FRANKLIN PUD

THE POWER IS YOURS

2024 INTEGRATED RESOURCE PLAN

PREPARED IN COLLABORATION WITH:

TEA

THE EnergyAuthority

JULY 2024

CONFIDENTIAL & PROPRIETARY

Section 1 Executive Summary

1.1 Background

Public Utility District No. 1 of Franklin County (FPUD) is required by Washington State law, Chapter 19.280 of the Revised Code of Washington (RCW), to develop "a comprehensive resource plan that explains the mix of generation and demand-side resources it plans to use to meet its customers' electricity needs in both the long term and the short term." The law stipulates that FPUD produces a comprehensive plan every four years and provides an update to that plan every two years. The Integrated Resource Plan (IRP) analysis 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 nonrenewable resources; a preferred plan for meeting the utility's requirements; and a formal action plan.

The goal of this 2024 IRP is to forecast the future electric demand of our customers and to identify the optimal mix of resources that is affordable and reliable while meeting regulatory requirements and social expectations of our community. FPUD's previous IRP was adopted by the Board in August 2020. The 2020 IRP analysis showed that FPUD's existing long-term Bonneville Power Administration (BPA) power supply contract and its other owned and contracted resources can provide enough energy to meet its forecast need on an average annual basis through 2030. The 2020 IRP also identified a strategy to meet the short- and long-term electricity needs of FPUD customers and Washington State renewable portfolio standard (RPS) obligations for the 2020 through 2030 study period. The preferred portfolio included relying on market purchases for any short-term capacity deficits and procuring renewable energy credits (RECs) to address a projected shortfall in RPS compliant generation beginning in 2025.

FPUD developed a Progress Report in 2022 that reviewed the changing conditions in the wholesale energy market and planning environments as well as its progress in carrying out the strategy and formal action plan of the 2020 IRP. The Progress Report is consistent with the State of Washington's regulatory requirements (RCW 19.280.030).

FPUD contracts with The Energy Authority Inc. (TEA) for a suite of services including Portfolio Management, load forecasting, bilateral power trading, regulatory reporting, and integrated resource plans (IRPs). TEA's clients are located throughout the United States, operating in both bilateral and organized markets, including MISO, CAISO, ERCOT, SPP, and PJM. Founded by three public power owners to address changes in the electric utility industry, enhance the use of its clients' electric generating assets in the wholesale electric energy market, and optimize power sales and purchases for their systems, TEA's commitment to public power utilities has fueled its growth. Since 1997, TEA has expanded to seven owners and now serves over 60 total clients across the nation with generating assets and contract rights exceeding 25,000 megawatts. TEA has over 270 employees operating from its offices in Jacksonville, FL, and Bellevue, WA.

1.2 Franklin Public Utility District

FPUD provides electric service to approximately 33,500 residential, commercial, industrial, and street lighting customers countywide. FPUD purchases most of its wholesale power from the Bonneville Power Administration (BPA) at cost, through the long-term Slice and Block Power Sales Agreement. Most of the BPA power supply comes from the Federal Columbia River Power System (FCRPS) hydroelectric projects. BPA also markets the output of the

Columbia Generating System (nuclear plant) near Richland, Washington, and makes miscellaneous energy purchases on the open market. FPUD augments its remaining energy and capacity requirements primarily through contracts for portions of the Nine Canyon and White Creek wind projects and the PowerEx, Packwood Lake, and Esquatzel Canal hydroelectric generating facilities.

1.3 Future Load and Resource Balance

FPUD's load was forecast for this IRP using linear and non-linear regression models developed by TEA and trained on historical weather, customer demand, and econometric data for the period from 2004 – 2024. The load forecast provides hourly granularity for the full study period from 2025 – 2044 based on econometric forecasts for Franklin County from Woods and Poole. In addition, the load forecast used in this study incorporates additional load growth due to building and vehicle electrification in excess of what has been seen historically. This growth was forecast separately using regression models trained on data from S&P Global Commodity Insights (S&P Global) and the National Renewable Energy Laboratory (NREL).

In aggregate, these models forecast average energy and peak demand growth of 1.6% per year over the 2025 to 2044 time period. In addition to the reference case scenario that is based on this base case load forecast, FPUD considered high and low load scenarios. The high load was developed by increasing the base load growth rate by 0.5% per year. The low load reduced the base load by 0.5% per year.

FPUD is currently forecast to have sufficient resources available to meet average energy demand through 2028. However, on a capacity basis, FPUD is currently at a deficit and is projected to grow that deficit to 231 MW of summer capacity and 131 MW of winter capacity by the end of the study period absent additional resource procurement. That deficit is partially exacerbated by the additional capacity required to comply with the Western Resource Adequacy Program (WRAP), which is modeled to take effect in November 2027.

1.4 Resources to Meet Future Growth and CETA Requirements

New resources are needed to address this substantial capacity deficit. Due to significant lead times required for construction and interconnecting a resource to the electric system, timely planning for each new resource is critical to ensure capacity requirements are met. To ensure compliance with the requirements of the Clean Energy Transformation Act (CETA), FPUD evaluated only carbon-free supply-side resource options including solar, wind, lithium-ion battery storage, geothermal, small-modular nuclear reactors, BPA Tier 2 power, market-based PPAs, and extensions of existing PPA contracts.

1.5 Conclusions

FPUD is currently meeting the energy demand of its customers with 90% carbon-free electric power and is projected to maintain a balance between its load and resources in spite of a roughly 1.6% year-over-year projected load growth through the study period. However, on a capacity basis, FPUD has a considerable deficit and, without the implementation of a comprehensive and well-planned strategy, would likely see that deficit increase to as much as 231 MW by 2044.

FPUD will leverage all the tools available to meet this need reliably, affordably, and sustainably. First, FPUD will maximize use of Bonneville Power Administration (BPA) Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. FPUD will also acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments. FPUD will continue to explore opportunities for adding both utility-scale renewables and behind-the-meter renewable resources, such as community solar projects, to its resource portfolio. FPUD will consider the possible extension of current renewable PPA contracts that are set to expire during the study period. In addition, FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. FPUD will also consider BPA Tier 2 opportunities and market-based purchases. FPUD continues to monitor emerging technologies, including geothermal, hydrogen, and small-modular nuclear reactors (SMR) for possible future procurement.

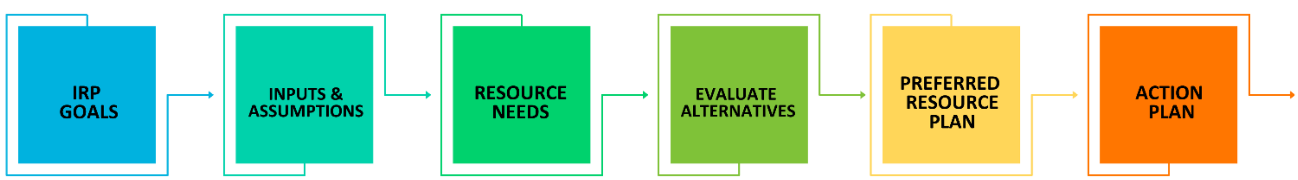
Section 2 IRP Methodology

Integrated Resource Planning (IRP) is a comprehensive and strategic planning process that FPUD performs on a regular basis to ensure the utility is utilizing an optimal mix of resources that minimize future costs while meeting the goals of FPUD and its community. Key outputs of the process are Net Present Value of Revenue Requirements (NPVRR), Levelized Cost of Energy (LCoE), and the amount of carbon emissions. Energy Exemplar's PLEXOS capacity planning model was utilized in the development of this 2024 IRP study.

The following are the steps taken by FPUD to develop this resource planning study:

1. IRP goals: IRP methodology begins with identification and establishment of the objectives of the IRP process. FPUD's goals include delivery of safe, reliable and cost-effective service while maintaining environmental responsibilities and regulatory compliance.
2. Inputs and Assumptions: This step involves identifying potential future resource options, developing assumptions for costs and operating characteristics of current and potential resources, and estimating future electric demand.
3. Resource Needs: The third step compares capacity contributions from existing resources with load forecast estimates to identify expected timing and magnitude of future capacity shortfalls.
4. Alternatives Evaluation: The capacity planning model is used to identify resource plans that meet utility objectives. To identify operational risks, resource plans are developed under multiple scenarios and sensitivities. This comprehensive evaluation helps FPUD develop strategies that mitigate risk and ensure resilience in the face of unforeseen circumstances.
5. Preferred Resource Plan: A preferred resource plan is selected based on its performance across multiple scenarios and sensitivities. A resource plan is considered effective if it is capable of meeting FPUD's goals listed in the first step of the process.
6. Action Plan – A series of steps is developed to carry out the preferred resource plan. These steps may include developing additional studies, issuing requests for proposals (RFPs), and procuring and contracting additional resources.

IRP 6-Step Process



Section 3 Policy And Regulation

3.1 Integrated Resource Planning

FPUD is required by Washington State law, Chapter 19.280 of the Revised Code of Washington (RCW), to develop "a comprehensive resource plan that explains the mix of generation and demand-side resources it plans to use to meet its customers' electricity needs in both the long term and the short term." The law stipulates that FPUD produces a comprehensive plan every four years and provides an update to that plan every two years. The Integrated Resource Plan (IRP) analysis 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 nonrenewable resources; a preferred plan for meeting the utility's requirements; and a formal action plan.

The goal of this 2024 IRP is to forecast the future electric demand of our customers and to identify the optimal mix of resources that is affordable and reliable while meeting regulatory requirements and social expectations of our community. FPUD's previous IRP was adopted by the Board in August 2020. The 2020 IRP analysis showed that FPUD's existing long-term Bonneville Power Administration (BPA) power supply contract and its other owned and contracted resources can provide enough energy to meet its forecast need on an average annual basis through 2030. The 2020 IRP also identified a strategy to meet the short- and long-term electricity needs of FPUD customers and Washington State RPS obligations for the 2020 through 2030 study period. The preferred portfolio included relying on market purchases for any short-term capacity deficits and procuring renewable energy credits (RECs) to address a projected shortfall in RPS compliant generation beginning in 2025.

FPUD developed a Progress Report in 2022 that reviewed the changing conditions in the wholesale energy market and planning environments as well as its progress in carrying out the strategy and formal action plan of the 2020 IRP. The Progress Report is consistent with the State of Washington's regulatory requirements (RCW 19.280.030).

3.2 Energy Independence Act

In 2006, Washington State voters approved the Energy Independence Act (EIA), RCW 19.285 (I-937). The act stipulates that any utility servicing over 25,000 customers must serve load with an increasing proportion of renewable energy. In 2012, 3% of retail load was required to be sourced from renewable generation, 9% in 2016, and finally 15% in 2020. The goal is that eventually renewable energy will become the sole energy provider within a utility's portfolio. Furthermore, the EIA requires that FPUD outline its achievable cost-effective conservation potential every two years, as well as a focus on the ten-year energy efficiency potential. The EIA defines the following as eligible resources: water, wind, solar energy, geothermal energy, landfill gas, wave, ocean or tidal power, gas for sewage treatment plants, biodiesel fuel, and biomass energy.

FPUD was initially exempt from the EIA and only came into compliance in 2016 when it surpassed 25,000 customers. As a result, FPUD's compliance mandate is on a different timeline compared to those affected by the EIA when it first came into law. The first compliance mandate is 3% starting in 2021, then 9% in

2025, and 15% in 2029. If FPUD fails to meet the requirement, it will be assessed a penalty of $50/MWh, in 2007 dollars, equating to approximately $76/MWh in 2024 dollars.

3.3 Washington Climate Commitment Act

The Climate Commitment Act (CCA) was passed by the Washington State Legislature in 2021 and went live on January 1, 2023. The act establishes a Cap-and-Invest program which places a declining cap on statewide emissions to help reach the State's 2050 goal of eliminating 95% of emissions. Business types covered under this program include fuel suppliers, natural gas and electric utilities, waste-to-energy facilities (starting in 2027), and railroads (starting in 2031). Additionally, electric utilities, natural gas utilities, and EITEs (emissions intensive trade exposed) receive "no cost" allowances. Entities that emit over 25,000 metric tons of CO_2e are required to retire allowances for compliance. Further, entities emitting more than 10,000 metric tons of CO_2e are required to report emissions annually. These reports are due June 1st of the following year for electric power entities, and March 31st of the following year for any other entities. As noted in Table 1, 63.3M allowances were distributed in 2023 across all sectors, and the no cost allowance budget decreases by 7% annually for the first compliance period. In 2023, 17.5M allowances were distributed to the electric sector at no cost.

Table 1. Total program allowance budget for the first compliance period (CP1) where 1 allowance equals 1 MT CO2e

Emissions Year	Total Covered Emissions ($MT\ CO_2e$)
2023	63, 288, 565
2024	58, 524, 909
2025	53, 761, 254
2026	48, 997, 598

FPUD and other electric utilities that are subject to CETA were allocated allowances for the first compliance period based on the cost burden effect. The cost burden effect calculates emissions based on the MWh volume of load served by coal, load served by natural gas, load served by Asset-Controlling Supplier resources (such as BPA), load served by non-emitting resources, and load served by unspecified generation. FPUD's allowance allocation, in Table 2 is assumed to provide sufficient allowances for compliance over the first compliance period. These allowances may be sold at auction or retired for compliance.

$$\text{Cost Burden Effect} = (\text{Load}_{NG} \times \text{EF}_{NG}) + (\text{Load}_{Coal} \times \text{EF}_{Coal}) + (\text{Load}_{NE,RE} \times 0) + (\text{Load}_{Remaining} \times \text{EF}_{Unspecified}) + (\text{Load}_{ACS} \times \text{EF}_{ACS})$$

Eq. 230-1

Where:

Load_{xxx} = Amount of retail electric load served by natural gas (NG), coal, and nonemitting and renewable resources (NE, RE), sources which has a designated asset controlling supplier (ACS) emission factor, and remaining load for which generation source is unknown or unspecified.

EF = Emission factor for natural gas (NG), coal, asset controlling suppliers (ACS), and unspecified electricity.

Table 2. FPUD allowance allocation for the first compliance period of the Cap-And-Invest program.

	2023	2024	2025	2026
FPUD Allowances	140,118	140,609	141,274	TBD

The most recent cap and invest auction at the time of the IRP took place in June 2024. At the June 2024 Auction, 7.8M vintage 2023 and 2024 allowances were offered, and all allowances sold at a price of $29.92/MTCO2s. Additionally, 1,317,000 2027 vintage allowances were sold at advanced auction at the floor price of $24.02 leaving 883,000 vintage 2027 allowances unsold. Any allowances that go unsold are offered again at the following auction. Notably, the settlement price for current vintage allowances decreased from its peak of $63.03 in Auction 2 to $29.92 in Auction 6.

Initiative 2117 (I-2117) will be voted on in Washington State in the November 2024 election. If passed, I-2117 would eliminate the CCA and prohibit the existence of any cap-and-trade programs within the state of Washington. Given that at the time of the IRP the outcome of this initiative is unknown, the IRP assumes that the Cap-and-Invest program will continue as planned, and thus includes the cost of carbon as an input to the market simulation. If the CCA is repealed, FPUD would no longer be subject to any compliance obligation, and the no cost allowances distributed to FPUD would lose all value. FPUD contracts with TEA to actively manage risks associated with the Cap and Invest program.

3.4 Clean Energy Transformation Act (CETA)

The Clean Energy Transformation Act (CETA) (SB 5116, 2019) was signed into Washington law by Governor Jay Inslee in May 2019, and requires utilities to be 80% clean and GHG neutral by 2030 and prohibits the use of fossil fuel electricity production by the year 2045. Alongside this requirement, there are objectives that need to be achieved on time. The first one, completed in 2022, required utilities to create a clean energy implementation plan (CEIP) outlining actions regarding energy efficiency and renewable energy. CEIPs must be submitted every four years, and accompanying progress reports will be required starting in 2026. Further, all utilities must remove coal-fired electricity by 2025. As a result of this requirement, the Centralia Steam Plant, in Centralia, Washington, is on schedule to be retired by the end of 2025. Units 1 and 2 of the Colstrip Plant, in Colstrip, Montana, were retired in January 2020, and Units 3 and 4 will likely retire in the early 2030s. These retirements are included in the IRP market simulation. The “no coal” restriction also excludes coal that may be acquired through unspecified forward market purchases for terms greater than 1 month. As a result, utilities will be less able to rely on unspecified physical forward market purchases as a mechanism for hedging market exposure and may therefore face reduced hedging liquidity or higher prices in the forward market.

3.5 Western Resource Adequacy Program (WRAP)

As a result of increasing concern across the region about capacity sufficiency, the Western Resource Adequacy Program (WRAP) was created. This program is designed to leverage load and resource diversity and deliver resource adequacy efficiencies to participants. The WRAP has a forward showing program and an operational program. The forward showing program requires that 7 months prior to each season

(Winter or Summer), participants in WRAP need to demonstrate that they have obtained sufficient capacity to meet their P50 Peak Load plus an additional Planning Reserve Margin (PRM). The operational program occurs each day of the season with 7 days of consideration before said operating day and calculates if WRAP participants have a shortage or surplus of their resources. Additionally, the program looks at the larger forward showing forecast and compares it to a forecast consisting of a few days ahead. Based on these forecasts and if a participant is at a deficit or surplus there will be allocations of energy to ensure all participants meet their energy needs.

FPUD is currently participating in the WRAP non-binding program through the TEA Load Serving Entity (LSE) group. Participating as a single LSE allows FPUD to take advantage of the diversity benefit that is provided by aggregating obligations and resources with three other utilities who have load in different locations. Under a planned product contract such as Slice/Block FPUD is considered the Load Responsible Entity (LRE). In contrast, under a Load Following contract, BPA would be WRAP LRE on FPUD's behalf. BPA made the decision to participate in the WRAP binding program in 2022.

3.5.1 Qualifying Capacity Contribution

Qualifying Capacity Contribution (QCC) is a vital metric in capacity planning, used to evaluate and quantify the reliable contribution of energy resources to the overall capacity mix. It specifically refers to the capacity of a resource that meets defined criteria to contribute to the energy supply or capacity needs of a system or grid. QCC considers factors such as resource availability, variability, and the capability to dispatch power as required. However, QCC assessments focus solely on evaluating the resource type and do not address associated transmission deliverability requirements. Table 3 shows the percentage of installed capacity by resource type for QCC requirements.

Table 3. WRAP QCC Capabilities by Resource Type

Month	Season	BPA Product	Wind (VER1)	Solar (VER1)	ESR / Hybrid (Mid-C)	Thermal / Geothermal (Mid-C)	RoR (Mid-C)
January	Winter	100%	6%	3%	86%	90%	15%
February	Winter	100%	9%	3%	82%	90%	22%
March	Winter	100%	14%	5%	100%	90%	36%
April	Spring						
May	Spring						
June	Summer	100%	23%	29%	100%	90%	60%
July	Summer	100%	16%	17%	77%	90%	59%
August	Summer	100%	14%	12%	88%	90%	50%
September	Summer	100%	11%	6%	88%	90%	45%
October	Fall						
November	Winter	100%	8%	1%	100%	90%	22%
December	Winter	100%	7%	3%	100%	90%	19%

The WRAP QCC is not fixed; it can be adjusted as the WRAP initiative develops. The WRAP specifically targets two seasons—winter and summer—to fulfill capacity requirements.

3.6 Federal Policies & Regulations

3.6.1 PURPA

The Public Utility Regulatory Policies Act of 1978 (PURPA) directs state regulatory authorities and non-FERC jurisdictional utilities (including FPUD) to consider certain standards for rate design and other utility procedures. FPUD 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. FPUD may be subject to certain provisions of the Energy Policy Act of 2005, relating to transmission reliability and non-discrimination. Under the Enabling Act, FPUD 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 each 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 many 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. FPUD is currently a purchaser of RECs from Idaho PURPA solar generation facilities, which contribute to satisfying FPUD’s EIA renewable requirements.

In 2020, the FERC reviewed its implementation of PURPA citing reports from utilities that developers may have been 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, prior to the FERC review, those greater than one mile apart were considered to be separate facilities. The new FERC policy, issued July 16, 2020, still considers equipment located less than a mile apart to be the same facility, and equipment located ten or more miles apart to be a separate facility. There is now a "rebuttable presumption" that equipment located between one and ten miles apart is considered to be located on different sites;

however, utilities can now challenge this presumption by exposing common characteristics between the projects.

3.6.2 Inflation Reduction Act (IRA)

On August 16th, 2022, President Biden signed the Inflation Reduction Act into law. The Act includes provisions for healthcare reform and clean energy investment, with a specific focus on the reduction of greenhouse gas emissions. The IRA allocates $370 billion for clean energy investments, supporting the development of carbon-free electricity generation through tax incentives, grants, and loan guarantees. The Act impacts numerous sectors including energy, manufacturing, environmental, transportation, agriculture, and water, with a primary focus on the electric industry.

The IRA extends investment tax credits (ITC) and production tax credits (PTC) to incentivize the creation of carbon-free resources and enable tax-exempt entities to maintain project ownership. The ITC is awarded based on the total investment upon project completion, while the PTC is paid over a decade based on the project's energy output. Both Sections 48E ITC and 45Y PTC offer technology-neutral credits for facilities with zero or negative greenhouse gas emissions. Facilities for new solar, wind, geothermal, and nuclear energy qualify for these tax credits, as do battery storage facilities for ITC.

Section 48E ITC: Section 48E of the U.S. tax code outlines a technology-neutral ITC for qualifying facilities constructed and operational after December 2024. The base ITC value for eligible energy projects is 6% of the capital investment upon project completion. This can be increased to 30% if the project meets certain prevailing wage and apprenticeship criteria. Additional bonus credits of 10% are available if the project complies with domestic content requirements and is in an energy community area such as a brownfield or fossil fuel community.

Section 45Y PTC: Section 45Y of the U.S. tax code details a clean energy PTC paid over ten years for qualifying facilities constructed after December 31, 2024. The base PTC amount is 2.75 cents per kilowatt-hour (kWh) of electricity produced and sold, adjusted for inflation. If the project meets certain prevailing wage and registered apprenticeship criteria. Additional 10% bonus credits are available for projects meeting domestic content requirements and for those located in a designated energy community area.

A significant provision of the IRA allows direct payments to nonprofit organizations like municipal electric utilities instead of tax credits. This shift from the previous system, where municipal utilities had to sign a Power Purchase Agreement (PPA) with a renewable developer to receive the tax credit, allows entities like FPUD to develop a self-build renewable project and receive PTC or ITC credits. However, for this study, TEA modeled FPUD renewable participation as PPA agreements.

3.6.3 Renewable Electricity Production Tax Credit (PTC)

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 was reduced to approximately $14.25/MWh for generators with a 2018 vintage and $9.50/MWh for those with a 2019 vintage. The PTC for new wind construction was sunset entirely by the end of 2019 before being extended until the end of 2020 and restored to $9.50/MWh for facilities that start construction during the 2020 calendar year.

Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by the Inflation Reduction Act of 2022 as described in Section 3.6.2. Previously it had been extended by the American Recovery and Reinvestment Act of 2009 (H.R. 1 Div. B, Section 1101 & 1102) in February 2009 (often referred to as "ARRA"), the American Taxpayer Relief Act of 2012 (H.R. 8, Sec. 407) in January 2013, the Tax Increase Prevention Act of 2014 (H.R. 5771, Sec. 155) in December 2014, and the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015, and the Taxpayer Certainty and Disaster Tax Relief Act of 2019.

3.6.4 Renewable Energy Investment Tax Credit (ITC)

The Renewable Energy Investment Tax Credit (ITC) allows taxpayers to claim a credit for expenditure on renewable generation assets installed on homes owned and lived in by the taxpayer. The taxpayer can elect whether to use the ITC or the PTC to best fit their needs. The ITC may be preferable in locations with lower expected generation as the ITC is not dependent on the unit’s generation.

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. Qualified expenditures include labor costs for on-site preparation, assembly, 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.

Most recently, the ITC has been expanded by the 2022 Inflation Reduction Act as described in Section 3.6.2.

Section 4 Load Forecast

4.1 Load Forecast Summary

Projected system load is the amount of electric energy FPUD's customers require for heating, lighting, motors, and other end-uses. The load forecasts for FPUD used in this study were developed using historical load, weather, and econometric data for Franklin County for the period from 1970 to 2024. Unlike previous IRP analyses, this IRP developed a load forecast down to the hourly level to better capture the challenges presented by integrating a high volume of renewables in a capacity-short market environment.

A linear regression model was trained to forecast annual load growth at monthly granularity through 2044 based on econometric forecasts by Woods and Poole. The conservation and efficiency resources are implicitly taken into consideration through the correlation between historical load and economic indicators. Hereby, the conservation and efficiency trend in the historical load is captured by the model and is reflected in the load forecasting based on economic projections. A machine learning model was then trained to resolve the forecast down to hourly demand over the study time horizon. Forecasts for the rate of building and vehicle electrification were then added. Low and high load scenarios were then developed at matching hourly granularity based on the range of historical growth rates. These scenarios are used to understand FPUD's power resource needs under different futures.

4.2 Monthly Forecast

The monthly load forecast incorporates the long-term impacts of economic demographics according to the steps below:

1. 20 years of historical monthly system total and peak load data (2003-2022) was collected from data provided by FPUD.
2. 20 years of historical weather data for the KPSC weather station (Jan. 2004 – Jan. 2024) was collected from DTN weather. A normalized weather pattern based on temperature was determined using the rank and median method and applied to historical years and forecast horizon years. For both the historical and normalized weather data, heating and cooling degree days were then calculated using the formula below for each day. For hours with temperatures above 65˚ F, heating degree days were set to zero. This same methodology was used for cooling degree days in hours with temperatures below 65˚ F. These heating and cooling degree days were then summed to the monthly level.

$$Cooling\ Degree\ Day = \sum \frac{(Hourly\ Temperature - 65^{\circ}\ F)}{24}$$

$$Heating\ Degree\ Day = \sum \frac{(65^{\circ}\ F - Hourly\ Temperature)}{24}$$

3. Econometric data for Franklin County was obtained from Woods & Poole's 2022 Complete Economic and Demographic Data Source[1]. This dataset included both historical data from 1970 to 2022 and forecasted data extending from 2023 to 2060. Eight different economic metrics for Franklin County were obtained and the total number of households was determined to have the best fit to the historical load data when weather normalized. Figure 1 shows the total number of households in Franklin County.

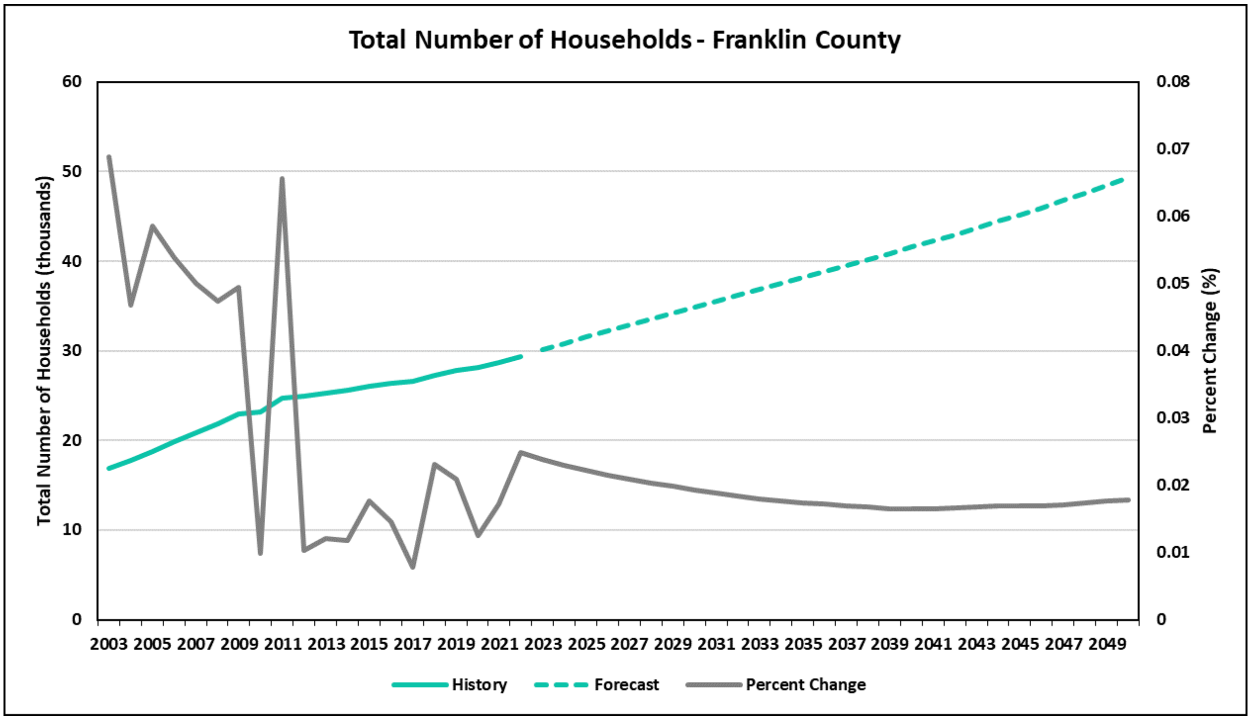


Figure 1. History and Forecast of Total Number of Households in Franklin County 2003 – 2050

4. Linear regression models were trained for predicting total and peak monthly load using the month of the year, historical heating/cooling degree days, and historical number of households.
5. These regression models were then used to project total and peak monthly load using the month of year, normalized weather, and economic projections for number of households in Franklin County. Figure 2 is a visual of annual total and peak load calculated from the monthly history and regression model projections.

[1] **Woods & Poole Economics, Inc.** "2022 Complete Economic and Demographic Data Source (CEDDS)®." 2022. Woods & Poole Economics, Inc. Accessed, 2023. https://www.woodsandpoole.com/our-databases/united-states/cedds/.

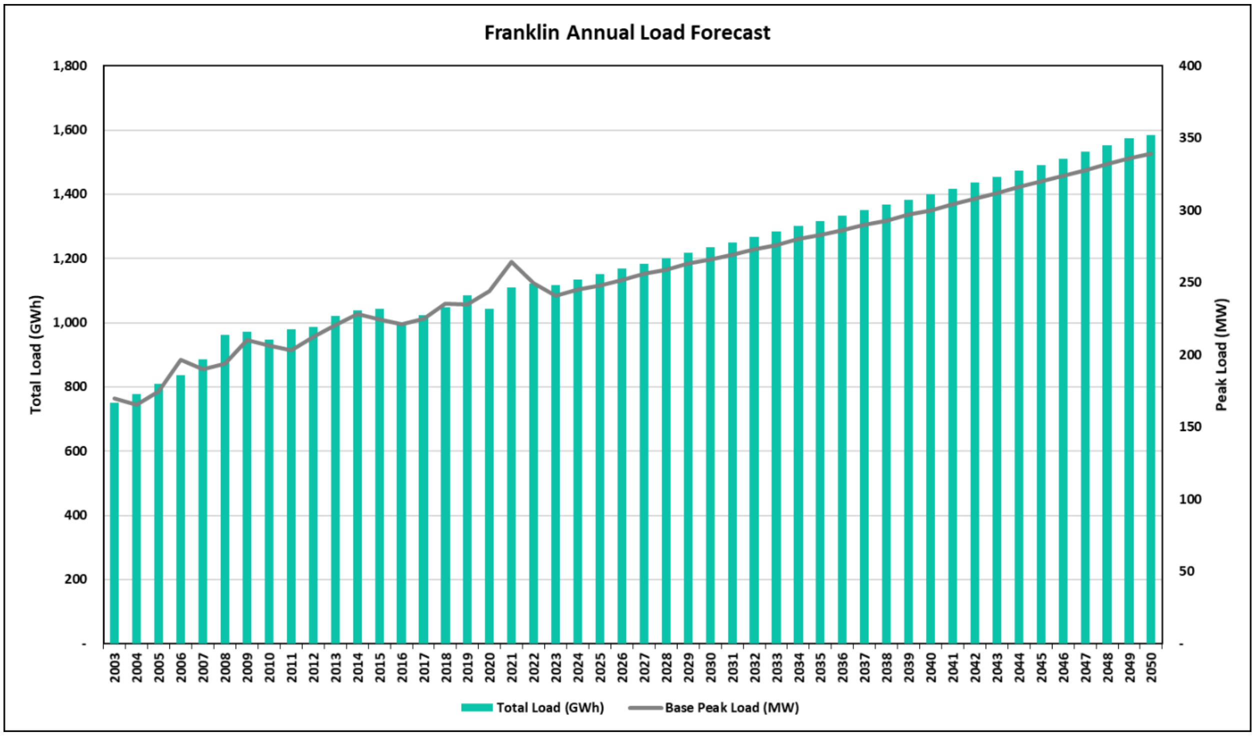


Figure 2. FPUD annual load history and forecast from 2003 – 2050

4.3 Hourly Forecast

The hourly load forecast was developed with the following steps:

1. Hourly historical meter-level load data was obtained for the last 5 years of load history. This CPOD level data was aggregated to calculate hourly system historical load for 2018-2022.
2. Hourly historical weather data for the KPSC weather station was collected from DTN weather. 10 years of historical weather data was then used to calculate hourly normalized weather using the rank and median method for the forecast horizon.
3. A non-linear machine learning model (GBM) was trained to predict load values given the historical weather data, actual system load, and time series features including hour of the day, month, and day of the week.
4. The trained model was then used to predict future load using the normalized weather forecast.
5. The hourly forecasted load was then fitted to the monthly total and peak load projections shown in the previous section. This was done to ensure congruency between the two predictions, since this hourly model has no feature which incorporates long-term load growth.

4.4 New Load Additions

Several large customers are expected to begin service with FPUD over the next few years. These expected new loads were added into the load forecast after the base forecast was developed. For simplicity, these new customers are assumed to have a flat load shape, consuming the same amount of energy every hour after beginning service. The impact of these new load additions on the projected peak and total load is shown in Figure 3 below.

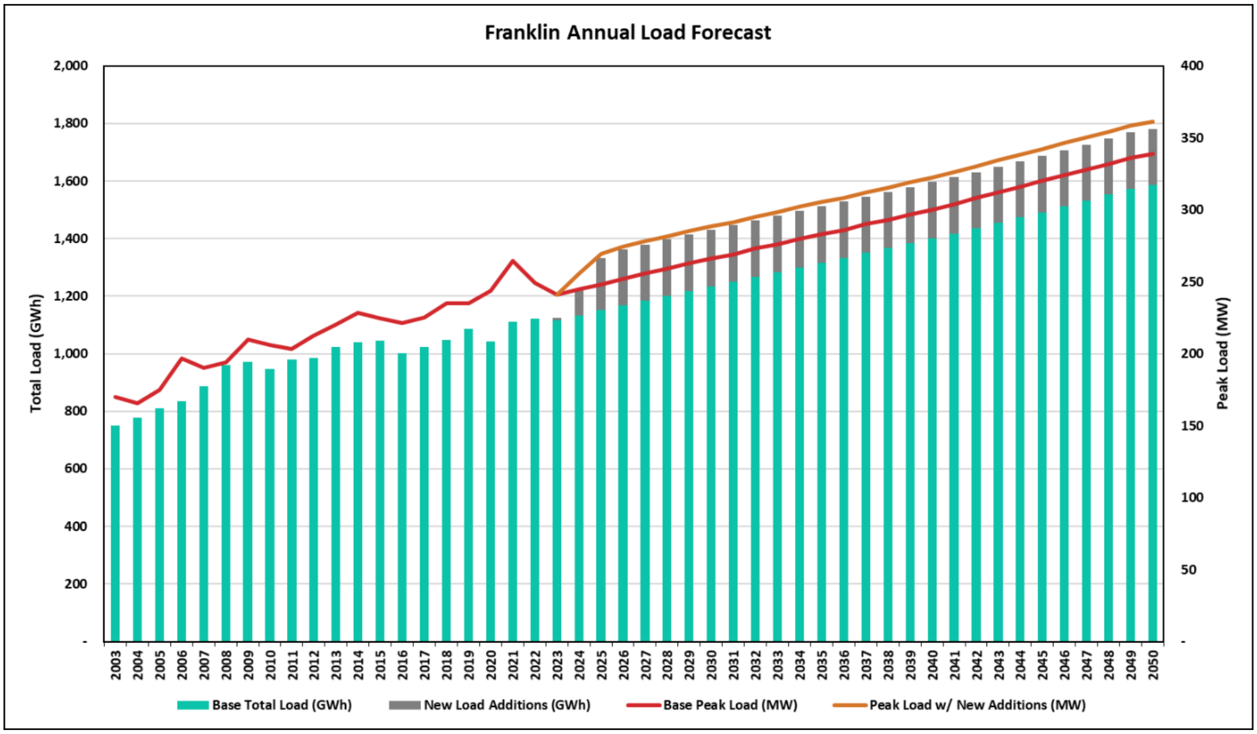


Figure 3. FPUD annual load history and forecast from 2003 - 2050 with new load additions

4.5 Electric Vehicle (EV) Forecast Methodology

The EV charging load forecast was developed separately and added on top of the base load forecast using the steps below.

