Clark Public Utilities

2024 INTEGRATED RESOURCE PLAN

PREPARED IN COLLABORATION WITH:

TEA
THE EnergyAuthority

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CONFIDENTIAL & PROPRIETARY

TABLE OF CONTENTS

Section 1 Executive Summary

1.1 Background

Clark Public Utilities (CPU) 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 CPU produces a comprehensive plan every four years and provide 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. CPU's previous IRP was adopted by the Board in August 2020. The 2020 IRP analysis showed that CPU'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 CPU 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 renewable portfolio standard compliant generation beginning in 2025.

CPU 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).

CPU 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 Clark Public Utilities

CPU provides electric service to approximately 228,000 residential, commercial, industrial, and street lighting customers countywide. CPU purchases about half 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, WA, and makes miscellaneous energy purchases on the open market.

CPU also owns River Road Generating Plant in Clark County and has power purchase agreements with Combine Hills Wind Project and Packwood Hydroelectric Project.

1.3 Future Load and Resource Balance

CPU'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 forecast for the full study period from 2025 – 2044 based on econometric forecasts for Clark County from Woods and Poole. In addition, the load forecast used in this study incorporates additional load growth due to building and vehicle electrification beyond 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 an average of 1.98% year-over-year load growth over the study time horizon. In addition to this expected case, CPU modeled a low and high load scenario, which forecast an average year-over-year load growth rate of 1.05% and 3.12% respectively. Over the study period, CPU shifts from a predominantly winter-peaking utility to a summer-peaking utility. CPU is currently forecast to have sufficient resources available to meet average energy demand through 2035. However, on a capacity basis, CPU is currently at a deficit and is projected to grow that deficit to roughly 750 MW of summer capacity and 500 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, especially in light of CPU's expected load growth and the retirement of aging regional 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. In order to be compliant with the requirements of the Clean Energy Transformation Act (CETA), CPU evaluated only carbon-free supply-side resource options including solar, wind, lithium-ion battery storage, geothermal, small-modular nuclear reactors, as well as short and long-term market capacity options.

1.5 Least Cost Action Plan Summary

CPU will meet the growing needs of its customers through a combination of strategies. First, CPU will maximize use of Bonneville Power Administration (BPA) Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. This will include thoughtful BPA product selection and negotiation for 2028 and specifically pursuing a 100% carbon-free BPA product. CPU will optimize River Road Generating Plant generation using the flexibility product installed in May 2024. CPU will also acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments. CPU will continue to explore opportunities for adding both utility-scale renewable and behind-the-meter renewable resources, such as community solar projects, to its resource portfolio. Additional utility-scale renewables will only be added to the resource portfolio when the load/resource balance shows that new resources are needed from an energy perspective.

1.6 Clean Energy Action Plan Summary

To meet the requirements of CETA, CPU will leverage the newly installed flexibility capabilities of the River Road Generating Plant to minimize use of carbon-emitting natural gas while maximizing use of BPA Tier 1 power and CPU's renewable resources including Combine Hills wind, Box Canyon hydroelectric project, as well as likely future solar resources contracted through Power Purchase Agreements (PPAs). In addition, CPU will pursue energy efficiency, demand response, and distributed generation programs within its service territory. Finally, CPU will continue to monitor and engage with opportunities for new low and zero carbon capacity resource technologies including geothermal and small modular nuclear reactors.

1.7 Conclusions

CPU is currently meeting the energy demand of its customers with approximately 65% carbon-free electric power and is projected to maintain balance between its load and resources into the mid-2030's despite a roughly 2% year-over-year projected load growth through that period. After 2035, CPU will need to procure additional energy resources to meet its customers' demand. However, on a capacity basis, CPU already 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 750 MW by 2044. CPU will leverage all the tools available to meet this need reliably, affordably, and sustainably. These tools include optimization of BPA Tier 1 power, CPU's RRGP, renewables, and battery storage options.

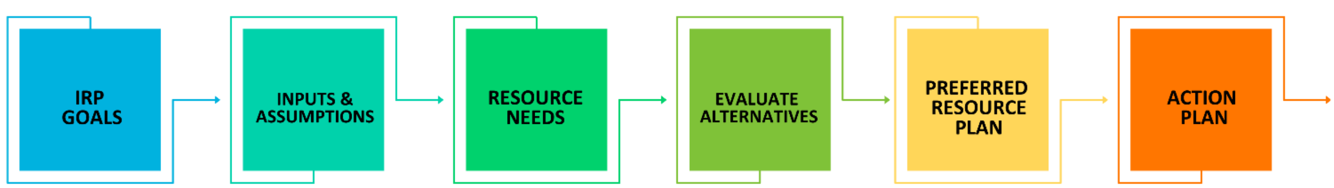
Section 2 IRP Methodology

Integrated Resource Planning (IRP) is a comprehensive and strategic planning process that CPU 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 CPU 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 CPU to develop this resource planning study:

1. IRP goals: IRP methodology begins with identification and establishment of the objectives of the IRP process. CPU'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 CPU to develop strategies mitigating risk and ensures 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 CPU'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

Public Utility District No. 1 of Clark County (CPU) 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 CPU produce a comprehensive plan every four years and provide 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.

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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, and as such, CPU is subject to I-937. If the CPU fails to meet the requirement, it will be assessed a penalty of $50/MWh, in 2007 dollars, equating to approximately $62/MWh in 2020 dollars. In 2012, 3% of retail load was required to be sourced from renewable generation, 9% in 2016, and finally 15% in 2020. Until 2023, CPU has been able to comply without meeting the percentage of load served by renewables by utilizing the "cost-cap" provision. Under the "cost-cap" provision, CPU has invested at least 4% of its total annual retail revenue requirement on the incremental levelized cost of qualifying renewable resources. The intention of this "cost-cap" provision is to act as a "safety valve" to limit the impacts of the law on ratepayers. The law states:

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

Historically, CPU has used the RECs associated with BPA's tier 1 resource pool, the Combine Hills II wind project and cost caps to meet the "cost-cap" provision's 4% revenue requirement. As of late, market prices have been higher and decreased the share of costs used toward qualifying renewables. Because of this, CPU is now required to serve 15% of load with eligible renewables. To address this, CPU has purchased Renewable Energy Credits (RECs) and contracted for additional qualifying renewables through a Power Purchase Agreement with the Combine Hills I wind project that began generating for CPU in February 2024. CPU is looking to add more renewable resources, including solar generation, to its portfolio soon. I-937 compliance is thus a key driver of resource acquisition decisions and IRP resource options.

