As shown in Figure 14, nearly all of cost-effective conservation potential is due to irrigation hardware measures and Low Elevation Spray Application (LESA) measures. LESA measures are part of an initiative under development by NEEA and are new for the Seventh Plan.

Figure 14

Annual Agriculture Potential by End Use

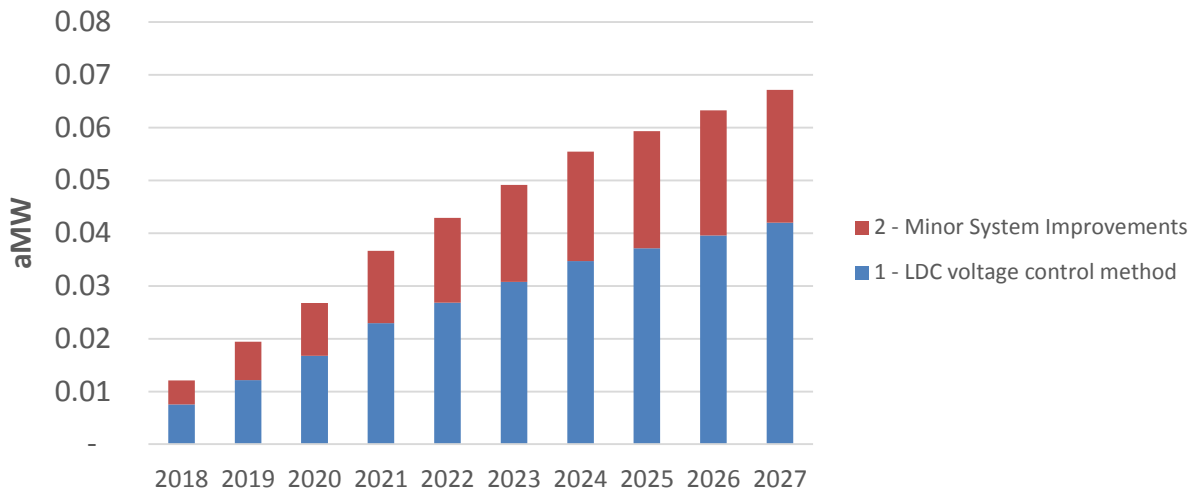


Distribution Efficiency

Distribution system energy efficiency measures regulate voltage and upgrade systems to improve the efficiency of utility distribution systems and reduce line losses. Distribution system potential was estimated using the Council's methodology. The Seventh Plan estimates distribution system potential based on end system energy sales. Systems sales were held constant to be consistent with the "last measure in" methodology, where each measure is assumed to be installed last to prevent the double-counting of savings where multiple measures may impact the same end-use. In the case of distribution system efficiency, any energy efficiency measure installed would reduce the overall load, and decrease the savings potential of utility distribution efficiency measures.

Distribution system conservation potential is shown in Figure 15. Although five measures were considered in the analysis, only two measures were cost effective.

Figure 15
Annual Distribution System Potential by End Use



Cost

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 8). The assumptions in this estimate include: 20 percent of measure cost for administrative costs and 35 percent of the incremental cost for incentives is assumed to be paid by the utility. A 20 percent allocation of measure costs to administrative expenses is a standard assumption for conservation programs. This figure was used in the Council's Seventh Power Plan. Table 8 costs are calculated based on a 35 percent utility-share, except in the utility distribution efficiency category, where Benton PUD is likely to pay the entire cost of any measures implemented. The 35 percent cost share assumption is consistent with Benton PUD's previous CPA.

This chart shows that Benton can expect to spend approximately $3.6 million to realize estimated savings over the next two years including program administration costs. The bottom row of Table 8 shows the cost per first year MWh.

Table 8
Utility Program Costs (2017$)

	2-Year	6-Year	10-Year	20-Year
Residential	$1,980,000	$6,635,000	$10,646,000	$18,172,000
Commercial	$903,000	$3,743,000	$7,213,000	$15,509,000
Industrial	$524,000	$1,554,000	$2,532,000	$3,205,000
Agricultural	$186,000	$563,000	$847,000	$1,183,000
Distribution Efficiency	$22,000	$130,000	$300,000	$825,000
Total	**$3,615,000**	**$12,625,000**	**$21,538,000**	**$38,894,000**
$/First Year MWh	$183	$184	$175	$166

The cost estimates above are conservative estimates for costs going forward since they are based on historic values. Future conservation achievement may be more costly or difficult since the lowest cost, easiest programs are usually implemented first. The next section provides a range of cost estimates for the planning period.

Cost Scenarios

To provide a range of program costs over the planning period, EES tested a High and Low cost scenario, relative to the Base Case conservation potential scenario. For the High Cost scenario, administrative costs were increased from 20 to 30 percent. The High Cost scenario reflects the case where program administration costs may increase in order for Benton PUD to connect with hard-to-reach customers.

For the Low scenario, the utility share of measure capital cost is reduced to 30 percent. A situation where the utility is responsible for a lower share of measure capital cost may result from higher conservation achievement through programs for which the customer is responsible for a higher fraction of measure cost. An example of this would be if more conservation were achieved through commercial or industrial custom projects where lower incentives may be needed. Table 9 shows 2, 6, 10 and 20-year program costs for the Expected, High and Low cost scenarios. Table 10 shows the cost per average megawatt for each of the cost scenarios.

Table 9
Utility Cost Scenarios for Base Case Cost-Effective Potential (2017$)

	2-Year	6-Year	10-Year	20-Year
Expected Case	$3,615,000	$12,625,000	$21,538,000	$38,894,000
Low Cost Case	$3,286,000	$11,477,000	$19,580,000	$35,358,000
High Cost Case	$4,272,000	$14,920,000	$25,454,000	$45,966,000

Table 10 Utility Cost Scenarios for Base Case Cost-Effective Potential (2017$/MWh)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Expected Case	$183	$184	$175	$166
Low Cost Case	$166	$167	$159	$151
High Cost Case	$216	$218	$206	$196

Table 9 costs are again presented as dollars per first year savings (MWh). These units do not consider the savings over the life of a measure, but they do provide an indication of the costs Benton PUD could expect to incur in order to acquire conservation going forward. Utility conservation costs ($/MWh) are higher in the earlier years of the planning period and decrease in later years. Annual conservation potential (and cost) is modeled using the Council's ramp rates. The Council applies ramp rates at the measure level to reflect the characteristics of a particular program (maturity, measure type, and availability etc.) The decreasing first year costs are a result of the ramp rate choice across all measures.

The cost estimates presented in this report are conservative estimates for future expenditures since they are based on historic values. Future conservation achievement may be more-costly since utilities often choose to implement the lowest cost programs first. In addition, as energy efficiency markets become more saturated, it may require more effort from Benton PUD to acquire conservation through its programs. The additional effort may increase administrative costs.

Over the next two years, conservation programs are expected to cost between $151 and $218/MWh (first year savings). Overall, Benton PUD can expect the biennium potential estimates presented in this report to cost between $3.6 and $4.3 million for utility incentives and administrative expenditures.

Besides looking at the utility cost, Benton PUD may also wish to consider the total resource cost (TRC) cost of energy efficiency. The total resource cost reflects the cost that the utility and ratepayer will together pay for conservation, similar to how the costs of other power resources are paid. The TRC costs are shown below (Table 11), levelized over the measure life of each measure. Distribution efficiency measures are by far the cheapest resource, with other measures costing approximately four cents per kilowatt-hour.

Table 11 TRC Levelized Cost (2017$/kWh)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	$0.037	$0.038	$0.037	$0.035
Commercial	$0.045	$0.044	$0.043	$0.042
Industrial	$0.034	$0.034	$0.034	$0.035
Agricultural	$0.035	$0.034	$0.032	$0.030
Distribution Efficiency	$0.007	$0.007	$0.007	$0.007
Total	**$0.034**	**$0.034**	**$0.033**	**$0.033**

Scenario Results

The costs and savings discussed up to this point describe the Base Case scenario. Under this scenario, annual potential for the planning period was estimated using Benton PUD's expected avoided costs and by applying the Council's 20-year ramp rates to each measure, which were found to be a reasonable match for Benton PUD's current level of achievement. Additional scenarios were then tested to identify the change in cost-effective potential when key input parameters, such as avoided cost and load growth assumptions, were changed.

For reference, the load growth assumptions of the Base Case are listed below. Load growth estimates were based on frozen efficiency levels, and therefore do not include planned energy efficiency savings.

Base Case

- Base market price forecast and avoided cost assumptions
- Residential growth = 1.37%
- Commercial growth = 0.73%
- Industrial growth = 0.1%

Scenarios

Additional scenarios were developed to identify a range of possible outcomes and to account for uncertainties over the planning period. In addition to the Base Case scenario, this analysis first tested the sensitivity of different avoided cost assumptions under Base Case load growth assumptions. Also tested were Low and High load growth scenarios, as well as an Accelerated Base Case scenario. The High and Low load growth scenarios are relative to the Base Case load growth assumptions. The Accelerated Scenario retains the Base Case avoided cost and load growth assumptions, but changes ramp rates to acquire savings early. These additional scenarios are described in the following subsections.