1. A regression model was trained to project EVs as a percentage of total vehicles on the road by year. State-level data on the percentage of EVs on the road for 5 different years was sourced from S&P Global[2]. Additionally, economic projections of income per capita by state were obtained from Woods & Poole. The economic projections were assumed to be the primary driver of EV growth, particularly in the near term. After model training using this state-level data, annual per-capita income projections for Franklin County, Washington, were then input into the regression model to project the percentage of vehicles on the road that are EVs. These percentages were multiplied

[2] **S&P Global Mobility.** "State Electric Vehicle Forecast." S&P Global Mobility. Accessed April 2023. https://www.spglobal.com/mobility/en/index.html.

by the total number of vehicles on the road, obtained for Franklin County from Washington Department of Transportation data[3].

2. The EVI-Pro Lite tool from the National Renewable Energy Laboratory (NREL) provides an hourly charging load shape[4]. This tool requires several inputs, listed below.
   a. EV count projections by year, obtained from the previous step.
   b. Average temperature, which is varied by month depending on the average monthly temperature from the last 10 years at the Pasco/Tri Cities Airport (KPSC).
   c. Average miles traveled per day for an EV owner – assumed to be 35 miles.
   d. Full EV vs. plug-in hybrid – assumed to be an even split between the two.
   e. EV Sedans vs SUVs – assumed to favor sedans.
   f. Assumed EV owners who have access to a home charger and prefer to charge at home, both assumed to be 100%.
   g. Charger type, assumed to be an even split between level 1 and level 2 for home chargers and favor level 2 for public chargers.
   h. Charging strategy – assume customer charging behavior pattern follows immediate strategy, where customers charge their vehicles as quickly as possible once plugged in.
3. The EVI-Pro Lite tool provided the output of the hourly EV charging shape given the assumptions above. This hourly forecast was then added on top of the base load forecast, enabling the load forecast to be available with and without forecast EV charging impacts. Figure 4 shows the annual energy and peak load resulted by EVs for Franklin County after including new load additions and EV charging load.

[3] **Washington State Department of Transportation.** "Registration Activity by Fiscal Year and Primary Use." data.wa.gov. Accessed January 2024. https://data.wa.gov/Transportation/Registration-Activity-by-Fiscal-Year-and-Primary-U/f8kb-pm6f.

[4] **National Renewable Energy Laboratory (NREL).** "EVI-Pro Lite Tool." NREL. Accessed May 2023. https://www.nrel.gov/transportation/evi-pro.html.

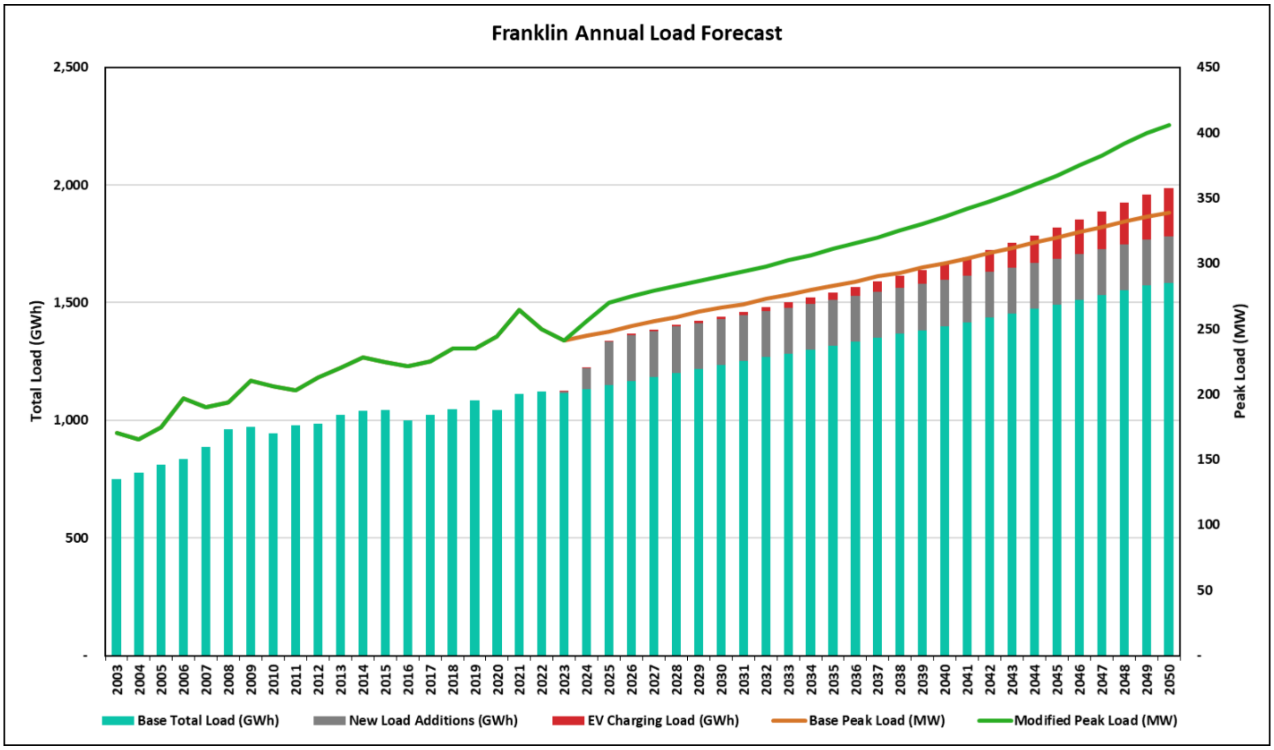


Figure 4. FPUD Load from 2003 - 2050 with New Load Additions and EV Charging Load

4.6 High and Low Load Scenarios

In addition to the base load scenario (the expected case), high and low scenarios are provided to account for uncertainties and multiple possible futures in the forecast model. Figure 5 below shows the base, high, and low energy forecasts. Figure 6 shows the base, high, and low peak demand forecasts.

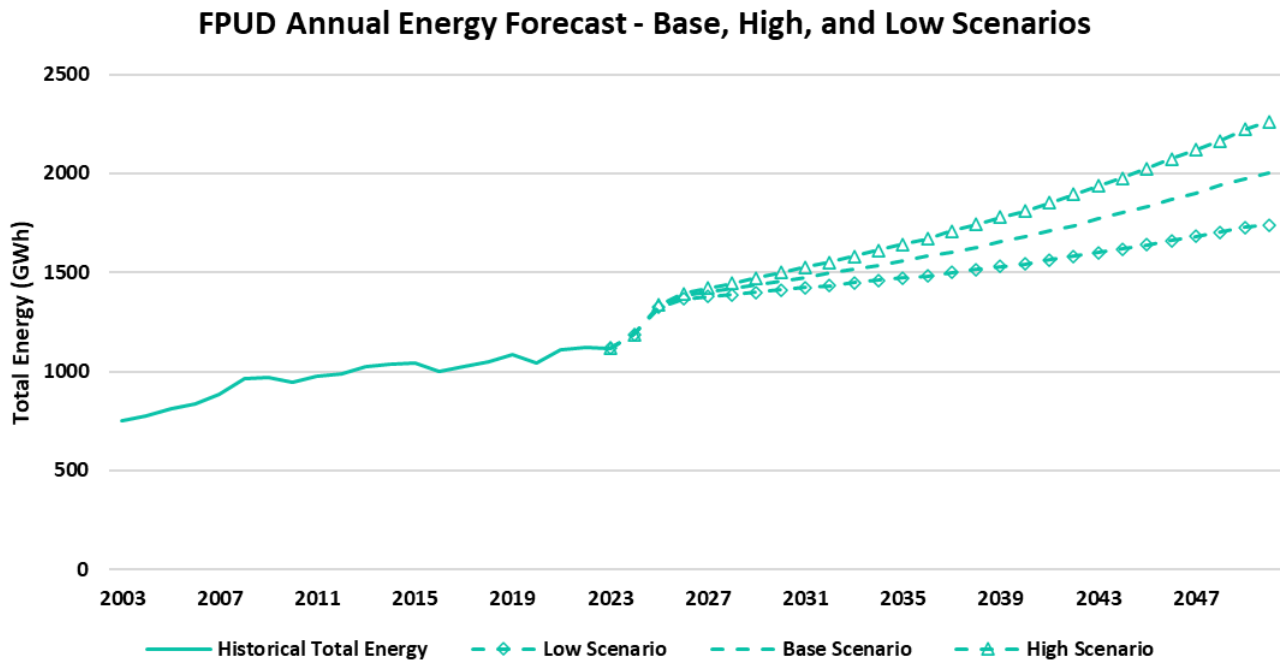


Figure 5. FPUD Annual Load Forecast Scenarios

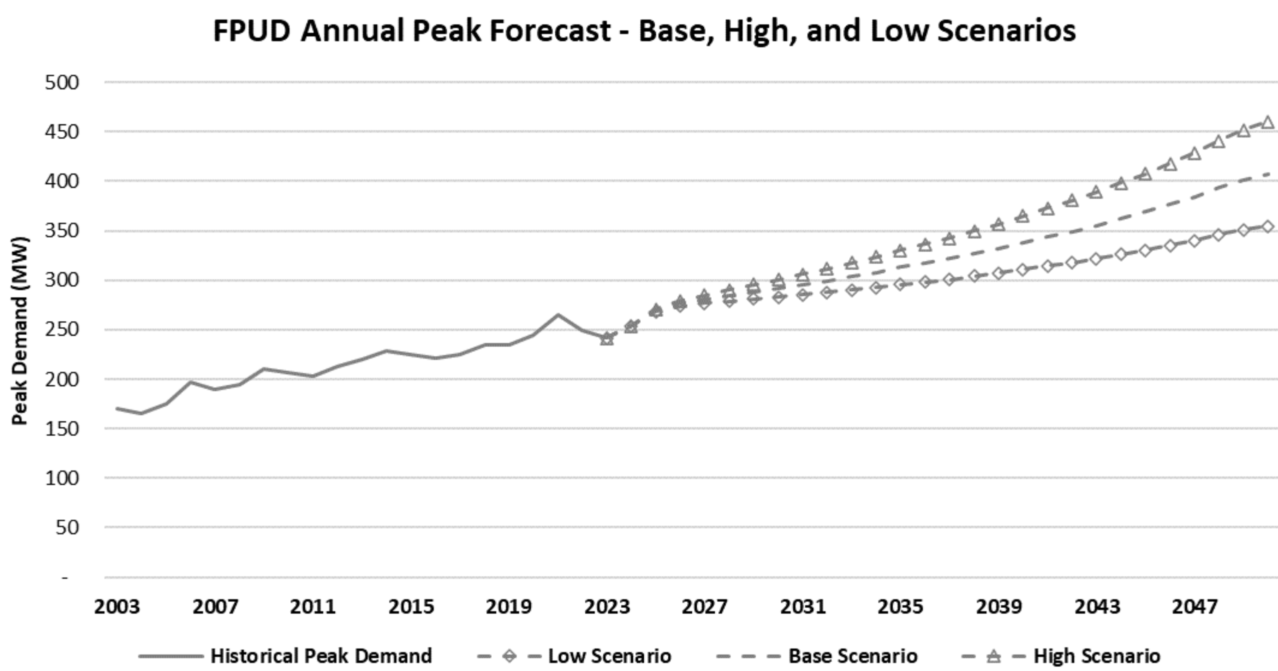


Figure 6. FPUD Annual Peak Demand Forecast Scenarios

Additionally, Table 4 below provides the annual projected growth rates and year-over-year change for different scenarios.

Table 4. FPUD Annual Load Forecast Scenarios

	Low Scenario				Base Scenario				High Scenario			
	Total Energy (GWh)		Peak Demand (MW)		Total Energy (GWh)		Peak Demand (MW)		Total Energy (GWh)		Peak Demand (MW)	
Year	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change
2025	1,323		268		1,329		270		1,336		271	
2026	1,367	3.4%	274	2.1%	1,381	3.9%	277	2.6%	1,395	4.4%	279	3.1%
2027	1,379	0.9%	277	1.0%	1,400	1.4%	281	1.5%	1,421	1.9%	285	2.0%
2028	1,387	0.6%	279	0.7%	1,419	1.4%	284	1.3%	1,444	1.6%	290	1.7%
2029	1,401	1.0%	281	0.9%	1,437	1.2%	288	1.4%	1,473	2.0%	296	1.9%
2030	1,412	0.8%	283	0.7%	1,455	1.3%	292	1.2%	1,499	1.8%	300	1.7%
2031	1,423	0.8%	285	0.8%	1,474	1.3%	296	1.4%	1,526	1.8%	306	1.9%
2032	1,432	0.6%	288	0.8%	1,495	1.4%	300	1.3%	1,551	1.6%	312	1.8%
2033	1,447	1.0%	290	1.0%	1,515	1.3%	304	1.5%	1,583	2.1%	318	2.0%
2034	1,459	0.9%	293	0.8%	1,536	1.4%	308	1.3%	1,613	1.9%	323	1.8%
2035	1,472	0.9%	296	1.1%	1,557	1.4%	313	1.6%	1,643	1.9%	330	2.1%
2036	1,482	0.7%	298	0.8%	1,581	1.5%	317	1.3%	1,671	1.7%	336	1.8%
2037	1,499	1.2%	301	0.8%	1,604	1.4%	322	1.4%	1,708	2.2%	342	1.8%
2038	1,514	1.0%	304	1.2%	1,628	1.5%	327	1.7%	1,742	2.0%	350	2.2%
2039	1,530	1.0%	307	0.9%	1,654	1.6%	332	1.4%	1,778	2.0%	357	1.9%
2040	1,543	0.8%	311	1.2%	1,681	1.7%	338	1.8%	1,811	1.9%	365	2.3%
2041	1,563	1.3%	314	1.2%	1,708	1.6%	344	1.8%	1,853	2.3%	373	2.2%
2042	1,581	1.2%	318	1.0%	1,738	1.7%	349	1.5%	1,894	2.2%	380	2.0%
2043	1,600	1.2%	322	1.3%	1,768	1.8%	355	1.8%	1,937	2.2%	389	2.3%
2044	1,617	1.0%	326	1.3%	1,801	1.9%	362	1.9%	1,976	2.1%	398	2.3%
2045	1,641	1.5%	330	1.3%	1,833	1.8%	369	1.9%	2,025	2.5%	408	2.4%
2046	1,662	1.3%	335	1.5%	1,867	1.8%	377	2.1%	2,072	2.3%	418	2.5%
2047	1,683	1.3%	340	1.5%	1,902	1.9%	384	2.1%	2,121	2.3%	429	2.6%
2048	1,702	1.1%	346	1.7%	1,939	2.0%	393	2.3%	2,166	2.1%	441	2.8%
2049	1,727	1.5%	351	1.5%	1,974	1.8%	401	2.0%	2,221	2.5%	452	2.5%
2050	1,741	0.8%	354	0.9%	2,001	1.4%	407	1.5%	2,261	1.8%	460	1.9%

Section 5 Current Resources

5.1 Overview of Existing BPA Resources

About 75% of FPUD's power is currently supplied through its Slice/Block agreement with the Bonneville Power Administration (BPA), the federal agency that markets the Federal Columbia River Power System (FCRPS). The FCRPS is managed and operated by a collaboration of three federal agencies: BPA, the U.S. Army Corps of Engineers (Corps of Engineers), and the Bureau of Reclamation. The FCRPS consists of 31 multipurpose hydroelectric dams, the Columbia Generating Station, and a small amount of generation from contracts with wind farms. The dams provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate 800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration, n.d.). Due to the size of the system, up to 10,000 MW of generation capacity can be offline for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to overall hydrological conditions, with higher precipitation years generally resulting in higher power generation years and vice versa. Hydrological conditions are cataloged by measuring the quantity of water runoff at a specific point for a specific period. 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 period, total runoff varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1949-2023) is illustrated in Figure 7.

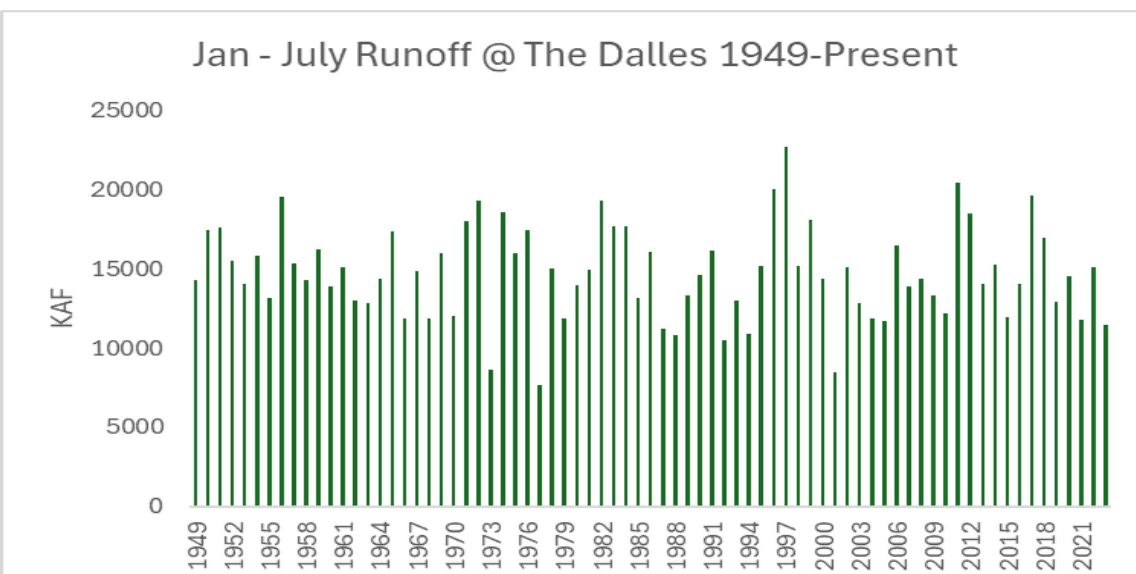


Figure 7. Historical Water Years (1949-2023)

The 1937 water year stream flows represented the worst (lowest) on record and was chosen as the benchmark "critical water" year to represent baseline system capability. Until 2022, BPA conservatively measured the system capability by determining its average annual energy output in critical water conditions. In October 2022, BPA shifted from using the 1937 water year to using a "P10" approach for determining the firm generation for the federal system. In this approach, the monthly 10th percentile of the most recent 30 years of stream flows are used to set the firm generation expectation. This change in methodology is intended to capture the impact of climate change on system generation, and it resulted in an 87 average megawatt decrease in annual generation.

As a BPA Slice/Block customer, FPUD receives a fixed monthly block of guaranteed generation and a variable allotment (Slice) of the Federal Columbia River Power System (FCRPS) output. The Slice portion is an allocated share of the total FCRPS for FPUD to operate and manage to serve FPUD's load while observing constraints for water conditions, fish migration and spawning, migratory bird considerations, and flood control. BPA Tier 1 customers' FCRPS power allocation is referred to as the Contract High Water Mark (CHWM). CHWMs under the current contract were calculated to achieve load-resource balance between Tier 1 energy and a utility's 2010 adjusted loads less the utility's resources used to serve load (dedicated resources). The amount of power a Tier 1 customer is entitled to purchase in each rate period is then adjusted from the CHWM for any changes in FCRPS capability and is referred to as the Rate Period High Water Mark (RHWM). FPUD's share of annual Slice output is roughly 72 aMW in an average water year but can vary substantially depending on hydrological conditions. This source of power is assumed to be 94% clean and CETA compliant based on BPA's fuel mix report from 2021-2023.

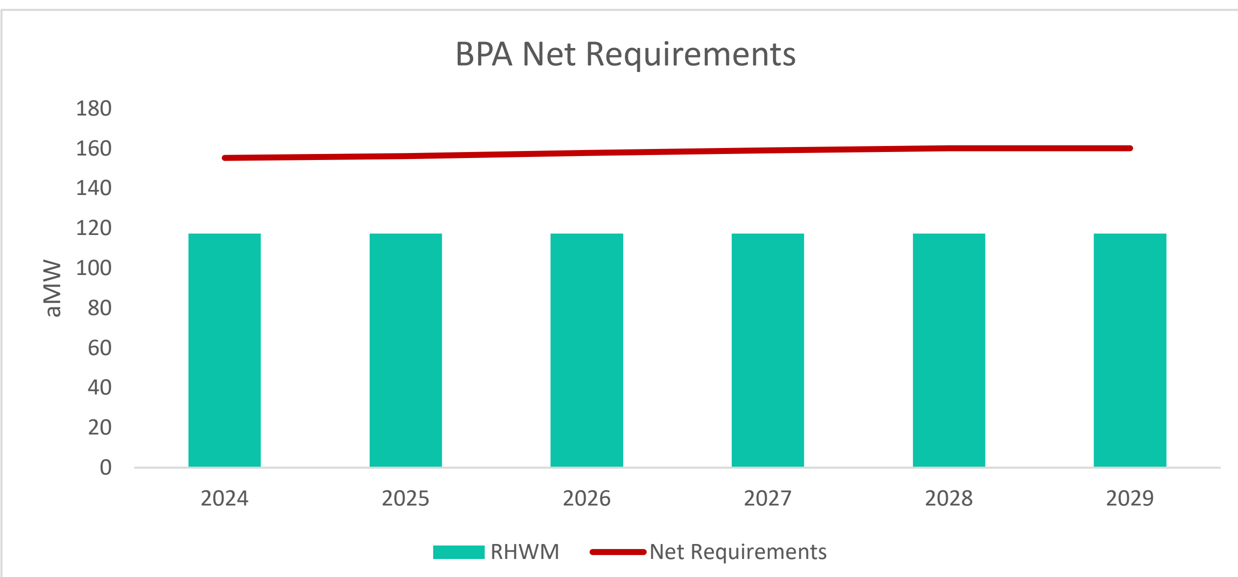


Figure 8. Retail Load vs. BPA Contract High Water Mark

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 RHWM, 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 FPUD 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 FPUD does not change. The power is shaped in advance into monthly blocks, which follow FPUD's monthly load profile. In other words, more Block power is delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 8,100 MW for the current two-year rate period, but daily generation will fluctuate from 4,000 MW to 15,000 MW or more. The FCRPS is a multipurpose system and power generation achieves only one of the system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. FPUD 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 FPUD to, at times, fulfill its load obligations with resources other than what is provided by BPA and FPUD's contracted non-federal resources.

5.1.1 BPA POST-2028 PRODUCT OPTIONS

Figure 9 shows BPA's Provider of Choice (POC) Timeline updated June 2024. Source: BPA Provider of Choice

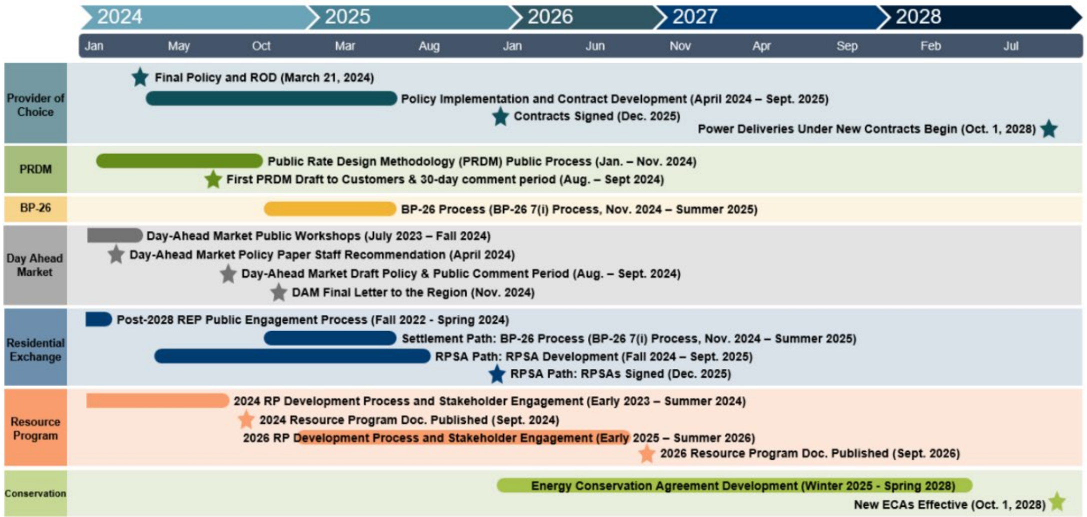


Figure 9. BPA's Provider of Choice (POC) Timeline

BPA's goal is that preference customers execute new power contracts by the end of 2025. As of the time the IRP, BPA has three main product options which include Load Following, Block Products, and Slice/Block. BPA will continue offer the Load Following product in Provider of Choice (POC), which will serve a utilities' hourly energy and peak net requirements load. The Load Following product is not expected to change materially under POC. Load Following customers will continue to have load service certainty, and BPA will continue to require resource shaping services to integrate non-federal resources that have been declared to serve load.

BPA will continue to offer the Block Product which provides a planned amount of firm power to meet utilities' Net Requirements. The Block Product will be offered in a flat annual amount, a monthly shaped amount, and a Block with Shaping Capacity option. BPA has made significant changes to the Block with Shaping Capacity product which was not selected by any utility under the Regional Dialogue (RD) contract. As proposed at the time of the IRP, the Block with Shaping Product provides a monthly volume that is shaped to the customer's load. These MWhs may be shaped by the utility prior to the Day-Ahead Market based on a fixed set of criteria including a maximum hourly volume, and minimum hourly volume, and a half-month usage constraint. Additionally, BPA has proposed offering a Peak Load Variance Service which will provide capacity up to a customer's P10 Load. BPA has not yet indicated how P10 load will be defined.

The Block with Shaping Capacity product as proposed appears to be a viable option for consideration given a similar risk profile to Load Following but better flexibility to integrate non-federal resources than Load Following. However, the viability of this product is contingent on how BPA chooses to define specific elements of the product, particularly the Peak Load Variance Service offering.

BPA has stated that they intend to continue to offer the Slice/Block product. However, BPA has suggested that it will require that a sufficient group of customers indicate interest in Slice/Block to continue developing the product. At the time of the IRP, BPA's proposed POC Slice/Block product is similarly structured to the RD Slice product, and differences between the two contracts largely stem from changes that BPA view as necessary to apply the product in an organized day-ahead market. As with the current contract, the block portion of the contract provides a fixed amount of power, and the slice portion of the contract is based on a percentage share of BPA's generation resources. This share fluctuates based on the generation output of BPA's generation assets which predominately consist of the hydroelectric projects that make up the Federal Columbia River Power System (FCRPS) and the Columbia Generating Station nuclear facility. Unlike the RD Slice product, BPA proposes that in POC Slice, the schedule be locked down on a day-ahead basis and may not be changed in real-time.

At the time of the IRP, BPA has floated the concept of adding "Federal Surplus" to a Block with Shaping Capacity Product. This concept is in its infancy, and there is no certainty whether Bonneville will offer this option. However, a Block with Shaping Capacity Product with Federal Surplus may prove to be a viable option for consideration given its potential for a similar risk profile to Load Following and similar flexibility to Slice.

5.2 Product Comparison

This section provides a summary of the products that BPA is considering offering to its customer utilities at the time of the IRP.

Proposed Product Attributes

Product	Fit to Load Shape	Anticipated Capacity Specific Charges	Capacity Provided above P50	Non-Fed Resource Flexibility	PNR Check
Slice/Block	Least	No Embedded	System Dependent	Yes	No @ 50/50
Block: Stand-Alone	Partial	No Embedded	No	Yes	No
Block: w/Shaping Capacity	Partial	Yes Embedded +	No	Yes	≤XX% No >XX% Yes
NEW! Block: w/ Shaping Capacity + Peak Load Variance Service	Partial	Yes Embedded ++	Yes	Yes	Yes
Load Following	Most	Yes Embedded ++	Yes	Limited	No

5.2.1 Cost Comparison

At the time this IRP was finalized, the Public Rate Design Methodology (PRDM) for the Provider of Choice contracts has yet to be finalized, and there will not be certainty regarding how the products compare from a rate standpoint until mid-2025. In general, all products will have similar costs in the long-term, given that BPA's rate design is intended to provide mechanisms for adjustments based on actual costs. While the costs are expected to be similar overall, there are some key differences in rate structure between the three products including capacity or demand charges and resource integration or Resource Support Services (RSS) charges. Slice/Block and Standalone Block, as proposed at the time of the IRP, have no anticipated charges for capacity or demand. This means that a utility would be responsible for meeting their net requirements load and capacity requirements in excess of the capability of the selected BPA Tier 1 product with non-federal resources or market mechanisms.

5.2.2 WRAP Comparison

Under a Load Following contract, BPA would be the LRE under WRAP. Alternatively, for planned product options such as Slice/Block and Block with Shaping, FPUD would be the LRE. Peak Load Variance Service (PLVS) has been proposed as an add on to the Block with Shaping Capacity product to provide capacity up to a P10 load. At the time of writing, it is unclear exactly how much capacity PLVS would provide to FPUD. The Slice/Block product is anticipated to provide capacity based on the WRAP QCC of the FCRPS. FPUD is anticipated to need to purchase additional capacity providing resources to serve above-HWM load regardless of product choice. The Slice product is anticipated to provide the least amount of capacity out of all three products, so to be WRAP compliant with this product, FPUD would need to add significant capacity resources (see Figure 10).

5.3 Columbia Generating Station

The largest non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, Washington, 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. FPUD’s share of output from CGS is equivalent to its Slice system allocation.

5.4 Nine Canyon Wind Project

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

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

5.5 White Creek Wind Project

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

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

5.6 Packwood Lake Hydroelectric Project

The Packwood Lake Hydroelectric Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an average output of approximately 10 aMW. It is owned and operated by Energy Northwest, but 12 Washington PUDs are participants in the project with "ownership-like" rights. It is located 5 miles east of Packwood, Washington, in Gifford Pinchot National Forest. FPUD receives a 10.5% share of the output from the project, 0.7 aMW under critical water conditions, and approximately 1.3 aMW under average water. The project does not qualify as a renewable resource and does not help FPUD meet its obligations under the EIA.

5.7 Esquatzel Canal Hydro Project

The Esquatzel Canal, which discharges into the Columbia River, is located about 5 miles north of Pasco, in Franklin County. In 2011, Green Energy Today, LLC installed a hydroelectric generation turbine at the confluence of the canal and the Columbia River to capture the kinetic energy of the flowing water and convert it into electricity. FPUD purchased all rights to the power and environmental attributes generated by the 0.9 MW Esquatzel Canal Hydroelectric Project through 2031 and has an option to extend the contract. The IRP therefore assumes that Esquatzel will remain as a resource through the study period. The project produces roughly 6,000 MWh of power annually.

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

5.8 PowerEx Hydro PPA

In 2020, FPUD signed a PPA with PowerEx Corporation, the marketing arm of BC Hydro, for a hydro energy purchase of 40 MW around-the-clock for the 3rd Quarter period (July through September) and 25 MW around-the-clock for all other months of the year. The PPA began in July 2023 and continues through the end of 2028, with an option to extend the contract upon mutual approval.

5.9 Solar PPAs

FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity (approximately 13 aMW of annual generation) through participation in the Ruby Flats and Palouse Junction projects. Both solar projects are expected to begin producing power in 2026, are 100 percent carbon-free, and qualify as renewable energy under the EIA and CETA.

5.10 Conservation

FPUD has been actively engaged in conservation/energy efficiency resources for 30 years. Since 2002, FPUD’s programs have resulted in the acquisition of over 10 aMW of conservation resources. Additional emphasis will be focused on conservation planning and acquisition in the future. Along with a renewable portfolio requirement, the EIA requires that qualifying utilities pursue all cost-effective conservation. FPUD’s 2023 Conservation Potential Assessment is included in the appendix. In this IRP, cost-effective conservation is assumed to be implicit in the load forecast and is therefore not treated separately as a resource to avoid double counting.

5.11 Existing Transmission

BPA Transmission Services (BPAT) as the Balancing Authority (BA) is the entity obligated to meet FPUD’s peak load. Each BPA Slice customer sets aside and cannot access its share 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 the use of this capacity. These revenues include Regulation, Imbalance Charges, Contingency Reserves, and both Variable and Dispatchable Energy Resources Balancing Service charges (VERBS and DERBS). Slice customers receive their share of these revenues as an offset to the Composite Charge. BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). By virtue of purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves) and contractually giving up its share of capacity for within-hour services, FPUD 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 is not addressed in the IRP.

5.12 Load/Resource Balance with Existing Resources

Figure 10 illustrates FPUD's current resource qualifying capacity in relation to average energy consumption, peak demand load, and WRAP reserve margin requirements. FPUD's existing resources fulfill average energy consumption needs until late 2028. However, comparing resource capacity to peak load and WRAP requirements shows a shortfall ranging from 46 MW to 231 MW. Presently, peak demand is met through market purchases. Therefore, additional peaking or immediate capacity will be necessary to satisfy capacity requirements and energy needs effectively.

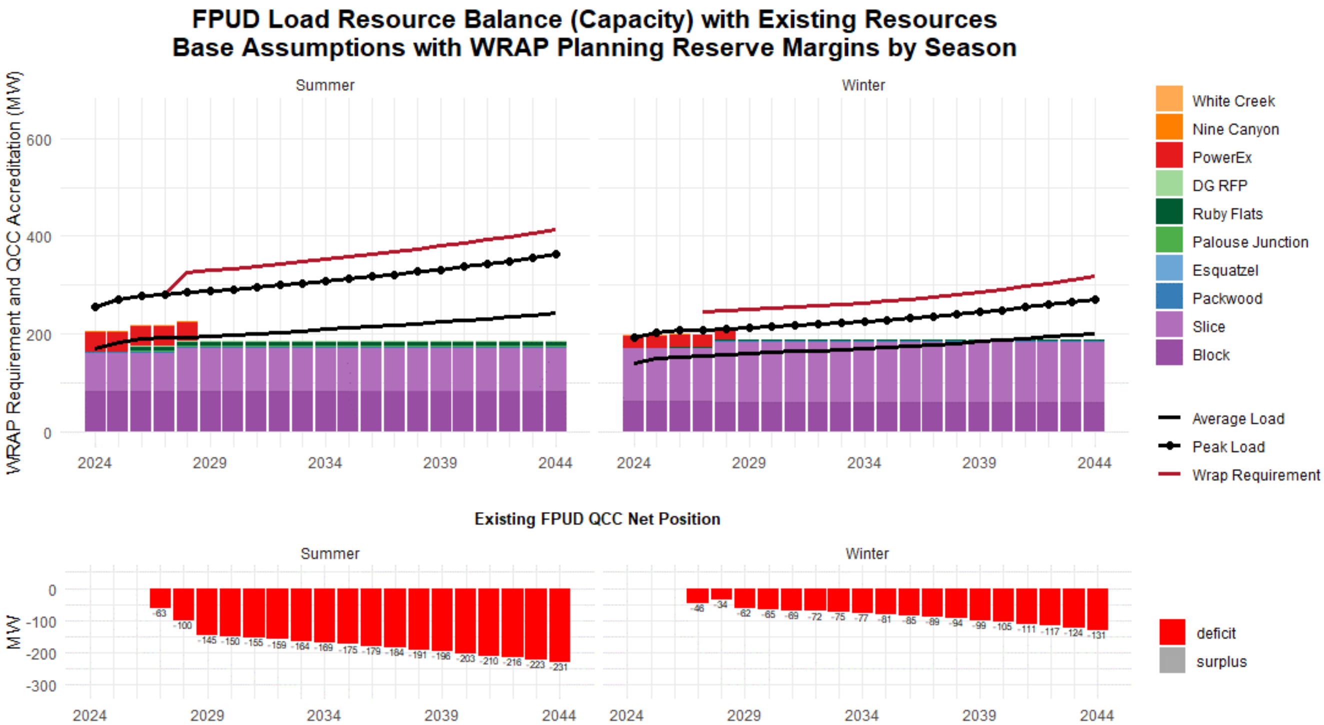


Figure 10. Existing Load Resource Balance

Section 6 New Resource Alternatives

New resources are needed to accommodate load growth and the retirement of aging generation units. Due to significant lead times required for construction and interconnecting a resource to the electric system, timely planning for each new resource is critical to ensure capacity requirements are met.