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 1st, 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 act 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, 63.2M 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

CPU and other electric utilities who are subject to CCA were allocated allowances for the first compliance period based on the cost burden effect. The cost burden effect calculates emissions from load served by coal, natural gas, Asset-Controlling Supplier resources (such as BPA), non-emitting resources, and unspecified generation. CPU'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. CPU incurs compliance obligations through emissions at River Road Generating Plant and through electricity imports.

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

	2023	2024	2025	2026
CPU Allowances	**1,020,697**	**1,033,055**	**1,056,902**	**877,215**

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 2024 allowances unsold. Any allowances that go unsold are offered again at the following auction. Notably, the settlement price for current vintage allowances in auction #2 decreased from its peak of $63.03 to that of $29.92 in auction #6.

Initiative 2117 (I-2117) will be voted on in the November 2024 election. If passed, I-2117 would eliminate the Climate Commitment Act 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, CPU would no longer be subject to any compliance obligation, and the no cost allowances distributed to CPU would lose all value. CPU 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. 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.

CPU is currently participating in the WRAP non-binding program through the TEA Load Serving Entity (LSE) group. Participating as a single LSE allows CPU 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 CPU's current Slice/Block contract with BPA, CPU is the Load Responsible Entity. However, under a Load Following contract, BPA would be the WRAP LRE on CPU'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 CPU) to consider certain standards for rate design and other utility procedures. CPU 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. CPU may be subject to certain provisions of the Energy Policy Act of 2005, relating to transmission reliability and non-discrimination. Under the Enabling Act, CPU 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 a large number of applications from solar developers (as many as 130 solar projects). Oregon, however, has many PURPA facilities in the pipeline. In March 2016, the Oregon PUC decided to keep its 20-year guaranteed contracts in place with 15 years of fixed prices, which pleased renewable developers. Washington, on the other hand, doesn't have a required standard contract length for QFs. In addition, the depressed wholesale market prices (when compared to other markets) due to low-cost hydro makes the avoided cost of power too low for PURPA projects in Washington to be economically viable to developers. CPU is currently a purchaser of RECs from Idaho PURPA solar generation facilities which contribute to satisfying CPU's EIA renewable requirements.

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

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 located 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 CPU to develop a self-build renewable project and receive PTC or ITC credits. However, for this study, TEA modeled CPU renewable participation as PPA agreements.

3.6.3 Renewable Electricity Production Tax Credit (PTC)

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

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

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

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. The maximum allowable credit, equipment requirements and other details vary by technology, as outlined in Table 4.

Table 4. ITC Eligibility by Resource Type

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

Section 4 Load Forecast

4.1 Load Forecast Summary

Projected system load is the amount of electric energy CPU's customers require for heating, lighting, motors, and other end-uses prior to accounting for conservation, demand response, rooftop solar, and other distribution system resources. The load forecasts for CPU used in this study were developed using historical load, weather, and econometric data for Clark 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. A non-linear regression 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 CPU'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. 14 years of historical monthly system total and peak load data (Jan. 2010- Jan. 2024) was collected from CPU. The dataset divides CPU's load into six classes including: Residential, Commercial, Industrial, Lighting, District, and Interdepartmental.
2. 20 years of historical weather data for the Portland International Airport (KPDX) weather station (Jan. 2004 – Jan. 2024) were 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 calculated off a standard temperature of 65˚ F using the formula below for each day. For hours with temperatures above 65˚ F, heating degree days were set to zero, while hours with temperatures below 65˚ F had zero cooling degree days. 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 Clark County was obtained from Woods & Poole's 2023 Complete Economic and Demographic Data Source[1]. This dataset included both historical data from 1970 to 2023 and forecasted data extending from 2024 to 2060 for five economic metrics. Linear regression models were trained for each customer class (residential, commercial, etc.). For residential and commercial loads, linear regression was used to match the best fitting econometric growth indicator from the historical data to the monthly residential and commercial energy as well as the peak load. The industrial, district, interdepartmental, and lighting load forecast models were trained using the month of the year and historical heating/cooling degree days. Table 5 shows the chosen economic metric for each customer class and the peak load.

Table 5. Economic Indicator by Customer Class

Customer Class	Economic Indicator
District	No Indicator
Industrial	No Indicator
Interdepartmental	No Indicator
Lighting	No Indicator
Commercial	Total Employment
Residential	Total Retail Sales Including Food Sales
Peak Demand	Total Employment

4. These regression models were then used to project monthly per-customer class energy and peak load using the month of year, normalized weather, and their specific economic projections. Below is a visual of annual per-customer class load after distribution losses calculated from the monthly history and regression model projections.