To understand the sensitivity of the identified savings potential to avoided cost values alone, the Base Case growth rates were held constant while varying avoided cost inputs.

Table 12 summarizes the Base, Low, and High avoided cost input values. Rather than using a single generic risk adder applied to each unit of energy, the Low and High avoided cost values consider lower and higher potential future values for each avoided cost input. These values reflect potential price risks based upon both the energy and capacity value of each measure. The final row tabulates the implied risk adders for the Low and High scenarios by summarizing all additions or subtractions relative to the Base Case values. Risk adders are provided in both energy and demand savings values. The first set of values is the maximum (or minimum in the case of negative values). The second set of risk adder values are the average values in energy terms. Further discussion of these values is provided in Appendix IV.

Table 12 Avoided Cost Assumptions by Scenario, $2012			
	Base	**Low**	**High**
Energy, 20-yr levelized $/MWh	Market Forecast	-1.25s*	+1.25s*
Social Cost of Carbon, $/MWh	$2.65/MWh	$0	Federal/7th Power Plan Values
Value of REC Compliance	Existing RPS	Existing RPS	25% RPS
Distribution System Credit, $/kW-yr	$31	$31	$31
Transmission System Credit, $/kW-yr	$26	$26	$26
Deferred Generation Capacity Credit, $/kW-yr	$81.95	$0	$115
Implied Risk Adder $/MWh $/kW-yr	N/A	Up to: -$51/MWh -$81.95/kW-yr Average of: -$14/MWh -$81.95/kW-yr	Up to: $71/MWh $33.05/kW-yr Average of: $30/MWh $33.05/kW-yr

**As noted above, the standard deviation of historical prices was calculated and applied to the base market energy price forecast.*

Table 13 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

Table 13 Cost-Effective Potential - Avoided Cost Scenario Comparison				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Base Case	2.25	7.83	14.08	26.80
Low Scenario	1.08	3.75	7.09	14.90
High Scenario	2.79	10.04	18.79	39.39

Table 13 shows that the savings potential has a high degree of sensitivity to both upward and downward changes in avoided costs. Specifically, the cost-effective achievable potential of all low and high scenarios differ by more than 100%. This result is evident from the Benefit-Cost Ratio supply curve presented earlier in the report in Figure 9. The curve has a steep slope on both sides of the line where the BCR equals 1.0.

Overall, energy efficiency remains a low-risk resource for Benton PUD for several reasons. First, energy efficiency is purchased in small increments over time, meaning that buying too much energy efficiency is unlikely. Second, while the different avoided cost scenarios described above are all hypothetically possible, it is unlikely that energy prices will decrease further below their already historically low values. Detailed scenario results are provided below.

Low Scenario

The Low Conservation scenario evaluates energy efficiency cost effectiveness under a low market price forecast and with low load growth in Benton PUD's service territory. The Base Case market price forecast and other avoided cost assumptions were adjusted downward as outlined in Table 11 above.

Under the Low scenario, load growth in Benton PUD's residential sector is 0.47 percentage points lower compared with the Base Case scenario. Commercial sector growth rate is both 0.3 percentage points lower than the Base Case scenario, while the industrial load growth remains unchanged. Results of the Low scenario analysis are shown in Table 14. Under this scenario, 48.7 aMW of technically-achievable potential is available over the 20-year planning period, although only 14.4 aMW is cost effective.

Key parameters for the Low scenario include:

- Low market price and avoided cost assumptions
- Residential growth = 0.9%
- Commercial growth = 0.4%
- Industrial growth = 0.1%

Table 14
Cost Effective Potential - Low Scenario (aMW)

	2-Year*	6-Year	10-Year	20-Year
Residential	0.49	1.54	2.96	6.50
Commercial	0.32	1.28	2.42	4.88
Industrial	0.12	0.35	0.57	0.84
Agricultural	0.11	0.35	0.59	0.98
Distribution Efficiency	0.03	0.19	0.43	1.19
Total	**1.08**	**3.70**	**6.96**	**14.39**

High Scenario

Benton PUD's High Conservation scenario makes use of the high avoided cost assumptions described above in Table 11.

Under the High scenario, residential growth was increased to 1.8%, 0.43 percentage points higher than the base case. Commercial growth was assumed to be 1.1%, a similar increase above the base case. Industrial load growth was again left unchanged. Results of the High scenario are shown in Table 15. Under this scenario, 52.4 aMW of technically-achievable potential is available over the 20-year planning period, and 40.6 aMW is cost effective.

Key parameters for the High scenario include:

- High market price forecast and avoided cost assumptions
- Residential growth = 1.8%
- Commercial growth = 1.1%
- Industrial growth = 0.1%

Table 15 Cost Effective Achievable Potential - High Scenario (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	1.42	5.14	10.01	23.54
Commercial	0.66	2.69	5.21	11.14
Industrial	0.46	1.35	2.18	2.73
Agricultural	0.23	0.71	1.08	1.54
Distribution Efficiency	0.04	0.26	0.61	1.68
Total	**2.80**	**10.14**	**19.09**	**40.63**

Accelerated Scenario

The Accelerated Base scenario where Benton PUD ramps up programs to target reducing the summer peak demand. In this scenario, a subset of measures was modeled with more aggressive ramp rates, to acquire savings more quickly than what is presented in the Base Case. The measures chosen include:

- Commercial Energy Management
- Commercial Interior Lighting
- Industrial Lighting
- Industrial Energy Management

In the Accelerated Scenario, avoided cost and customer growth assumptions were kept the same as in the Base Case Scenario. Table 16 shows the results of the Accelerated Base Scenario. Note that since only commercial and industrial measures were accelerated, only these rows are different from the Base Case Scenario. This scenario acquires approximately 20 and 10 percent more energy savings in the first two and six years of the study period, respectively. Those additional energy savings translate to

Table 16 Cost Effective Achievable Potential – Accelerated Base Scenario (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	1.03	3.43	6.16	12.17
Commercial	0.68	2.48	4.46	9.63
Industrial	0.74	1.78	2.42	2.72
Agricultural	0.22	0.69	1.05	1.51
Distribution Efficiency	0.03	0.19	0.43	1.19
Total	**2.71**	**8.57**	**14.71**	**27.23**

Since this scenario was considered as a means to reduce peak demand, Table 17 below shows the estimated reductions in peak demand associated with this scenario. The pace of the incremental peak demand savings is similar to the incremental energy savings described above, or 20 percent in the first two years and 10 percent over the first six years.

Table 17
Cost Effective Peak Demand Savings – Accelerated Base Scenario (MW)

	2-Year	6-Year	10-Year	20-Year
Residential	1.33	4.49	7.94	15.34
Commercial	0.79	2.76	5.19	10.25
Industrial	0.97	2.36	3.27	3.70
Agricultural	0.56	1.76	2.72	3.93
Distribution Efficiency	0.03	0.18	0.43	1.17
Total	**3.68**	**11.56**	**19.56**	**34.40**

Scenario Summary

A comparison of the 20-year cost-effective potential for the scenarios outlined above is shown in Table 18 below. Based on the results of this table, it is evident that the results of the analysis are more sensitive to changes in avoided cost than load growth. Changes to load growth changed the results very little beyond the impact of the avoided cost assumptions.

Table 18
Scenario Comparison - 20-Year Cost-Effective Potential (aMW)

		Load Growth		
		Low	Base	High
Avoided Costs	Low	14.4	14.9	
	Base		26.8	
	High		39.4	40.5

Table 19 compares the 2, 6, 10, and 20-year potential from each scenario.

Table 19
Cost-Effective Potential - Scenario Comparison

	2-Year	6-Year	10-Year	20-Year
Base Case	2.25	7.83	14.08	26.80
Accelerated Base	2.71	8.57	14.71	27.23
High Avoided Cost	2.79	10.04	18.79	39.39
High Avoided Cost & Growth	2.80	10.14	19.09	40.63
Low Avoided Cost	1.08	3.75	7.09	14.90
Low Avoided Cost & Growth	1.08	3.70	6.96	14.39

Figure 16 graphs the annual potential for each scenario. The Base Case from the 2015 CPA is provided for comparison.