The requirements of the Clean Energy Transformation Act (CETA), which became effective on January 1, 2020, were major factors in determining the viability of potential resource alternatives. CETA requires that all utilities in Washington supply carbon-neutral electricity by 2030. Although FPUD retains the flexibility to include carbon-emitting resources in its portfolio equal to up to 20 percent of its retail load until 2045, any carbon emissions generated from these resources must be offset by the procurement of renewable energy credits or investment in renewable energy projects. In addition, when contemplating such resources, the societal cost of carbon must be included in the evaluation. CETA stipulates that by 2045, utilities must eliminate all carbon emissions by producing power exclusively with renewable and other non-emitting sources. For these reasons, FPUD evaluated only carbon-free supply-side resource options. The following supply options are considered currently or potentially viable within the study period and were included in this IRP analysis:

6.1 Solar PPA

Solar resources were modeled as 20 MW PPAs based on large-scale solar photovoltaic projects. This option satisfies the long-term requirements of CETA. The rapid growth in electric generation from solar resources across the U.S. has been driven by declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale solar capacity in the U.S. has risen from less than 1 GW in 2010 to approximately 100 GW[5] by the end of 2023 and provided approximately 4%[6] of the total electric generation in the U.S. in 2023.

FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. Additional solar resources considered by FPUD are assumed to have a 3-year construction period and to be located in southeastern Washington within the BPA balancing authority. Based on market data, the cost of energy from a solar PPA, fixed for the duration of a 15-year term, is assumed to be $75/MWh for a project with a 2026 commercial date. Prices in subsequent years were based on expected changes in construction costs and subsidies available through the Inflation Reduction Act. Future overnight capital cost assumptions were provided by The National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL

[5] Buttel, Lindsey. America's Electricity Generation Capacity 2024 Update, American Public Power Association. America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[6] Fitzgerald Weaver, John. "Solar generated 5.5% of U.S. electricity in 2023, a 17.5% increase." PV Magazine USA. https://pv-magazine-usa.com/2024/02/29/solar-generated-5-5-of-u-s-electricity-in-2023-a-17-5-increase/, accessed on 7/1/2024.

projects utility-scale solar capital costs to decline by an average of 2.9%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. Figure 11 shows the projected solar PPA prices assumed in the study.

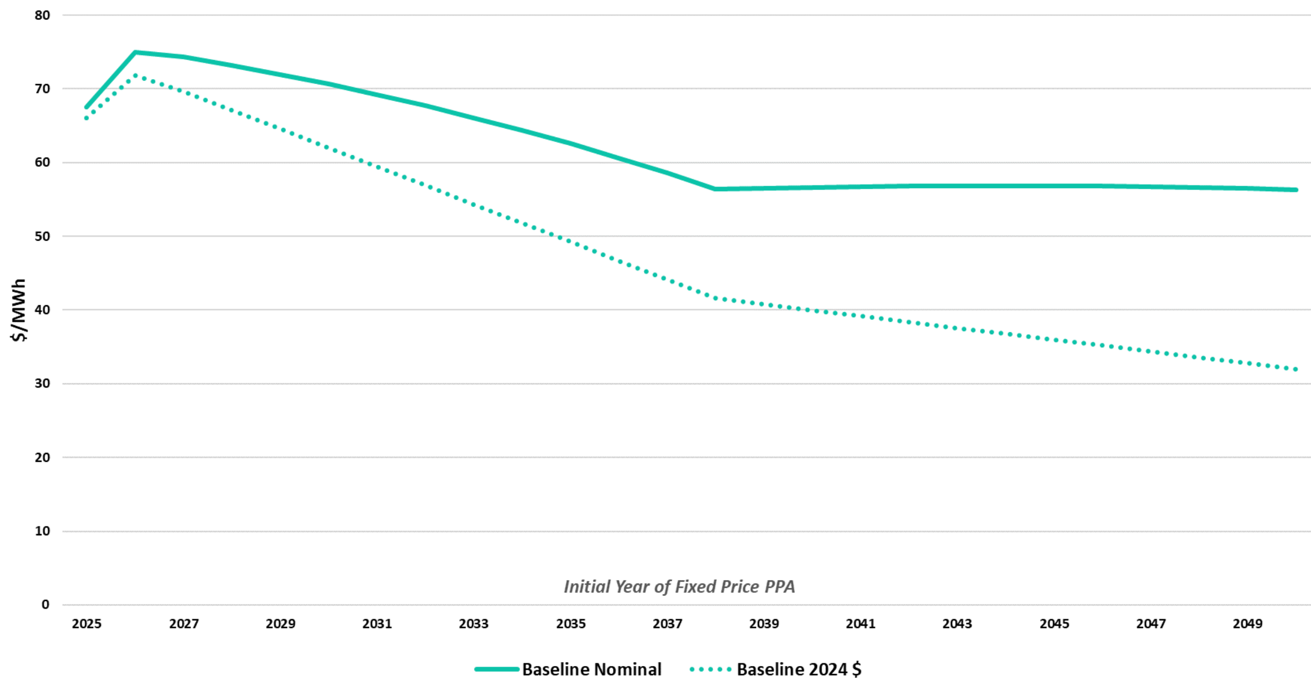


Figure 11. Pacific Northwest Solar PPA Price

6.2 Wind PPA

Wind resources were modeled as 25 MW PPAs based on utility-scale on-shore wind projects. Wind resources also satisfy the long-term requirements of the EIA and CETA. As with solar, the strong growth of wind generation has also benefitted from declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale wind capacity in the U.S. has grown from 46 GW in 2010 to over 150 GW[7] today. In 2023 wind generation provided over 10% of the total electric generation[8,9] in the US.

Wind resources considered by FPUD are assumed to have a three-year construction period and to be located within the BPA balancing authority. Based on market data, the cost of energy from a wind PPA, fixed for the duration of a 15-year term, is assumed to be $70/MWh for a project with a 2026 commercial date. Prices in subsequent years were based on expected changes in construction costs and subsidies available through the Inflation Reduction Act. Future overnight capital cost assumptions were provided by NREL in its 2023 Annual Technology Baseline. NREL projects utility-scale wind capital costs to decline by an average of 1.3%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. Figure 12 shows the projected wind PPA prices assumed in the study.

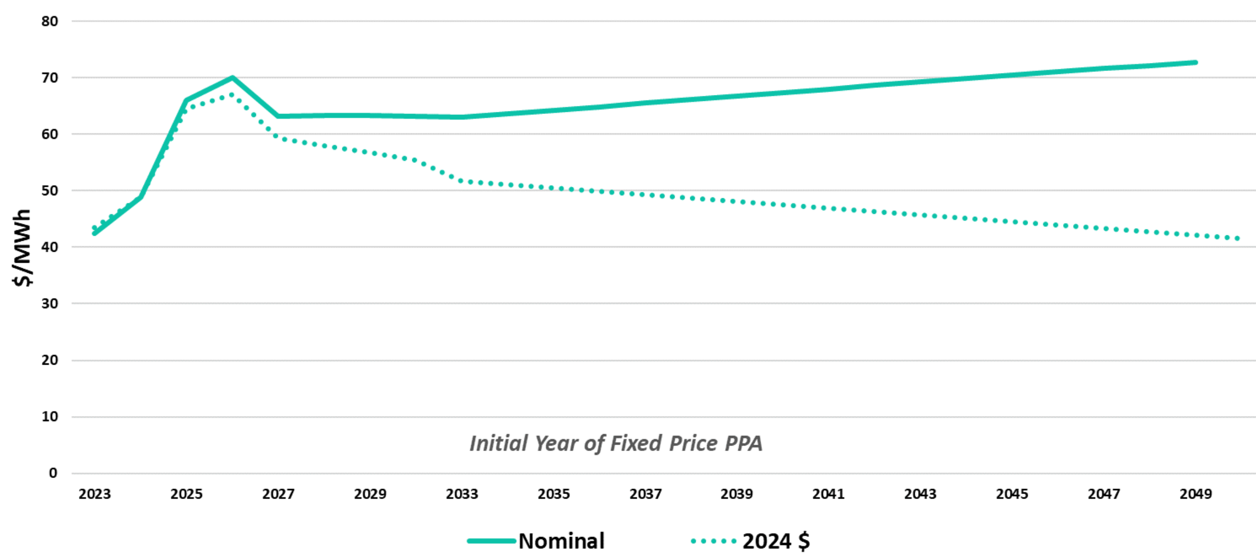


Figure 12. Pacific Northwest Wind PPA Price

[7] Buttel, Lindsey. America's Electricity Generation Capacity 2024 Update, American Public Power Association. URL: America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[8] Morey, Mark, and Jell, Scott. "Wind generation declined in 2023 for the first time since the 1990s." U.S. Energy Information Administration (EIA), April 30, 2024. URL: https://www.eia.gov/todayinenergy/detail.php?id=61943, accessed on 7/1/2024.

[9] Form EIA-923 detailed data with previous form data (EIA-906/920). U.S. Energy Information Administration (EIA). URL: https://www.eia.gov/electricity/data/eia923/, accessed on 7/1/2024.

6.3 Battery Storage PPA

Battery storage allows energy from the power grid or renewable resources such as wind or solar to be stored for later use. Enabling the storage and dispatch of power from renewable resources is vital in the transition towards cleaner, more sustainable energy and achieving full reliance on renewable and carbon-free generation by 2045.

Currently, most utility-scale battery storage installations rely on lithium-based battery chemistry. Advantages include high energy density, long cycle life, and a history of declining costs. For utility peak shaving or load shifting applications, a Li-ion battery can discharge at its rated capacity level for up to a 4-hour duration.

Battery storage is modeled as a Li-ion battery PPA with 4-hour discharge capability. Storage projects are assumed to have a 3-year construction period and to be located within the BPA balancing authority. The first year of availability is assumed to be 2027. Based on market data, the cost of battery storage, fixed for a 15-year term, is assumed to be $144/kW-yr in 2027. Prices in subsequent years are based on expected changes in construction costs and investment tax credits available through the Inflation Reduction Act. Future overnight capital cost assumptions are from the National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale battery storage capital costs to decline by an average of 2.7%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. Figure 13 shows the projected battery storage PPA prices assumed in the study.

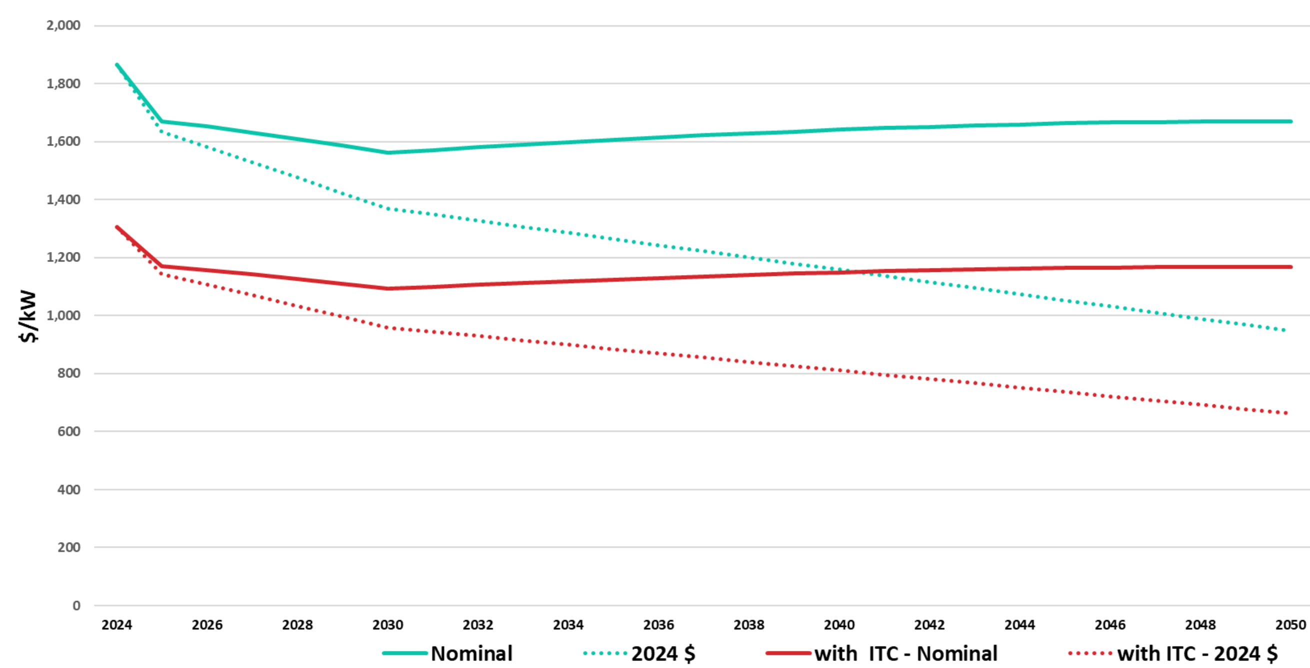


Figure 13. Battery Storage - Overnight Capital Cost

6.4 Geothermal PPA

Geothermal power is a renewable energy source that uses the natural heat stored beneath the earth's surface to generate carbon-free electricity. The U.S. is the world leader in geothermal electric generation with approximately 4 GW of installed capacity.

Conventional geothermal resources naturally contain the presence of hot rocks, fluid, and underground permeability. In these locations, wells are drilled to harness the naturally occurring reservoirs of steam or hot water to drive turbines and generate electricity. These reservoirs are typically found in limited regions with high geothermal activity.

New or Advanced Geothermal resources refer to emerging techniques that can be used to harness geothermal energy in areas without naturally occurring reservoirs. One such technique is Enhanced Geothermal Systems (EGS). EGS involves drilling deep into the earth's crust, injecting water into the rock to create fractures, and then circulating the water through the fractures to create steam and generate electricity. This method can theoretically be used anywhere, as heat is always present deep in the earth's crust, making it more versatile than traditional geothermal energy. These emerging geothermal technologies also include methods to improve efficiency and reduce environmental impact. For example, some systems are designed to reinject used geothermal fluids back into the ground to sustain the pressure of the geothermal reservoir and to prevent surface disposal of these fluids.

Given the limited options to supply the carbon-free generation required by CETA, FPUD considers electric generation using geothermal energy as a potential option in the future. In this IRP's Reference Portfolio Scenario, a 25 MW block of traditional Geothermal generation was assumed to be available to FPUD beginning in 2035 as well as 75 MW of new geothermal. New geothermal refers to Enhanced Geothermal Systems (EGS), which involves drilling into the earth's crust and injecting high-pressure water to create artificial geothermal reservoirs. The heated water is then brought back to the surface and used to generate power. New geothermal is more expensive than traditional geothermal but may be able to expand the use of geothermal generation which is now currently limited to geologically active sites. The cost of energy from a 25-year PPA based on traditional geothermal is assumed to be $90/MWh in 2024 dollars, while the cost of energy from a 25-year PPA based on new geothermal is assumed to be $105/MWh. These costs are escalated at the inflation rate of 2.2%/year.

6.5 Small Modular Reactor (SMR) PPA

SMR is an emerging technology that could play a significant role in decarbonizing the electric generation industry in the future. If brought successfully to market, the technology will provide flexible nuclear power generation in a smaller size than the current base load nuclear plants that typically exceed 1,000 MW. The compact designs can be factory-fabricated and transported by truck or rail to a designated site.

The modular design of SMRs allows for less on-site construction, increased containment efficiency, and enhanced safety due to passive nuclear safety features. Co-location of multiple modules of approximately 60 MW each would provide precise amounts of generating capacity in locations where power is specifically needed. SMRs are part of a new generation of nuclear technology and have the potential to reduce the financial burden and risk associated with nuclear power. SMR technology may prove to be a source of significant carbon-free electric generation in the future.

Given the requirements of CETA and the inability to utilize natural gas-fired generation beyond 2045, FPUD has been open to considering the inclusion of SMRs in its future resource portfolio and would prefer to purchase SMR generation through a PPA. In this IRP's Reference Portfolio Scenario, the first year of SMR availability is assumed to be 2035. Based on The Energy Information Administration's January 2024 report, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," developed by Sargent & Lundy, the cost of energy from SMRs is assumed to be approximately 45% higher than that of traditional geothermal; therefore, energy from a 25-year SMR PPA is assumed to cost $130/MWh in 2024 dollars and is escalated at the inflation rate of 2.2%/year.

6.6 Other Resource Options

Several additional opportunities are modeled in the study.

- Extension of existing PPA contracts
    - White Creek wind – a 10-year extension is assumed to be available from 2027 through 2036 at a cost of approximately $75/MWh in 2024 dollars escalated at the 2.2%/ annual inflation rate.
    - PowerEx hydro – two 5-year extensions are assumed to be available in 2029 and 2034 with a market-based variable charge and a fixed charge of approximately $110 to $120/kW-year
    - Nine Canyon wind – a 10-year extension is assumed to be available from 2030 through 2039 at a cost of approximately $83/MWh in 2024 dollars and escalated at the 2.2% annual inflation rate.
- BPA Tier 2

  From 2026 through 2028, up to 10 MW is assumed to be available in 5 MW blocks at a cost of $80 per MWh.

  From 2029 through 2035, up to 20 MW is assumed to be available in 5 MW blocks at a cost of $85 per MWh.

- Short-Term Contract

  Short-term (1-year) contracts of up to 125 MW in 25 MW block sizes are assumed to be available during the 2026-2034 period prior to the availability of geothermal and SMR PPAs. The energy price is assumed to be $90/MWh in 2024 dollars with no escalation.

Options considered in this study are summarized in Table 5.

Table 5. Supply Resource Options

Supply Options	Max Build (MW)	First Available (Date)	Economic Life (Years)	Unit Size (Net MW)	Contract Price (2024$/MWh)	FOM (2024$/kW-yr)	Escalation rate (%)
4-Hr Storage PPA	200	2027	15	25	0.00	144.00	Note[10]
BPA Tier 2 (2026-2028)	10	2026	2	5	80.00	0.00	0.00%
BPA Tier 2 (2029-2035)	20	2029	2	5	85.00	0.00	0.00%
Geothermal PPA (New)	75	2035	25	25	105.00	0.00	2.20%
Geothermal PPA (Traditional)	25	2035	25	25	90.00	0.00	2.20%
Nine Canyon (2030-2039)	10	2030	10	10	82.83	0.00	2.20%
PowerEx (2029-2033)	25/40	2029	5	25/40	Index	111.28[11]	0.00%
PowerEx (2034-2038)	25/40	2029	5	25/40	Index	116.85[11]	0.00%
SMR	100	2035	25	25	130.00	0.00	2.20%
Solar PPA	Note[12]	2027	15	20	75.00	0.00	Note[10]
ST Contract (2026-34)	125	2026	1	25	90.00	0.00	0.00%
White Creek (2027-2036)	10	2027	10	10	74.95	0.00	2.20%
Wind PPA	40	2027	15	5	75.00	0.00	Note[10]

[10]Emerging technologies like solar and storage follow a unique growth curve to accommodate for advancements in technology and government incentives.

[11]PowerEx FOM is projected based on existing rates, with a 5% increase for each extension.

[12]The solar installed capacity will gradually be permitted, allowing up to 200MW by 2029, then up to 400MW by 2033, and after 2040, there will be no limits.

Distributed Energy Resources (DER)

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

DER are typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DER are being adopted at increasing rates due to favorable policies from both state and federal governments, improvements in technology, reduction in costs, and identifiable customer benefits, both at the individual and grid levels. Once DER adoption passes certain levels, DER can begin to cause significant issues for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of ratepayers. It is important for electric utilities to identify potential economic and grid issues and benefits from DER. DER are becoming more widespread with increasing commercial availability, decreasing costs, and evolving consumer preferences. FPUD is proactively investigating and exploring programs and 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.

Section 7 Market Simulation

7.1 Methodology Overview

Long-term resource planning requires a fundamental price forecast used to value existing and future capacity resource options. Operators, participants, and other market entities utilize a production cost model to simulate future market conditions to forecast prices. This following section details the methodologies used to create a market environment outlook that can generate prospective power prices.

7.1.1 Modeling Approach

Electric price simulation is generated using a fundamental production cost model. Figure 14 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 load forecasts, regional generation portfolio changes, carbon penalty assumptions, and regional RPS. The second phase of the study uses the inputs from the first step to run a capacity expansion analysis. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 20-year time horizon. In the third and final phase, the long-term production cost model performs a 20-year dispatch of the entire Western Interconnect using the modified supply stack to simulate market prices. The following sections will describe how the model assumptions and inputs were derived, and the price simulation in further detail.

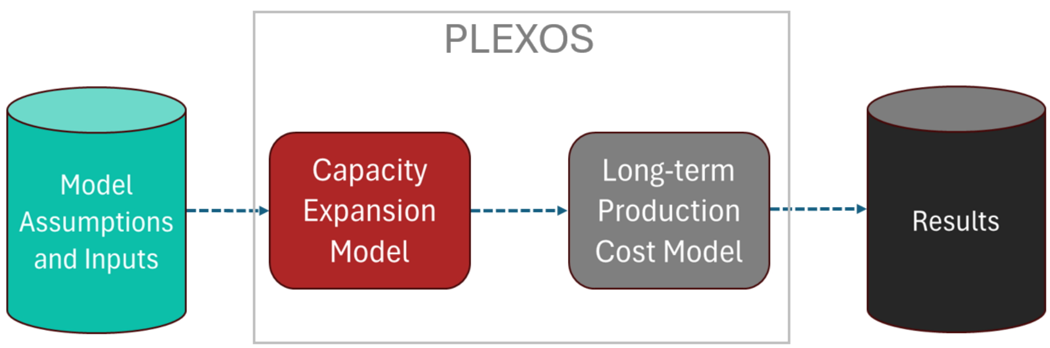


Figure 14. Modeling Approach

7.1.2 Model Structure

The primary tool used to determine the long-term market environment is PLEXOS. PLEXOS is a production cost software, licensed through Energy Exemplar LLC, that simulates the supply and demand fundamentals of the physical power market and ultimately produces a long-term power price forecast. Using factors such as economic and performance characteristics of supply resources, regional demand profiles, and zonal transmission constraints, PLEXOS then simulates a Western Electricity Coordinating Council (WECC) system expansion to produce a generation portfolio capable of satisfying future electricity demand. The model simulates resource dispatch which is then used to create long-term price and capacity expansion forecasts.

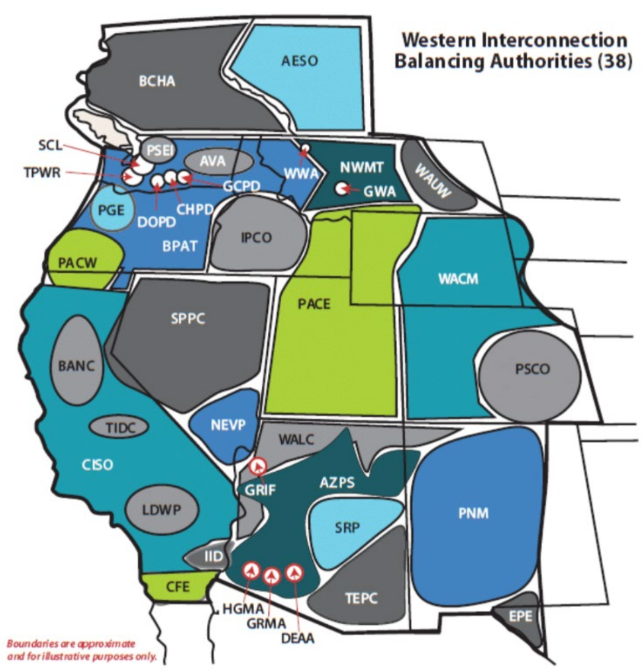
PLEXOS is utilized for three main purposes:

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

Forecast drivers were either created or leveraged from reputable third-party vendors for such key variables as regional load growth rates, planning reserve margins, natural gas prices, hydro generation, and carbon prices. Renewable resource additions were set to correspond to the regional load growth and RPS set by each state. Upon the completion of a WECC footprint capacity expansion study, a set of scenario analyses was conducted using various combinations of natural gas and carbon prices. These scenarios were used to generate a long-term price forecast for the Mid-Columbia (Mid-C) trading hub.

7.1.3 WECC-Wide Forecast

The 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). PLEXOS 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. Although the study forecast focuses on the Mid-C electricity market, it is important to model the entire region due to how fundamentals in other parts of the WECC can exert a strong influence on the Pacific Northwest market. 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.

7.1.4 Long-Term Fundamental Simulation

A vital part of the long-term market simulation is the capacity expansion analysis. The study utilized PLEXOS to determine what types of generation resources will likely be added in the WECC over the next 20 years, given our current expectations of future load growth, natural gas prices, and regulatory environment. PLEXOS' WECC dataset includes known or projected retirement dates for existing resources as well as online dates for proposed resources. PLEXOS then conducts a capacity expansion simulation in which load increases, resources are retired or derated due to regulatory requirements, and new generating resources are added to serve load requirements and meet planning reserve margins and RPS requirements. The resources that are chosen are the best economic performers – i.e., the resources that provide the most regional benefit for the lowest price based on the constraints previously detailed.

7.2 Principal Assumptions

Market conditions change regularly, driven by a multitude of factors. Energy demand, regulations, fuel and capital costs, and environmental goals all influence the future economic viability of generating resource options. As regional resource portfolios transform, power price values and shapes will shift. The intent of this section is to detail the methodologies used to model the expected changes across the WECC footprint during the 2020s through the 2040s that will best capture the impact to future power prices that will be used in the portfolio analysis.

7.2.1 WECC Load

PLEXOS's default annual demand forecasts for zones in the WECC region are based on WECC's Data Archives and FERC-714 filings. The data available in the PLEXOS WECC database includes loads for 34 regions through 2054. FERC only published forecast data for ten years and to account for the additional years, the final three-year average of the FERC growth is applied to generate load by region, for the subsequent years. For example, on average, annual peak load is expected to increase at a 0.86% rate.

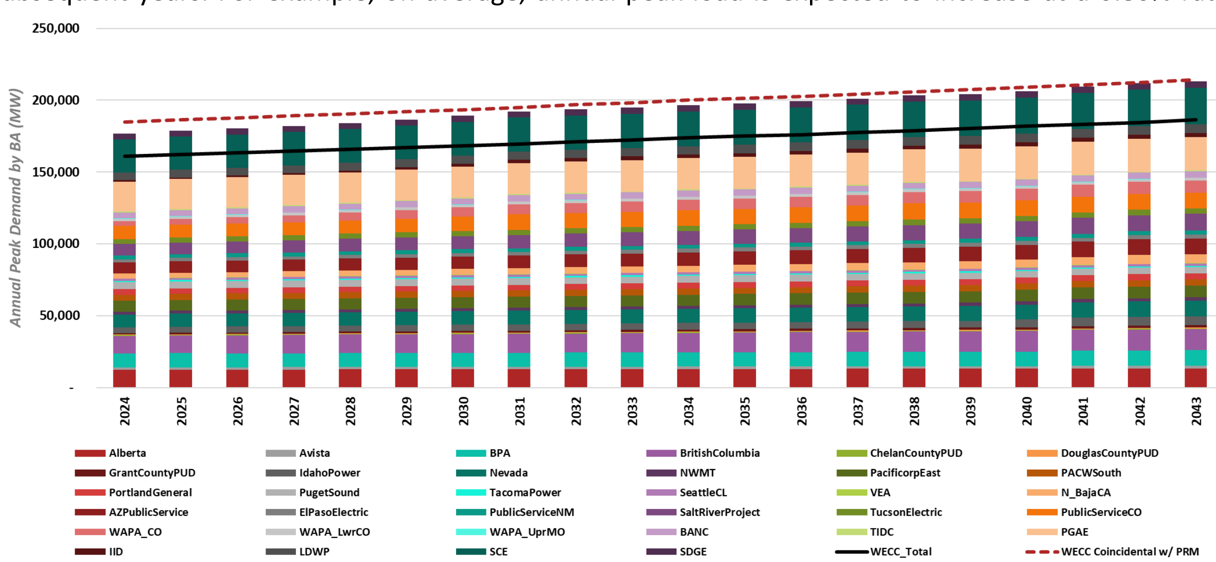


Figure 15. WECC Annual Peak Load Projections

Annual load projections are then shaped at the hourly level using three-year historical hourly load data and Energy Exemplar's "Smooth-Ranked" methodology, which removes volatility and creates a typical hourly load profile. The typical load profile, in conjunction with the total and peak energy inputs and PLEXOS build function, are used to develop the hourly load forecast in PLEXOS through 2054 for each region.

7.2.2 Regional Planning Reserve Margins (PRM)

To ensure there will be sufficient generating capacity to meet demand, a defined amount of generating reserve capacity is built into the market. These operating reserves are often extra generating capacity at existing operating plants, or fast-start generators, which can start-up and reach maximum capacity within a short amount of time. Historically these fast-start resources have been natural gas-fired generators, but the shift to batteries or other energy storage resources is on the rise.

Planning reserve margins (PRM) 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 PRM is an important metric used to determine the amount of new generation capacity that will need to be built in the future. A 15% planning reserve margin on each zone was modeled during the capacity expansion simulation, consistent with WECC reliability assumptions in the 2021 WECC Western Assessment of Resource Adequacy.

7.2.3 WECC Renewable Portfolio Standards (RPS)

RPS are state-level requirements that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. Currently, there are not federally mandated RPS requirements; instead, states have set their own based on their environmental, economic, and political needs.

Among states in the WECC, California has the highest RPS requirement at 60% by 2030, with Oregon following shortly behind it with a 50% requirement for its IOUs by 2040. In Washington, there is a 15% RPS requirement, but with the 2019 enactment of the Clean Energy Transformation Act (CETA), there is now also an 80% carbon-free requirement by 2030. A wide variability in the requirements exists between states in the region, which could have a sizeable effect on electricity pricing within the region. Figure 16 details the RPS goals for each state or province included in the PLEXOS WECC database.

State/Province	Program Type	Description
Alberta	RPS	30% renewable energy by 2030
Arizona	RPS	15% renewable energy by 2025
California	RPS	60% renewable energy by 2030
Colorado	RPS	30% renewable energy by 2020
Neveda	RPS	50% renewable energy by 2030
Neveda	PRS_Solar	6% solar energy by 2030
New Mexico	RPS	80% renewable energy by 2040
New Mexico	PRS_Solar	4% solar energy by 2040
Oregon	RPS	50% renewable energy by 2040
Utah	RPS	20% renewable energy by 2025
Washington	RPS	15% renewable energy by 2020

Figure 16. PLEXOS WECC RPS Assumptions

7.2.4 Carbon Goals and Pricing

Initiative 2117 (I-2117) is to be voted on in the November 2024 election. If passed, I-2117 would eliminate the CCA and prohibit the existence of any cap-and-trade programs within the state of Washington. Given at the time of the IRP the outcome of this initiative is unknown, the IRP assumes that the Cap-and-Invest program will continue as planned, and thus includes the cost of carbon as an input to the market simulation. Figure 17 details the Carbon Reduction goals for each state or province included in the PLEXOS WECC database.

State/Province	Program Type	Description
British Columbia	Carbon	93% renewable of zero-carbon by 2020
California	Carbon	100 zero-carbon by 2045
Neveda	Carbon	100 zero-carbon by 2050
New Mexico	Carbon	100 zero-carbon by 2045
Oregon	Carbon	100 zero-carbon by 2040
Washington	Carbon	100 zero-carbon by 2045

Figure 17. PLEXOS WECC Carbon Goal Assumptions

For carbon pricing the IRP uses recent auction settlements and bilateral Washinton Carbon Allowance (WCA) and California Carbon Allowance (CCA) trades on ICE as inputs to the expected case in Figure 18. The WCA 2024 expected price of \$52/MT CO2e was based on an average of the most recent 100 days of WCA ’24 settlements on ICE as of February 2024. Similarly, the CCA 2024 expected price of \$42/MT CO2e was based on an average of the most recent 100 days of WCA ’24 settlements on ICE as of February 2024. From 2027 onward, one carbon price was assumed for both Washington and California given the expectation that Washington and California will link markets after Washington’s first compliance period ends. The WCA floor price and ceiling prices were set to Ecology’s 2024 floor and ceiling prices of \$24/MT CO2e and \$88/MT CO2e respectively. All prices were escalated by 5% annually based on the WAC 173-446-335 rule that states floor and ceiling prices will be escalated by 5% plus inflation annually.

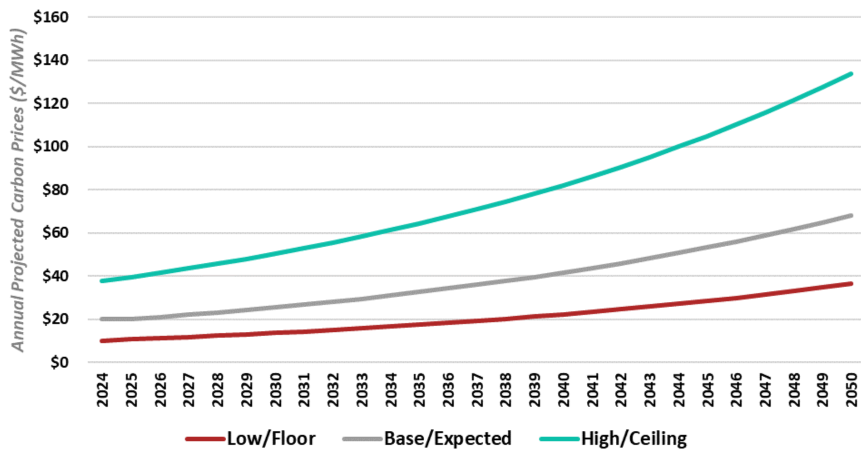


Figure 18. Washington Carbon Allowance Price Assumption in $/MWh in nominal dollars. Uses the $/MT CO2e price assumption multiplied by the unspecified per MWh emissions.

7.2.5 Natural Gas Price

TEA developed a base case forecast of Pacific Northwest natural gas prices that was used in all scenarios. The forecast was based on February 7, 2024 NYMEX prices through 2027 and Henry Hub price forecasts developed by S&P Global for the remainder of the study period. S&P Global price forecasts are based on a detailed analysis of natural gas supply and demand fundamentals. The forecasts referenced were from the January 2024 short-term and September 2023 long-term outlooks.

In addition to the base case forecast, TEA has high and low natural gas price forecasts. The high forecast is based on the Low Gas and Oil Supply Availability forecast from the 2023 Annual Energy Outlook (AEO23) produced by the Energy Information Administration (EIA). The low forecast is based on the AEO23 High Gas and Oil Supply Availability forecast. These forecasts are shown below in Figure 19.

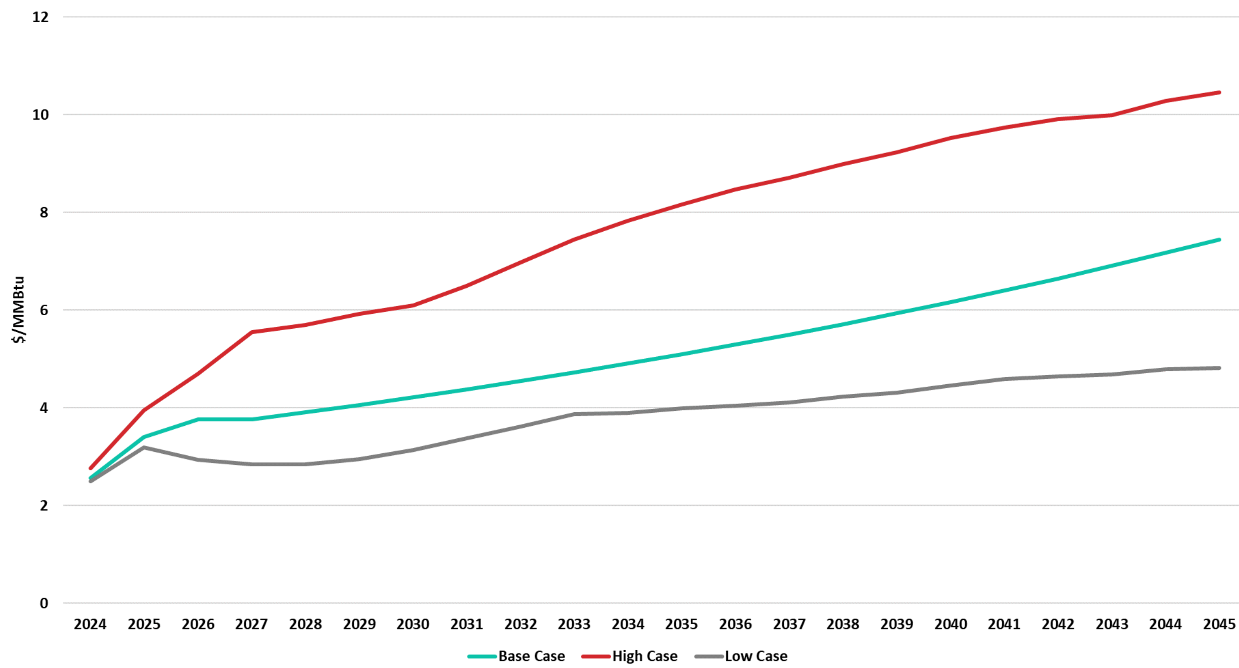


Figure 19. Annual average Henry Hub natural gas price, by price scenario

In the base case, Henry Hub prices in nominal dollars grow from an average of $2.56/mmBtu in 2024 to $7.45/mmBtu in 2045 (see Figure 20 below). The average annual growth rate during this period is 5.2%. Future U.S. LNG exports and an eventual shift to higher-cost natural gas basins are the major factors driving this price increase.