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

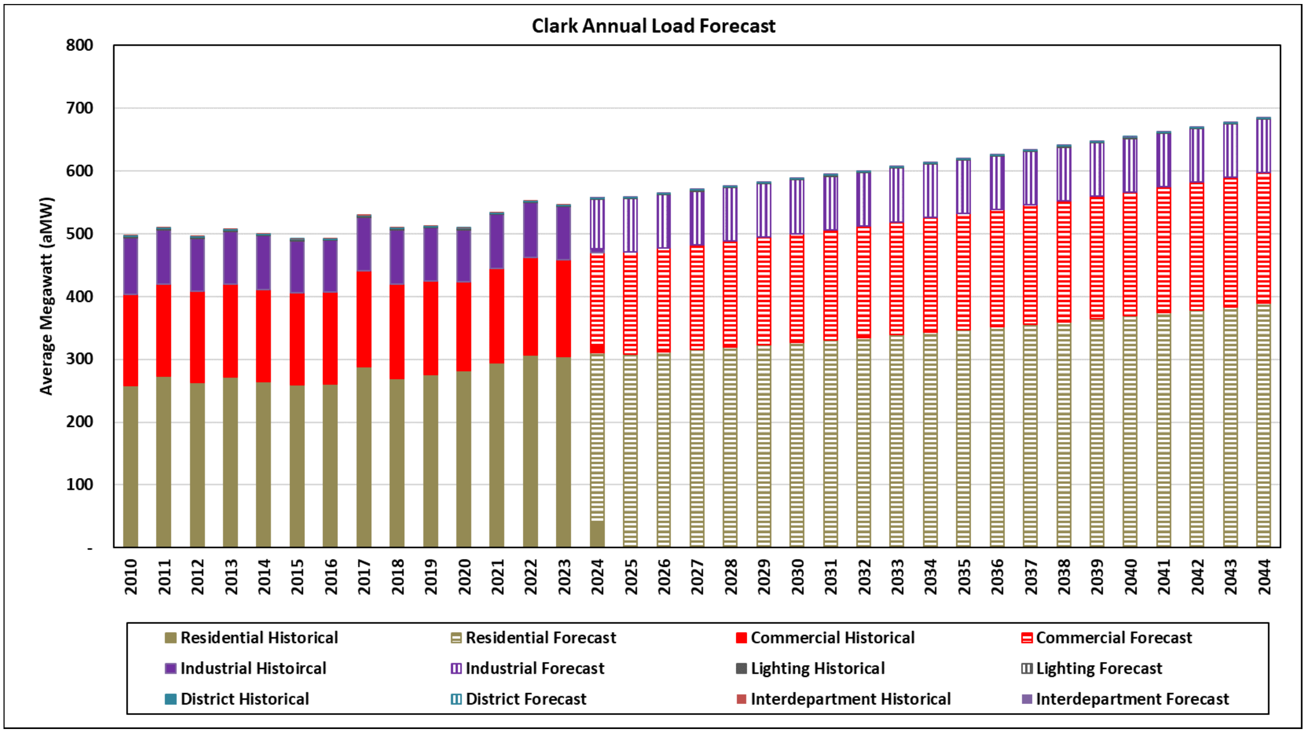

Figure 1. CPU annual load history and forecast by customer class from 2010 - 2044.

Below is a visual of annual total energy and peak load calculated from the history and regression model projections.

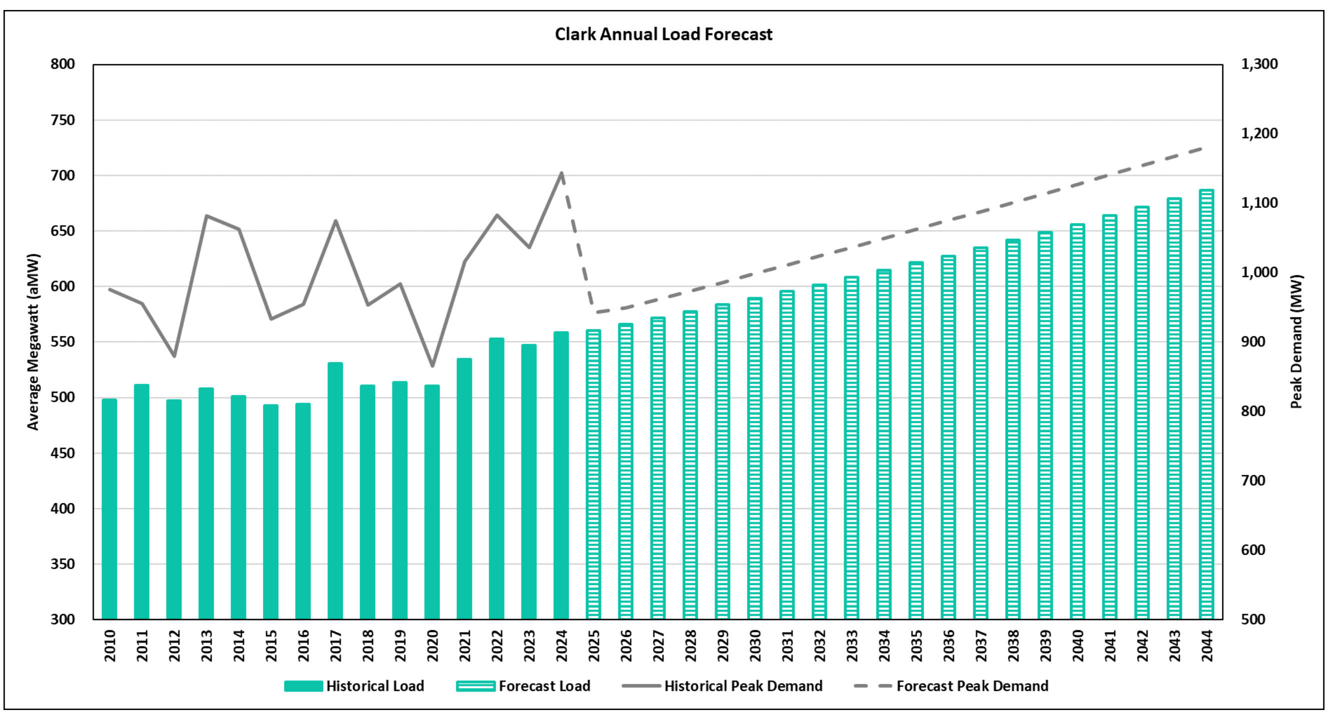

Figure 2. CPU annual load (left y-axis) and peak demand (right y-axis) history and forecast from 2010 to 2044.

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.
2. Hourly historical weather data for the KPDX 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 base energy 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 EV Forecast Methodology

The electric vehicle (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 in EV growth, particularly in the near-term. After the model using this state-level data, annual per-capita income projections for Clark 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 by the total number of vehicles on the road, obtained for Clark 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.

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

[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.

b) Average temperature, which is varied by month depending on the average monthly temperature from the last 10 years at the Portland International Airport.
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 – two charging behavior archetypes are modeled in this study
   i) Immediate Charging: customers charge their vehicles immediately after getting home, resulting in significant charging during peak demand periods.
   ii) Slow Charging: customers time their charging during off-peak periods.

   The split between these two behaviors will significantly impact CPU's peak load, while the total monthly energy remains the same. A combination of Immediate and slow charging is assumed for the expected case in this study. Specifically, slow charging behavior is assumed to grow from 0% in 2024 to 50% in 2050 in a linear trend, while immediate charging behavior drops from 100% in 2024 to 50% in 2050.

3) The EVI-Pro Lite tool provided the output of the hourly EV charging shape given the assumptions above. The below figure shows the annual energy and peak load resulted by EVs for Clark County.