Figure 16
Benton PUD Conservation Scenarios – Annual Potential (aMW)

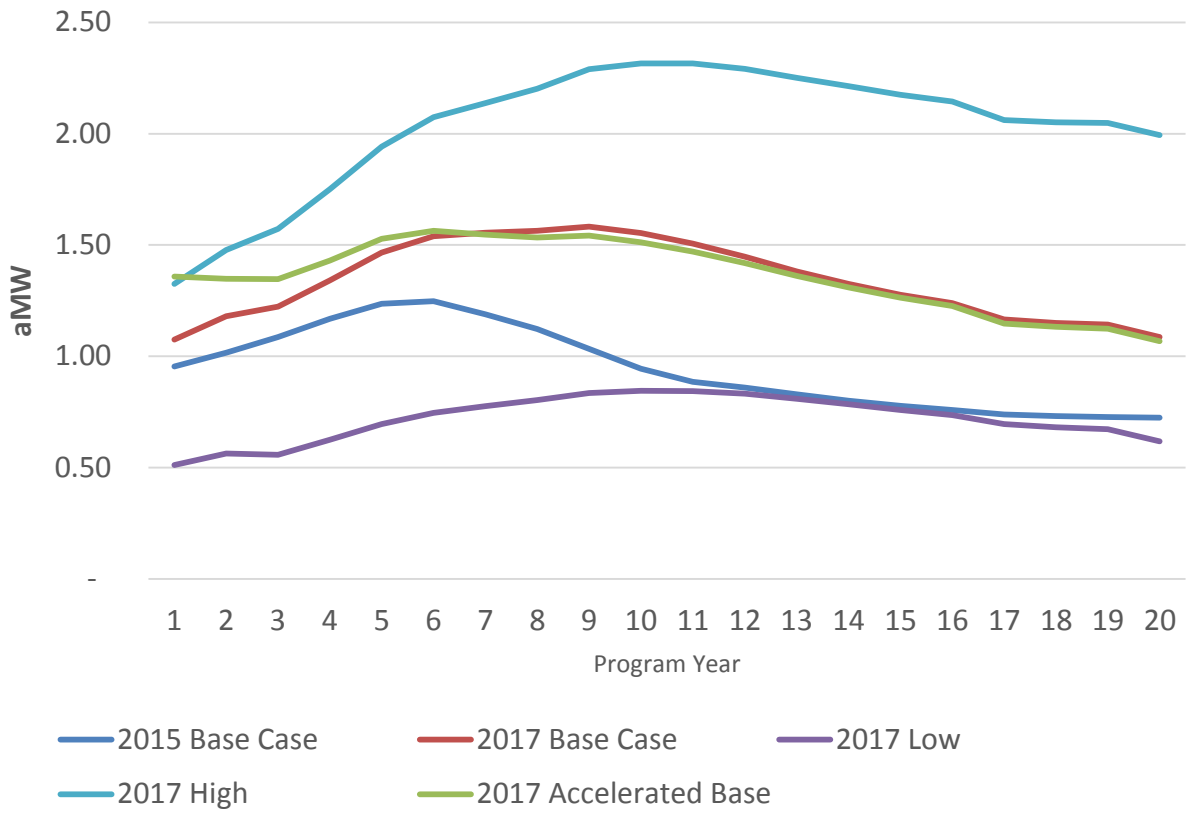


Figure 16 shows that the near-term projections of the 2017 Base Case are higher than the 2015 Base Case. The projections for year one (2018) in the 2017 Base Case start at approximately the same level as the projections for year three (also 2018) from the 2015 CPA. This shows that Benton PUD has met the targets set from the 2015 CPA as well as the fact that the ramp rates used in this CPA are a good fit for Benton PUD's current level of achievement.

Because 2017 CPA identified more cost-effective potential, the annual potential increases through the first nine years of study period, whereas in 2015, the annual potential only increased for the first six years. Later in the study period, the annual cost-effective potential remains higher to capture all cost-effective potential over the twenty-year study period.

Summary

This report summarizes the results of the 2017 CPA conducted for Benton Public Utility District. The assessment provides estimates of energy savings by sector for the period 2018 to 2037, with a focus on the first 10 years of the planning period, as per EIA requirements. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

Despite lower market prices, additional cost-effective potential from advancements in LED technologies, the inclusion of a social cost of carbon per the updated EIA rules, as well as improvements in quantifying the capacity value of measures has resulted in an increase in conservation potential. Conservation remains the lowest cost and lowest risk resource and will serve to keep future electricity costs to a minimum.

Methodology and Compliance with State Mandates

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

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

Conservation Targets

The EIA states that utilities must establish a biennial target that is "no lower than the qualifying utility's pro rata share for that two-year period of its cost-effective conservation potential for the subsequent ten-year period."[48] However, the State Auditor's Office has stated that:

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

> The term pro-rata can be defined as equal portions but it can also be defined as a proportion of an "exactly calculable factor." For the purposes of the Energy Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10-year assessment but state law does not require an even 20 percent.[49]

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

Summary

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

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

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Appendix I – Acronyms

aMW –Average Megawatt

BPA – Bonneville Power Administration

CFL – Compact Fluorescent Light Bulb

Benton PUD – Benton Public Utility District

EIA – Energy Independence Act

EES – EES Consulting

EUI – Energy use intensity

HLH – Heavy load hour energy

HVAC – Heating, ventilation and air-conditioning

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

MF –Multi-Family

MH –Manufactured Home

MW –Megawatt

MWh –Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

UC – Utility Cost

Appendix II – Glossary

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

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

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

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

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

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

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

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

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

Non-Lost Opportunity: Measures that can be acquired at any time, such installing low-flow shower heads.

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

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the

Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

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

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

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

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

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

Appendix III – Documenting Conservation Targets

References:

1) Report – "Benton Public Utilities 2017 Conservation Potential Assessment". Final Report – October 3, 2017.
2) Model – "EES CPA Model-v2.1a-Base.xlsm" and supporting files
    a. MC_and_Loadshape_v3.0_24segment-Benton-Base.xlsm – referred to as "MC and Loadshape file" – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(i) **Technical Potential:** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could physically be installed or implemented, without regard to achievability or cost.	The model includes estimates for stock (e.g. number of homes, square feet of commercial floor area, industrial load) and the number of each measure that can be implemented per unit of stock. The technical potential is further constrained by the amount of stock that has already completed the measure.	Model – the technical potential is calculated as part of the achievable potential, described below.
(ii) Achievable Potential: Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired.	The assessment conducted for Benton PUD used ramp rate curves to identify the amount of achievable potential for each measure. Those assumptions are for the 20-year planning period. An additional factor of 85% was included to account for market barriers in the calculation of achievable potential. This factor comes from a study conducted in Hood River where home weatherization measures were offered for free and program administrators were able to reach more than 85% of home owners.	Model – the use of these factors can be found on the sector measure tabs, such as 'Residential Measures'. Additionally, the complete set of ramp rates used can be found on the 'Ramp Rates' tab.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(iii) **Economic Achievable Potential**: Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a benefit-cost (BC) ratio greater than one were tallied. These measures are considered achievable and cost-effective (or "economic").	Model – BC Ratios are calculated at the individual level by ProCost and passed up to the model.
(iv) **Total Resource Cost**: In determining economic achievable potential, perform a life-cycle cost analysis of measures or programs	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
(v) Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits	Cost analysis was conducted per the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (I.e., those greater than one are cost-effective).	Model – the "Measure Info Rollup" files pull in all the results from each avoided cost scenario, including the BC ratios from the ProCost results. These results are then linked to by the Conservation Potential Assessment model. The TRC analysis is done at the lowest level of the model in the ProCost files.
(vi) Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes	Savings, cost, and lifetime assumptions from the Council's 7th Plan and RTF were used.	Model – supporting files include all of the ProCost files used in the Seventh Plan, with later updates made by the RTF. The life-cycle cost calculations and methods are identical to those used by the Council.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(vii) Calculate the value of energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation	The Council's Seventh Plan measure load shapes were used to calculate time of day of savings and measure values were weighted based upon peak and off-peak pricing. This was handled using the Council's ProCost program so it was handled in the same way as the Seventh Power Plan models.	Model – See MC_AND_LOADSHAPE_v3.0_24segment Excel files for load shapes. The ProCost files handle the calculations.
(viii) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures	Operations and maintenance costs for each measure were accounted for in the total resource cost per the Council's assumptions.	Model – the ProCost files contain the same assumptions for periodic O&M as the Council and RTF.
(ix) Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	A regional market price forecast for the planning period was created and provided by EES. A discussion of methodologies used to develop the avoided cost forecast is provided in Appendix IV.	Report –See Appendix IV. Model – See MC_AND_LOADSHAPE_v3.0_24segment Excel Files ("Base Market Forecast" worksheet).
(x) Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission and distribution capacity expansion benefits were given a benefit of $26/kW for bulk transmission in the cost-effectiveness analysis. The high case evaluates a local distribution system credit of $31/kW-yr. These are the same assumptions used by the Council in the Seventh Power Plan.	Model – this value can be found on the ProData page of each ProCost file.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
(xi) Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion benefits were given a value of $ 81.95/kW-yr in the cost effectiveness analysis for the Base Case Scenario. This is based upon Benton PUD's marginal cost for generation capacity. See Appendix IV for further discussion of this value.	Model – this value can be found on the ProData page of the ProCost Batch Runner file. The generation capacity value was not originally included as part of ProCost during the development of the 7th Plan, so there is no dedicated input cell for this value. Instead, the value has been combined with the distribution capacity benefit, since the timing of Benton PUD's distribution system peak and the regional transmission peak occur at different times.
(xii) Include the social cost of carbon emissions from avoided non-conservation resources	The avoided cost data include estimates of future high, medium, and low CO_2 costs. For the base case, EES has used assumptions that mirror modeling for the District's IRP.	Multiple scenarios were analyzed and these scenarios include different levels of estimated costs and risk. There are MC_AND_LOADSHAPE_v3.0_24segment Excel files contain the carbon cost assumptions for each avoided cost scenario.
(xiii) Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided non-conservation resources	In this analysis, risk was considered by varying avoided cost inputs and analyzing the variation in results. Rather than an individual and non-specific risk adder, our analysis included a range of possible values for each avoided cost input.	The scenarios section of the report documents the inputs used and the results associated. Appendix IV discusses the risk adders used in this analysis.
(xiv) Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Council's Seventh Power Plan. Non-energy benefits include, for example, water savings from clothes washers.	Model – the ProCost files contain the same assumptions for non-power benefits as the Council and RTF. The calculations are handled in ProCost.