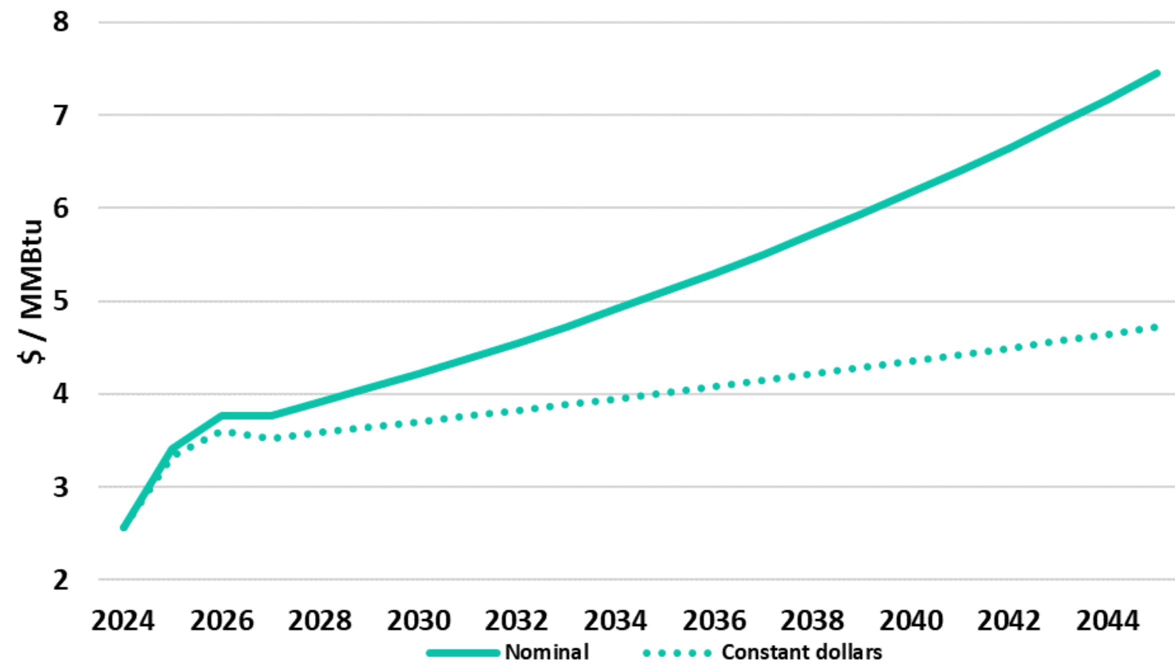


Figure 20. Natural gas prices at Henry Hub in nominal and constant 2024 dollars per mmBtu.

TEA added a basis estimate to the Henry Hub price forecast to estimate future prices delivered to Washington. The projected basis was derived by comparing forward price curves from April 8, 2024 for Sumas and Stanfield to NYMEX. Based on historical data, TEA assumed that 58% of deliveries would come through Sumas and 42% through Stanfield. The price of natural gas delivered to the Pacific Northwest and the natural gas price at Henry Hub are shown in Figure 21 below.

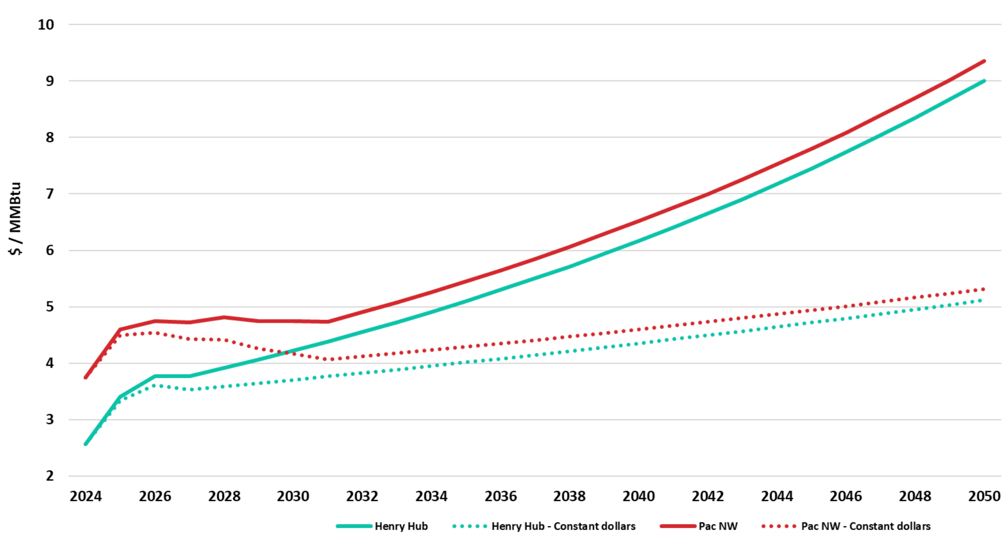


Figure 21. Annual natural gas prices delivered to the Pacific Northwest for the 2024 through 2045 period.

Figure 22 compares the Pacific Northwest pricing to that of Henry Hub. Note that the basis differential between Henry Hub and the Pacific Northwest is typically negative for April through October and positive for the winter months of November through March.

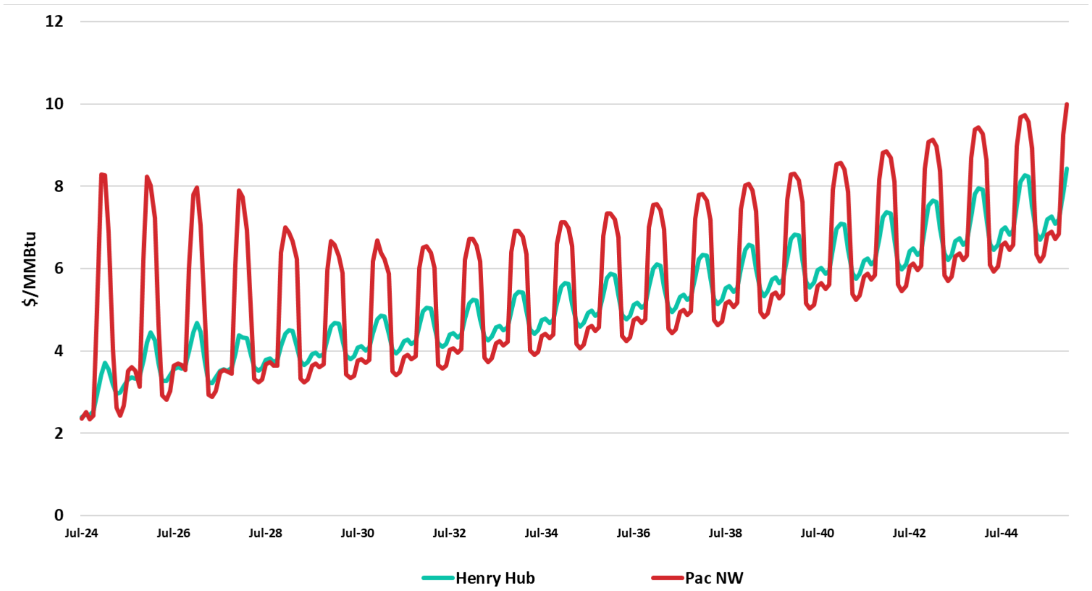


Figure 22. Henry Hub versus Delivered Pacific Northwest Natural Gas Prices

7.3 Simulations

After the development of the market model and assumptions, the model itself can be used for various purposes. First, a capacity expansion simulation was conducted where resources are removed and added to the market footprint based on constraints and market drivers. Second, the resulting portfolio was in a market dispatch simulation that produced forward power prices. These forward power prices are a fundamental input to the portfolio analysis that determines the least cost solution to meet future capacity needs. The following sections detail the process.

7.3.1 Capacity Expansion & Retirements

The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, storage, hydro, geothermal, and biomass. The PLEXOS WECC dataset contained economic assumptions for each resource option, such as capital cost, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal efficiency), performance standards such as forced and scheduled maintenance rates, and generation shapes for variable energy resources. The update to existing resources resulted in significant changes in the pattern and volume of new natural gas, wind, and solar capacity built as WECC continues to divest its interest in conventional energy resources for more sustainable/renewable sources.

Figure 23 details the baseline year-by-year capacity retirements and additions across the WECC system from 2023-2040 prior to the capacity expansion simulation. Announced retirements for existing resources are input into the model with their scheduled retirement dates, which include many coal resources set to retire throughout the decade. In addition to coal resources, the Diablo Canyon Nuclear facility, the last nuclear plant in California, will retire by 2029. Just under 28 GW of capacity is expected to be retired, with 90% of that being either coal or natural gas. Over 33 GW of known capacity is estimated to be installed in the system by 2032; of which 45% is expected from solar generators, followed by natural gas at 27%, 24% wind, and 2% hydro.

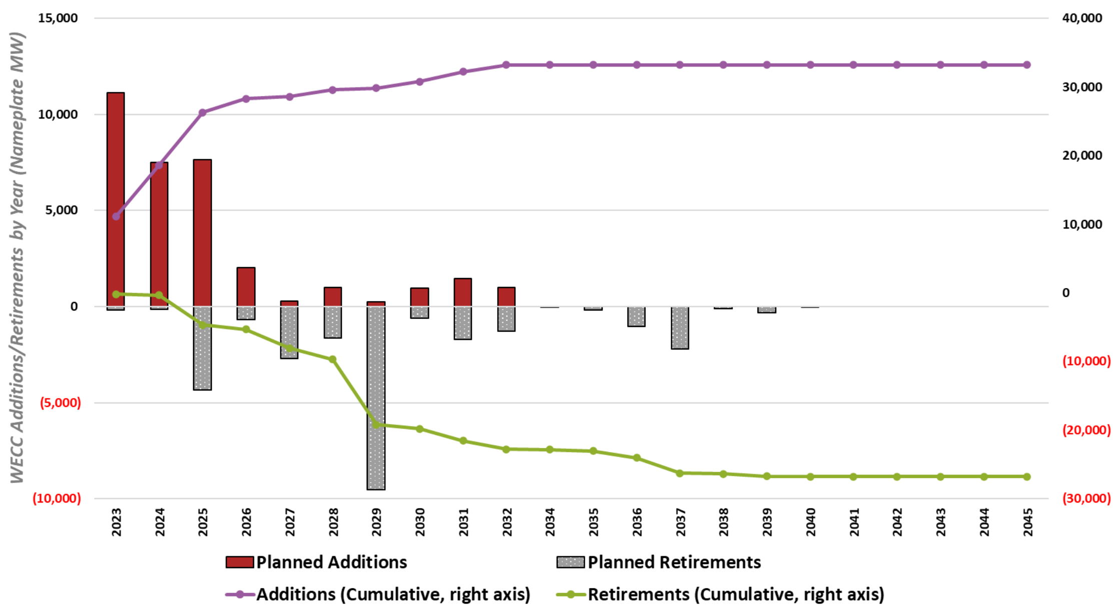


Figure 23. WECC Generation Additions and Retirements (pre-Capacity Expansion)

Based on the parameters outlined above, PLEXOS then determines the ideal mixture of new resource additions and further retirements to meet the input constraints in the most economical way. In conjunction with the expected retirements and additions noted above and the PLEXOS baseline capacity expansion simulation, the 2023 Western Assessment of Resource Adequacy was used to supplement the resource additions. A summary of the near-term, mid-term, and long-term period additions can be seen in Figure 24.

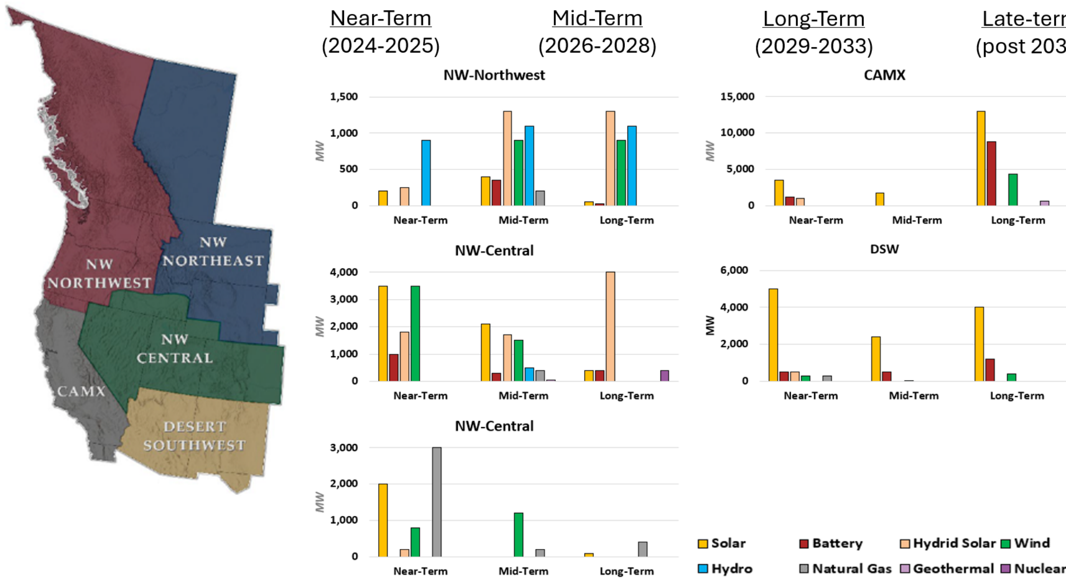


Figure 24. WECC Generation Additions and Retirements (post-Capacity Expansion)

Resources added post-2033 were done exclusively by PLEXOS for meeting either demand needs or RPS goals. Figure 25 illustrates the total additions, year by year, across the entire WECC capacity expansion simulation.

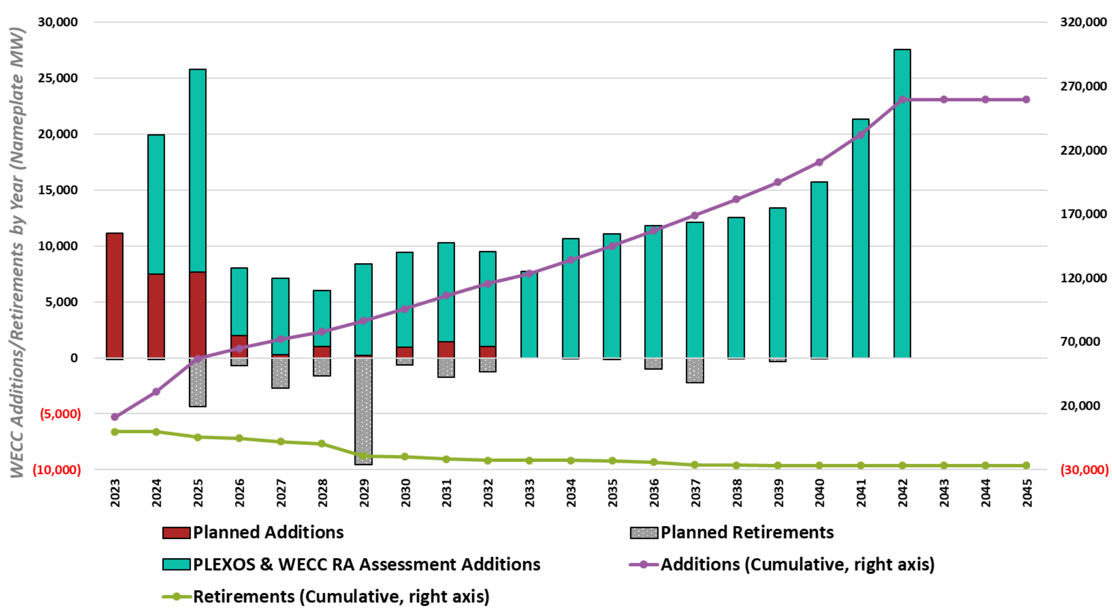


Figure 25. Annual nameplate capacity retirements and additions

Over 90 GW of new generation is added to the WECC footprint by 2033 with Wind and Solar making up 53 GW and Batteries and Hybrid making up 28 GW. By 2042, the final year of the capacity expansion simulation, nearly 260 GW of new generation is available to WECC. The notable drivers for adding this volume of new generation is due to the reduction in capacity accreditation for standalone wind and solar project, but the added need for these resources in order to meet the carbon reduction goals, most of which hit their 100% adoption in the 2040s. A breakdown in percentage of fuel type is represented in Figure 26.

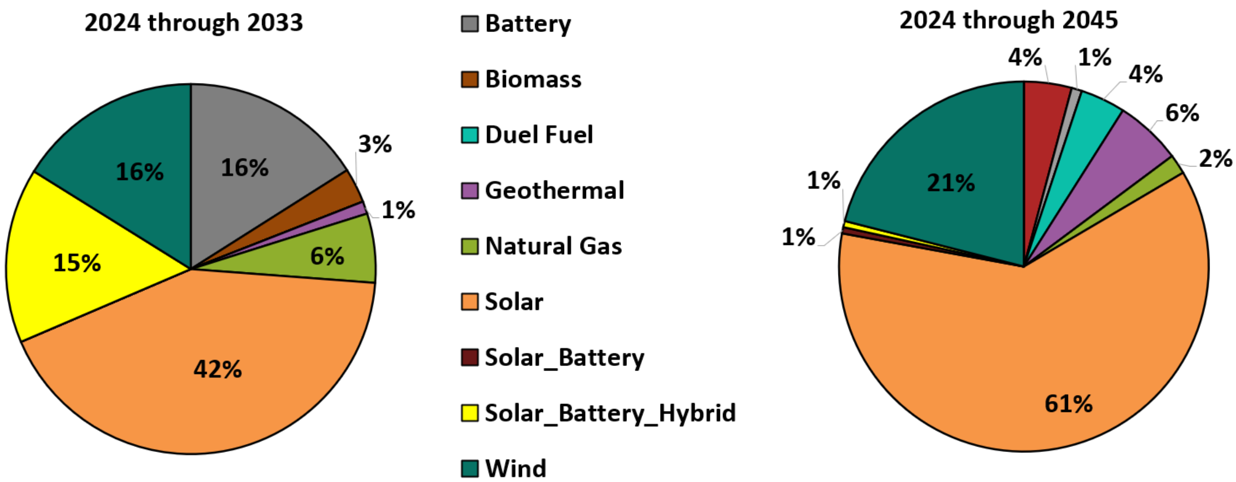


Figure 26. WECC Capacity Additions Percentages (Nameplate), by Fuel Type

Figure 27 and Figure 28 illustrate the expected new resource expansion and retirements through 2042 in the Pacific Northwest and California/Mexico regions.

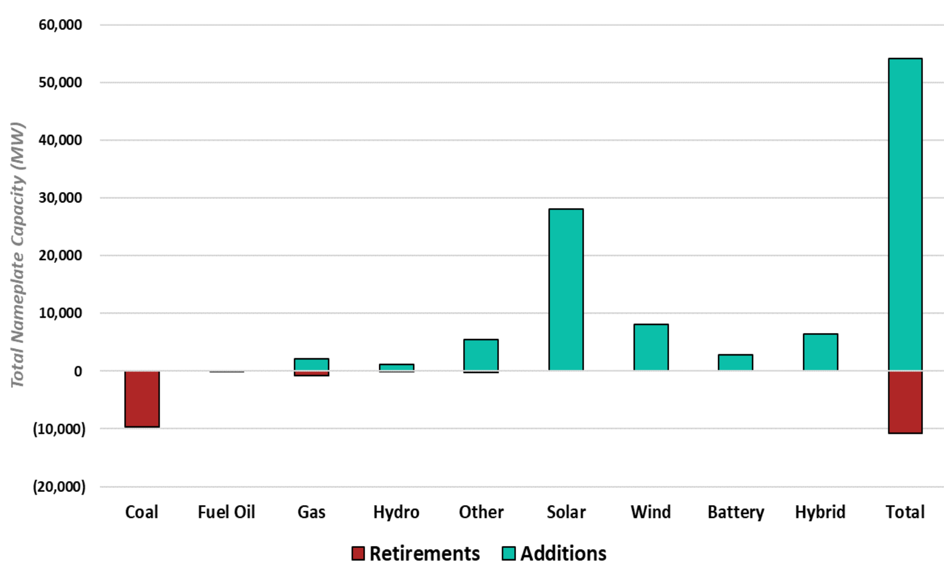


Figure 27. Forecasted Pacific Northwest Generation Capacity Retirements and Additions through 2042, by Fuel Source

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

Solar is the renewable fuel type of choice for fulfilling RPS requirements across the simulation. A shift to batteries or hybrid resources occurs in the mid-term and long-term periods. The cumulative expansion in the Pacific Northwest over the study period is over 54 GW, of which 8 GW comes from wind, 28 GW from solar, and 9 GW from batteries or hybrid resources.

In addition to a significant build-out of solar in the region, just 2,100 MW of Combined Cycle (CCGT) or Combustion Turbine (CT) Gas generation is added. This addition largely offsets some of the lost capacity from retiring coal generation. Due to the assumption of increasing loads across the WECC, more capacity will be required to serve load, and this build-out of natural gas resources, coupled with the addition of storage, supports the growing need for capacity in the region. The additional cost of carbon and future carbon reduction goals, however, puts thermal resources at a disadvantage for meeting overall energy needs, preventing a higher buildout of this resource type.

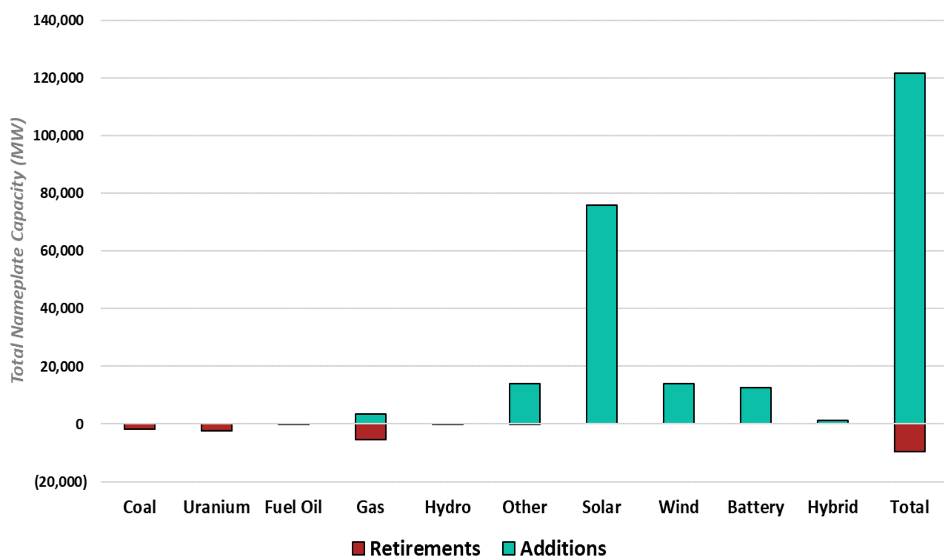


Figure 28. Forecasted California Generation Capacity Requirements and Additions through 2042, by Fuel Source

In California, there are substantial natural gas and coal resource retirements and the retirement by 2030 of Diablo Canyon, the final nuclear facility in CAISO. As in the Northwest, most of the generation expansion is from solar (76 GW), wind (14 GW), and batteries/hybrid (14 GW), but there is also over 14 GW of geothermal expected to be added. By 2042 over 121 GW of new generation is projected to be added to meet California/Baja demand, RPS, and carbon reduction goals.

7.3.2 Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained for various future scenarios. Figure 29 shows the average monthly nominal heavy load hourly (HLH) and light load hourly (LLH) Mid-C power prices from the long-term WECC dispatch simulation.

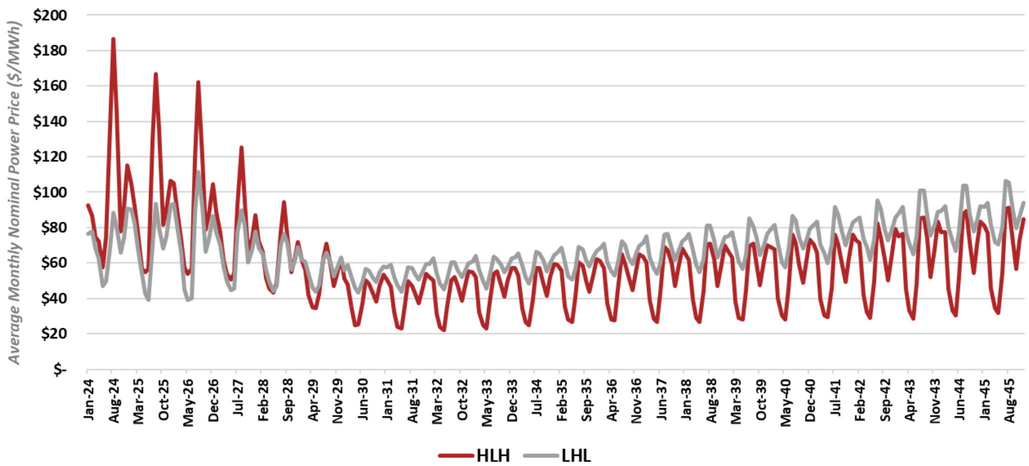


Figure 29. Historical and Forecast Mid-C Prices

Within the past couple of years, a paradigm shift has started in some US-based markets and regions. Where traditional HLH prices have been at a premium to LLH, some months of the year have begun to post pricing for LLH above HLH. This is a dramatic shift in the power market and correlated to the implementation of large volumes of Solar generation. During the spring hydro runoff period, low loads, and low natural gas prices, when combined with an increase in renewable generation, lead to the collapse of the HLH premium. Results from the WECC market simulation project an annual switch from HLH to LLH being the premium time-of-use product to occur in the late-2020s as seen in Figure 30.

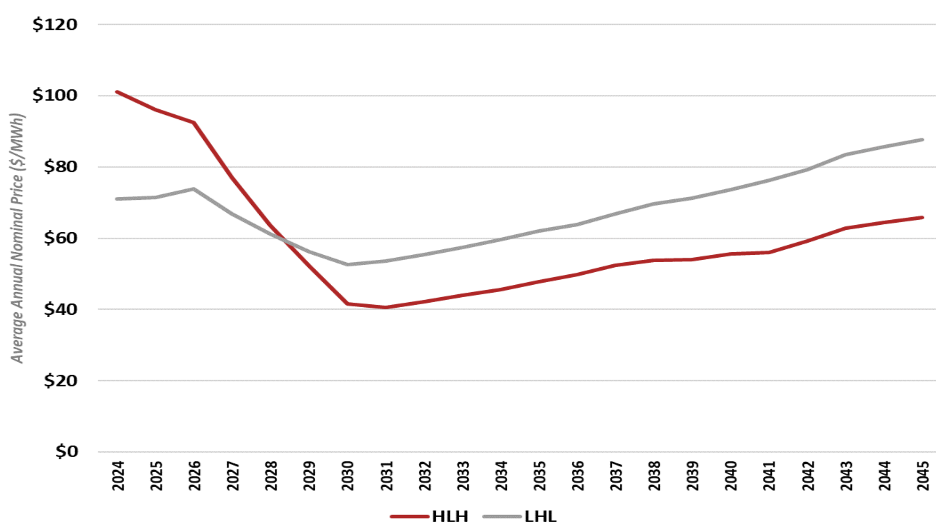


Figure 30. Projected Annual Mid-C Prices

Figure 31 below shows the average 24-hour profile of Mid-Columbia power prices by season across various years in the simulation. This view is intended to show the expected change in the shape of Mid-C prices as volumes of renewable generation is added to the system. The “Duck Curve” traditionally seen in California prices begin to take shape in the northwest power markets by the late 2020s. As mentioned earlier, the spring hydro runoff, low load, and now high renewable generation are expected to push power prices down to the $0/MWh level for extended hours during the Spring season.

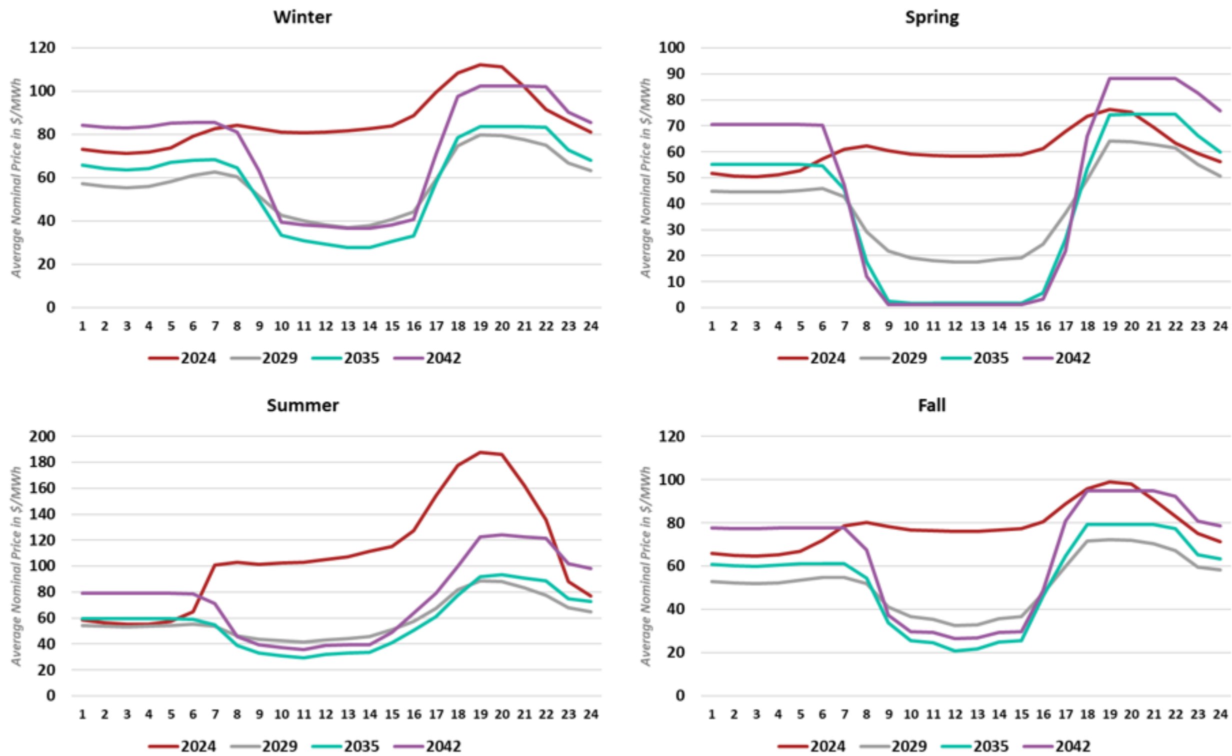


Figure 31. Projected Mid-C Average Hourly Price Profile, by Season, for 2024, 2029, 2035, and 2042

7.4 WECC Simulation Scenario Analysis

In addition to the above Base Case scenario, three alternative scenarios were considered. Although not used in the IRP analysis itself, these scenarios are intended to stress two of the key assumptions, natural gas and carbon prices, that went into the market simulation, and, based on the IRP team’s judgment, could potentially change in the future. 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 three alternative scenarios include:

1) Base Natural Gas and No Carbon Prices: Although this scenario did not consider a change in the natural gas prices it did remove the additional cost on the WECC system associated with carbon pricing in the Northwest. This scenario was intended to simulate a future where I-2117 is passed, and the Washington Cap-and-Invest program is eliminated.

2) High Natural Gas and Ceiling Carbon Prices: Carbon reduction goals across the US have become more progressive. A future where added pressure on natural gas production and usage is very plausible. In this future, it is also believed that to curtail natural gas usage and further development in the generation

technology, added costs to carbon production would be needed as well. This scenario is meant to simulate this type of future.

3) Low Natural Gas and Floor Carbon Prices: In the case of higher than anticipated renewable and low carbon buildout, both Natural Gas and WCA prices would see a commensurate reduction compared to the base case.

In Figure 32 the annual average nominal Mid-C price for all four scenarios is presented. In all four scenarios the years 2024 and 2025 are held to be the same. Starting in 2026, prices begin to diverge as the impact of having different natural gas and carbon prices in the simulations take hold.

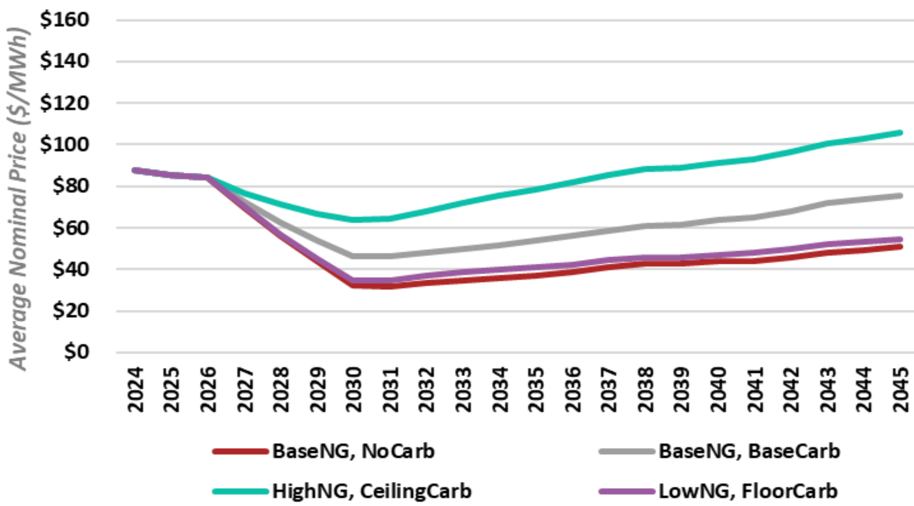


Figure 32. Projected Mid-C Average Nominal Price, by Scenario

As expected, removing the carbon price, and reducing the natural gas and carbon prices produces a market environment details the change in price for the alternative scenarios as compared the Base Case across the 2024-to-2045-time horizon.

	BaseNG, NoCarb	BaseNG, BaseCarb	HighNG, CeilingCarb	LowNG, FloorCarb
Average Price	**$49.03**	**$63.53**	**$83.14**	**$51.68**
Price Difference ($/MWh)	**-23%**		**31%**	**-19%**
Price Difference (%)	**($14.50)**		**$19.61**	**($11.85)**

Figure 33. Variance from Base Natural Gas and Base Carbon Scenario

Section 8 Risk Analysis and Portfolio Selection

FPUD's objectives are to develop an optimal resource plan capable of managing uncertainties in projected monthly peak demands and to meet the WRAP requirements. The IRP process is a strategic approach used to achieve these objectives. It evaluates and plans for future capacity and energy requirements while considering various objectives and constraints. It involves a comprehensive analysis integrating technical, economic, environmental, and regulatory factors to develop a balanced and optimal resource plan. The IRP process also uses scenario and sensitivity analysis to detect gaps, communicate insights, and identify risks and opportunities.

Scenarios typically involve key business decisions or pathways based on varying one or more assumptions. The assumptions can encompass changes in an organization's portfolio, the timing of decisions, or regulatory factors impacting the organization. These scenarios allow the organization to explore a range of possibilities and assess how different factors might influence the outcomes of the IRP.

Sensitivity analysis is used to evaluate how sensitive the outcomes of the IRP are to varying input variables. Its use is important in assessing reliability, understanding uncertainty, and enhancing the robustness of resource plans. It quantifies the impact of changes in each input variable on the outputs by varying one input at a time while holding all others constant. This analytical approach supports developing plans that are resilient and adaptable to changing conditions, thereby mitigating risks effectively.