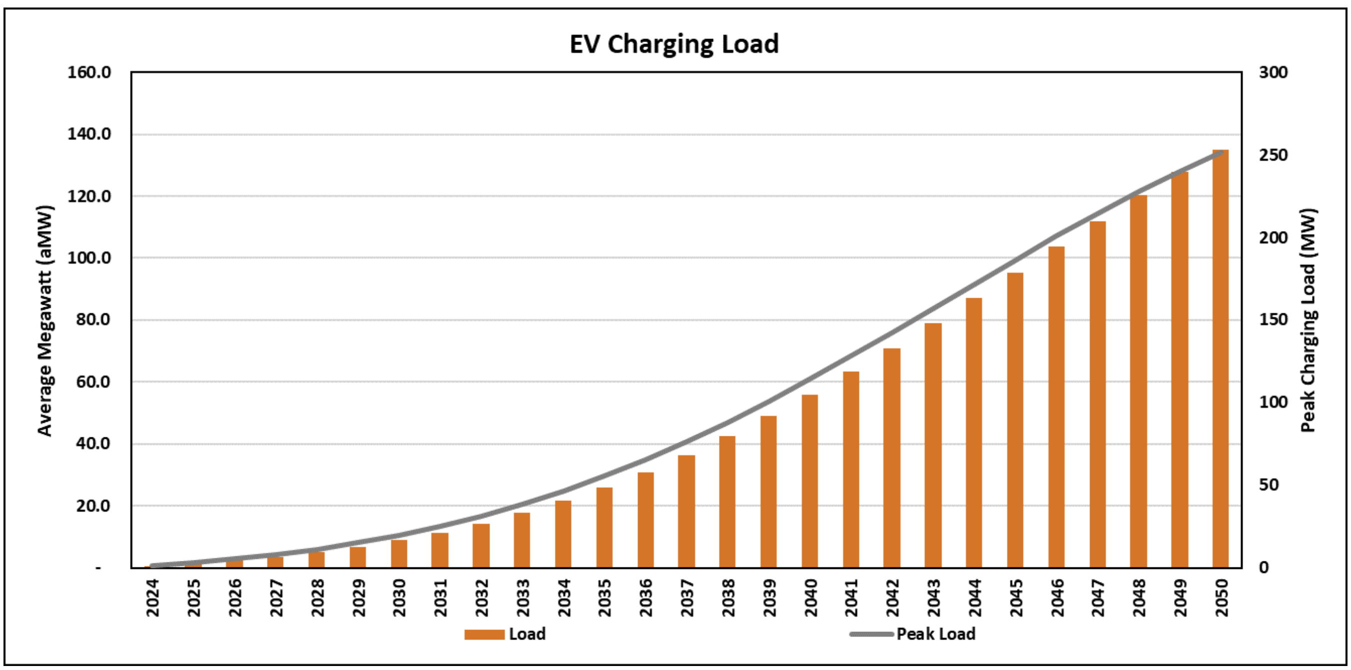

Figure 3. CPU forecast EV charging load.

4.5 Building Electrification Forecast Methodology

The building electrification 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 the hourly load profile for each building with different technology stock considering weather normalization in state level using the hourly historical data provided by NREL in the Electrification Futures Study (EFS)[5][6].
    a) Five scenarios with different levels of electrification are projected by NREL in EFS. This study used the medium electrification scenario.
    b) This study models the electrification of four main classes of building technology: residential A/C & heating, residential water heaters, commercial A/C and heating and commercial water heaters.
2) The state-level projections are scaled down to the county-level using the econometric projection provided by Woods & Poole namely, number of households and employment rates.
3) Finally, the projected additional electrification load is calculated for each technology. Figure 4 shows the annual energy and peak load resulted by different technology stocks of Building Electrification for Clark County.

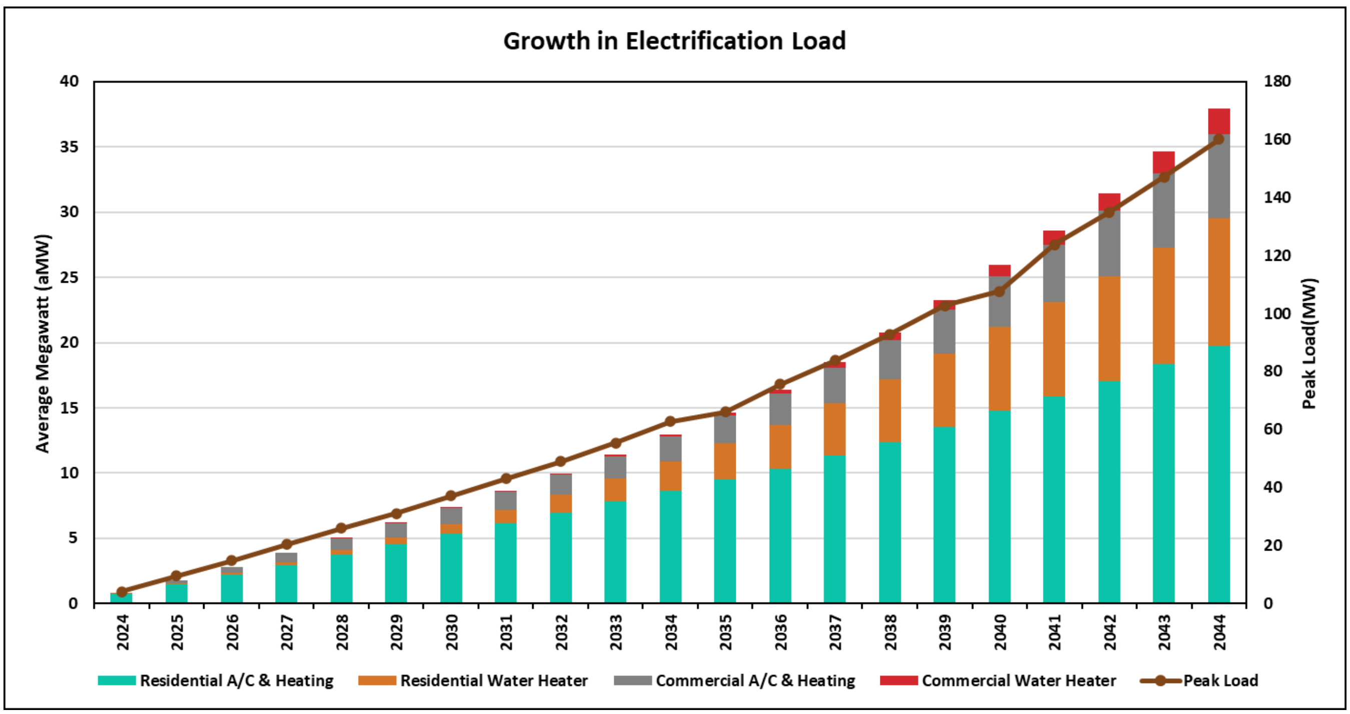

Figure 4. Projected load from building electrification in Clark County.

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[5] **National Renewable Energy Laboratory (NREL).** "Electrification Futures Study (EFS)." NREL. Accessed September 2023. https://www.nrel.gov/analysis/electrification-futures.html.

[6] **National Renewable Energy Laboratory (NREL).** "Electrification Futures Study: Hourly Load Profiles." NREL. Accessed September 2023. https://data.nrel.gov/submissions/92.

4.6 Annual Summary

The charts below depict both historical and forecasted annual energy and peak load, both with and without EV and building electrification.