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

Appendix IV – Avoided Cost and Risk Exposure

EES Consulting, Inc. (EES) has conducted a Conservation Potential Assessment (CPA) for Benton PUD (the District) for the period 2018 through 2037 as required under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, the District must evaluate the cost-effectiveness of conservation by setting avoided energy costs equal to a forecast of regional market prices. In addition, several other components of the avoided cost of energy efficiency savings must be evaluated including generation capacity value, local distribution and regional transmission costs, risk, and the social cost of carbon. This appendix describes each of the avoided cost assumptions and provides a range of values that was evaluated in the 2017 CPA. The 2017 CPA presents 4 avoided cost scenarios: Base, Accelerated, Low, and High avoided cost scenarios. Each of these is discussed below.

Avoided Energy Value

For the purposes of the 2017 CPA, EES has prepared a forecast of market prices for the Mid-Columbia (Mid-C) trading hub. This section summarizes the methodology and results of the market price forecast and compares the forecast to the market forecast used for the District's 2015 CPA (2016-17 biennium).

Methodology

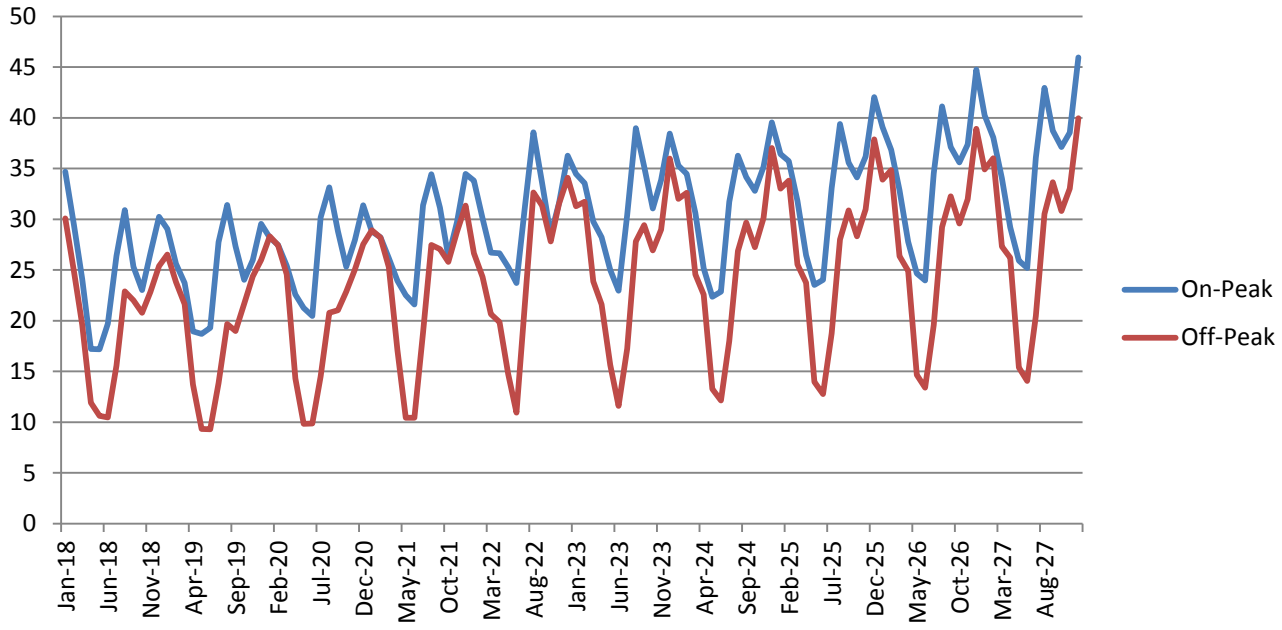
Merchant natural gas-fired power plants operate on the margin in the Northwest. As the market price of electricity is usually set by the cost of the marginal unit, EES developed the market price forecast using a forecast of natural gas prices and projected market-implied heat rates or sparks spread. The projected market-implied heat rates reflect the average efficiency of gas-fired power plants in the Pacific Northwest. Projections are based on historic market-implied heat rates which are calculated by dividing historic Mid-C wholesale market prices by historic Sumas natural gas prices. EES developed a natural gas price forecast based on NYMEX forward gas prices for the Henry Hub trading hub, Sumas basis differentials, and projected market heat rates. The following steps were taken to produce the wholesale electric load forecast for the 2017 CPA:

1. Forward prices for natural gas at Henry Hub are available through December 2029. A 4 percent annual growth rate is assumed after December 2029.
2. The Sumas basis differential is used to adjust the Henry Hub forward prices to Northwest prices. Sumas forward gas prices are equal to NYMEX forward prices (Henry Hub) plus the Sumas basis.
3. Projected monthly market-implied heat rates are applied to the Sumas forward gas price forecast to result in a forecast of Mid-C prices. Or, Mid-C prices are equal to Sumas forward prices multiplied by forecast heat rates.
4. Projected heat rates are based on historic heat rates (Mid-C wholesale electricity prices divided by Sumas natural gas prices).
5. Monthly heat rates are shaped to better match up with BPA's Mid-C price forecast in its Initial Proposal for FY18-19 power rates (BP-18).
6. Forecast Mid-C prices are benchmarked against other market price forecasts.

Results

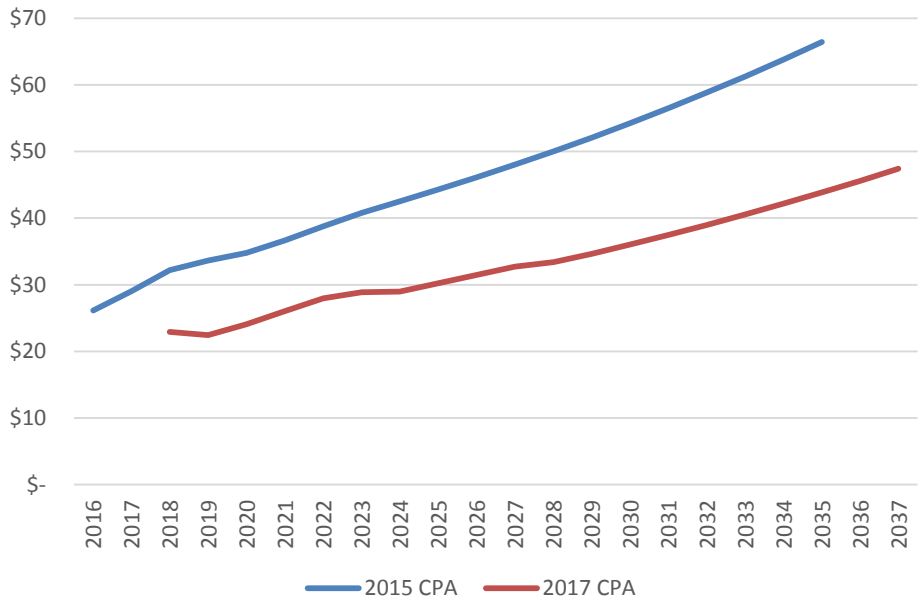
Figure IV-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of market prices over the study period is $32.16/MWh assuming a 4 percent real discount rate.

Figure IV-1
Forecast Market Prices ($/MWh)



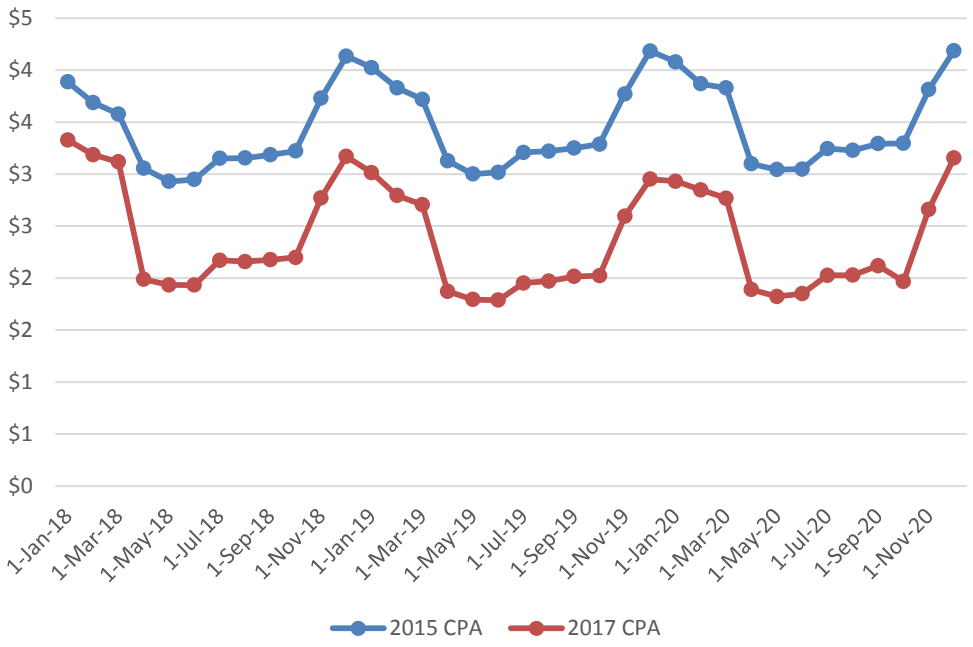
The 2017 market price forecast (April 6, 2017) is lower than the market price forecast used in the District's most recent CPA (the 2015 CPA). Figure IV-2 compares the two forecasts.