The IRP incorporates several key assumptions guiding FPUD's decisions on future energy and capacity resources:

- **20-year demand forecast:** A prediction of electricity consumption over two decades guiding capacity planning and infrastructure investment decisions.
- **Existing and planned resource dispatchable variable cost:** The operational costs associated with current and future dispatchable resources, influencing operational decisions and cost projections.
- **Supply-side generation resource options:** Estimation of factors such as availability, capital expenditures, fixed costs, and variable costs for the development and procurement of various generating technologies.
- **Fuel, economic, and market product costs:** Projections of fuel prices, economic indicators such as inflation and discount rates, and market prices for electricity and related products.

These assumptions, among others, provide a comprehensive framework for FPUD to make informed decisions regarding existing capacity resources and strategically plan for future requirements. They form the basis for developing a resilient and cost-efficient plan that aligns with regulatory requirements and market dynamics.

This study uses a long-term generation expansion model to determine the least cost replacement and expansion resource mix. The PLEXOS electricity production cost model is used to simulate FPUD's production cost and interactions within the electric market. PLEXOS integrates the system and resource assumptions to optimize and select the least cost resource mix.

The primary goal of PLEXOS is to minimize the incremental Net Present Value of Revenue Requirements (NPVRR) while complying with system and regulatory requirements. NPVRR represents the net cost that must be recovered for all resources in FPUD's portfolio, adjusted for the time value of money. This includes capital costs for new resources, variable costs, and fixed costs incurred during the study period. It excludes existing debt service costs, sunk costs prior to the study period, and costs incurred 5 years beyond the study period.

The model provides a mathematically optimal selection of future resources based on defined input assumptions, diverse resource types and capacities, and specific constraints such as import limits and minimum reserve margins.

8.1 Scenario Cases and Results

FPUD has considered two scenarios to help meet its objectives: the Reference Portfolio and a Renewable portfolio. The Reference Portfolio is used as a baseline to compare against other scenarios and sensitivities. For the Reference Portfolio the following assumptions were provided:

- Inflation rate of 2.2% and a discount rate of 4.75%.
- WRAP reserve requirements, as detailed in Section 3.5, include additional constraints aimed at ensuring seasonal adequacy rather than focusing solely on peak month demands.
- Base Load as described in Section 4.2.
- Operating information and variable costs for existing owned and contracted resources.
- Supply-side generation resource options in accordance with 0.
- Base natural gas price and market price forecast as discussed in Sections 7.2.5 and 7.3.2 respectively.

In the Reference Portfolio, FPUD assumes that the WRAP implementation starts in November 2027 and continues through the entire planning horizon.

Acknowledging the cost competitiveness and environmental benefits of renewable energy initiative, FPUD also assumes a scenario to explore more aggressive implementation of wind and solar energy sources. Restrictions on the adoption have been removed from both wind and solar energy sources, but limits remain on battery storage adoption. Table 6 outlines how the scenarios are incorporated into the IRP.

Table 6. Scenario Analysis Assumptions

Scenario	Load	NG Price	Carbon	WRAP Implementation	Technology
Reference Portfolio	Base	Base	Base	11/2027	Base
Renewable Portfolio	Base	Base	Base	11/2027	Unlimited wind & solar

8.1.1 Reference Portfolio Results

The PLEXOS modeling software optimized a cost-effective portfolio, illustrated in Figure 34, to fulfill FPUD's seasonal WRAP requirements throughout the study horizon. The figure depicts existing resources and proposed additions optimized to meet the WRAP requirements. Resources identified by PLEXOS are labeled as "New" with their respective source type, ST Contract or Tier 2. Existing resources are projected to satisfy average energy consumption through 2028, highlighting a need for intermediate to peak resources to bridge the gap thereafter. PowerEx 10-year extension has been selected to meet average energy, complemented by the integration of battery storage and short-term energy solutions. Battery storage selection incorporates capacity and operational advantages. Initially, Short-term energy and capacity needs are fulfilled by Tier 2 and ST contracts later transitioning on to battery storage. Solar additions are progressively expanded to meet the remaining capacity and energy needs.

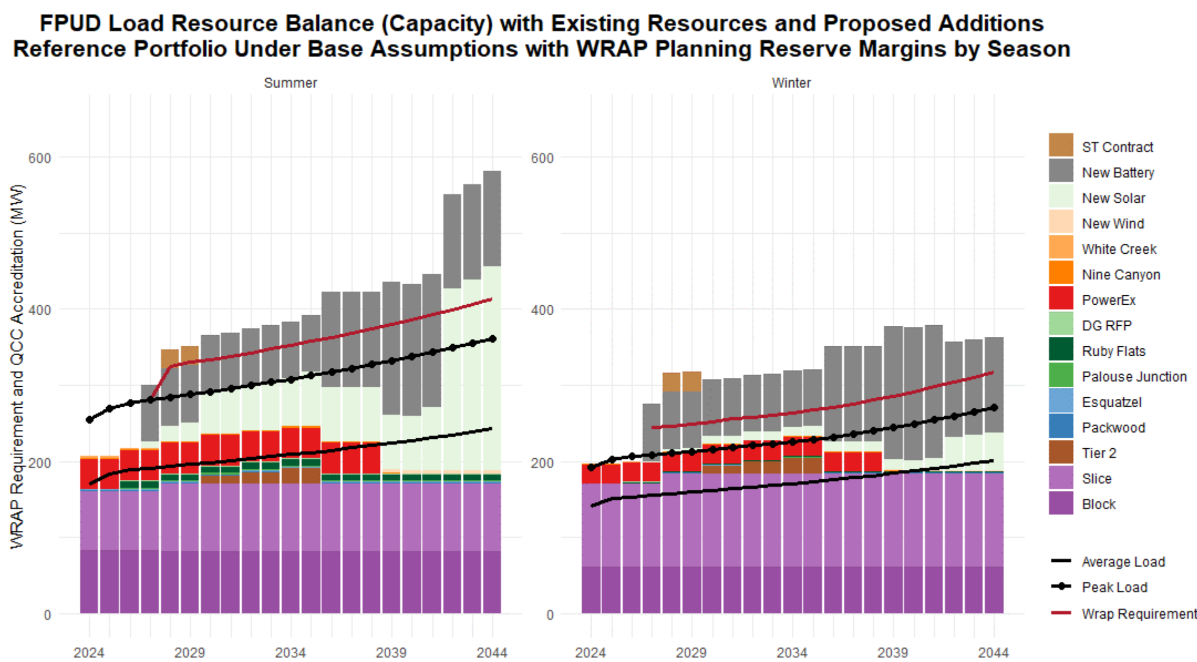


Figure 34. Demand and Resource Load Balance for Reference Portfolio

Figure 35 displays the seasonal energy generated by the existing and proposed resource additions in average megawatts (aMW) per year. This measure is derived by dividing the resource's seasonal energy production by the total number of hours in a season. FPUD's current resources, including the PowerEx extensions, meet average energy consumption through 2038. Beyond 2039, when the PowerEx contract expires, solar and wind energy sources will be utilized to fill the energy gap. The intermittent nature of these sources reduces the system flexibility; however, integrating battery storage and leveraging the market can enable economic sales and enhance energy management capabilities.

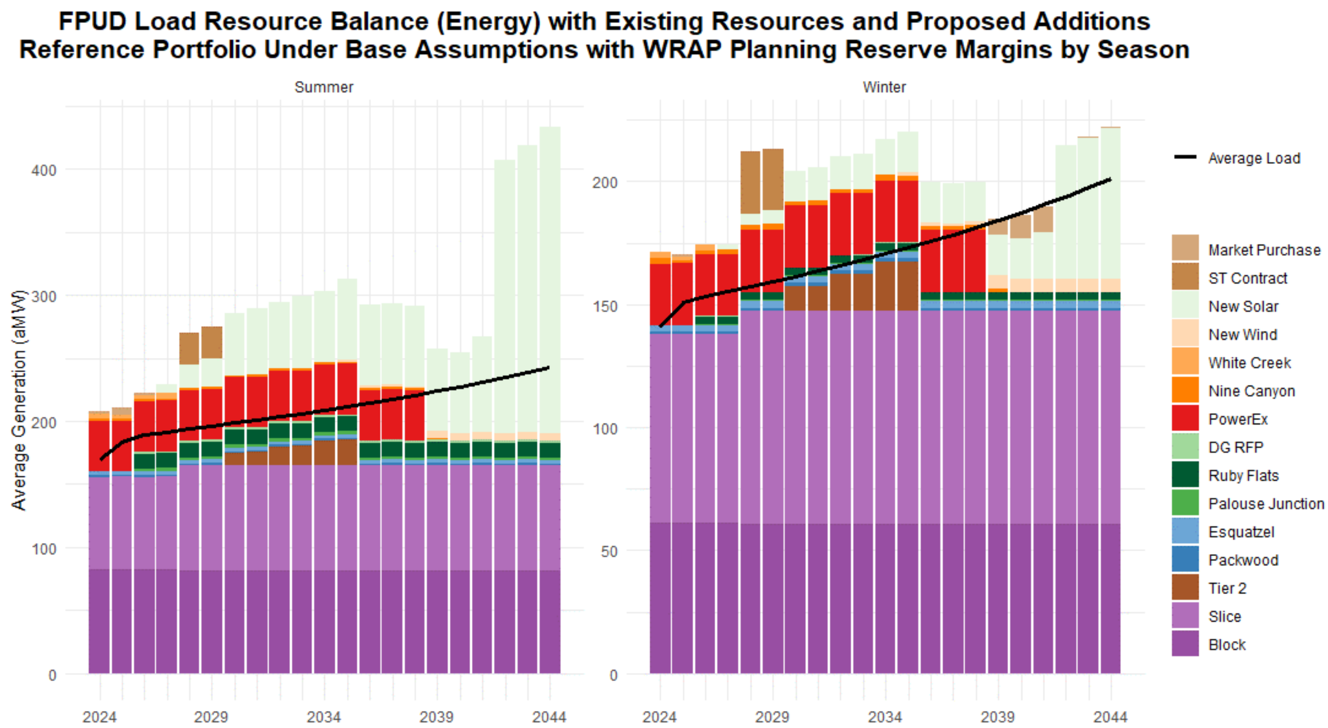


Figure 35. Energy Resource Load Balance for Reference Portfolio

Figure 36 shows the annual variable and incremental revenue requirements with qualifying capacity changes for the Reference Portfolio. This analysis excludes existing debt servicing costs and sunk costs prior to the study period.

The Variable Operations and Maintenance (VOM) cost is tied to current resources. When PowerEx goes offline in 2039, the VOM cost decreases. The Fixed Operations and Maintenance (FOM) cost correlates with batteries, which increases gradually as battery storage is integrated into the portfolio. The Construction (Build) cost is linked to the installation of wind and solar additions. The cumulative incremental NPVRR for the Reference Portfolio totals $947 million over the study period. This amount serves as the benchmark for scenario comparisons and sensitivity analyses.

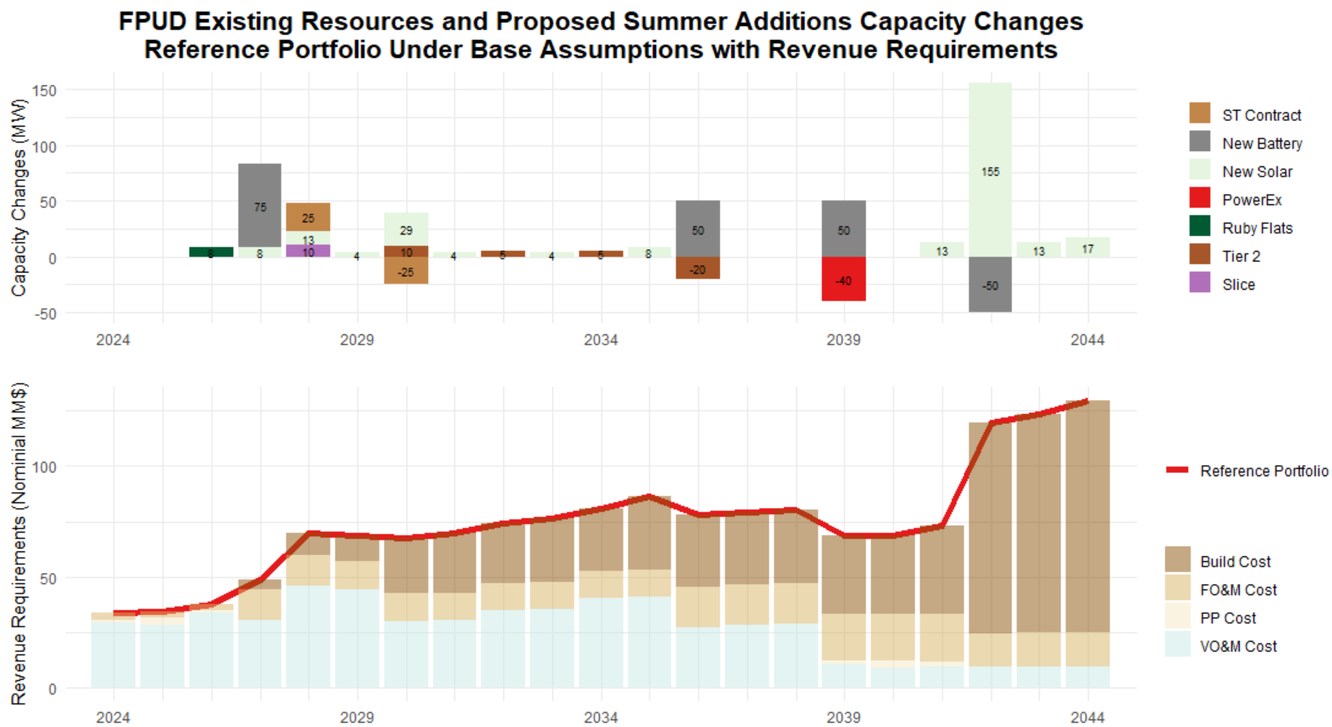


Figure 36. Nominal Revenue Requirements for Reference Portfolio

Battery storage, with its distinctive characteristics unlike traditional thermal sources, functions both as a load and a capacity resource. It can store significant amounts of energy and shift it to periods when the system faces shortages in energy supply. This capability is advantageous for a portfolio of this scale, especially in later years when numerous intermittent resources are installed. Figure 37 provides a simulated view of how this is accomplished within FPUD's portfolio after the adoption of significant amounts of renewable energy.

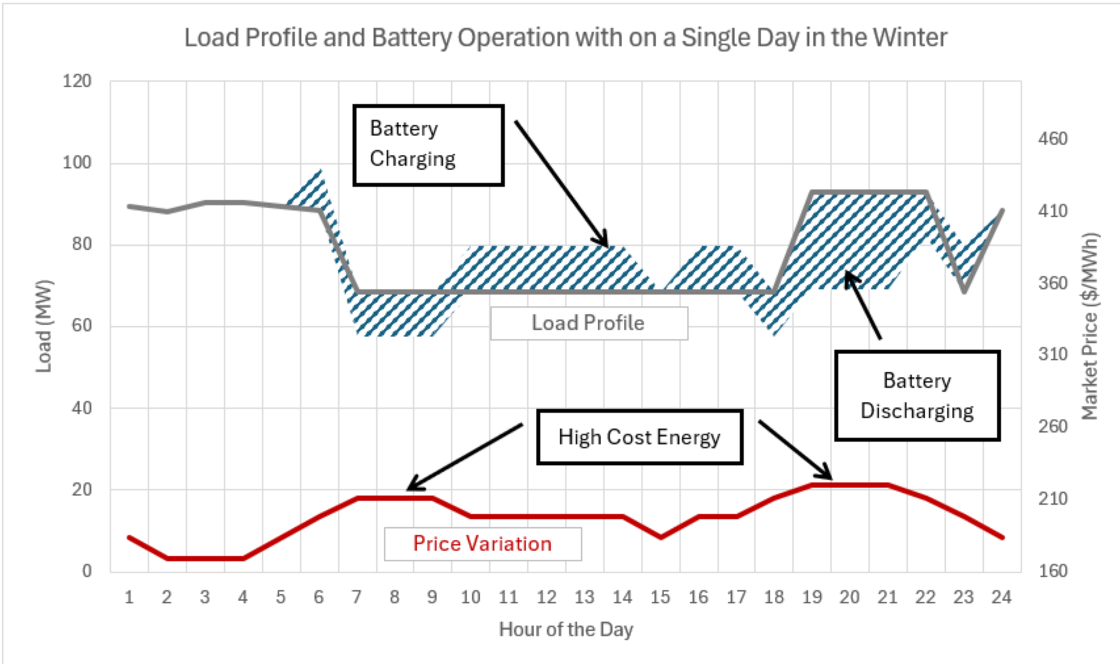


Figure 37. PLEXOS Simulated Output of Energy Shifting Within FPUD Reference Portfolio

The Reference Portfolio includes resources that enhance system resiliency while renewable energy capacity is increasing significantly. Battery storage plays a crucial role in bridging short-term capacity gaps due to changing WRAP requirements. Battery operation will allow flexibility for effectively integrating over 1,200 MW of renewable energy into the portfolio, ensuring adaptive and sustainable energy management strategies.

8.1.2 Renewable Portfolio Results

The renewable portfolio was introduced to understand the economic opportunities and cost associated with transitioning to a low carbon and sustainable energy system. This analysis provides insights into the resources required using current technology options and help provide strategic pathways necessary to achieve a sustainable energy future.

Figure 38 shows FPUD's current energy portfolio is well-balanced and capable of meeting average energy consumption with minimal exposure to market price fluctuations. Before 2027, there are no economic opportunities for resource selection. In the renewable portfolio, restricting the portfolio to renewable resources preserves the reliance on battery storage. While wind plays a smaller role in meeting energy and capacity needs, solar capacity expands within the portfolio. These dynamics highlight the evolving mix of renewable sources and emphasize strategic adjustments to enhance reliability and sustainability in energy supply.

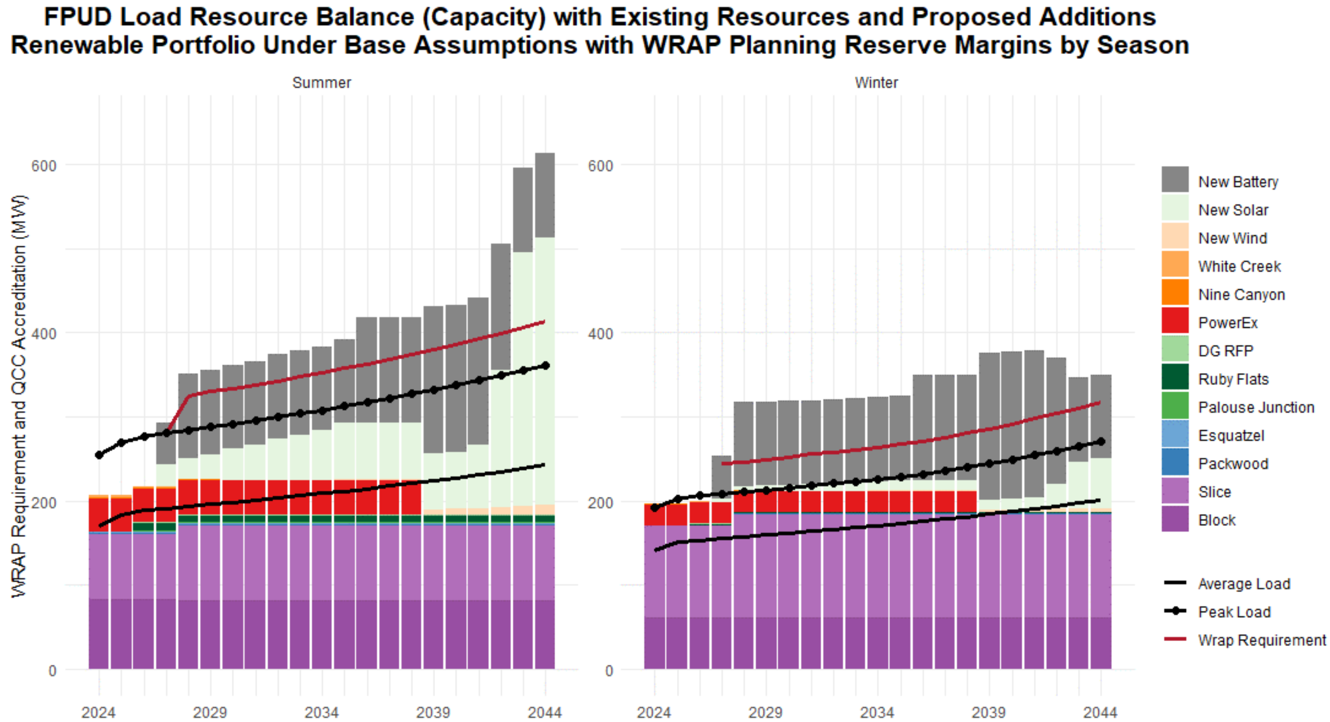


Figure 38. Demand and Resource Load Balance for Renewable Portfolio

Figure 39 displays the seasonal energy generated by the existing resources and proposed additions in average megawatts (aMW) per year for the Renewable Portfolio. The renewable portfolio reflects similar characteristics as the reference cases solution, including an overbuild of intermittent energy to ensure capacity requirements are met. Existing resources remain the primary source of energy for the portfolio.

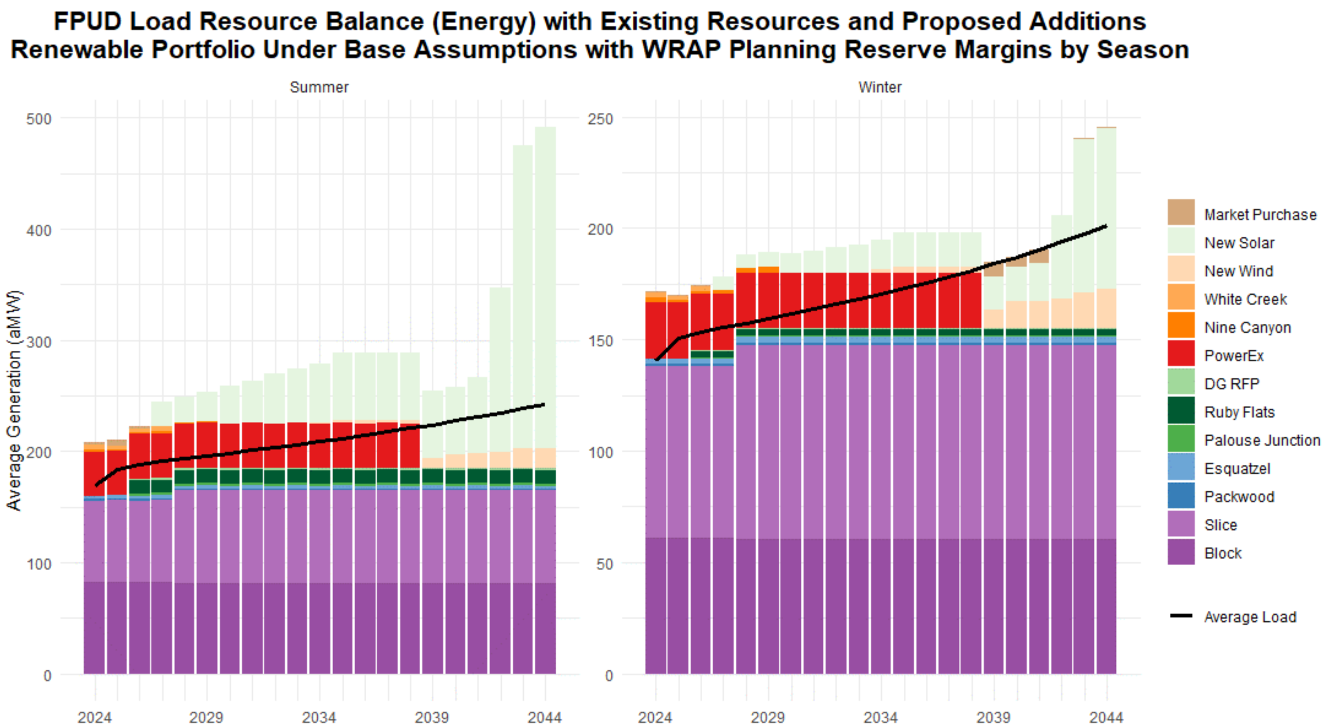


Figure 39. Energy Resource Load Balance for Renewable Portfolio

Figure 40 illustrates that the NPVRR of the renewable portfolio is lower than that of the reference portfolio. The renewable analysis enables the model to strategically choose renewable resources for the portfolio. Unrestricted solar additions provide further benefits by optimizing resource allocation, including larger solar installations in 2027. Moreover, this approach mitigates the need for costly short-term solutions like ST Contracts and Tier 2 option.

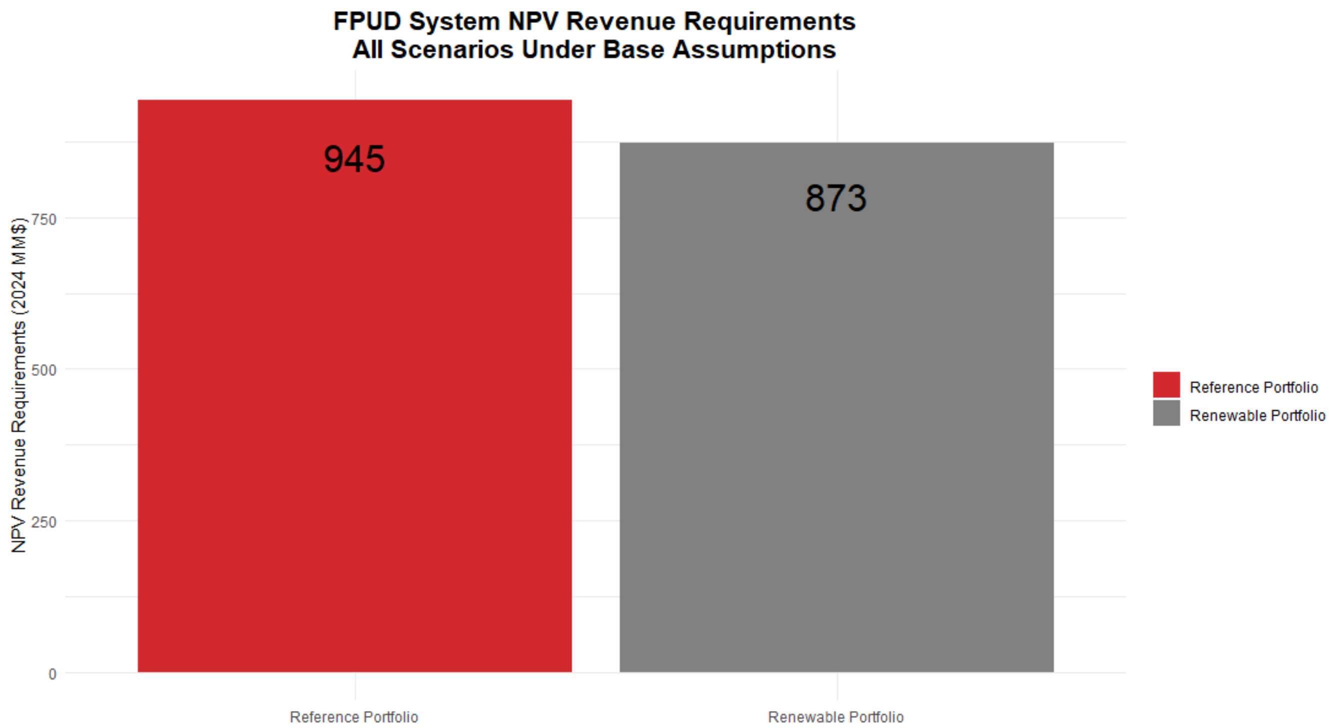


Figure 40. 20-year NPVRR for All Scenarios

FPUD performed a comparison between two portfolios: the reference portfolio, which imposes restrictions on the integration of solar and wind resources, and the renewable portfolio, removing these constraints. Both portfolios were limited to 200MW battery storage in which both used optimally 175 MW. The remaining capacity requirements are fulfilled through increased solar adoption, requiring an overbuild of solar energy to meet these obligations.

In the reference portfolio, which utilizes short-term contracts for capacity needs, these options proved costly and offered no additional flexibility compared to the renewable portfolio. The availability of renewable energy technologies played a crucial role in effectively meeting FPUD's capacity requirements.

Overall, the study highlights the advantages of a flexible approach to renewable energy integration, demonstrating how removing constraints on solar and wind installations can lead to cost savings, increased flexibility (compared to fixed contract energy), and more efficient capacity management within FPUD's portfolio.

8.2 Sensitivity Analysis and Results

FPUD has incorporated sensitivity analysis to address the uncertainty surrounding its load forecast. The load forecast is a key driver for future infrastructure investments required to maintain system reliability. Understanding the potential impact load can have on these investments is crucial to this IRP process. The IRP includes three load sensitivity analyses: low (annual demand growth of 1.1%), base (annual demand growth of 1.6%), and high (annual demand growth of 2.1%). Table 7 outlines how sensitivity analyses are incorporated into the IRP.

Table 7. Sensitivity Analysis Assumptions

Sensitivity	Load	NG Price	Carbon	WRAP	Technology
Low Load	Low	Base	Base	Base	Base
Base Assumptions	Base	Base	Base	Base	Base
High Load	High	Base	Base	Base	Base

These analyses offer an understanding of how FPUD's current and future resource needs would change under different possible load growth scenarios.

Figure 41 presents the load resource balance using existing and proposed resources across various scenarios and sensitivity combinations. Instead of depicting changes over 20 years, specific years are highlighted. The year 2028 marks a full year of WRAP implementation in the Reference Portfolio scenario. The years 2033 and 2036 represent periods before and after resources such as SMR and geothermal become available under the same scenario. Finally, 2044 marks the conclusion of the IRP study.

At a high level, resource selection remains uniform across all scenarios and sensitivity variations. Battery storage remains the primary resource for meeting capacity requirements, with solar adoption progressively increasing to fulfill both capacity and energy demands. Capacity levels adjust accordingly across different studies, showing increased adoption in response to higher load levels.

Resource selection remains consistent across most scenario and sensitivity combinations:

- In sensitivities with incremental restrictions on solar additions, short-term products are added in the reference cases.
- High load sensitivity introduces additional resources such as wind and geothermal into the mix.
- Throughout all studies, battery storage and solar remain primary resources.

After the completion of the load forecast used for this IRP, FPUD received a new population growth forecast from the City of Pasco that likely implies a higher load growth than the high scenario used in this study. A portion of the City of Pasco’s load falls outside of the service territory of FPUD, so it is unclear how much of the projected new load will impact FPUD. However, if FPUD’s load growth exceeds that forecasted in the high scenario in this study, this analysis indicates that the portfolio of resources would be unlikely to change. Instead, the same resources would likely remain cost-effective and simply be needed in larger quantities.

Figure 41. Sensitivity Load Resource Balance

Figure 42 compares the NPVRR of each of the sensitivities. The NPVRR graph reveals insights into the financial dynamics of renewable adoption within the portfolio. It demonstrates increasing the deployment of renewables results in cost savings, ranging from $7 to $59 million, with the most significant savings observed in the high load scenario. Moreover, there is a clear correlation between load levels and costs: as load decreases, costs also decrease, whereas higher loads correspond to increased costs. The reference case exhibits greater cost variability due to fluctuations in load, highlighting the critical role of load management in optimizing financial outcomes. These findings give emphasis to the economic advantages of scaling renewable integration while emphasizing the strategic importance of load-sensitive planning in achieving cost efficiency.

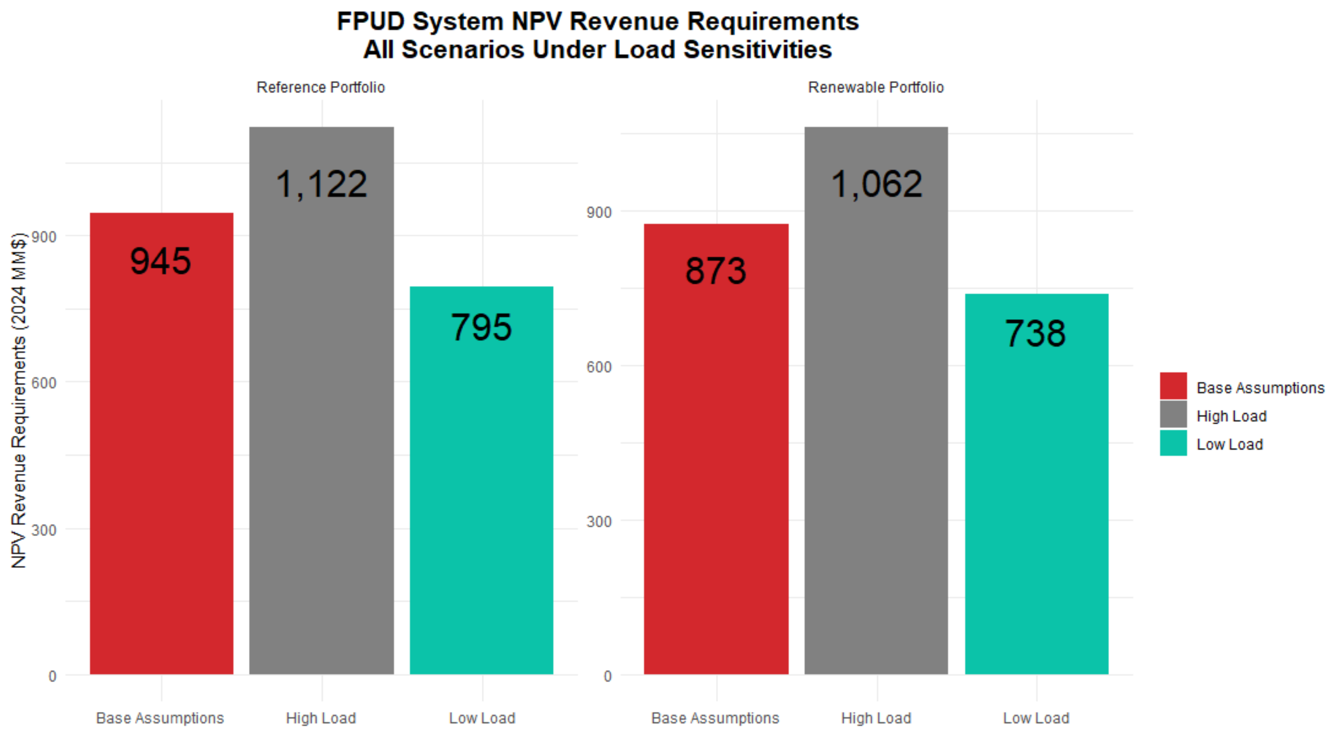


Figure 42. Sensitivity NPVRR

Battery storage and solar power play pivotal roles in meeting both capacity and energy requirements for FPUD. Effectively scaling renewable integration is crucial to mitigating potential cost escalations. Planning for future load growth is key to managing costs effectively. By strategically managing these resources, FPUD not only optimizes energy allocation but also enhances overall infrastructure efficiency, ensuring sustainable and reliable energy solutions for future demands.

8.3 BPA Load Following

FPUD will have the option of changing products with BPA under the next BPA power contract, known as the Provider of Choice (POC) contract. Neither the design of the products nor the rates for those products under the POC have yet been finalized. FPUD will review all BPA product offerings carefully once these products have been defined and select the option the best fits the needs of FPUD's customers.

Section 9 Conclusions

FPUD is currently meeting the energy demand of its customers with 90% carbon-free electric power and is projected to maintain a balance between its load and resources in spite of a roughly 1.6% year-over-year projected load growth through the study period. However, on a capacity basis, FPUD has a considerable deficit that could grow to as much as 231 MW by 2044 if not addressed through additional conservation and power procurement. In addition, the introduction of the WRAP in 2027 would significantly increase the effective capacity need of FPUD.

The menu of options available to FPUD to meet this growing deficit is constrained by several environmental policies in the State of Washington. These include Washington's RPS, CETA, and the CCA. In combination, these policies make it either economically infeasible or illegal to procure additional greenhouse-gas-emitting resources. As such, FPUD will pursue all options available to meet its capacity needs using carbon-neutral resources.

First, among these options, FPUD will maximize the use of BPA Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. Notably, 2028 marks the start of a new 20-year contract with BPA in which FPUD will have the opportunity to re-evaluate its BPA product choice. At this time, the BPA products and rates that will be offered in 2028 have not been defined. FPUD will remain fully engaged with the BPA process crafting these products and will carefully evaluate the product options once they are defined to select the product that offers the best fit for FPUD's needs over the next 20-year contract period.