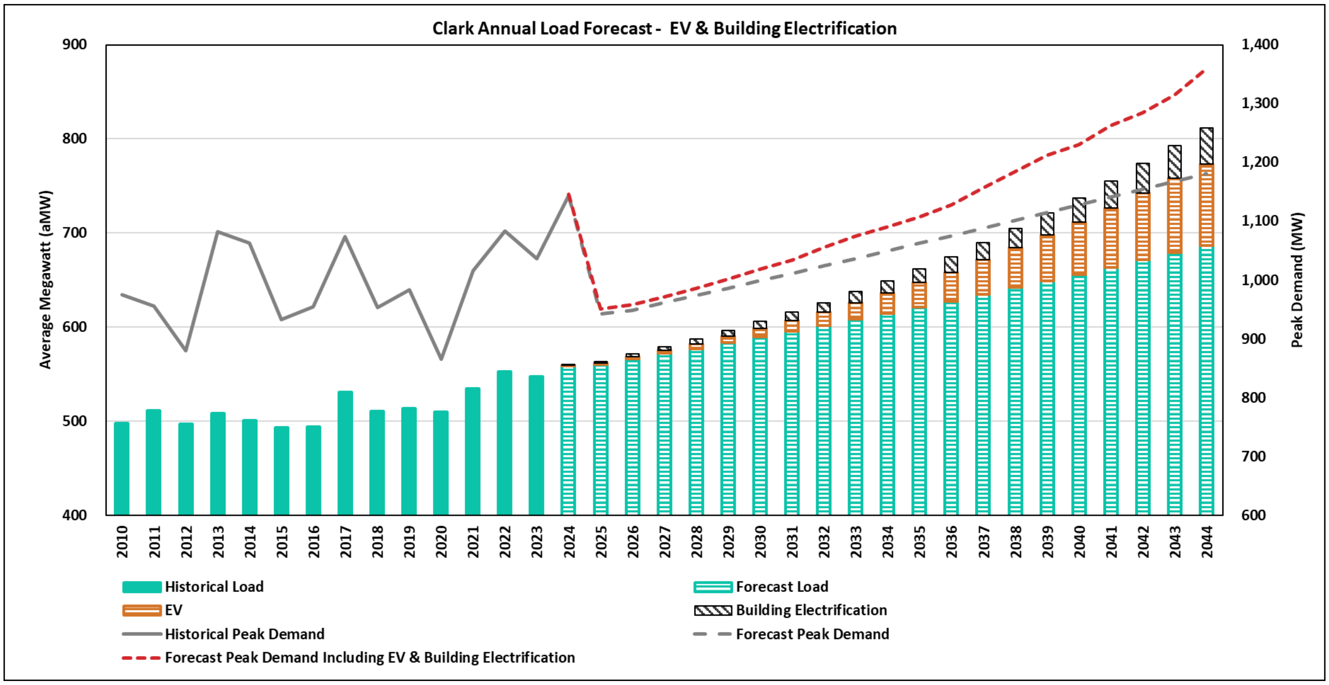


Figure 5. CPU annual load (left y-axis) and peak demand (right y-axis) history and forecast including electric vehicle (EV) and building electrification load.

Additionally, Table 6 provides the annual historical and projected growth rates and year-over-year change.

Table 6. Forecast for Total Energy and Peak Demand

Year	Load (aMW) Actual & Forecast	Load (aMW) YoY Change (%)	Peak Demand (MW) Actual & Forecast	Peak Demand (MW) YoY Change (%)
2004	462	-	867	-
2005	488	5.2%	944	8.9%
2006	506	3.6%	880	-6.8%
2007	525	3.9%	950	8.0%
2008	551	5.1%	1,059	11.4%
2009	538	-2.7%	1,115	5.3%
2010	516	-4.0%	975	-12.5%
2011	531	2.7%	956	-2.0%
2012	518	-2.5%	879	-8.0%
2013	527	1.9%	1,082	23.1%
2014	521	-1.3%	1,063	-1.8%
2015	513	-1.6%	933	-12.2%
2016	516	0.5%	954	2.3%
2017	553	7.1%	1,074	12.6%
2018	532	-3.7%	953	-11.3%
2019	539	1.1%	983	3.2%
2020	535	-0.9%	866	-12.0%
2021	559	4.5%	1,016	17.4%
2022	579	3.4%	1,083	6.6%
2023	571	-1.0%	1,036	-4.3%
2024	568	-1.0%	1,144	10.4%
2025	570	0.4%	951	-16.9%
2026	579	1.4%	959	0.8%
2027	587	1.4%	972	1.4%
2028	596	1.6%	986	1.5%
2029	605	1.3%	1,001	1.5%
2030	615	1.6%	1,019	1.8%
2031	626	1.6%	1,033	1.4%
2032	638	1.9%	1,056	2.1%
2033	647	1.6%	1,075	1.9%
2034	661	1.9%	1,091	1.4%
2035	675	1.9%	1,107	1.5%
2036	690	2.2%	1,127	1.8%
2037	704	2.0%	1,157	2.6%
2038	718	2.2%	1,185	2.4%
2039	737	2.3%	1,212	2.4%
2040	756	2.5%	1,230	1.5%
2041	773	2.2%	1,263	2.7%
2042	792	2.4%	1,285	1.7%
2043	810	2.5%	1,315	2.4%
2044	834	2.7%	1,359	3.4%

4.7 Monthly Electrification Load Forecast

The charts below show historical and forecast energy and peak load with and without EV and building electrifications:

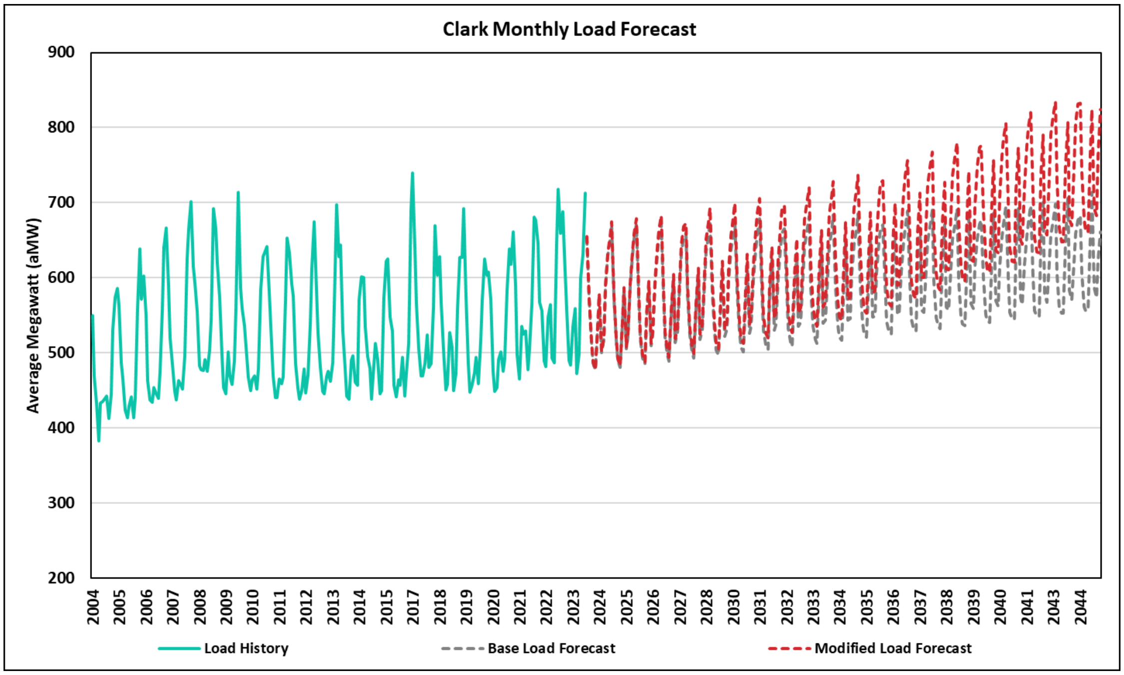


Figure 6. CPU monthly load history and forecast 2004 - 2044.

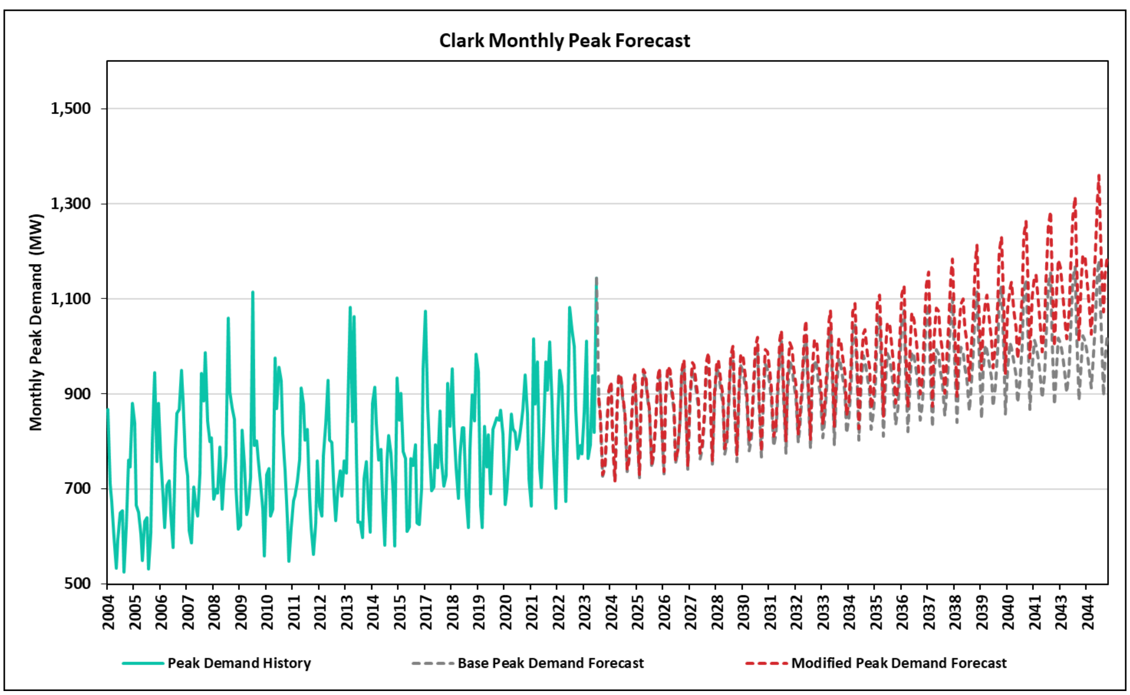


Figure 7. CPU monthly peak demand history and forecast 2004 – 2044.

4.8 Forecast High Low Scenarios

In addition to the expected load forecast (the base case), high and low scenarios are provided to account for uncertainties and multiple possible futures in the forecast model.

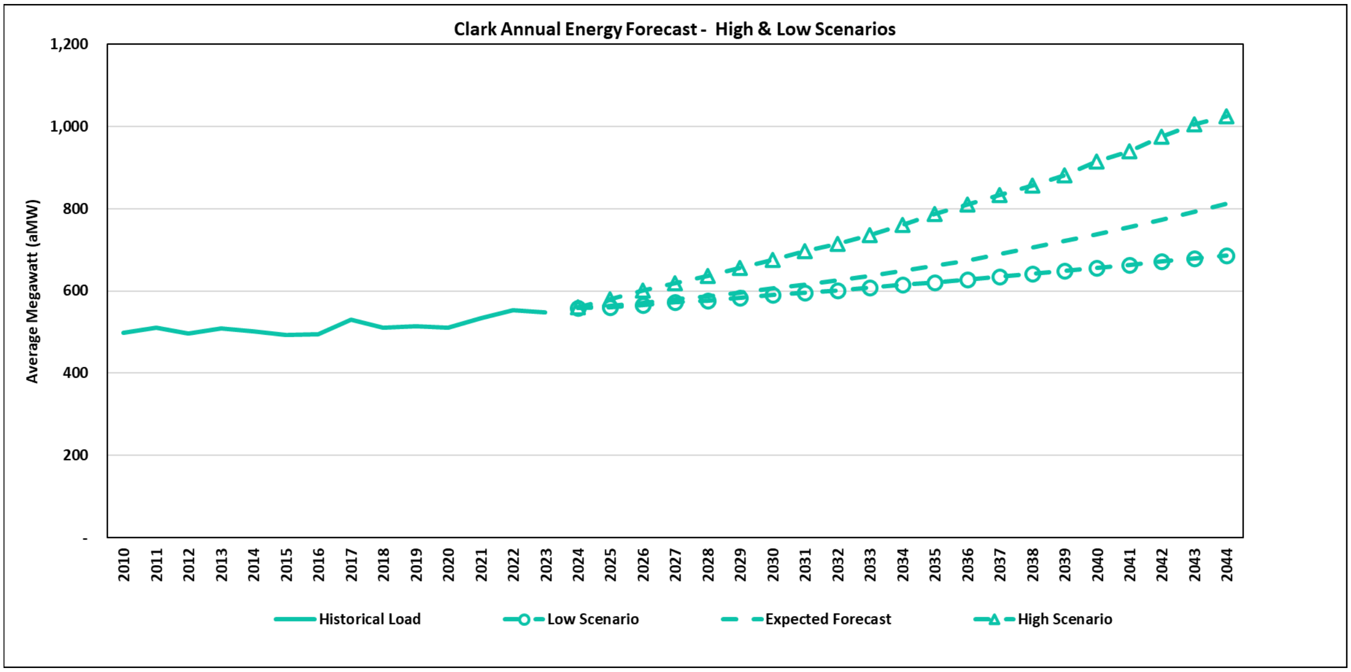


Figure 8. CPU annual load forecast scenarios: low, expected, and high.