Figure IV-2
Forecast Market Prices in 2015 CPA and 2017 CPA ($/MWh)



The 2017 CPA's 20-year market price forecast is 26 percent lower compared with the 2015 CPA's market price forecast due to changes in market conditions mainly due to decreases in natural gas prices. Figure IV-3 illustrates decrease in forward natural gas prices between the 2015 and 2017 CPAs. The projected average 2018 Sumas natural gas price included in the 2017 CPA ($2.51/MMBtu) is 26 percent less than the projected average 2018 Sumas natural gas price included in the 2015 CPA ($3.39/MMBtu).

Figure IV-3
Forward Sumas Natural Gas Prices ($/MMBtu)

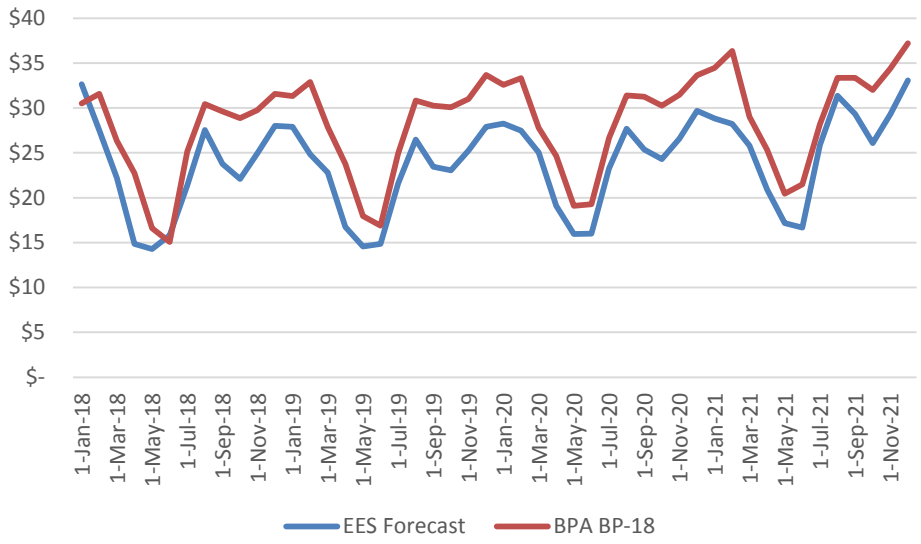


* Source: Henry Hub and Sumas Basis Differential Futures quotes as provided by CME Group

Benchmarking

Figure IV-4 compares the January 2018 through December 2021 EES market forecast with the forecast included in BPA's Initial Proposal for FY18-19 rates. The difference in overall price levels is due to the fact that natural gas prices decreased between the time that BPA developed its forecast in the fall of 2016 and when EES developed its price forecast in April 2017.

Figure IV-4
Forecast Market Prices compared to BPA's Market Price Forecast ($/MWh)



* BPA's market price forecast is per the market price forecast included in BPA's November 2016 initial rate proposal for FY18-19 power rates.

High and Low Scenarios

To reflect a range of possible future outcomes, EES calculated a high- and low-case market price forecasts. To do this, EES looked at a history of Mid-C energy prices from the past ten years and, after adjusting for inflation, calculated the standard deviation as a percentage of the mean price for each month over the 10-year period, for both high and low load hours. One and a quarter standard deviations were added or subtracted to our base market prices to calculate the high and low market price forecasts, respectively. Figures IV-5 and IV-6 compare the resulting price forecasts, for high and low load hours, respectively.

Figure IV-5

Low, Base, and High Case Price Forecast of HLH Prices (2012$/MWh)

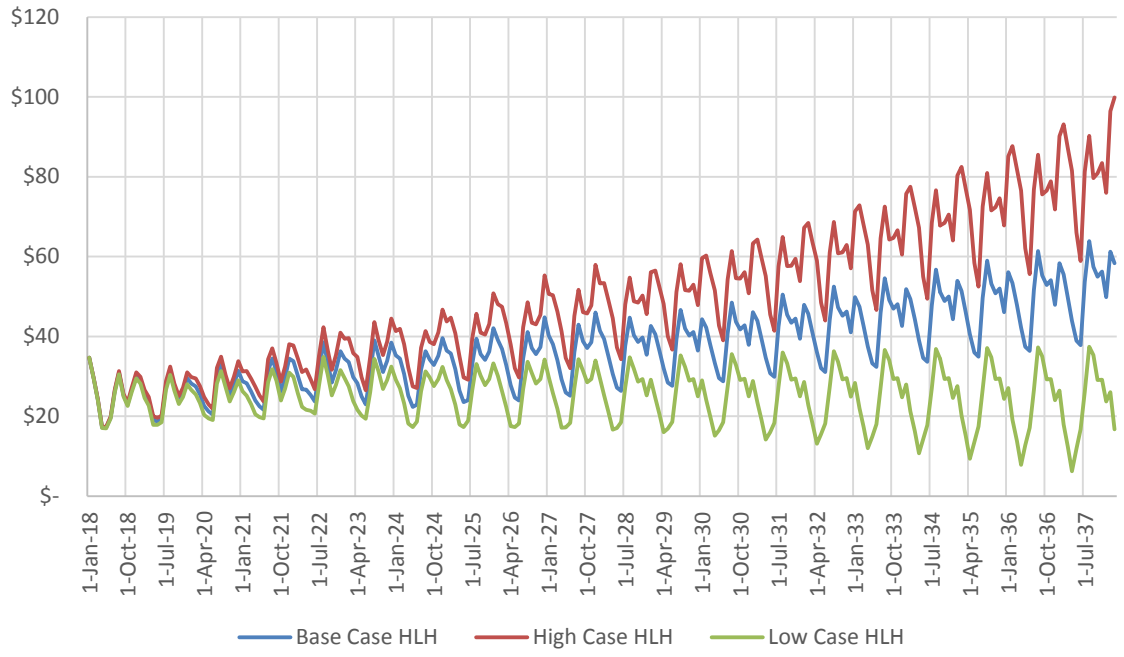
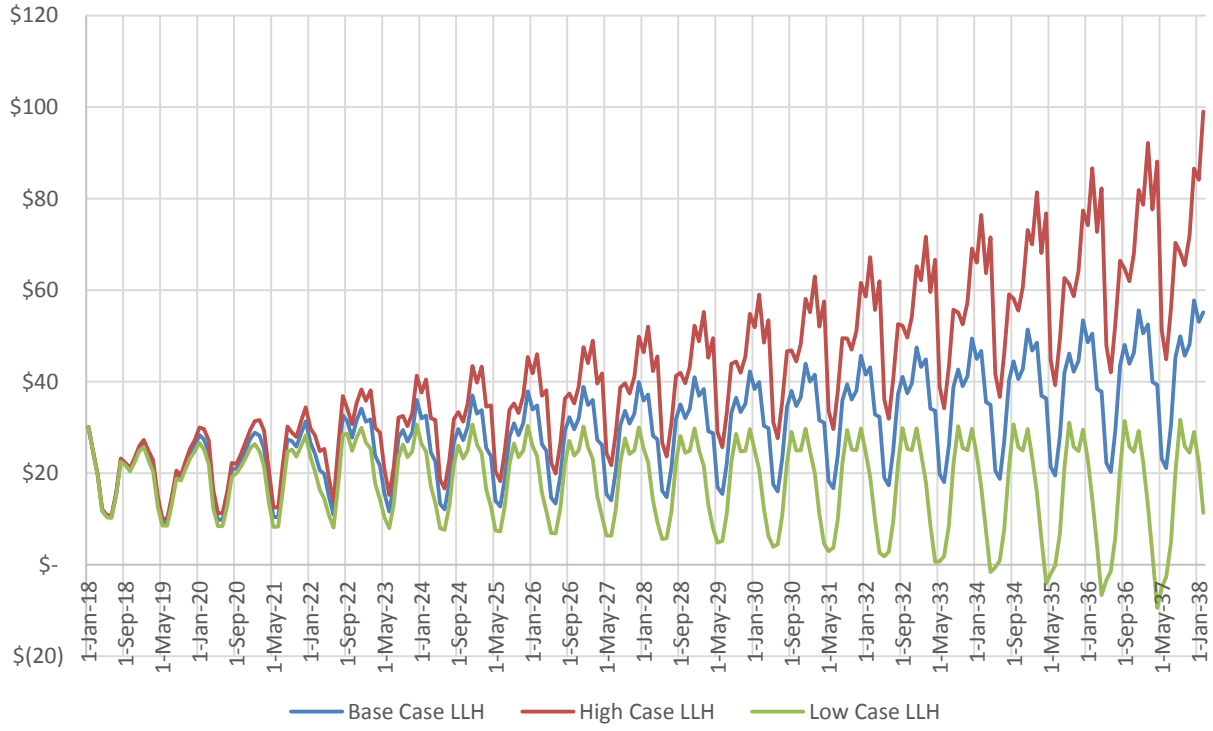