In addition to maximizing BPA Tier 1 power, FPUD will continue to evaluate opportunities for procuring additional resources and consider extending current PPA contracts that are otherwise set to expire during the study period. The findings in this study indicate that a new resource portfolio dominated by solar and utility-scale batteries would be the most cost-effective way to meet its needs while complying with state environmental policies, given the current costs and attributes of eligible generation technologies. FPUD is already in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. FPUD will also consider BPA Tier 2 opportunities and market-based purchases wherever competitive.

FPUD continues to monitor several emerging technologies, most notably geothermal, hydrogen, and small-modular nuclear reactors (SMR) for possible future procurement. At this time, these resources do not appear to be cost-competitive with solar and batteries, but technological innovations may change that dynamic within the timeframe of the study.

Finally, FPUD will acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments that could cost-effectively reduce its need for new capacity resources.

Appendix Amended Conservation Potential Assessment

Exhibit A, Resolution 1413

PREPARED BY EES CONSULTING

Franklin Public Utility District

Amended

Conservation Potential Assessment: 2024-2043

Final Report

March 26, 2024

EES Consulting

a GDS Associates Company

March 26, 2024

Mr. Brian Johnson
Franklin PUD
P.O. Box 2407
Pasco, WA 99302-2407

SUBJECT: Amended Conservation Potential Assessment 2024-2043– Final Report

Dear Mr. Johnson:

Please find attached the Amended Conservation Potential Assessment for 2024-2043.

The amended potential estimated for the 2024-2025 biennium is 1.09 aMW.

Very truly yours,

Amber Gschwend
Managing Director, EES Consulting

Contents

1 Executive Summary

This report describes the methodology and results of the Amended Conservation Potential Assessment (CPA) for Franklin PUD (the District). This assessment provides estimates of energy savings by sector for the period 2024 to 2043. The assessment considers a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

1.1 BACKGROUND

The District provides electricity service to over 27,000 customers located in Franklin County, Washington; a service territory that covers approximately 435 square miles and includes 1,041 miles of transmission and distribution lines. The utility has offered conservation programs for over 30 years and continues to include demand-side management resources as priority resources in its resource planning.

Washington's Energy Independence Act (EIA), effective January 1, 2010, 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 2021 Power Plan. Thus, this Conservation Potential Assessment will support the District's compliance with EIA requirements.

This assessment was built on the technical workbooks developed for the Final 2021 Power Plan. The primary model assumptions included the following changes since the previous study:

- Avoided Costs
    - Recent forecast of power market prices prepared by the Council in April 2023.
    - Avoided generation capacity value updated with recent wholesale rates.
- Updated Customer Characteristics Data
    - Residential home counts.
    - Commercial floor area based on recent load growth.
    - Industrial sector consumption based on recent load growth.
- Measure Updates
    - Measure savings, costs, and lifetimes were updated based on the latest data available the 2021 Power Plan supply curves.
- 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.

1.2 RESULTS

Table 1-1 shows the high-level results of this assessment, the cost-effective potential by sector in 2, 6, 10, and 20-year increments. The total 20-year energy efficiency potential is 9.45 aMW. The most important numbers per EIA are the 10-year potential of 5.67 aMW, and the two-year potential of 1.09 aMW. These numbers are also illustrated in Figure 1-1 below.

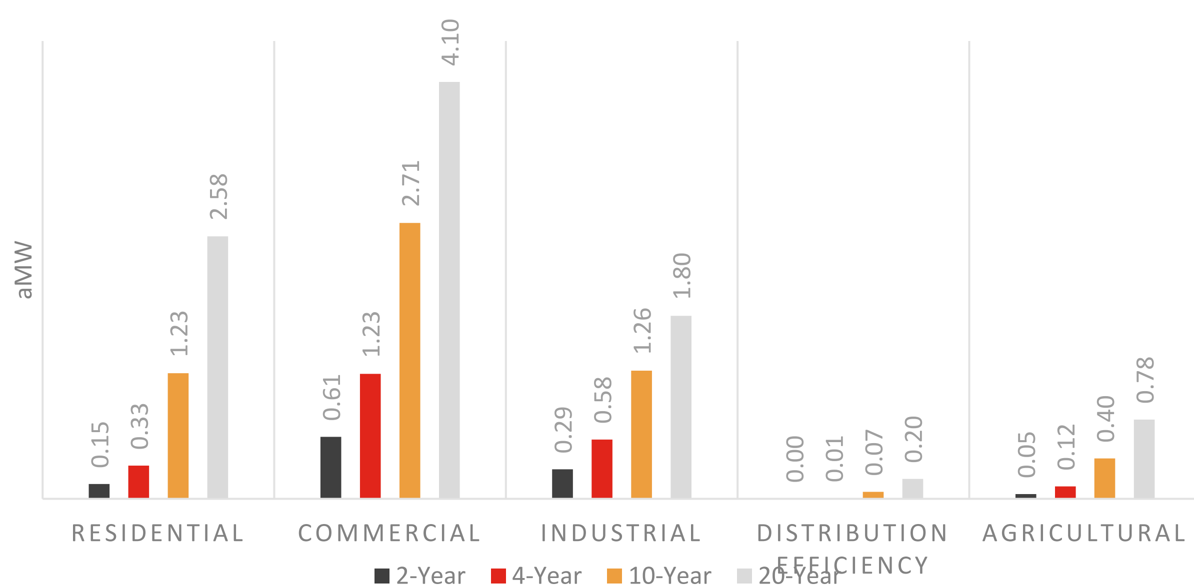
These estimates include energy efficiency achieved through the District's own utility programs and through its share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. Some of the potential may be achieved through code and standards changes, especially in later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA's Momentum Savings work.

TABLE 1-1: COST-EFFECTIVE POTENTIAL (aMW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.15	0.33	1.23	2.58
Commercial	0.61	1.23	2.71	4.10
Industrial	0.29	0.58	1.26	1.80
Distribution Efficiency	0.00	0.01	0.07	0.20
Agricultural	0.05	0.12	0.40	0.78
Total	**1.09**	**2.27**	**5.67**	**9.45**

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

FIGURE 1-1: COST-EFFECTIVE ENERGY EFFICIENCY POTENTIAL ESTIMATE



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 2021 Power Plan and a District-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 1-2 below.

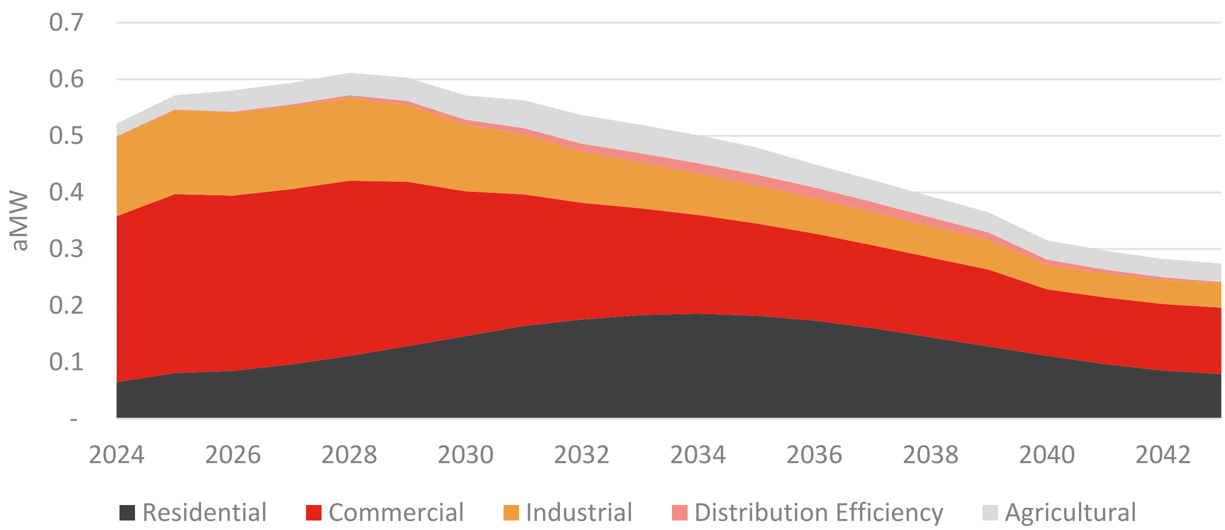
The savings from most energy efficiency measures are concentrated in those periods when energy is being used, and not evenly throughout the day. Thus, the peak demand reduction, measured in MW, is greater than the annual average energy savings. The District's annual peak occurs most frequently on summer evenings, between 4 and 6 PM. In addition to these peak demand savings, demand savings would occur in varying amounts throughout the year.

TABLE 1-2: COST-EFFECTIVE DEMAND SAVINGS (MW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.47	1.05	4.06	8.89
Commercial	0.36	0.74	1.80	3.35
Industrial	0.35	0.70	1.50	2.14
Agricultural	0.01	0.04	0.20	0.38
Distribution Efficiency	0.00	0.01	0.08	0.24
Total	**1.19**	**2.53**	**7.65**	**15.00**

The 20-year energy efficiency potential is shown on an annual basis in Figure 1-2. This assessment shows potential starting around 0.52 aMW in 2024 and ramping up to a maximum of 0.61 aMW per year in 2028. Potential then gradually decreases through the remaining years of the planning period as the remaining retrofit measure opportunities diminish over time.

FIGURE 1-2: ANNUAL COST-EFFECTIVE ENERGY EFFICIENCY POTENTIAL ESTIMATE



Nearly 27% of the potential is in the residential sector. The largest contributing measure categories for residential applications include water heating and HVAC. Measures with notable potential in this end use include:

- Smart thermostat
- Low flow shower heads efficiency 1.5 gallons per minute (gpm) or better
- Faucet aerators
- Water heater circulator controls and circulators
- Air source heat pump

The largest share of conservation is available in the District's commercial sector. The potential in the commercial sector is higher compared with the potential estimated in the 2021 CPA. The District has also achieved significant savings in lighting measures in recent years, leaving limited remaining savings. Savings in the commercial sector are spread across numerous end uses, but the primary areas for opportunity are in the HVAC end use. Notable measures in this area include:

- Residential-Sized and Commercial-Sized Heat Pump Water Heaters
- Heat Recovery Ventilation
- Chillers and AC
- Commercial Lighting
- Refrigeration

This study identified lower potential in the industrial sector relative to the 2021 CPA due mostly to customer participation in energy efficiency programs.

1.3 COMPARISON TO PREVIOUS ASSESSMENT

Table 1-3 shows a comparison of the 2, 10, and 20-year Base Case conservation potential by customer sector for this assessment and the results of the District's 2021 CPA.

TABLE 1-3: COMPARISON OF 2021 CPA AND 2023 CPA COST-EFFECTIVE POTENTIAL

	2-Year			10-Year			20-Year		
	2021	2023	% Change	2021	2023	% Change	2021	2023	% Change
Residential	0.15	0.15	-6%	2.36	1.23	-48%	6.19	2.58	-58%
Commercial	0.86	0.61	-29%	9.93	2.71	-73%	24.46	4.10	-83%
Industrial	0.50	0.29	-43%	2.52	1.26	-50%	5.03	1.80	-64%
Distribution Efficiency	0.03	0.00	-94%	0.39	0.07	-82%	1.09	0.20	-82%
Agricultural	0.07	0.05	-31%	0.27	0.40	45%	0.32	0.78	146%
Total	**1.61**	**1.09**	**-32%**	**15.47**	**5.67**	**-63%**	**37.10**	**9.45**	**-75%**

**Note that the 2021 columns refer to the CPA completed in 2021 for the time period of 2022 through 2041. The 2023 assessment is for the timeframe: 2024 through 2043.*

The change in conservation potential estimated since the 2021 study is the result of several changes to the input assumptions, including measure data and avoided cost assumptions. Additionally, new measures were added to the assessment and ramp rates were adjusted to account for program maturity, lingering COVID impacts, and 2021 Power Plan assumptions. A detailed analysis is provided in the Results section of this study.

1.3.1 Measure Data

Measure data was updated to include the Final 2021 Power Plan supply curve data.

1.3.2 Avoided Cost

An updated forecast of market prices was used to value energy savings. This forecast is lower than the forecast used in the 2021 assessment. Other avoided cost assumptions remained largely the same.

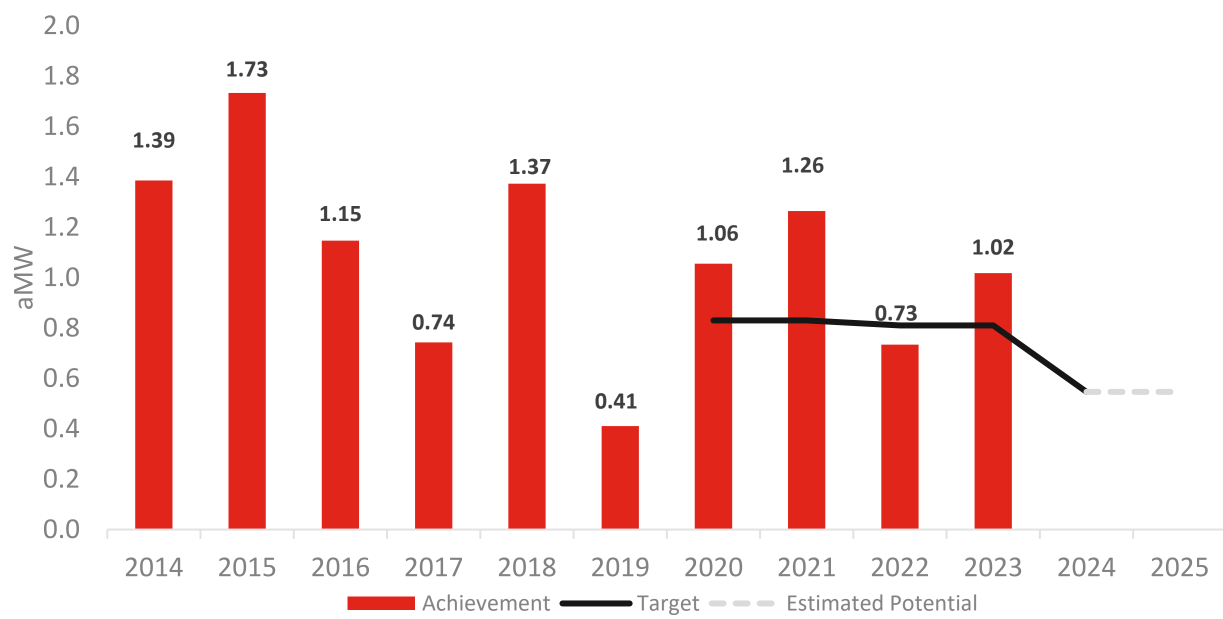
1.3.3 Customer Characteristics

No changes were made from the last CPA. However, growth in usage and number of customers was accounted for in the base year assumptions.

1.4 TARGETS AND ACHIEVEMENT

Figure 1-3 compares the District's historic achievement with its targets. The estimated potential for 2024 and 2025 is based on the Base Case scenario presented in this report and represents approximately a 45% reduction over the 2022-23 biennium. A decrease was expected based on higher efficiency baselines since the 2021 Power Plan was finalized plus the lower value of energy based on the Council's 2023 market price forecast. The figure below also shows that the District has consistently met its biennial energy efficiency targets, and that the potential estimates presented in this report are achievable through the District's various programs and the District's share of NEEA savings.

FIGURE 1-3: HISTORIC ACHIEVEMENT AND TARGETS



1.5 CONCLUSION

This report summarizes the CPA conducted for the District for the 2024 to 2043 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 and ramp rates for RTF and Council measures, and multiple scenario analyses.

The near-term results of this assessment are lower than the previous assessment, primarily due to the large amount of efficiency already achieved both regionally and by the District and the updated efficient baselines resulting from building codes and the 2021 Power Plan baselines. The results show a total 10-year cost effective potential of 5.67 aMW and a two-year potential of 1.09 aMW for the 2024-25 biennium, which is a 32% decrease from the target for the previous biennium. This decrease is due primarily to reduced cost-effectiveness for some measures, and program achievements.

2 Introduction

2.1 OBJECTIVES

The objective of this report is to describe the results of the Franklin PUD (the District) 2023 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2023 to 2044, with the primary focus on the initial 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 Washington Clean Energy Transformation Act (CETA) and is part of the District's compliance documentation. The results and guidance presented in this report will also assist the District in strategic planning for its conservation programs. Finally, the resulting conservation supply curves can be used in the District's Integrated Resource Plan (IRP).

The conservation measures used in this analysis are based on the measures that were included in the Council's 2021 Power Plan. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

2.2 ELECTRIC UTILITY RESOURCE PLAN REQUIREMENTS

According to Chapter RCW 19.280, utilities with at least 25,000 retail 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 2022. More background information is provided below.

2.3 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 is detailed below:

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 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.[1]

This report summarizes the preliminary results of a comprehensive CPA conducted following the requirements of the EIA and additions made by the passage of CETA. A checklist of how this analysis meets EIA requirements is included in Appendix III.

2.4 OTHER LEGISLATIVE CONSIDERATIONS

Washington state enacted several laws that impact conservation planning. Washington HB 1444 enacts efficiency standards for a variety of appliances. Washington also enacted a clean energy law, SB 5116. CETA (2019) requires the use of specific values for avoided greenhouse gas emissions. This study follows the CETA requirements to value energy efficiency savings at the prescribed value established by the Department of Ecology. Finally, CETA requires that all sales of electricity be greenhouse gas neutral by 2030 and greenhouse gas free by 2045. This provision has been incorporated into the assumptions of this CPA. Specifically, this impacts the avoided cost of conservation, as described in Appendix IV.

2.5 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 the District'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 transmission and distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits

[1] 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.

to be representative estimates of these avoided costs. A value for generation capacity was also included but may change as the Northwest market continues to evolve.

- 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.
- Forecasted Load and Customer Growth – The CPA bases the 20-year potential estimates on forecasted loads and customer growth provided by the utility. These forecasts include a level of uncertainty especially considering the recovery from COVID related load impacts.
- 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 2021 Plan to estimate peak demand savings over the planning period, based on shaped energy savings. Since the load shapes are a mix of older Northwest and California data, peak demand savings presented in this report may vary from actual peak demand savings.
- Frozen Efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

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

2.6 COVID IMPACTS

Impacts from COVID-19 have been incorporated into this study in various ways such as:

- Load levels have largely recovered since the 2020 pandemic. The baseline load and customer counts reflect current and future usage levels.
- Ramp rates, in some cases, were adjusted due to the slowdown of program uptake since the pandemic began. At first, projects were stopped due to concerns over spreading the virus. In addition to the lower participation rates, supply chain issues have delayed many projects. Largely, the 2021 Power Plan ramp rates were applied for each measure; however, some measure ramp rates were slowed to reflect recent achievements despite the District's efforts to promote programs.

The above considerations have been modeled in this study.

2.7 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 – The District's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions
- Results – Energy Savings and Costs – Primary base case results
- Scenario Results – Results of all scenarios
- Summary
- References & Appendices

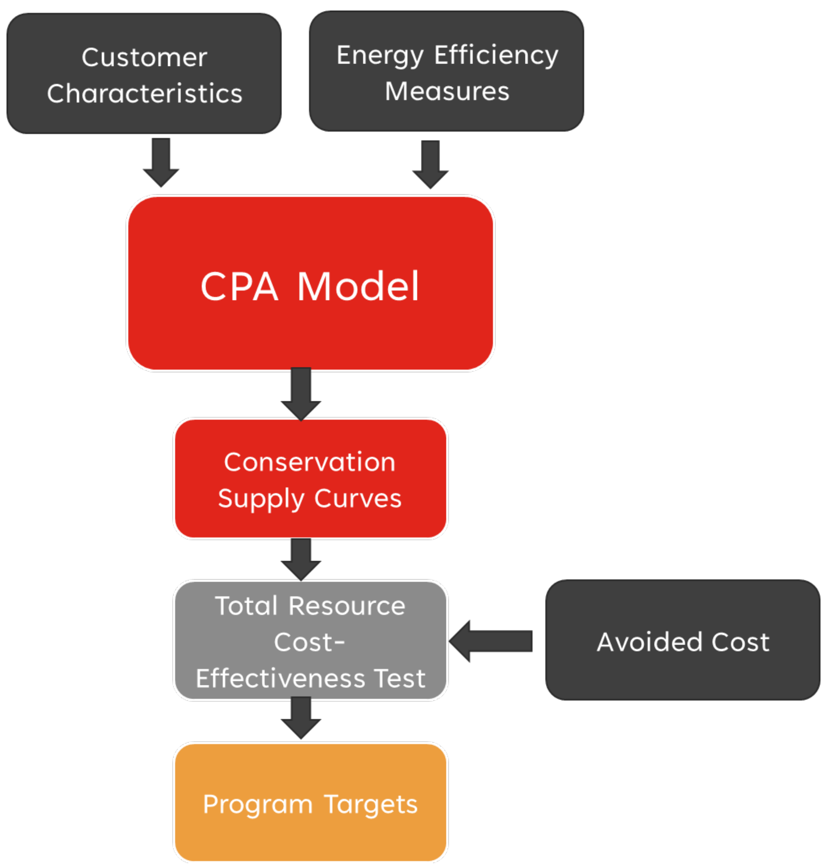
3 CPA Methodology

This study is a comprehensive assessment of the energy efficiency potential in the District'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 2021 Power Plan. This section provides a broad overview of the methodology used to develop the District's conservation potential target. Specific assumptions and methodology as they pertain to compliance with the EIA and CETA are provided in Appendix III of this report.

3.1 BASIC MODELING METHODOLOGY

The basic methodology used for this assessment is illustrated in Figure 3-1. A key factor is the kilowatt hours saved annually from the installation of an individual energy efficiency measure. The savings from each measure are 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 3-1: CONSERVATION POTENTIAL ASSESSMENT PROCESS



3.2 CUSTOMER CHARACTERISTIC DATA

Assessment of customer characteristics includes estimating both the number of locations where a measure could be feasibly installed as well as the share—or saturation—of measures that have already been installed. For this analysis, the characterization of the District's baseline was determined using data provided by the District, NEEA's commercial and residential building stock assessments, and census 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 2021 Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources. This data was updated with NEEA's 2016 Residential Building Stock Assessment and the District's historic conservation achievement data, where applicable. The District's historic achievement is discussed in detail in the next section.

3.3 ENERGY EFFICIENCY MEASURE DATA

The characterization of efficiency measures includes measure savings, costs, and lifetime. Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The Council's 2021 Power Plan is the primary source for conservation measure data.

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

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

3.4 TYPES OF POTENTIAL

Once the customer characteristics and energy efficiency measures are fully described, energy efficiency potential can be quantified. Three types of potential are used in this study: technical, achievable, and economic or cost-effective potential. Technical potential is the theoretical maximum efficiency available in the service territory if cost and market barriers are not considered. Market barriers and other consumer acceptance constraints reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 3-2 illustrates the four types of potential followed by more detailed explanations.

FIGURE 3-2: TYPES OF ENERGY EFFICIENCY POTENTIAL[2]

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

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Additionally, the number of applicable units must be estimated. Applicable units are the units across a service territory where the measure could feasibly be installed. This includes accounting for units that may have already been installed. The value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. A saturation factor accounts for measures that have already been completed.

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

The total technical potential is often significantly more than the amount of achievable and economic potential. The difference between technical potential and achievable potential is a result of the number

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

of measures assumed to be affected by market barriers. Economic potential is further limited due to the number of measures in the achievable potential that are not cost-effective.

Achievable Technical – Achievable technical potential, also referred to as achievable potential, is the amount of potential that can be achieved with a given set of market conditions. It 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. In the Seventh Power Plan, the Council assumes that 85% of technical potential can be achieved 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. These assumptions will be updated in the next study based on a measure-by-measure analysis of maximum achievability rates as finalized in the forthcoming 2021 Power Plan. 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 both the achievability and ramp rate assumptions.

Economic – Economic potential is the amount of potential that passes an economic benefit-cost test. In Washington State, EIA requirements stipulate that the total resource cost test (TRC) be used to determine economic potential. The TRC evaluates all costs and benefits of the measure regardless of who pays the 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 from energy efficient clothes washers.

For this potential assessment, the Council's ProCost model was used to determine cost effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2021 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.

3.5 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.

3.5.1 Energy

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

3.5.2 Social Cost of Carbon

The social cost of carbon is a cost that society incurs when fossil fuels are burned to generate electricity. Both the EIA rules and CETA require that CPAs include the social cost of carbon when evaluating cost effectiveness using the total resource cost test (TRC). CETA further specifies the social cost of carbon values to be used in conservation and demand response studies. These values are shown in Table 3-1 below and were the same value used in the 2023 CPA.

TABLE 3-1: SOCIAL COST OF CARBON VALUES[3]

Year in Which Emissions Occur or Are Avoided	Social Cost of Carbon Dioxide $2018/metric ton	Social Cost of Carbon Dioxide $2023/short ton[1]
2020	$62	$77
2025	$68	$85
2030	$73	$91
2035	$78	$97
2040	$84	$105

**ProCost model inputs for $/CO2 are in short tons. In the modeling, 2023 dollars are converted to $2016 to be consistent with the 2021 Power Plan measure data.*

According to WAC 194-40-110, values may be adjusted for any taxes, fees or costs incurred by utilities to meet portfolio mandates.[4] For example, the social cost of carbon is the full value of carbon emissions which includes the cost to utilities and ratepayers associated with moving to non-emitting resources. Rather than adjust the social cost of carbon for the cost of RECs or renewable energy, the values for RECS and renewable energy are excluded from the analysis to avoid double counting.

The emissions intensity of the marginal resource (market) is used to determine the $/MWh value for the social cost of carbon. Ecology states that unspecified resources should be given a carbon intensity value of 0.437 metric tons of CO_2e/MWh of electricity (0.874 lbs/kWh).[5] This is an average annual value applied to in all months in the conservation potential model.[6] The resulting levelized cost of carbon is $34/MWh over the 20-year study.

[3] WAC 194-40-100. Available at :https://apps.leg.wa.gov/wAc/default.aspx?cite=194-40-100&pdf=true.

[4] WAC 194-40-110 (b).

[5] WAC 173-444-040 (4).

[6] The seasonal nature of carbon intensity is not modeled due to the prescriptive annual value established by Ecology in WAC 173-444-040.

3.5.3 Renewable Portfolio Standard Cost

Renewable energy purchases need to meet both RPS and CETA and can be avoided through conservation. Utilities may meet Washington RPS through either bundled energy purchases such as purchasing the output of a wind resource where the non-energy attributes remain with the output, or they may purchase unbundled RECs. As stated above, the value of avoided renewable energy credit purchases resulting from energy efficiency is accounted for within the social cost of carbon construct. The social cost of carbon already considers the cost of moving from an emitting resource to a non-emitting resource. Therefore, it is not necessary to include an additional value for renewable energy purchases prior to 2045 when all energy must be non-emitting or renewable.

Beginning in 2045, the social cost of carbon may no longer be an appropriate adder in resource planning. However, prior to 2045 utilities may still use offsets to meet CETA requirements. Since the study period of this evaluation ends prior to 2045, the avoided social cost of carbon is included in each year. For future studies that extend to 2045 and beyond, it would be appropriate to include renewable energy or non-emitting resource costs as the avoided cost of energy rather than market plus the social cost of carbon.

3.5.4 Transmission and Distribution System

The EIA requires that deferred capacity expansion benefits for transmission and distribution systems be included in the assessment of cost effectiveness. To account for the value of deferred transmission and distribution system expansion, a distribution system credit value of $8.53/kW-year and a transmission system credit of $3.83/kw-year were applied to peak savings from conservation measures, at the time of the regional transmission and the District's local distribution system peaks (adjusted to $2023). These values were developed by Council staff in preparation for the 2021 Power Plan.[7]

3.5.5 Generation Capacity

While the District is a slice/block customer of BPA, and does not directly pay demand rates, BPA's demand rates are an appropriate avoided cost value for demand savings. BPA demand rates are escalated 3% each rate period (every two years). Over the 20-year analysis period, the resulting cost of avoided capacity is $104/kW-year (2023$) in levelized terms.

In the Council's 2021 Power Plan,[8] a generation capacity value of $143/kW-year was explicitly calculated ($2023). This value is used in the high scenario.

[7] Northwest Power and Conservation Council Memorandum to the Power Committee Members. Subject; Updated Transmission & Distribution Deferral Value for the 2021 Power Plan. March 5, 2019. Available at: https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf.

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

3.5.6 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 and generation capacity value. Through the variance of these components, implied risk credits of up to $11/MWh and $39/kW-year were included in the avoided cost. Note that the capacity value of energy efficiency measures is associated with more uncertainty compared with the energy value. With the implementation of the energy imbalance market (EIM) in the Pacific Northwest, and increased renewables in the region, capacity values are expected to be more volatile compared with energy market prices.

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

3.5.7 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.

3.6 DISCOUNT AND FINANCE RATE

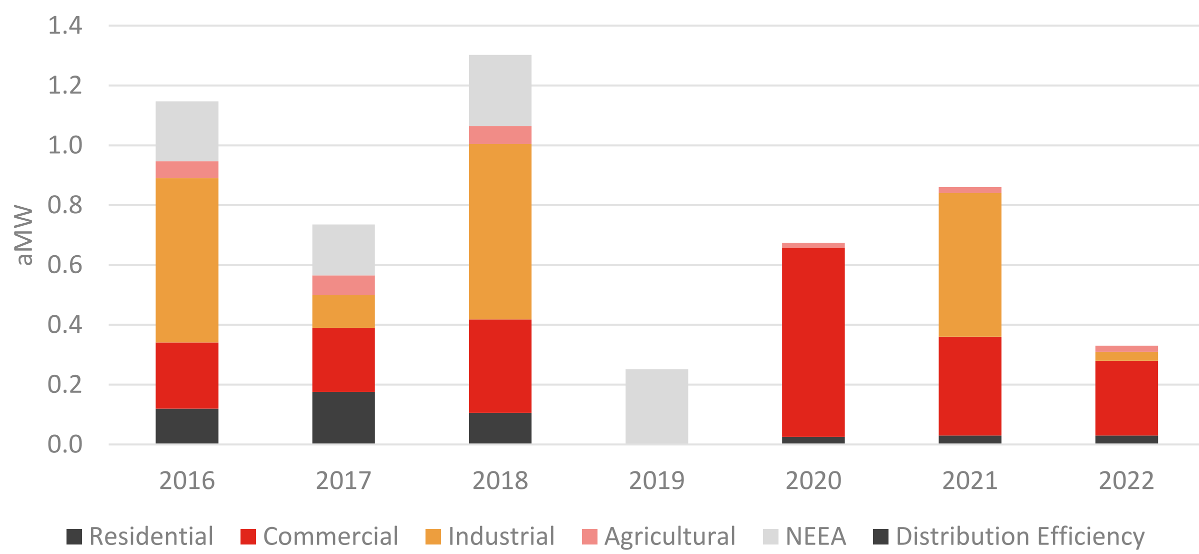
The Council develops a real discount rate for each of its Power Plans. In preparation for the 2021 Power Plan, the Council proposed using a discount rate of 3.75%. This discount rate was used in this CPA. The discount rate is used to convert future costs and benefits into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives.

4 Recent Conservation Achievement

The District has pursued conservation and energy efficiency resources for many years. Currently, the utility offers a variety of programs for residential, commercial, industrial, and agricultural customers. These include residential weatherization, Energy Star® appliance rebates, new construction programs for commercial customers, and energy-efficiency audits. In addition to utility programs, the District receives credit for market-transformation activities that are accomplished by the Northwest Energy Efficiency Alliance (NEEA) in its service territory.

Figure 4-1 shows the distribution of conservation among the District's customer sectors and through Northwest Energy Efficiency Alliance (NEEA) efforts over the past five years. NEEA's work helps bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters to the Northwest markets. Note that savings achievement for 2020 were lower than historic achievements primarily due to the COVID-19 pandemic. Economic factors and risk for COVID-19 transmission both likely contributed to fewer measures being implemented in the District's service area. More detail of these savings is provided below for each sector.

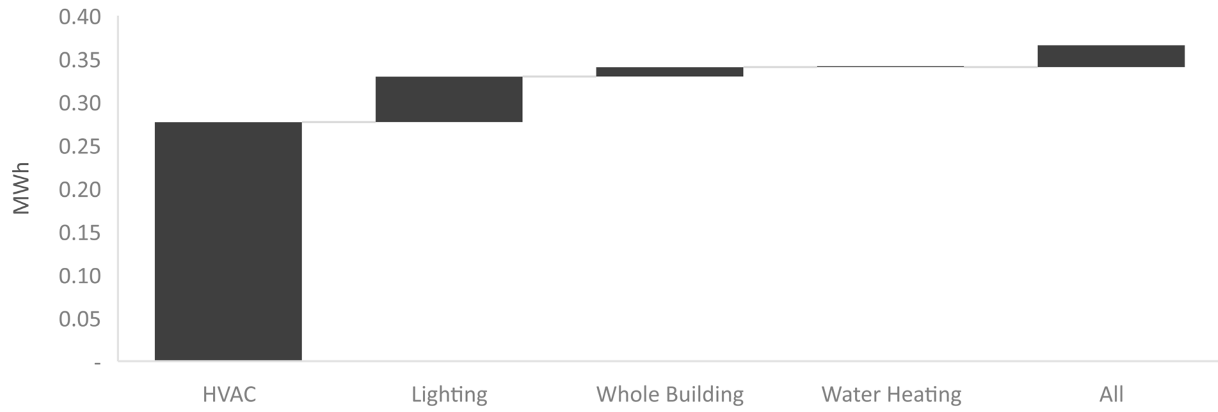
FIGURE 4-1: RECENT CONSERVATION HISTORY BY SECTOR



4.1 RESIDENTIAL

Figure 4-2 shows historic conservation achievement by end use in the residential sector. Savings from HVAC measures account for most of the savings. Note that in the figure below, HVAC includes weatherization measures.

FIGURE 4-2: 2017-2022 RESIDENTIAL SAVINGS ACHIEVEMENT



4.2 COMMERCIAL & INDUSTRIAL

Historic achievement in the commercial and industrial sectors is primarily due to lighting, grocery, and custom HVAC projects. Figures 4-3 and 4-4 show the breakdown of commercial and industrial savings, respectively, from 2017 to 2023 year to date.

FIGURE 4-3: 2017-2022 COMMERCIAL SAVINGS

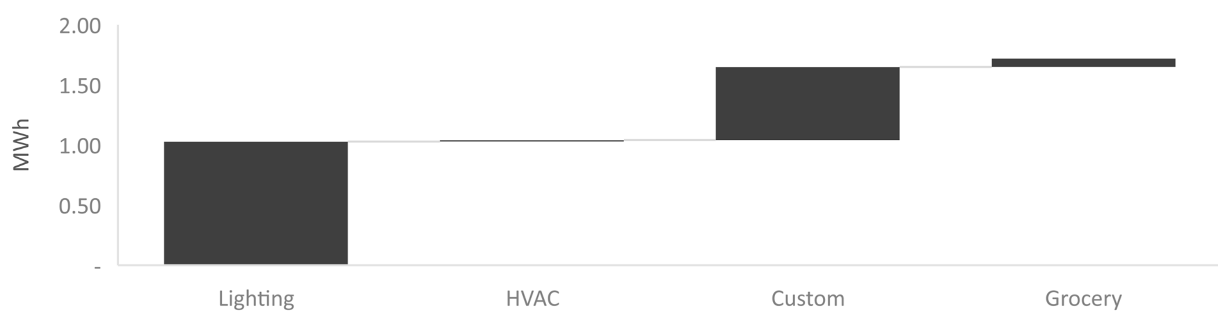
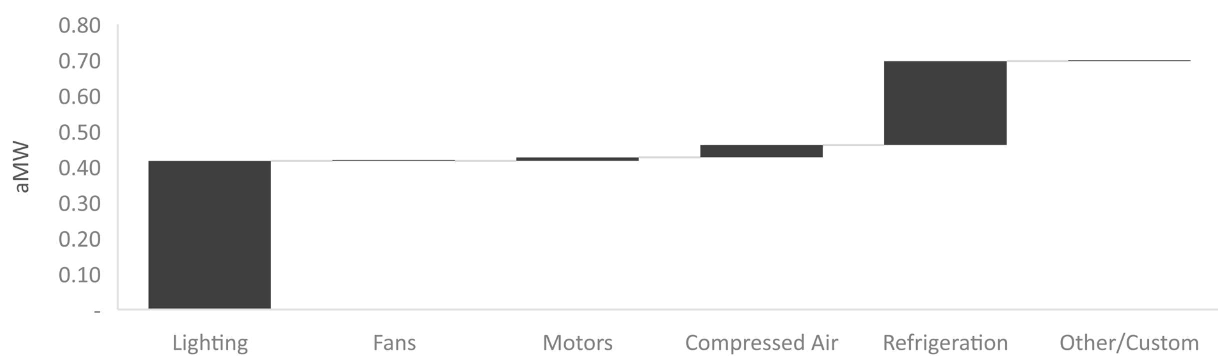


FIGURE 4-4: 2017-2022 INDUSTRIAL SAVINGS



4.3 AGRICULTURE

Savings in the agriculture sector have largely been due to lighting projects with some motor rewinds. For the period 2019-July 2021, the District has conserved 0.01 aMW in the agricultural sector. The District did not report additional savings from this sector for the period 2022-2023 YTD.