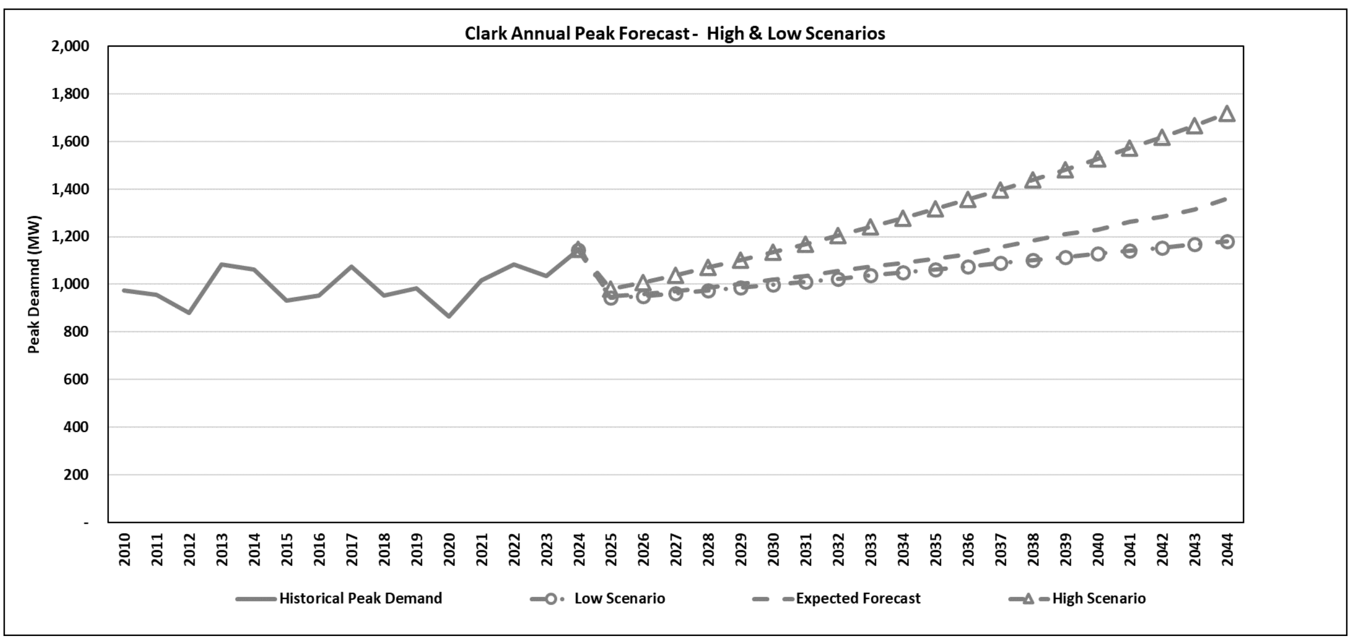


Figure 9. CPU annual peak demand forecast scenarios: low, expected, and high.

Additionally, Table 7 provides the annual projected growth rates and year-over-year change for different scenarios.

Table 7. Forecast of Total Energy and Peak Demand by Scenarios

Year	Low Scenario				Expected Forecast				High Scenario			
	Load		Peak Demand		Load		Peak Demand		Load		Peak Demand	
	(aMW)	YoY Change (%)	(MW)	YoY Change (%)	(aMW)	YoY Change (%)	(MW)	YoY Change (%)	(aMW)	YoY Change (%)	(MW)	YoY Change (%)
2024	558				560				560			
2025	560	0.3%	943		563	0.6%	951		580	3.7%	979	
2026	566	1.0%	949	0.7%	571	1.4%	959	0.8%	601	3.6%	1009	3.0%
2027	572	1.0%	961	1.3%	579	1.4%	972	1.4%	619	3.0%	1039	3.0%
2028	577	0.9%	974	1.3%	587	1.3%	986	1.5%	637	2.8%	1070	3.0%
2029	584	1.1%	986	1.3%	597	1.6%	1001	1.5%	657	3.1%	1102	3.0%
2030	590	1.0%	999	1.3%	606	1.6%	1019	1.8%	675	2.8%	1135	3.0%
2031	596	1.0%	1011	1.3%	616	1.6%	1033	1.4%	697	3.2%	1169	3.0%
2032	601	0.9%	1024	1.2%	626	1.6%	1056	2.1%	714	2.5%	1204	3.0%
2033	608	1.2%	1037	1.2%	638	1.9%	1075	1.9%	735	3.0%	1240	3.0%
2034	615	1.1%	1050	1.2%	649	1.9%	1091	1.4%	761	3.4%	1278	3.0%
2035	621	1.1%	1062	1.2%	662	1.9%	1107	1.5%	787	3.4%	1316	3.0%
2036	627	1.0%	1075	1.2%	675	1.9%	1127	1.8%	811	3.1%	1356	3.0%
2037	635	1.2%	1088	1.2%	690	2.2%	1157	2.6%	833	2.7%	1396	3.0%
2038	642	1.1%	1101	1.2%	705	2.2%	1185	2.4%	856	2.8%	1438	3.0%
2039	649	1.1%	1115	1.2%	721	2.3%	1212	2.4%	881	2.9%	1481	3.0%
2040	656	1.0%	1128	1.2%	737	2.3%	1230	1.5%	914	3.8%	1526	3.0%
2041	664	1.2%	1141	1.2%	756	2.5%	1263	2.7%	940	2.8%	1571	3.0%
2042	671	1.1%	1154	1.2%	774	2.4%	1285	1.7%	975	3.7%	1619	3.0%
2043	679	1.2%	1168	1.2%	793	2.5%	1315	2.4%	1005	3.1%	1667	3.0%
2044	686	1.1%	1181	1.2%	812	2.4%	1359	3.4%	1025	2.0%	1717	3.0%

Section 5 Current Resources

5.1 Overview of Existing BPA Resources

About half of CPU'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. It 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, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period. 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 10.