Figure IV-6

Low, Base, and High Case Price Forecast of LLH Prices (2012$/MWh)



Avoided Cost Adders and Risk

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

Energy-Based Avoided Cost Adders:

1. Social Cost of Carbon
2. Renewable Energy Credits
3. Risk Reduction Premium

Peak Demand-Based Adders:

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

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

Social Cost of Carbon

The social cost of carbon is a cost that society incurs when fossil fuels are burned to generate electricity. EIA rules require that the social cost of carbon be included in the total resource cost test (TRC). The value of the social cost of carbon is not defined by markets; therefore, the CPA includes the social cost of carbon in an uncertainty analysis through scenario modeling. For the base case, EES has used assumptions that mirror modeling for the District's IRP. The IRP assumed a $25 per ton carbon tax and concluded that market prices would rise an average of $2.65/MWh.

In addition, a value of zero is used in the low case of the scenario analysis. The zero value reflects that carbon costs are not likely to be borne by only utility ratepayers directly in the near future and are not included in the modeling of other resources in the District's IRP.

The Power Council used the federal Interagency Workgroup estimate of a social cost of carbon in scenarios of the Seventh Power Plan. The federal carbon cost estimates range from $44 to $63 (2012$) per metric ton over the 20-year planning period. These values were used for the high cost scenario. For the high case, the variation of the marginal generation resource over time also needs to be considered. In the spring runoff season, hydropower and wind are the likely the marginal resources, while a gas turbines serve as the marginal resource at other times of the year. Accordingly, EES has assumed zero pounds of CO_2 production per kWh in April through July, and 0.84 lbs. of CO_2 per kWh in the other months.

Value of Renewable Energy Credits

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

The EIA allows for alternate modes of compliance. Utilities can comply by spending four percent or more of the annual retail revenue requirement on the incremental cost of renewable energy—essentially a four percent cost cap. Utilities with no load growth can comply by spending one percent or more of the retail revenue requirement.

In 2016, the District purchased Renewable Energy Credits (RECs) to fulfill its requirement of sourcing 9% of its energy from renewable sources. Energy savings from conservation measures reduces this expense by reducing the net retail revenue requirement.

Under a 9% RPS requirement, for every 100 units of energy efficiency acquired, the District's RPS spending requirement is reduced by 9 units. In effect, this adds nine percent of the costs of RECs to the avoided costs of energy efficiency. EES has used a blend of several forecasts of REC prices and incorporated them into the avoided costs of energy efficiency accordingly. In the high scenario, this value was increased to 25% of REC value to account for potential increases in the cost of RECs or potential increases in the stringency of Washington's RPS requirements.

Risk Adder

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

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

The value of the Council's risk adder has varied depending on the avoided cost input values. The adder is the result of stochastic modeling and represents the lower risk nature of energy efficiency resources. While the Council uses stochastic portfolio modeling to value the risk credit, utilities conduct scenario and uncertainty analysis. The scenarios modeled in the District's CPA include an inherent value for the risk credit.

For the District's 2017 CPA, the avoided cost parameters have been estimated explicitly, and, a scenario analysis is performed. Therefore, no risk adder was used for the base case. Variation in other avoided cost inputs covers a range of reasonable outcomes and is sufficient to identify the sensitivity of the cost-effective energy efficiency potential to a range of outcomes. The scenario results present a range of cost-effective energy efficiency potential, and the identification of the District's biennial target based on the range modeled is effectively selecting the utility's preferred risk strategy and associated risk credit.

Deferred Local Distribution and Bulk Transmission System Investment

Energy efficiency measure savings reduce capacity requirements on both the local distribution system and the regional transmission system. The value of these capacity savings have been estimated in the Seventh Power Plan at $31/kW-year and $26/kW-year for distribution and transmission systems, respectively ($2012). These assumptions are used in all scenarios in the CPA.

Deferred Investment in Generation Capacity

The District's 2016 Integrated Resource Plan states that the District relies upon market purchases to meet peak demands. Thus, the District does not currently avoid any capital expenses associated with generation resources by reducing peak demands. The region may face capacity shortfalls in 2021 when several large coal plants in the Northwest are scheduled to be decommissioned. Further, the District's need for generation capacity will increase when its Power Purchase Agreement with the Frederickson 1 Generating Station expires in 2022.

To be conservative, EES has included a value for generation capacity deferral beginning in 2021. EES used BPA's monthly demand charges as a proxy value for the monthly value of generation capacity, as those charges were based upon the cost of a generating unit. By assuming a monthly shape to the District's peak demand reductions due to conservation, the generation capacity costs were converted into a value of $85.24/kW-year. For the base case, it was assumed the demand charges would increase in real terms by 3% annually. Over the 20-year analysis period, the resulting cost of avoided capacity is $81.95/kW-year (2012$) in levelized terms.

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

In the Council's Seventh Power Plan[50], a generation capacity value of $115/kW-year was explicitly calculated ($2012). This value will be used in the high scenario.

Summary of Scenario Assumptions

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

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

Table IV-1 Avoided Cost Scenario Assumptions, $2012			
	Base	**Low**	**High**
Energy, 20-yr levelized $/MWh	Market Forecast	-1.25s*	+1.25s*
Social Cost of Carbon, $/MWh	$2.65/MWh	$0	Federal/7th Power Plan Values
Value of REC Compliance	Existing RPS	Existing RPS	25% RPS
Distribution System Credit, $/kW-yr	$31	$31	$31
Transmission System Credit, $/kW-yr	$26	$26	$26
Deferred Generation Capacity Credit, $/kW-yr	$82.93	$0	$115
Implied Risk Adder $/MWh $/kW-yr	N/A	Up to: -$51/MWh -$82.93/kW-yr Average of: -$14/MWh -$82.93/kW-yr	Up to: $71/MWh $32.07/kW-yr Average of: $30/MWh $32.07/kW-yr

**As noted above, the standard deviation of historical prices was calculated and applied to the base market energy price forecast.*

Appendix V – Ramp Rate Documentation

This section is intended to document how ramp rates were reviewed for alignment between the near-term potential and recent achievements of Benton PUD's programs.

Benton PUD's sector-level program achievements from 2015-2016 and estimates for 2017 were compared with the first three years of the study period, 2018-2020, using the ramp rates assigned to each measure in the Seventh Power Plan. Savings from NEEA's market transformation initiatives were allocated to the appropriate sectors. It was decided that savings from 2016-17 provided the best basis for comparison, since NEEA savings declined significantly in 2016 when baselines were reset with the release of the Seventh Power Plan.

Table V-1 below shows the results of the comparison by sector.

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

	Program History				Potential		
	2015	**2016**	**2017**	**'16-'17 Avg**	**2018**	**2019**	**2020**
Residential	1.01	0.51	0.65	0.58	0.49	0.54	0.53
Commercial	0.75	0.27	0.28	0.28	0.23	0.29	0.34
Industrial	0.55	0.35	0.13	0.24	0.24	0.22	0.21
Agricultural	0.28	-	0.11	0.06	0.11	0.11	0.11
Utility DE	-	-	-	-	0.01	0.02	0.03
Total	**2.59**	**1.14**	**1.17**	**1.15**	1.08	1.18	1.22

This table shows that the default Seventh Power Plan ramp rates provide a good match for Benton PUD's current level of achievement.

The residential sector makes up the largest portion of the potential, so this sector was reviewed at the end use level, in Table V-2 below. Note that the program history excludes measures for which there is no comparable measure in the potential model. In this table, NEEA savings are unable to be allocated to individual end uses. The text below discusses the comparison.

Table V-2 Comparison of Residential Program Achievement and Potential (aMW)							
	Program History				Potential		
End Use	**2015**	**2016**	**2017**	**'16-'17Avg**	**2018**	**2019**	**2020**
Dryer	-	-	-	-	-	-	-
Electronics	-	-	-	-	0.02	0.04	0.05
Food Preparation	-	-	-	-	0.00	0.00	0.00
HVAC	0.12	0.15	0.07	0.11	0.24	0.24	0.24
Lighting	0.16	0.14	0.29	0.21	0.15	0.18	0.14
Refrigeration	-	-	-	-	-	-	-
Water Heating	0.01	0.00	0.00	0.00	0.07	0.08	0.09
Whole Bldg/Meter Level	0.01	0.02	0.00	0.01	-	-	-
NEEA	0.73	0.10	0.10	0.10			
Total	**1.03**	**0.41**	**0.46**	**0.43**	**0.49**	**0.54**	**0.53**

Electronics: NEEA has an initiative in consumer electronics and other retail products, and smart power strips are an emerging measure opportunity still being piloted in the region. A small amount of savings growing slowly is appropriate here.