4.4 CURRENT CONSERVATION PROGRAMS

The District offers a wide range of conservation programs to its customers. These programs include many types of deemed conservation rebates, energy audits, net metering, and custom projects. The current programs offered by the District are detailed below.

4.4.1 Residential

- *Energy Star Rebates* – Franklin PUD offers several rebates for Energy Star appliances. These include $25 for Energy Star clothes washers and $50 for clothes dryers and up to $100 for qualifying smart thermostats.
- Rebates for insulation may be available by contacting the Energy Services Department.

4.4.2 Non-Residential

Custom project incentives available, but customer must request the upgrades prior to project initiation.

4.5 SUMMARY

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

5 Customer Characteristics Data

The District serves over 29,053 electric customers in Franklin County, Washington, with a service area population of approximately 102,563. 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.

5.1 RESIDENTIAL

For the residential sector, the key characteristics include house type, space heating fuel, and water heating fuel. Tables 5-1, 5-2 and 5-3 show relevant residential data for single family, multi-family and manufactured homes in the District's service territory as analyzed in the 2019 CPA. The data is based on billing data provided by the District, which was used to estimate the share of homes with electric heating systems, as well as the 2016 Residential Building Stock Assessment (RBSA), developed by NEEA.

TABLE 5-1: RESIDENTIAL BUILDING CHARACTERISTICS

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	1	1	29,053	102,463

TABLE 5-2: HOME HEATING & COOLING SYSTEM SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
Existing Stock, Homes[1]	80%	4%	16%
Electric Forced Air Furnace	7%	16%	56%
Heat Pump	11%	0%	6%
Ductless Heat Pump	2%	0%	0%
Electric Zonal/Baseboard	7%	67%	0%
Central Air Conditioning	63%	12%	45%
Room Air Conditioning	30%	63%	49%

1.Franklin County Assessor database 2019. No high-rise multifamily homes were identified in the District's service area.

TABLE 5-3: APPLIANCE SATURATIONS

	Single Family	Multifamily - Low Rise	Manufactured
DHW buffer	81%	73%	90%
Refrigerator	136%	105%	119%
Freezer	45%	16%	50%
Clothes Washer	96%	53%	100%
Clothes Dryer	91%	49%	100%
Dishwasher	87%	67%	88%
Microwave	96%	98%	100%
Electric Oven	96%	96%	96%
RAC	67%	29%	29%

5.2 COMMERCIAL

Building floor area 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. The commercial building floor area used in the 2021 CPA utilized the Franklin County Assessor database, which included building square foot values. The previous assessment utilized MWh consumption and EIU data to develop square footage estimates; however, the County Assessor database has been found to be a reliable data source specific to the District, and is the preferred data source. Table 5-6 summarizes the 2022 floor area. This floor area is estimated by increasing the 2020 floor area by the square footage of buildings built since 2020.

TABLE 5-6: COMMERCIAL BUILDING SQUARE FOOTAGE BY SEGMENT

Segment	Projected 2024 Floor Area (Square Feet)
Large Office	-
Medium Office	763,067
Small Office	1,487,422
Extra Large Retail	649,349
Large Retail	1,813,516
Medium Retail	-
Small Retail	178,114
School (K-12)	466,879
University	8,560
Warehouse	12,804,483
Supermarket	305,392
Mini Mart	109,050
Restaurant	307,243
Lodging	904,578
Hospital	198,584
Residential Care	75,712
Assembly	1,178,637
Other Commercial	5,211,645
Total	**26,462,230**

The commercial square footage shown in Table 5-6 was used to estimate commercial potential for this assessment.

5.3 INDUSTRIAL

The methodology for estimating industrial potential is different than the approaches used for 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.

The District provided 2020 energy use for its industrial customers. These values maintained at their 2020 level. Individual industrial customer usage is summed by industrial segment in Table 5-7. Future load growth is projected to remain at this level based on the District’s load forecast.

TABLE 5-7: INDUSTRIAL SECTOR LOAD BY SEGMENT

Industrial Segment	2020 Retail Sales (MWh)
Mechanical Pulp	-
Frozen Food	211,928
Other Food	17,138
Lumber	-
Panel	-
Fruit Storage	4,331
Cold Storage	8,964
Miscellaneous Manufacturing	7,638
Total	**249,999**

5.4 AGRICULTURE

To determine agriculture sector characteristics in the District's service territory, EES utilized data provided by the United States Department of Agriculture (USDA) as shown in Table 5-8. 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 2017 census, which was published in 2019.

The District provides electric service to agriculture customers in Franklin County. Minimal changes in agricultural customers were observed by the District since the previous study.

TABLE 5-8: AGRICULTURAL INPUTS

Number of Dairy Farms	268,527
Total Irrigated Acreage	71,281
Total Number of Pumps	881
Total Number of Farms	398
Stock Tanks	385
Back-Up Generator	4

5.5 DISTRIBUTION EFFICIENCY

The load forecast developed for the District's 2022 IRP Progress Report[9] was used to estimate distribution efficiency savings. The forecast has an average growth rate of 0.2%. This growth rate is based on the compound average growth rate for the utility-provided forecast. Distribution system conservation is discussed in detail in the next section.

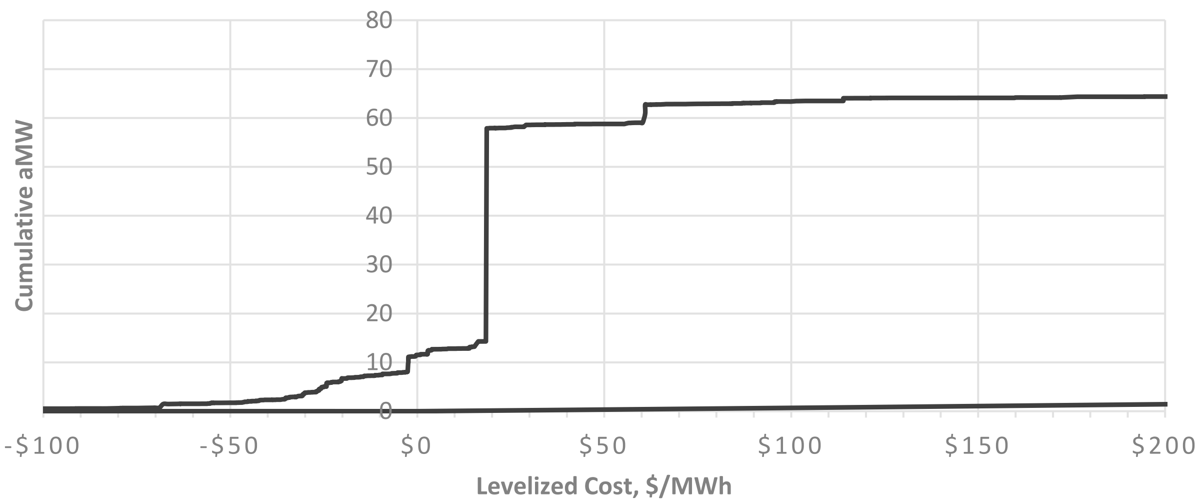
[9] Franklin PUD. 2022 IRP Progress Report July 13, 2022. https://www.franklinpud.com/assets/uploads/Draft_Report_for_Posting_-_CLEAN_Franklin_PUD_2022_IRP_Progress_Report_Format_7.13.2022_1.pdf.

6 Results – Energy Savings and Costs

6.1 ACHIEVABLE CONSERVATION POTENTIAL

Achievable potential is the amount of energy efficiency potential that is available regardless of cost. Figure 6-1, below, shows a supply curve of 20-year achievable potential. A supply curve is developed by plotting cumulative energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the savings when measures are sorted in order of ascending cost. The potential shown in Figure 6-1 has not been screened for cost effectiveness. Costs are levelized, allowing for the comparison of measures with different lifetimes. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with integrated resource plans. Figure 6-1 shows that approximately 58 aMW of cumulative saving potential are available for less than $50/MWh.

FIGURE 6-1: 20-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE



6.2 ECONOMIC CONSERVATION POTENTIAL

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

Table 6-1 shows the economic potential by sector in 2, 4, 10 and 20-year increments. Compared with the technical and achievable potential, it shows that 9.45 aMW of the total 64 aMW is cost effective for the District. The last section of this report discusses how these values could be used for setting targets.

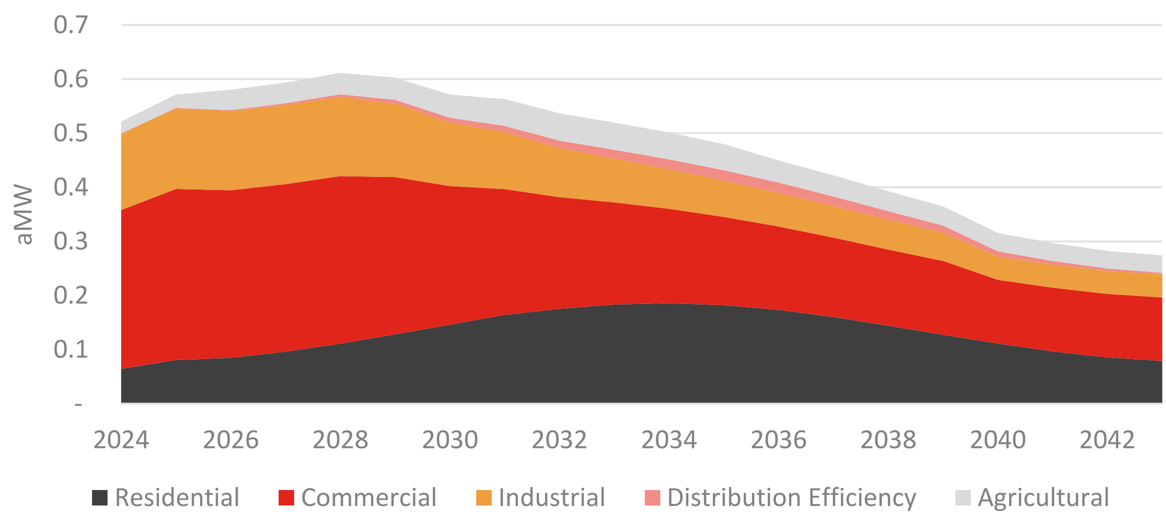
TABLE 6-1: COST-EFFECTIVE ACHIEVABLE POTENTIAL – BASE CASE (aMW)

	2-Year	4-Year	10-Year	20-Year
Residential	0.15	0.33	1.23	2.58
Commercial	0.61	1.23	2.71	4.10
Industrial	0.29	0.58	1.26	1.80
Distribution Efficiency	0.00	0.01	0.07	0.20
Agricultural	0.05	0.12	0.40	0.78
Total	**1.09**	**2.27**	**5.67**	**9.45**

6.3 SECTOR SUMMARY

Figure 6-2 shows economic potential by sector on an annual basis.

FIGURE 6-2: ANNUAL COST-EFFECTIVE POTENTIAL BY SECTOR



The largest share of the potential is in the commercial sector followed by substantial savings potential in the residential and industrial sectors. Ramp rates from the 2021 Power Plan were used to establish reasonable conservation achievement levels. In some cases, alternate ramp rates were assigned to reflect The District's current rate of program achievement. Achievement levels are affected by factors including timing of equipment turnover and new construction, supply chain delays, economic factors, program and technology maturity, market trends, and current utility staffing and funding.

6.3.1 Residential

Near-term residential conservation potential is higher than what was identified in the 2019 assessment. Savings potential has been impacted by new measures added by the Council for the 2021 Power Plan, the avoided cost updates, and program achievement.

Within the residential sector, water heating and HVAC (including weatherization) measures make up the largest share of savings (Figure 6-3). This is due, in part, to the fact that The District's residential customers rely mostly on electricity for space and water heating. Many weatherization measures are no longer cost-effective due to changes in costs and in energy savings values. The large amount of potential for water heating is primarily due to 1.5 gpm or lower shower heads, efficient clothes washers, aerators, and heat pump water heaters.

FIGURE 6-3: ANNUAL RESIDENTIAL COST-EFFECTIVE POTENTIAL BY END USE

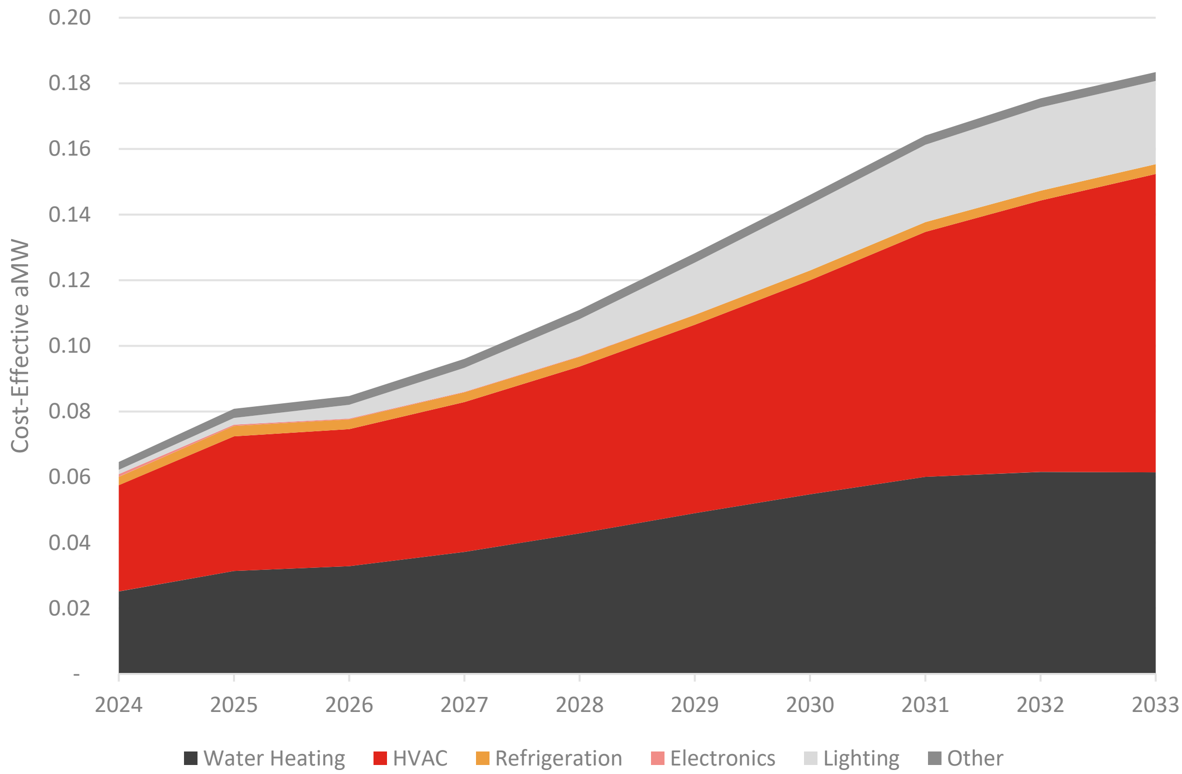


Figure 6-4 shows how the 10-year residential potential breaks down into end uses and key measure categories. The area of each block represents its share of the total 10-year residential potential.

FIGURE 6-4: RESIDENTIAL COST-EFFECTIVE POTENTIAL
BY END USE AND MEASURE CATEGORY

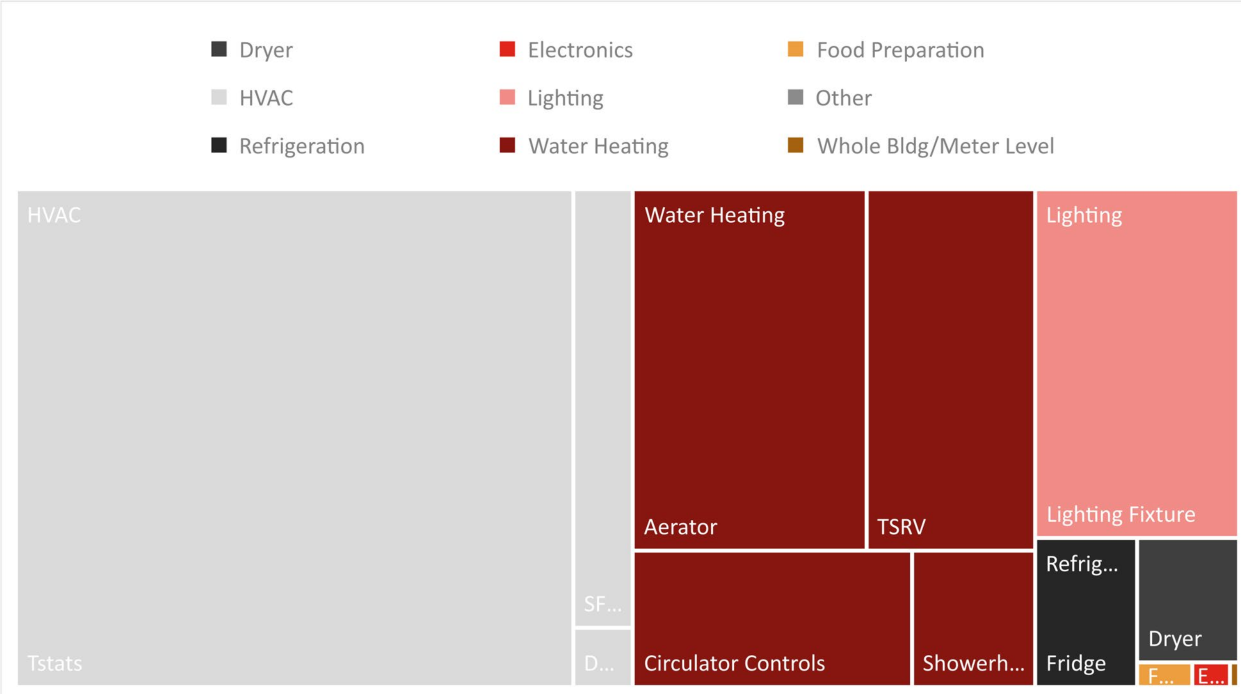


Table 6-2 compares how the savings potential has changed since the 2021 CPA. The primary drivers are reduced cost effectiveness as well as updated measure baselines.

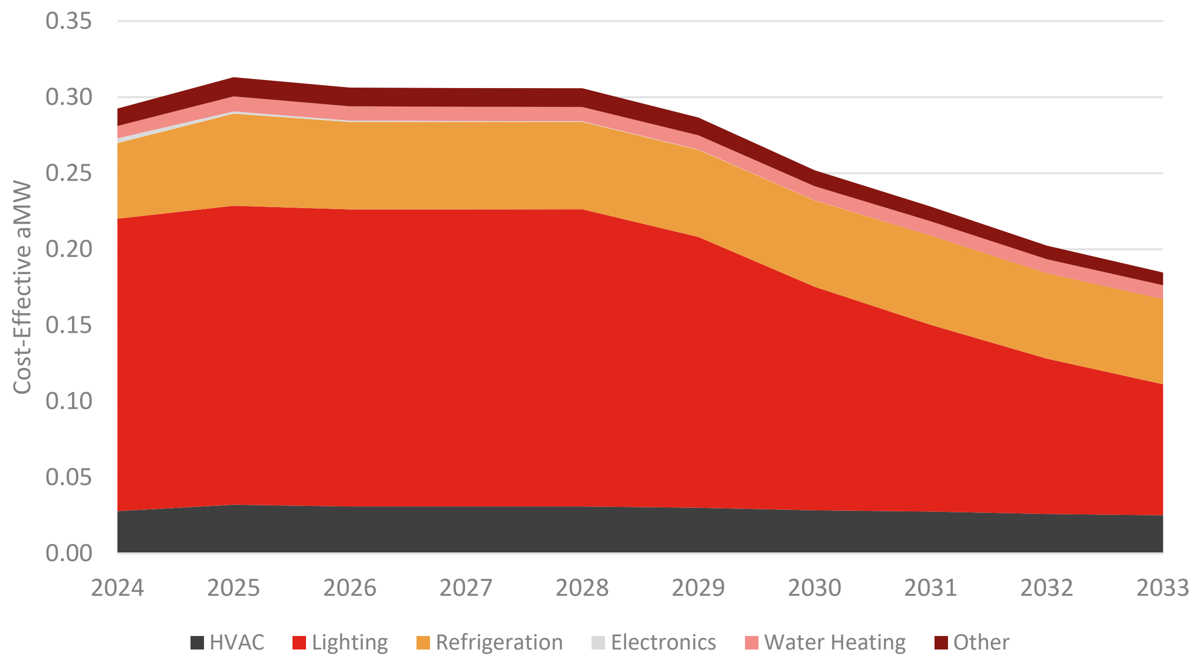
TABLE 6-2: COMPARISON RESIDENTIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
Water Heating	2.19	0.85	Reduced cost-effectiveness
HVAC	1.62	1.38	Added measure permutations, reduced cost-effectiveness
Lighting	0.52	0.24	Reduced cost-effectiveness
Electronics	0.57	0.00	Updated computer measures, reduced cost-effectiveness
Food Preparation	0.03	0.00	Reduced cost-effectiveness
Dryer	1.06	0.04	Updated to 2021 Plan methodology/measures
Refrigeration	0.07	0.06	Updated saturation
Whole Bldg./Meter Level	0.14	0.00	Updated saturation/applicability, Reduced cost-effectiveness
Well Pumps		0.00	Well pumps not cost-effective
Total	**6.19**	**2.58**	

6.3.2 Commercial

The diverse nature of commercial building energy efficiency is reflected in the variety of end-uses and corresponding measures as shown in Figure 6-5. Beyond HVAC and lighting, additional sources of potential are available in water heating, electronics, motors, food preparation and process loads.

FIGURE 6-5: ANNUAL COMMERCIAL COST-EFFECTIVE POTENTIAL BY END USE



The key end uses and measures within the commercial sector are shown in Figure 6-6. The area of each block represents its share of the 10-year commercial potential.

FIGURE 6-6: COMMERCIAL COST-EFFECTIVE POTENTIAL BY END USE AND MEASURE CATEGORY

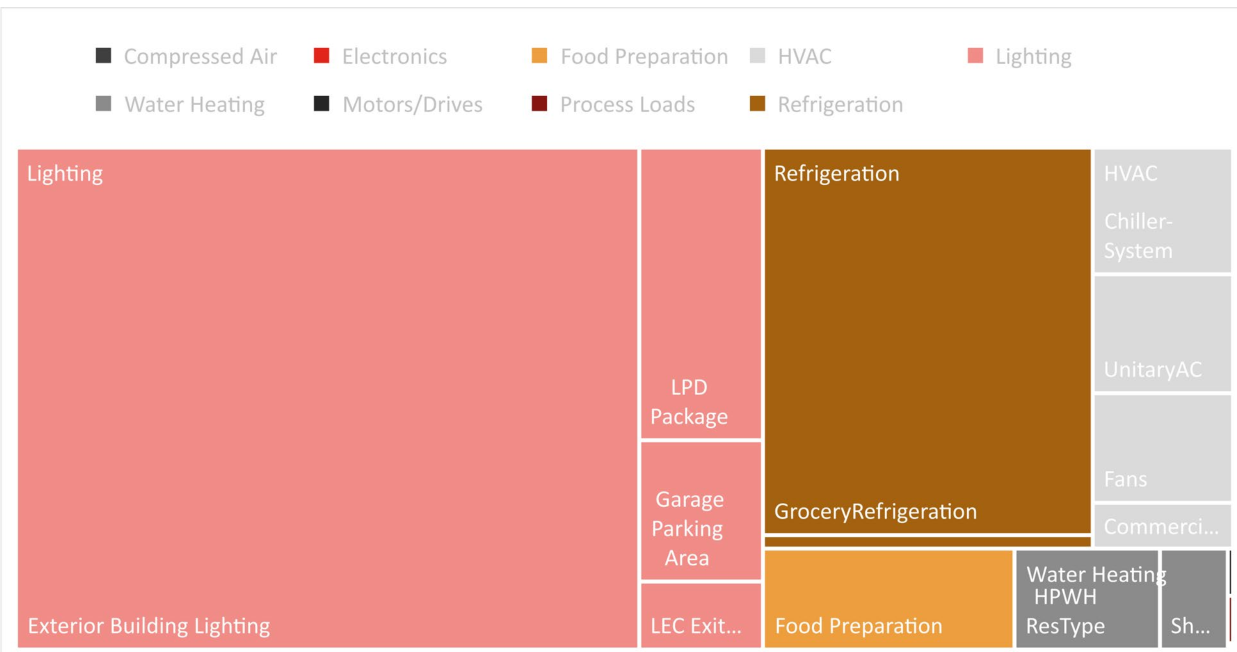


Table 6-3 provides a summary of the differences between the 2021 assessment and this 2023 CPA by end-use.

TABLE 6-3: COMPARISON COMMERCIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
Food Preparation	0.20	0.18	Updated measure data/baselines
Lighting	7.14	2.08	Reduced cost-effectiveness
Electronics	0.41	0.00	Updated measure data/baselines
Refrigeration	1.30	1.12	Reduced costs, added measures.
Process Loads	0.09	0.00	Not cost effective
Compressed Air	1.22	0.00	Updated to 2021 Plan methodology/measures
HVAC	2.85	0.54	Reduced cost-effectiveness, Adjusted applicability
Motors/Drives	0.11	0.00	Reduced cost-effectiveness, Added Commercial Clean Water Pumps
Water Heating	10.88	0.18	Reduced cost-effectiveness; removed older water heating measures, adjusted applicability based on building type
Total	**24.46**	**4.10**	

6.3.3 Industrial

Much of the District's industrial load is composed of food processing and chemical facilities. These segments contribute significantly to end-use savings in the energy management measures (Figure 6-7). The "Other" is very small and doesn't show up on the chart below. This category includes compressed air and pumps.

FIGURE 6-7: ANNUAL INDUSTRIAL COST-EFFECTIVE POTENTIAL BY END USE

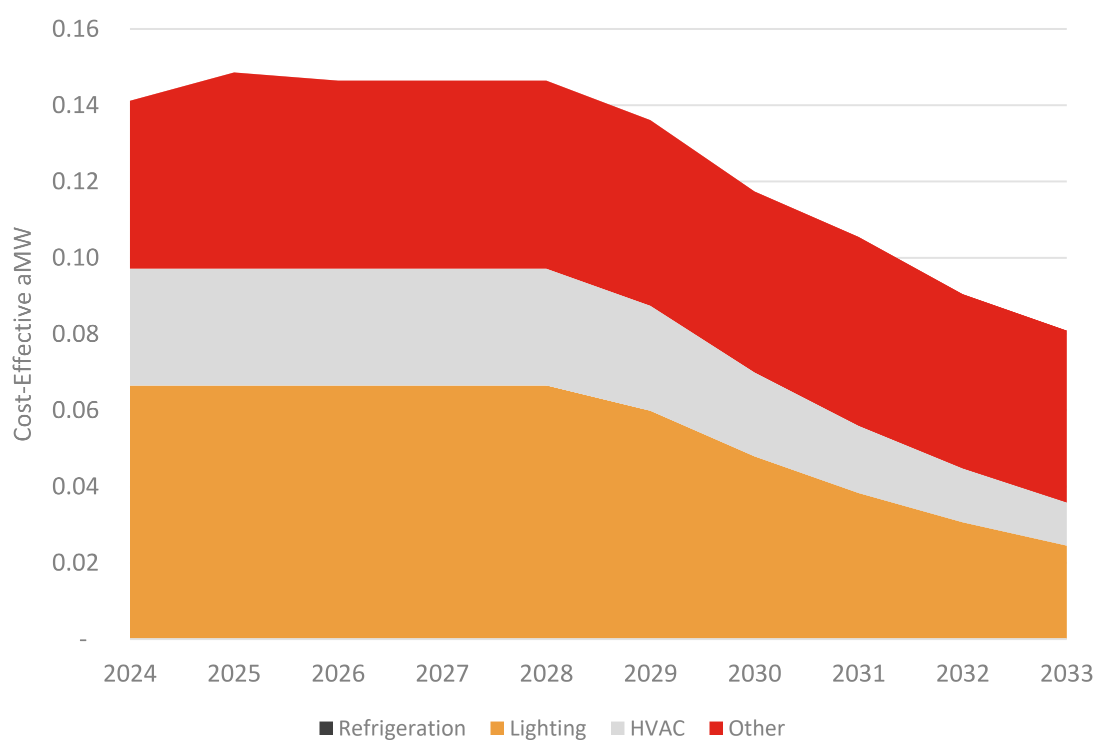
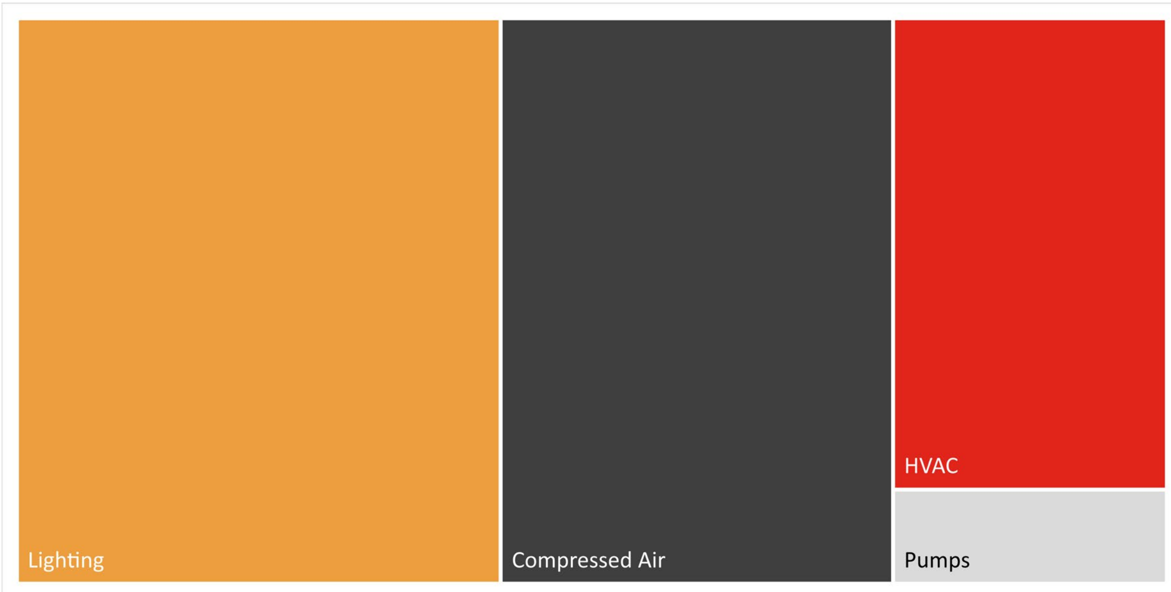


Figure 6-8 shows how the 10-year industrial potential breaks down by end use and measure categories.

FIGURE 6-8: INDUSTRIAL COST-EFFECTIVE POTENTIAL BY END USE AND MEASURE CATEGORY



The most impactful change in the industrial savings potential is the adjustment for recent program achievements. Based on the data provided by the District, the District has completed nearly 1.75 aMW in energy efficiency projects since 2016. This is reflected in the updated results in the table below. Table 6-4 compares the potential estimated in this study to the 2021 assessment. The end use categories have been updated to align with the 2021 Plan Industrial Tool.

TABLE 6-4: COMPARISON INDUSTRIAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA
Compressed Air	0.02	0.82
Energy Project Management	0.93	NA
Fans	0.08	0.00
Food Processing	1.21	NA
Food Storage	0.98	NA
Hi-Tech	0.01	NA
Integrated Plant Energy Management	0.82	NA
Lighting	0.30	0.61
Municipal Sewage Treatment	0.24	NA
Plant Energy Management	0.27	NA
Pumps	0.17	0.09
HVAC	NA	0.28
Low Temp Refrigeration	NA	0.00
Med Temp Refer	NA	0.00
All Electric	NA	0.00
Material Processing	NA	0.00
Material Handling	NA	0.00
Melting and Casting	NA	0.00
Other	NA	0.00
Total	**5.03**	**1.80**

6.3.4 Agriculture

Potential in agriculture is a product of total acres under irrigation in the District's service territory, number of pumps, and the number of farms. As shown in Figure 6-9, most of the cost-effective conservation potential is due to lighting and irrigation pump motors.

FIGURE 6-9: ANNUAL AGRICULTURE COST-EFFECTIVE POTENTIAL BY END USE

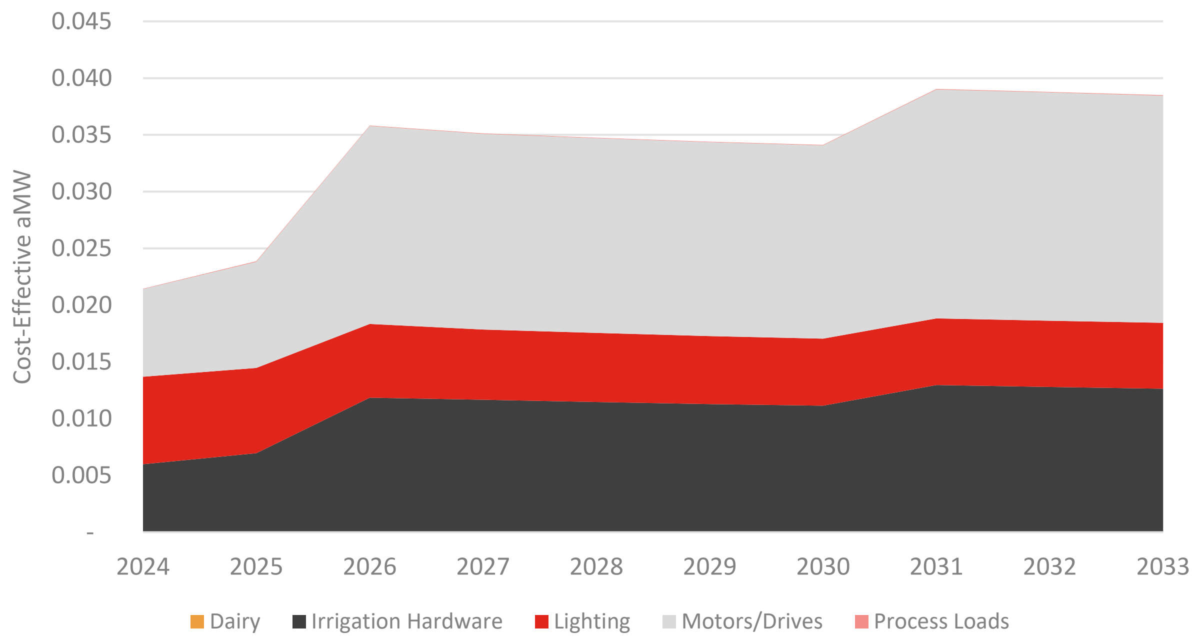


Table 6-5 compares the results of the 2021 CPA with this updated assessment.

TABLE 6-5: COMPARISON AGRICULTURAL 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
Irrigation	0.25	0.22	Reduced cost-effectiveness for irrigation hardware
Lighting	0.02	0.12	Updated applicability
Dairy Efficiency	0.01	NA	
HVAC	NA	0.00	Not Cost Effective
Motors/Drives	0.03	0.33	Updated irrigation pump measures
Process Loads	NA	0.00	Added energy free stock tanks
Refrigeration	NA	0.11	Previously under Dairy
Total	**0.32**	**0.78**	

6.3.5 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 2021 Plan methodology. The 2021 Plan estimates distribution system potential based on end of system energy sales.

Table 6-6 compares the results of the 2021 CPA with this updated assessment.