HVAC: The potential in this end use appears to be higher, but some savings from NEEA count towards this category.

Lighting: The potential in this category aligns well with program history. Although 2017 is predicted to be a high year, the savings opportunities in this end use are affected by a standard that takes effect soon and programs may not continue to operate in this market.

Water Heating: Like the HVAC category, the potential in this category is higher than recent program accomplishments, but savings from NEEA count in this category as well. The potential in this category includes heat pump water heaters, an emerging technology, as well as low-flow showerheads, which are a measure that is easy to ramp up.

Appendix VI – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2017 CPA. The CPA evaluated thousands of measures; the measure list does not include each individual measure; rather it summarizes the measures at the category level, some of which are repeated across different units of stock, such as single family, multifamily, and manufactured homes. Specifically, utility conservation potential is modeled based on incremental costs and savings of individual measures. Individual measures are then combined into measure categories to more realistically reflect utility-conservation program organization and offerings. For example, single-family attic insulation measures are modeled for a variety of upgrade increments: R-0 to R-38, R-0 to R-49, or R-19 to R-38. The increments make it possible to model measure savings and costs at a more precise level. Each of these individual measures are then bundled across all housing types to result in one measure group: attic insulation.

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

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

Table VI-1 Residential End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dryer	Heat Pump Clothes Dryer	7th Plan
Electronics	Advanced Power Strips	7th Plan, RTF
	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
Food Preparation	Electric Oven	7th Plan
	Microwave	7th Plan
HVAC	Air Source Heat Pump	7th Plan, RTF
	Controls, Commissioning, and Sizing	7th Plan, RTF
	Ductless Heat Pump	7th Plan, RTF
	Ducted Ductless Heat Pump	7th Plan
	Duct Sealing	7th Plan, RTF
	Ground Source Heat Pump	7th Plan, RTF
	Heat Recovery Ventilation	7th Plan
	Attic Insulation	7th Plan, RTF
	Floor Insulation	7th Plan, RTF
	Wall Insulation	7th Plan, RTF
	Windows	7th Plan, RTF
	Wi-Fi Enabled Thermostats	7th Plan
Lighting	Linear Fluorescent Lighting	7th Plan, RTF
	LED General Purpose and Dimmable	7th Plan, RTF
	LED Decorative and Mini-Base	7th Plan, RTF
	LED Globe	7th Plan, RTF
	LED Reflectors and Outdoor	7th Plan, RTF
	LED Three-Way	7th Plan, RTF
Refrigeration	Freezer	7th Plan
	Refrigerator	7th Plan
Water Heating	Aerator	7th Plan
	Behavior Savings	7th Plan
	Clothes Washer	7th Plan
	Dishwasher	7th Plan
	Heat Pump Water Heater	7th Plan, RTF
	Showerheads	7th Plan, RTF
	Solar Water Heater	7th Plan
	Wastewater Heat Recovery	7th Plan
Whole Building	EV Charging Equipment	7th Plan

Table VI-2 Commercial End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Compressed Air	Controls, Equipment, & Demand Reduction	7th Plan
Electronics	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
	Smart Plug Power Strips	7th Plan, RTF
	Data Center Measures	7th Plan
Food Preparation	Combination Ovens	7th Plan, RTF
	Convection Ovens	7th Plan, RTF
	Fryers	7th Plan, RTF
	Hot Food Holding Cabinet	7th Plan, RTF
	Steamer	7th Plan, RTF
	Pre-Rinse Spray Valve	7th Plan, RTF
HVAC	Advanced Rooftop Controller	7th Plan
	Commercial Energy Management	7th Plan
	Demand Control Ventilation	7th Plan
	Ductless Heat Pumps	7th Plan
	Economizers	7th Plan
	Secondary Glazing Systems	7th Plan
	Variable Refrigerant Flow	7th Plan
	Web-Enabled Programmable Thermostat	7th Plan
Lighting	Bi-Level Stairwell Lighting	7th Plan
	Exterior Building Lighting	7th Plan
	Exit Signs	7th Plan
	Lighting Controls	7th Plan
	Linear Fluorescent Lamps	7th Plan
	LED Lighting	7th Plan
	Street Lighting	7th Plan
Motors/Drives	ECM for Variable Air Volume	7th Plan
	Motor Rewinds	7th Plan
Process Loads	Municipal Water Supply	7th Plan
Refrigeration	Grocery Refrigeration Bundle	7th Plan, RTF
	Water Cooler Controls	7th Plan
Water Heating	Commercial Clothes Washer	7th Plan, RTF
	Showerheads	7th Plan
	Tank Water Heaters	7th Plan

Table VI-3 Agriculture End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dairy Efficiency	Efficient Lighting	7th Plan
	Milk Pre-Cooler	7th Plan
	Vacuum Pump	7th Plan
Irrigation	Low Energy Sprinkler Application	7th Plan
	Irrigation Hardware	7th Plan, RTF
	Scientific Irrigation Scheduling	7th Plan, BPA
Lighting	Agricultural Lighting	7th Plan
Motors/Drives	Motor Rewinds	7th Plan

Table VI-4 Industrial End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Compressed Air	Air Compressor Equipment	7th Plan
	Demand Reduction	7th Plan
Energy Management	Air Compressor Optimization	7th Plan
	Energy Project Management	7th Plan
	Fan Energy Management	7th Plan
	Fan System Optimization	7th Plan
	Cold Storage Tune-up	7th Plan
	Chiller Optimization	7th Plan
	Integrated Plant Energy Management	7th Plan
	Plant Energy Management	7th Plan
	Pump Energy Management	7th Plan
	Pump System Optimization	7th Plan
Fans	Efficient Centrifugal Fan	7th Plan
	Fan Equipment Upgrade	7th Plan
Hi-Tech	Clean Room Filter Strategy	7th Plan
	Clean Room HVAC	7th Plan
	Chip Fab: Eliminate Exhaust	7th Plan
	Chip Fab: Exhaust Injector	7th Plan
	Chip Fab: Reduce Gas Pressure	7th Plan
	Chip Fab: Solid State Chiller	7th Plan
Lighting	Efficient Lighting	7th Plan
	High-Bay Lighting	7th Plan
	Lighting Controls	7th Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	7th Plan
	Cold Storage Retrofit	7th Plan
	Grocery Distribution Retrofit	7th Plan
Material Handling	Material Handling Equipment	7th Plan
	Material Handling VFD	7th Plan
Metals	New Arc Furnace	7th Plan
Misc.	Synchronous Belts	7th Plan
	Food Storage: CO2 Scrubber	7th Plan
	Food Storage: Membrane	7th Plan
Motors	Motor Rewinds	7th Plan
Paper	Efficient Pulp Screen	7th Plan
	Material Handling	7th Plan
	Premium Control	7th Plan
	Premium Fan	7th Plan
Process Loads	Municipal Sewage Treatment	7th Plan
Pulp	Efficient Agitator	7th Plan
	Effluent Treatment System	7th Plan
	Premium Process	7th Plan

	Refiner Plate Improvement	7th Plan
	Refiner Replacement	7th Plan
Pumps	Equipment Upgrade	7th Plan
Transformers	New/Retrofit Transformer	7th Plan
Wood	Hydraulic Press	7th Plan
	Pneumatic Conveyor	7th Plan

Table VI-5
Distribution Efficiency End Uses and Measures

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

Appendix VII – Annual Energy Efficiency Potential by End-Use

Residential	aMW																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Dryer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electronics	0.02	0.04	0.05	0.06	0.08	0.10	0.11	0.12	0.13	0.13	0.13	0.12	0.11	0.10	0.09	0.08	0.07	0.07	0.07	0.06
Food Preparation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.24	0.24	0.24	0.25	0.25	0.23	0.20	0.17	0.14	0.12	0.10	0.08	0.06	0.05	0.04	0.04	0.01	0.01	0.01	0.01
Lighting	0.15	0.18	0.14	0.16	0.18	0.20	0.22	0.23	0.27	0.28	0.29	0.29	0.30	0.30	0.30	0.31	0.31	0.31	0.31	0.31
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heating	0.07	0.08	0.09	0.10	0.12	0.13	0.14	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Whole Bldg/Meter Level	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.49**	**0.54**	**0.53**	**0.58**	**0.63**	**0.66**	**0.67**	**0.67**	**0.70**	**0.69**	**0.68**	**0.66**	**0.64**	**0.62**	**0.60**	**0.59**	**0.56**	**0.56**	**0.56**	**0.56**