TABLE 6-6: COMPARISON DEI 20-YEAR ECONOMIC ACHIEVABLE POTENTIAL, AMW

End Use	2021 CPA	2023 CPA	Discussion
EMC-1 LDC with no VVO	0.48	0.20	Updated Measure Information
ECM-2 & ECM-3 LDC with VVO & AMI	0.61	0.00	Reduced cost-effectiveness
Total	**1.09**	**0.20**	Updated to 2021 Plan Measures

6.4 COST

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 6-7). The assumptions in this estimate include 20 percent of measure cost for administrative costs and 35 percent of the incremental measure costs is assumed to be paid by the utility as incentives. 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 2021 Power Plan. The 35 percent utility-share of measure costs is used in all sectors except in the utility distribution efficiency category, where the District is likely to pay the entire cost of any measures implemented and no incentives will be paid. These assumptions are consistent with the District's previous CPA.

This chart shows that the District can expect to spend approximately $2.8 million to realize estimated savings over the next two years including program administration costs. The bottom row of Table 6-7 shows the cost per MWh of first year savings.

TABLE 6-7: UTILITY PROGRAM COSTS (2023$)

	2-Year	4-Year	10-Year	20-Year
Residential	$570,000	$1,300,000	$5,080,000	$10,430,000
Commercial	$1,440,000	$2,910,000	$6,750,000	$11,400,000
Industrial	$650,000	$1,310,000	$2,720,000	$3,450,000
Distribution Efficiency	$0	$10,000	$120,000	$350,000
Agricultural	$90,000	$240,000	$780,000	$1,520,000
Total	**$2,750,000**	**$5,770,000**	**$15,450,000**	**$27,150,000**
$/First Year MWh	$287	$291	$311	$328

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 than historic conservation achievement 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 the District to acquire conservation through its programs. Although not included in the above estimates, residential Low-Income programs are also significantly more costly to implement due to rebates being paid at 3 to 5 times the level of non-low-income residential programs. The additional effort may result in increased administrative costs.

TABLE 6-8: TRC LEVELIZED COST (2023$/MWH)

	2-Year	4-Year	10-Year	20-Year
Residential	$53	$53	$55	$57
Commercial	$27	$27	$28	$32
Industrial	$40	$40	$38	$32
Distribution Efficiency	$0	$15	$18	$18
Agricultural	$20	$20	$19	$19
Total (weighted average)	**$32**	**$32**	**$33**	**$34**

7 Scenario Results

The costs and savings discussed throughout the report thus far describe the Base Case avoided cost scenario. Under this scenario, annual potential for the planning period was estimated by applying assumptions that reflect the District's expected avoided costs. In addition, the Council's 20-year ramp rates were applied to each measure and then adjusted to more closely reflect the District's recent level of achievement.

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

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

Table 7-1 summarizes the Base, Low, and High avoided cost input values. Relative to the values used in the 2019 CPA, many of the avoided cost assumptions have decreased including energy and capacity estimates. These changes reduced the 20-year potential estimate due to decreased cost-effectiveness; however, the adjusted ramp rates for the new time horizon increase the near-term potential slightly compared with the 2019 results.

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 7-1: AVOIDED COST ASSUMPTIONS BY SCENARIO, $2023

	Base	Low	High
Energy	NWPCC April 2023 Baseline Price Forecast	10% Lower than NWPCC April 2023 Baseline Price Forecast	NWPCC April 2023 High Westside Demand
Social Cost of Carbon, $/short ton	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh
Avoided Cost of RPS Compliance	Included in Social Cost of Carbon		
Distribution System Credit, $/kW-yr	$8.53	$8.53	$8.53
Transmission System Credit, $/kW-yr	$3.83	$3.83	$3.83
Deferred Generation Capacity Credit, $/kW-yr	$104	$0	$143.18
Implied Risk Adder, 20-year Levelized $/MWh $/kW-yr	N/A	Average: -$1/MWh and $104/kW-year	Average: $11/MWh and $39/kW-year

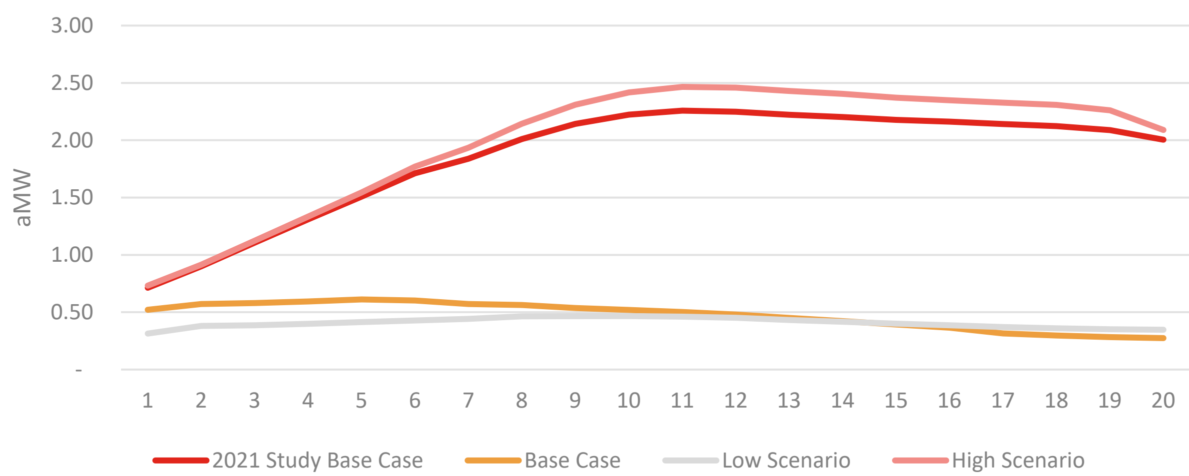
Table 7-2 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

TABLE 7-2: COST-EFFECTIVE POTENTIAL – AVOIDED COST SCENARIO COMPARISON

	2-Year	4-Year	10-Year	20-Year
Base Case	1.1	2.3	5.7	9.5
Low Scenario	0.7	1.5	4.2	8.1
High Scenario	1.6	4.1	16.2	39.7

Figure 7-1 compares the results of the scenario analysis with the base case form the 2021 assessment.

FIGURE 7-1: SCENARIO COMPARISON



The high case is above the 2021 base case assessment results and the 2023 low and base case results are very similar. Because the low case is very similar to the Base Case, we can infer that capacity value is not a driving factor for cost-effectiveness when market prices are very low.

8 Summary

This report summarizes the results of the 2023 CPA conducted for the District. The assessment provides estimates of energy savings by sector for the period 2024 to 2043 with a focus on the first 10 years of the planning period, as required by the EIA. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

The cost-effective potential identified in this report is a low cost and low risk resource and helps to keep future electricity costs to a minimum. Additionally, conservation achievements inherently provide capacity savings to the District. Relative to the values used in the 2021 CPA, many of the avoided cost assumptions have decreased including energy value estimates. These changes reduced the 20-year potential estimate due to decreased cost-effectiveness.

8.1 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 documents the development of conservation targets for each WAC 194-37-070 requirement and describes how each item was completed. 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 District's 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.

8.2 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."[10] However, the State Auditor's Office has stated that:

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

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

> Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10-year assessment but state law does not require an even 20 percent.[11]

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 the District and approved by its Commission.

8.3 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.

[11] 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.

9 References

Cadmus Group. 2018. *Residential Building Stock Assessment II: Single family Homes Report 2016-17.* Portland, OR: Northwest Energy Efficiency Alliance.

Cadmus Group. 2018. *Residential Building Stock Assessment II: Multifamily Buildings Report 2016-17.* Portland, OR: Northwest Energy Efficiency Alliance.

Cadmus Group. 2018. *Residential Building Stock Assessment II: Manufactured Homes Report 2016-17.* Portland, OR: Northwest Energy Efficiency Alliance.

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

Northwest Power and Conservation Council. *Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*. August 2007. Retrieved from: http://www.nwcouncil.org/library/2007/2007-13.htm.

Northwest Power and Conservation Council. *7th Power Plan Technical Information and Data*. April 13, 2015. Retrieved from: http://www.nwcouncil.org/energy/powerplan/7/technical.

Northwest Power and Conservation Council. *Seventh Northwest Conservation and Electric Power Plan*. Feb 2016. Retrieved from: https://www.nwcouncil.org/energy/powerplan/7/plan/

Northwest Power and Conservation Council. *2021 Power Plan Technical Information and Data*. July 2020. Retrieved from: http://www.nwcouncil.org/energy/powerplan/2021/technical.

Office of Financial Management. (2012). Washington State Growth Management Population Projections for Counties: 2010 to 2040. [Data files]. Retrieved from: http://www.ofm.wa.gov/pop/gma/projections12/projections12.asp.

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

United States Department of Agriculture. 2012 Census of Agriculture. May 2014. Retrieved from: https://www.agcensus.usda.gov/.

Washington State Energy Code, Wash. (2012).

Washington State Legislature. RCW 19.285.040 Energy conservation and renewable energy targets. Retrieved from: http://apps.leg.wa.gov/rcw/default.aspx?cite=19.285.040.

Appendix I – Acronyms

ALH – Average Load Hours

aMW – Average Megawatt

BCR – Benefit-Cost Ratio

BPA – Bonneville Power Administration

CETA – Clean Energy Transformation Act

CPA – Conservation Potential Assessment

DVR – Demand voltage reduction

EIA – Energy Independence Act

ERWH – Electric Resistance Water Heater

EUI – Energy Use Intensity

GPM – Gallons per minute

HLH – Heavy load hour energy

HPWH – Heat Pump Water Heater

HVAC – Heating, ventilation and air-conditioning

IRP – Integrated Resource Plan

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

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

TRC – Total Resource Cost

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).

2021 Power Plan: A regional resource plan produced by the Northwest Power and Conservation Council (Council). At the time of this study, the Final plan is scheduled to be released in early 2022.

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 – "Franklin PUD Amended Conservation Potential Assessment: 2024-2043". Final Report – March 28, 2024
2) Model – "2023 Results Viewer Franklin-Base Amended.xlsm" and supporting files
    a. MC_and_Loadshape-Franklin-Base.xlsm – referred to as "MC and Loadshape file" – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
a) **Technical Potential:** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could physically be installed or implemented, without regard to achievability or cost.	The model includes estimates for stock (e.g. number of homes, square feet of commercial floor area, industrial load) and the number of each measure that can be implemented per unit of stock. The technical potential is further constrained by the amount of stock that has already completed the measure.	Model – the technical potential is calculated as part of the achievable potential, described below.
b) Achievable Potential: Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired.	The assessment conducted for the District 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 factors ranging from 85% to 95% were 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**
c)	**Economic Achievable Potential**: Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a benefit-cost ratio greater than one were tallied. These measures are considered achievable and cost-effective (or economic).	Model – Benefit-Cost ratios are calculated at the individual level by ProCost and passed up to the model.
d)	**Total Resource Cost**: In determining economic achievable potential, perform a life-cycle cost analysis of measures or programs	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – Supporting files include all of the ProCost files used in the 2021 Power Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
e)	Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits	Cost analysis was conducted per the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (I.e., those greater than one are 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.
f)	Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes	Savings, cost, and lifetime assumptions from the Council's Final 2021 Power Plan Supply Curves, and RTF were used.	Model – Supporting files include all of the ProCost files used in the 2021 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**
g)	Calculate the value of energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation	The Council's 2021 Power 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 tool, so it was handled in the same way as the 2021 Power Plan models.	Model – See MC_AND_LOADSHAPE files for load shapes. The ProCost files handle the calculations.
h)	Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures	Operations and maintenance costs for each measure were accounted for in the total resource cost per the Council's assumptions.	Model – The ProCost files contain the same assumptions for periodic O&M as the Council and RTF.
i)	Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	The Council's April 2023 Baseline market price forecast was used to value energy in the Base Case Scenario.	Report –See Appendix IV. Model – See MC_AND_LOADSHAPE files ("2021P Electric Mid" worksheet).
j)	Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission capacity expansion benefits were given a benefit of \$3.83/kW-year in the cost-effectiveness analysis. A distribution system credit of \$8.83/kW-year was also used (\$2023). These values were developed by the Council in preparation for the 2021 Power Plan.	Model – This value can be found on the ProData page of each ProCost file. Note that the input is in \$2016.
k)	Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion benefits were given a value of \$ 104/kW-year in the cost effectiveness analysis for the Base Case Scenario. This is based upon the District'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 V.4.006 file.
l)	Include the social cost of carbon emissions from avoided non-conservation resources	This CPA uses the social cost of carbon values specified in WAC 194-40-100.	The MC_AND_LOADSHAPE files contain the carbon cost assumptions for each avoided cost scenario.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
m) Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided 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.
n) Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Council's 2021 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.
o) Include an estimate of program administrative costs	Total costs were tabulated and an estimated 20% of the 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, Seventh Power plans and 2021 Power Plan.	Model – This value can be found on the ProData page of the ProCost V.4.006 file.
p) Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure	Costs of financing measures were included utilizing the same assumptions from the 2021 Power Plan.	Model – This value can be found on the ProData page of the ProCost V.4.006 file.
q) 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 3.75% was used, based on the Council's most recent analyses in support of the 2021 Power Plan.	Model – This value can be found on the ProData page of the ProCost V.4.006.
r) Include a ten percent bonus for the energy and capacity benefits of conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act	A 10% bonus was added to all measures in the model parameters per the Conservation Act.	Model – This value can be found on the ProData page of the ProCost V.4.006 ProData page.

Appendix IV – Avoided Cost and Risk Exposure

The 2021 the District's Conservation Potential Assessment (CPA) was conducted for the period 2022 through 2041 as required under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, the District must evaluate the cost-effectiveness of conservation by setting avoided energy costs equal to a forecast of regional market prices. In addition, several other components of the avoided cost of energy efficiency savings must be evaluated including generation capacity value, transmission and distribution costs, risk, and the social cost of carbon.

This appendix describes each of the avoided cost assumptions and provides a range of values that were evaluated in the 2021 CPA. The 2023 CPA considers three avoided cost scenarios: Base, Low, and High. Each of these is discussed below.

AVOIDED ENERGY VALUE

For the purposes of the 2023, EES used the Council's April 2023 market price forecasts. The Baseline forecast is used in the Base and Low scenarios. This price forecast reflects the large amount of renewable energy forecast to come online in the next 20 years. The high scenario assumes the High Westside Demand forecast scenario developed by the Council. In this scenario, electricity demand is increased on the West side of the Region due to aggressive electrification goals.

AVOIDED COST ADDERS AND RISK

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

FIGURE IV-1: OVERVIEW OF PORTFOLIO REQUIREMENTS

Energy-Based	Capacity Based
• Social Cost of Carbon	• Generation Capacity Deferral
• Renewable Energy Credits	• Transmission Capacity Deferral
• GHG-Free or Neutral Resources	• Distribution Capacity Deferral
• Risk Reduction Premium	

The estimated values and associated uncertainties for these avoided cost components are based on relevant portfolio requirements from the Clean Energy Transformation Act (CETA). The timeline below summarizes the relevant milestones for portfolio planning. The type of energy the District will need to procure is based on these requirements; therefore, the requirements set the avoided cost as it relates to capacity, renewable, and GHG-free power supply.

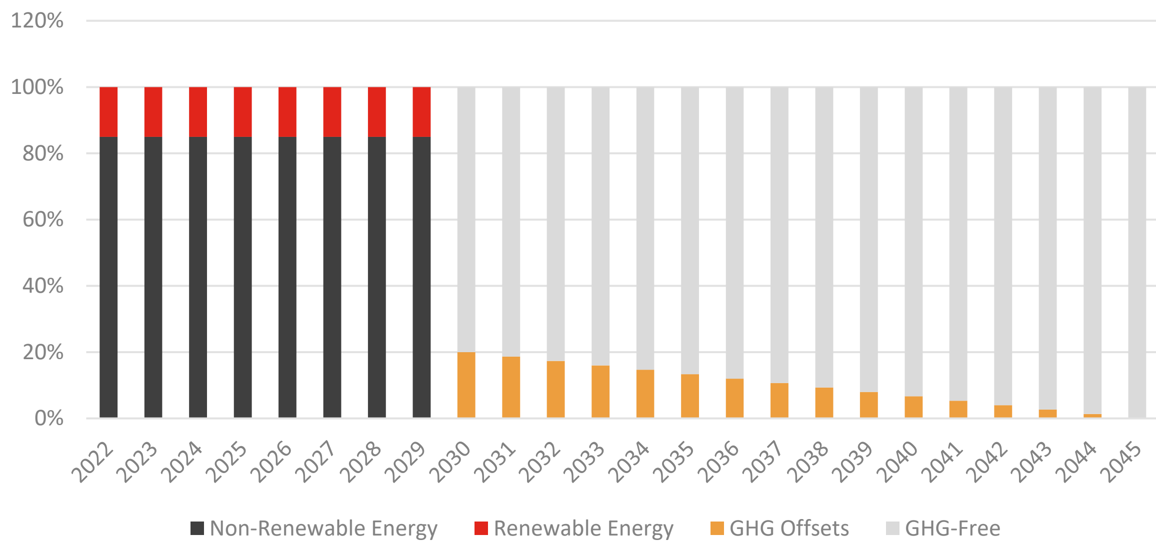
FIGURE IV-2: OVERVIEW OF PORTFOLIO REQUIREMENTS

Through 2030, the District must meet the renewable portfolio standard (RPS) set for Washington State Utilities. The RPS can be met through either bundled or unbundled RECs. Next, CETA establishes a 100% GHG neutral requirement by 2030. The requirement states that at least 80% of a utility's portfolio must be sourced directly from either renewable[12] or non-emitting resources.[13] A utility may then meet the mandate by purchasing no more than 20% of its portfolio in offsets such as unbundled REC purchases. The offsets will then be phased out by 2045 as shown in Figure IV-3.

[12] Renewable resources include water, wind, solar energy, geothermal, renewable natural gas, renewable hydrogen, wave, ocean or tidal power, and biodiesel not derived from crops raised on land cleared from old growth forest or first growth, or biomass. (Chapter 173-444 WAC available at: https://ecology.wa.gov/DOE/files/c0/c08b45ae-7140-4b30-a3c2-faf8aa042651.pdf).

[13] Non-emitting resources are those that generate electricity, or provide capacity of ancillary services to an electric utility that do not emit greenhouse gases as a by-product. *See id*.

FIGURE IV-3: SUMMARY OF RPS AND CETA PORTFOLIO REQUIREMENTS



Social Cost of Carbon

The social cost of carbon is a cost that society incurs when fossil fuels are burned to generate electricity. Both the EIA rules and CETA requires that CPAs include the social cost of carbon when evaluating cost effectiveness using the total resource cost test (TRC). CETA further specifies the social cost of carbon values to be used in conservation and demand response studies. These values are shown in Table IV-1 below.

TABLE IV-1: SOCIAL COST OF CARBON VALUES[14]

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

[14] WAC 194-40-100. Available at: https://apps.leg.wa.gov/wAc/default.aspx?cite=194-40-100&pdf=true.

According to WAC 194-40-110, values may be adjusted for any taxes, fees or costs incurred by utilities to meet portfolio mandates.[15] For example, the social cost of carbon is the full value of carbon emissions which includes the cost to utilities and ratepayers associated with moving to non-emitting resources. Rather than adjust the social cost of carbon for the cost of RECs or renewable energy, the values for RECS and renewable energy are excluded from the analysis to avoid double counting.

The emissions intensity of the marginal resource (market) is used to determine the $/MWh value for the social cost of carbon. Ecology states that unspecified resources should be given a carbon intensity value of 0.437 metric tons of CO_2e/MWh of electricity (0.874 lbs/kWh).[16] This is an average annual value applied to in all months in the conservation potential model.[17]

Avoided Renewable Energy Purchases

Renewable energy purchases need to meet both RPS and CETA and can be avoided through conservation. Utilities may meet Washington RPS through either bundled energy purchases such as purchasing the output of a wind resource where the non-energy attributes remain with the output, or they may purchase unbundled RECs.

As stated above, the value of avoided renewable energy credit purchases resulting from energy efficiency is accounted for within the social cost of carbon construct. The social cost of carbon already considers the cost of moving from an emitting resource to a non-emitting resource. Therefore, it is not necessary to include an additional value for renewable energy purchases prior to 2045 when all energy must be non-emitting or renewable.

Beginning in 2045, the social cost of carbon may no longer be an appropriate adder in resource planning. However, prior to 2045 utilities may still use offsets to meet CETA requirements. Since the study period of this evaluation ends prior to 2045, the avoided social cost of carbon is included in each year. For future studies that extend to 2045 and beyond, it would be appropriate to include renewable energy or non-emitting resource costs as the avoided cost of energy rather than market plus the social cost of carbon.

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

[15] WAC 194-40-110 (b).

[16] WAC 173-444-040 (4).

[17] The seasonal nature of carbon intensity is not modeled due to the prescriptive annual value established by Ecology in WAC 173-444-040.

the same as they are today, and subsequent sector shifts or economic downturns cause large industrial customers to close their operations. Energy efficiency investments in these facilities may not have been in place long enough to provide the anticipated low-cost resource.

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

The value of the risk adder has varied depending on the avoided cost input values. The adder is the result of stochastic modeling and represents the lower risk nature of energy efficiency resources. In the Sixth Power Plan the risk adder was significant (up to $50/MWh for some measures). In the Seventh Power Plan the risk adder was determined to be $0/MWh after the addition of the generation capacity deferral credit. The 2021 Power Plan used the same methodology as the Seventh Plan. 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 such has higher market prices due to a number of factors including electrification, and increased renewables integrated onto the grid.

For the District's 2023 CPA, the avoided cost parameters have been estimated explicitly, and a scenario analysis is performed. Therefore, no risk adder was used for the base case. Variation in other avoided cost inputs covers a range of reasonable outcomes and is sufficient to identify the sensitivity of the cost-effective energy efficiency potential to a range of outcomes. The scenario results present a range of cost-effective energy efficiency potential, and the identification of the District's biennial target based on the range modeled is effectively selecting the utility's preferred risk strategy and associated risk credit.

Deferred Transmission and Distribution System Investment

Energy efficiency measure savings reduce capacity requirements on both the transmission and distribution systems. The Council's 2021 Power assumes these avoided costs are $3.83/kW-year and $8.5/kW-year for transmission and distribution systems, respectively ($2023).[18] These assumptions are used in all scenarios in the CPA.

Deferred Investment in Generation Capacity

The District is a slice/block customer of BPA. While, the District doesn't pay demand rate directly, BPA's demand rates are an appropriate capacity value for the District's avoided cost of capacity. BPA demand

[18] Northwest Power and Conservation Council Memorandum to the Power Committee Members. Subject; Updated Transmission & Distribution Deferral Value for the 2021 Power Plan. March 5, 2019. Available at: https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf.

rates are escalated 3% each rate period (every two years).[19] Over the 20-year analysis period, the resulting cost of avoided capacity is $104/kW-year (2023$) in levelized terms.

In the Council's 2021 Power Plan,[20] a generation capacity value of $143/kW-year was explicitly calculated ($2023). This value is used in the high scenario.

SUMMARY OF SCENARIO ASSUMPTIONS

Table IV-2 summarizes the recommended scenario assumptions. The Base Case represents the most likely future.

TABLE IV-2 AVOIDED COST ASSUMPTIONS BY SCENARIO, $2023

	Base	Low	High
Energy	NWPCC April 2023 Baseline Price Forecast	10% Lower than NWPCC April 2023 Price Forecast	NWPCC April 2023 High Westside Demand
Social Cost of Carbon, $/short ton	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh	WAC 194-40-100 $34/MWh
Avoided Cost of RPS Compliance	Included in Social Cost of Carbon		
Distribution System Credit, $/kW-yr	$8.53	$8.53	$8.53
Transmission System Credit, $/kW-yr	$3.83	$3.83	$3.83
Deferred Generation Capacity Credit, $/kW-yr	$104	$104	$143.18
Implied Risk Adder, 20-year Levelized $/MWh $/kW-yr	N/A	Average: -$1/MWh and -$104/kW-yr	Average: $11/MWh and $39/kW-year

[19] BP-24 Rate Proceeding. July 2023. BP-24-A-02-AP01 Available online: https://www.bpa.gov/-/media/Aep/rates-tariff/bp-24/Final-Proposal/Appendix-BFinal-Proposal-Power-Rate-Schedules-and-GRSPsBP24A02AP01Rev-1.pdf.

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

Appendix V – Ramp Rate Documentation

This section is intended to document how ramp rates were adjusted to align near term potential with recent achievements of the District programs.

Modelling work began with the 2021 Power Plan ramp rate assignments for each measure. The District's program achievements from 2020 and estimates for 2021 were compared at a sector level with the first two years of the study period, 2024-2025. This allowed for the identification of sectors where ramp rate adjustments may be necessary.

Table V-1 below shows the results of the comparison by sector after ramp rate adjustments were made.

Table V- 1

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

	Program History				CPA Potential	
	2020	**2021**	**2022***	**20-'22 Avg**	**2024**	**2025**
Residential	0.03	0.03	0.03	0.03	0.06	0.08
Commercial	0.63	0.33	0.25	0.40	0.29	0.32
Industrial	0.00	0.48	0.03	0.17	0.14	0.15
Agricultural	0.02	0.02	0.02	0.02	0.02	0.02
Distribution Efficiency					0.00	0.00
NEEA	0.38	0.40	0.40	0.40		
Total	**1.06**	**1.26**	**0.73**	**1.02**	**0.52**	**0.57**

**Projected*

When viewing the achievement and potential at the sector level, adjustments were found to be necessary in the residential and commercial sectors. The 2021 Power Plan ramp rates were found to be a good match for the District programs in the industrial, agricultural, and distribution system sectors. The 2021 Power Plan assigns a fast ramp rate to exterior commercial lighting. The ramp rate for these measures was adjusted to smooth potential over the 20-year period (moving from Fast 80 to 20-year ramp rates. This adjustment accounts for COVID impacts in supply chain and program participation observed in 2020 and continuing into 2023. Additionally, several residential measures were assigned slower ramp rates due to lower historic achievement over the 2020-2022 period. The 2021 Power Plan documents do not consider COVID impacts, therefore, it is appropriate to make the adjustments to the potential in the near-term for purposes of target setting.

Appendix VI – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2023 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 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 2021 Plan 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
Appliances	Heat Pump Clothes Dryer	2021 Power Plan
	Clothes Dryer	2021 Power Plan
	Oven	2021 Power Plan
Electronics	Advanced Power Strips	2021 Power Plan
	Desktop	2021 Power Plan
	Laptop	2021 Power Plan
	Monitor	2021 Power Plan
	Air Cleaners	2021 Power Plan
Food Preparation	Electric Oven	2021 Power Plan
	Microwave	2021 Power Plan
HVAC	Air Source Heat Pump	2021 Power Plan
	Controls, Commissioning, and Sizing	2021 Power Plan
	Central Air Conditioning	2021 Power Plan
	Ductless Heat Pump	2021 Power Plan
	Ducted Heat Pump	2021 Power Plan
	Duct Sealing	2021 Power Plan
	Ground Source Heat Pump	2021 Power Plan
	Heat Recovery Ventilation	2021 Power Plan
	Attic Insulation	2021 Power Plan
	Floor Insulation	2021 Power Plan
	Wall Insulation	2021 Power Plan
	Windows	2021 Power Plan
	Cellular Shades	2021 Power Plan
	Whole House Fan	2021 Power Plan
	Wi-Fi Enabled Thermostats	2021 Power Plan
Lighting	Linear Fluorescent Lighting	2021 Power Plan
	Floor/Table Lamps	2021 Power Plan

Table VI-1
Residential End Uses and Measures

End Use	Measures/Categories	Data Source
	Ceiling and Wall Flush Mount	2021 Power Plan
	Downlight Fixture	2021 Power Plan
	Exterior Porch	2021 Power Plan
	Linear Porch	2021 Power Plan
	Track Lighting	2021 Power Plan
	Linear Base	2021 Power Plan
	Decorative Base	2021 Power Plan
Refrigeration	Freezer	2021 Power Plan
	Refrigerator	2021 Power Plan
Water Heating	Aerator	2021 Power Plan
	Water Heater Pipe Insulation	2021 Power Plan
	Clothes Washer	2021 Power Plan
	Dishwasher	2021 Power Plan
	Heat Pump Water Heater	2021 Power Plan
	Showerheads	2021 Power Plan
	Solar Water Heater	2021 Power Plan
	Circulator Controls	2021 Power Plan
	Thermostatic Valve	2021 Power Plan
	Wastewater Heat Recovery	2021 Power Plan
Whole Building	EV Charging Equipment	2021 Power Plan
	Behavior	2021 Power Plan
	Well Pump	2021 Power Plan

Table VI-2
Commercial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Controls, Equipment, & Demand Reduction	2021 Power Plan
Electronics	Desktop Computer	2021 Power Plan
	Laptop Computer	2021 Power Plan
	Smart Plug Power Strips	2021 Power Plan
	Data Center Measures	2021 Power Plan
Food Preparation	Combination Ovens	2021 Power Plan
	Convection Ovens	2021 Power Plan
	Fryers	2021 Power Plan
	Hot Food Holding Cabinet	2021 Power Plan
	Steamer	2021 Power Plan
	Pre-Rinse Spray Valve	2021 Power Plan
HVAC	Advanced Rooftop Controller	2021 Power Plan
	Chiller Upgrade	2021 Power Plan
	Commercial Energy Management	2021 Power Plan
	Demand Control Ventilation	2021 Power Plan
	Ductless Heat Pumps	2021 Power Plan
	Economizers	2021 Power Plan
	Secondary Glazing Systems	2021 Power Plan
	Variable Refrigerant Flow	2021 Power Plan
	Web-Enabled Programmable Thermostat	2021 Power Plan
	Fans	2021 Power Plan
	PTPH	2021 Power Plan
Lighting	Bi-Level Stairwell Lighting	2021 Power Plan
	Exterior Building Lighting	2021 Power Plan
	Exit Signs	2021 Power Plan
	Lighting Controls	2021 Power Plan
	Interior Lighting	2021 Power Plan
	Garage Lighting	2021 Power Plan
	Street & Roadway Lighting	2021 Power Plan
Motors/Drives	ECM for Variable Air Volume	2021 Power Plan
	Motor Rewinds	2021 Power Plan
Process Loads	Municipal Water Supply	2021 Power Plan
Refrigeration	Grocery Refrigeration Bundle	2021 Power Plan
	Freezer	2021 Power Plan
Water Heating	Commercial Clothes Washer	2021 Power Plan
	Showerheads	2021 Power Plan
	Clean Water Pumps	2021 Power Plan
	Heat Pump Water Heaters	2021 Power Plan
	Circulator Pumps	2021 Power Plan
Process Loads	Elevators	2021 Power Plan
	Engine Block Heater Control	2021 Power Plan

Table VI-3
Industrial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Air Compressor Equipment	2021 Power Plan
	Demand Reduction	2021 Power Plan
Energy Management	Air Compressor Optimization	2021 Power Plan
	Energy Project Management	2021 Power Plan
	Fan Energy Management	2021 Power Plan
	Fan System Optimization	2021 Power Plan
	Cold Storage Tune-up	2021 Power Plan
	Chiller Optimization	2021 Power Plan
	Integrated Plant Energy Management	2021 Power Plan
	Plant Energy Management	2021 Power Plan
	Pump Energy Management	2021 Power Plan
	Pump System Optimization	2021 Power Plan
Fans	Efficient Centrifugal Fan	2021 Power Plan
	Fan Equipment Upgrade	2021 Power Plan
Hi-Tech	Clean Room Filter Strategy	2021 Power Plan
	Clean Room HVAC	2021 Power Plan
	Chip Fab: Eliminate Exhaust	2021 Power Plan
	Chip Fab: Exhaust Injector	2021 Power Plan
	Chip Fab: Reduce Gas Pressure	2021 Power Plan
	Chip Fab: Solid State Chiller	2021 Power Plan
Lighting	Efficient Lighting	2021 Power Plan
	High-Bay Lighting	2021 Power Plan
	Lighting Controls	2021 Power Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	2021 Power Plan
	Cold Storage Retrofit	2021 Power Plan
	Grocery Distribution Retrofit	2021 Power Plan
Material Handling	Material Handling Equipment	2021 Power Plan
	Material Handling VFD	2021 Power Plan
Metals	New Arc Furnace	2021 Power Plan
Misc.	Synchronous Belts	2021 Power Plan
	Food Storage: CO2 Scrubber	2021 Power Plan
	Food Storage: Membrane	2021 Power Plan
Motors	Motor Rewinds	2021 Power Plan
Paper	Efficient Pulp Screen	2021 Power Plan
	Material Handling	2021 Power Plan
	Premium Control	2021 Power Plan
	Premium Fan	2021 Power Plan
Process Loads	Municipal Sewage Treatment	2021 Power Plan
Pulp	Efficient Agitator	2021 Power Plan
	Effluent Treatment System	2021 Power Plan
	Premium Process	2021 Power Plan
	Refiner Plate Improvement	2021 Power Plan
	Refiner Replacement	2021 Power Plan
Pumps	Equipment Upgrade	2021 Power Plan
Transformers	New/Retrofit Transformer	2021 Power Plan
Wood	Hydraulic Press	2021 Power Plan
	Pneumatic Conveyor	2021 Power Plan

Table VI-3 Agriculture End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dairy Efficiency	Efficient Lighting	2021 Power Plan
	Milk Pre-Cooler	2021 Power Plan
	Vacuum Pump	2021 Power Plan
Irrigation	Low Energy Sprinkler Application	2021 Power Plan
	Irrigation Hardware	2021 Power Plan
	Line Pressure Reduction	2021 Power Plan
Lighting	Agricultural Lighting	2021 Power Plan
Process Loads	Circulating Block Heater for Back -Up Generator	2021 Power Plan
	Energy Free Stock Tank	2021 Power Plan
Motors/Drives	Green Motor Rewinds	2021 Power Plan

Table VI-4 Distribution Efficiency End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Distribution Efficiency	ECM-1 LDC Voltage Control without VVO & AMI	2021 Power Plan
	ECM-2 & ECM 3 LDC Voltage Control with VVO & AMI	2021 Power Plan

Appendix VII –Energy Efficiency Potential by End-Use

Table VII-1 Residential Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Water Heating	0.01	0.02	0.02	0.04
HVAC	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00
Electronics	0.08	0.29	0.60	1.38
Food Preparation	0.00	0.04	0.14	0.24
Dryer	0.01	0.02	0.03	0.06
Refrigeration	0.06	0.22	0.46	0.85
Whole Bldg/Meter Level	0.00	0.00	0.00	0.00
Total	**0.15**	**0.59**	**1.26**	**2.58**

Table VII-2 Commercial Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Food Preparation	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00
Electronics	0.02	0.07	0.11	0.18
Refrigeration	0.06	0.19	0.30	0.54
Process Loads	0.39	1.17	1.64	2.08
Compressed Air	0.00	0.00	0.00	0.00
HVAC	0.00	0.00	0.00	0.00
Motors/Drives	0.11	0.34	0.57	1.12
Water Heating	0.02	0.06	0.09	0.18
Total	**0.61**	**1.83**	**2.71**	**4.10**

Table VII-3 Industrial Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Compressed Air	0.09	0.26	0.43	0.82
Fans	0.00	0.00	0.00	0.00
Lighting	0.13	0.39	0.53	0.61
Pumps	0.01	0.03	0.05	0.09
HVAC	0.06	0.18	0.25	0.28
Low Temp Refer	0.00	0.00	0.00	0.00
Med Temp Refer	0.00	0.00	0.00	0.00
All Electric	0.00	0.00	0.00	0.00
Material Processing	0.00	0.00	0.00	0.00
Material Handling	0.00	0.00	0.00	0.00
Melting and Casting	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00
Total	**0.29**	**0.87**	**1.26**	**1.80**

Table VII-4 Agricultural Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
Dairy Efficiency	0.00	0.00	0.00	0.00
Irrigation	0.00	0.00	0.00	0.00
Lighting	0.02	0.04	0.06	0.12
Motors/Drives	0.02	0.09	0.16	0.33
Process Loads	0.00	0.00	0.00	0.00
HVAC	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.02	0.06	0.11
	0.03	**0.13**	**0.23**	**0.45**

Table VII-5 Distribution Efficiency Economic Potential (aMW)				
	2 Year	**4 Year**	**10 Year**	**20 Year**
EMC-1 LDC with no VVO	0.00	0.02	0.07	0.20
ECM-2 & ECM-3 LDC with VVO & AMI	0.00	0.00	0.00	0.00
Total	**0.00**	**0.02**	**0.07**	**0.20**