Commercial	aMW																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Compressed Air	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Electronics	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food Preparation	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
HVAC	0.05	0.05	0.05	0.06	0.08	0.09	0.10	0.10	0.11	0.11	0.10	0.09	0.08	0.06	0.05	0.04	0.03	0.03	0.03	0.02
Lighting	0.12	0.18	0.22	0.25	0.28	0.30	0.31	0.32	0.33	0.33	0.34	0.34	0.34	0.34	0.35	0.35	0.34	0.35	0.35	0.30
Motors/Drives	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process Loads	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03
Water Heating	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total	**0.23**	**0.29**	**0.34**	**0.39**	**0.44**	**0.48**	**0.50**	**0.52**	**0.53**	**0.54**	**0.54**	**0.53**	**0.52**	**0.51**	**0.50**	**0.49**	**0.48**	**0.47**	**0.47**	**0.43**

Industrial	aMW																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Compressed Air	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy Management	0.12	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.11	0.10	0.08	0.06	0.05	0.04	0.03	0.03	0.02	0.02	0.02	0.02
Fans	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hi-Tech	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.05	0.03	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Low & Med Temp Refr	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Material Handling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Metals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Motors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Paper	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Loads	0.01	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.03	0.03	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Pulp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transformers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.24**	**0.22**	**0.21**	**0.22**	**0.23**	**0.23**	**0.23**	**0.22**	**0.20**	**0.18**	**0.14**	**0.11**	**0.08**	**0.06**	**0.04**	**0.03**	**0.02**	**0.02**	**0.02**	**0.02**

Agricultural	aMW																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Dairy Efficiency	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Irrigation	0.10	0.10	0.10	0.11	0.11	0.11	0.10	0.09	0.08	0.08	0.08	0.07	0.07	0.06	0.06	0.05	0.03	0.02	0.01	0.01
Lighting	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motors/Drives	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.11	0.11	0.11	0.12	0.12	0.12	0.10	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.06	0.05	0.03	0.02	0.01	0.01

Distribution Efficiency	aMW																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
1 - LDC voltage control method	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
2 - Light system improvements	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
3 - Major system improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 - EOL voltage control method	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A - SCL implement EOL w/ major system impro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	0.01	0.02	0.03	0.04	0.04	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08

Appendix VIII – Board Resolution Adopting Conservation Rebate Policy

RESOLUTION NO. 2312

MARCH 24, 2015

A RESOLUTION OF THE COMMISSION OF
PUBLIC UTILITY DISTRICT NO. 1 OF BENTON COUNTY
ADOPTING THE DISTRICT CONSERVATION REBATE POLICY

WHEREAS, Resolution No. 2048 was passed on September 8, 2009 authorizing establishment of an Energy Conservation Plan; AND

WHEREAS, The General Manager is authorized to enter into Bonneville Power Administration's Conservation Programs and other District determined programs financially beneficial to our service area as a means to achieve energy savings; AND

WHEREAS, Washington State Energy Independence Act (EIA), RCW 19.285 (Initiative 937) mandates that each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible; AND

WHEREAS, District Commissioners set a biennial target every two years to meet the requirements of the EIA; AND

WHEREAS, District staff establish biennial conservation budgets to assure the targets are met; AND

WHEREAS, Conservation program offerings are managed to meet the biennial budget and funding may not be adequate to provide rebates for all customer requests; AND

WHEREAS, The District wishes to outline the policy by which it will provide conservation rebates in an equitable manner.

NOW, THEREFORE BE IT HEREBY RESOLVED By the Commission of the Public Utility District No. 1 of Benton County that the attached Conservation Rebate Policy be adopted.

ADOPTED By the Commission of Public Utility District No. 1 of Benton County at an open meeting, with notice of such meeting being given as required by law, this 24th day of March, 2015.

Barry Bush, Vice-President

ATTEST:

Jeff Hall, Secretary

Benton PUD Conservation Rebate Policy

The District offers conservation rebates to all customers in a variety of diverse offerings with the primary purpose of saving energy that will count towards the Energy Independence Act requirements and providing customers opportunities to save energy on their electric bill.

The following outlines the District's Conservation Rebate Policy:

1. Every odd year the Benton PUD Commission approves an Energy Independence Act (EIA) Conservation Biennial Target in an open public meeting to establish a two year conservation target. The target is determined by the District's Conservation Potential Assessment (CPA) or other accepted target setting requirements of the EIA.
2. Following CPA approval by Commission, staff will prepare and present a two year Conservation Budget Plan that allocates the estimated necessary budget amounts to each customer class to achieve the EIA Conservation Biennial Target.
3. The District may budget a larger portion of the Commission approved target for the first year of each biennium to mitigate risk of postponed or cancelled projects and to ensure the biennial target is reached.
4. The District will consider using BPA funds first, when available, followed by District self-funding.
5. Conservation program rebate offerings and the unit energy savings (UES) per measure are calculated by the entity responsible (Northwest Power and Conservation Council, Bonneville Power Administration (BPA), District, etc.) for establishing the energy savings values, but can change throughout the biennial period.
6. The District may allow for Conservation Smoothing which allows banking of achieved savings that exceed the biennial target by up to 50% and spreads the excess over the next two bienniums beginning January 1, 2014.
7. Applications for conservation rebates will be reviewed on a first come first served basis and once approved by District staff, will be disbursed upon installation or project completion. When all funding is allocated, customers will be advised funds are no longer available and they may request rebates for the following year subject to item numbers 8 and 9 below.
8. Any potential rebate to a customer in excess of $100,000 must be presented to Commission for approval.
9. The Commission must approve any single customer request for a rebate that is greater than 50% of that customer class biennial budget or 50% of self-funding customer class biennial budget in the case of marijuana industry related rebate requests.

10. The Commission recognizes that large energy savings projects will be reviewed and discussed with District customers many months in advance to prepare for budgeting and project coordination and that some projects may take several years from beginning to end.
11. A baseline of energy consumption must be available for all customers requesting a rebate for new construction projects. If no baseline is available, supporting information will be required to satisfy documentation requirements for meeting EIA.
12. Any customer requesting conservation incentives related to the marijuana industry must be licensed with the State of Washington for legal marijuana activities. BPA conservation funds are not allowed for marijuana industry related rebates.
13. Distribution System Efficiency Savings programs may be funded via conservation funds from BPA, District Self-Funding, or through normal Engineering/Operations capital funding which is included in the District annual budget and approved by Commission as work orders.

Appendix C: Microgrid Economics

A regular theme at Utility conferences is the threat of losing residential kWh sales to microgrids (mgrid). An analysis of the costs of microgrids compared to utility residential rates is an important analysis to perform and update. Following are some assumptions used in the analysis.

Assumptions

- 10 year amortization
- The mgrid is able to buy and sell energy to BPUD in equal annual amounts (net zero)
- The mgrid is only charged the monthly meter charge (no demand charge)
- Battery can be charged by the grid in the winter
- 15 kW peak load, 1500 kWh average monthly load
- Installed solar cost in 2018 is $3/w and declines
- Solar system is sized to produce annual load of home
- Battery system is sized to provide 15 kW for two hours (30 kWh system)
- Battery charging losses are 10% of house load
- Battery installed cost is $700/kWh and declines
- Monthly O&M cost is $25/Mo
- Residential rates increase 3%/yr

Solar System Costs

The following table shows the installed costs of the solar portion of the system. Note it is assumed CF increases over time. The breakeven column shows needed costs to be equal with the residential rate.

Solar panel system	2018	2025	2030	Breakeven				
Solar CF	16%	20%	20%	20%	Input CF for local area			
Solar Panel Cost $/w	$ 3.00	$ 2.00	$ 1.50	$ 0.70	Input total installed cost of panels			
Subsidy $/w	$ 0.50	$ 0.10	$ -	$ -	Input any subsidy			
kW Solar to meet av load	14.13	11.30	11.30	11.30	Size the system to meet annual load			
Net Cost of Solar	$ 2.50	$ 1.90	$ 1.50	$ 0.70				
Solar upfront cost	$ 35,317	$ 21,473	$ 16,952	$ 7,911				

Battery System Costs

The following table shows the installed costs of the battery portion of the system. Note the decline in costs and the breakeven cost.

Battery	2018	2025	2030	Breakeven						
Daily hours at peak load	2	2	2	2	Meet peak load for a least 2 hours from microgrid					
Battery cost/kWh	$ 700	$ 400	$ 380	$ 250	Input total initial battery cost/kWh (E3 values shown)					
Total Battery kWh needed	30	30	30	30						
Total Battery Cost	$ 21,000	$ 12,000	$ 11,400	$ 6,000						

System Costs vs Utility Residential Rates

A microgrid sized for peak load and net zero annual energy is currently much higher cost than residential rates. The following table shows the cost comparison. Note the mgrid would only pay the utility daily system charge. As a net zero system, the mgrid would be buying and selling from the grid in equal annual amounts at the same rate. Note the amortization assumption is 10 years. As can be seen above, the breakeven solar cost would be $0.70/watt and battery cost would be $250/kWh.

	2018	2025	2030	Breakeven
Mgrid + Utility Total $/kWh	$0.39	$0.25	$0.22	$0.12
Utility total charge $/kWh	$0.08	$0.10	$0.12	$0.12

With a 20 year amortization, the mgrid would fare much better, but not quite hit breakeven in 2030.

	2018	2025	2030
Mgrid + Utility Total $/kWh	$0.25	$0.16	$0.15
Utility total charge $/kWh	$0.08	$0.10	$0.12