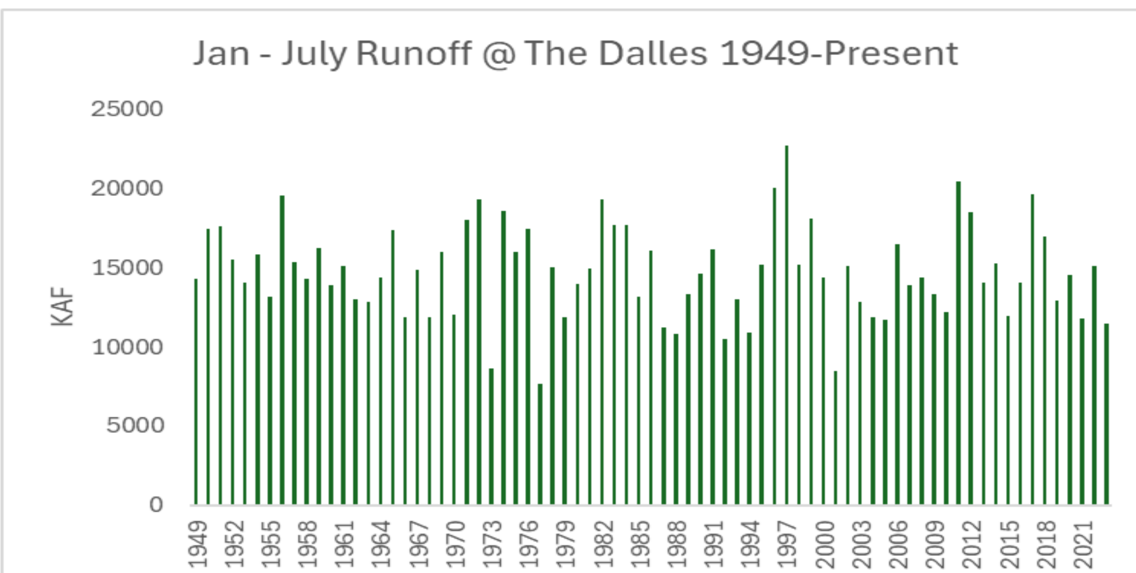


Figure 10. Historical Water Years (1949-2023)

The 1937 water year stream flows represented the worst (lowest) on record and was chosen as the benchmark "critical water" year to represents 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, CPU 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 CPU to operate and manage to serve CPU'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 their Contract High Water Mark (CHWM). CHWMs under the current contract were calculated to achieve load-resource balance between Tier 1 energy and the 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). CPU's share of Slice output is roughly 197 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.

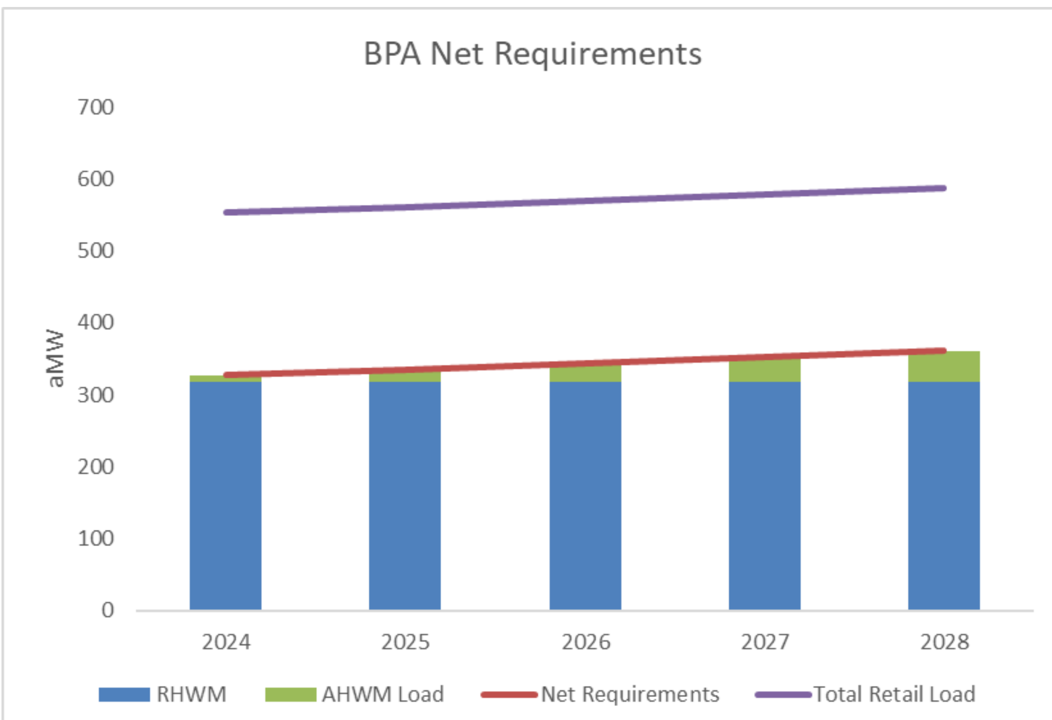


Figure 11. Retail Load vs. BPA Rate Period High Water Mark (RHWM)

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 CPU 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 CPU does not change. The power is shaped in advance into monthly blocks, which follows CPU's monthly load profile. In other words, more Block power is delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 8,537 MW for the current two-year rate period, but daily generation will fluctuate from between 4,000 MW to greater than 15,000 MW. The FCRPS is a multipurpose system and power generation achieves only one of the system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. CPU 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 CPU to, at times, fulfill its load obligations with resources other than what is provided by BPA and CPU's owned and non-federal contract resources.

5.1.1 BPA PRODUCT SWITCH

In June 2024, CPU's board voted to take advantage of an opportunity to switch from being a Slice/Block customer of BPA, to a Load Following customer of BPA. BPA conducted analysis and a public process in July 2024 and determined that it will allow CPU to switch products.

While CPU will be switching to the Load Following product, CPU's IRP's base case uses the Slice/Block product. While CPU will be a Load Following customer of BPA starting in October 2025, CPU believes that using the Slice/Block product is useful on a planning basis for several reasons:

1. CPU has not yet decided on which product they will elect for the BPA Provider of Choice Contracts starting in October 2028. CPU may elect to take another planned product, so performing the IRP under Slice/Block is helpful. Under the terms of the agreement to switch to the Load Following product in October 2025, the earliest CPU could return to the Slice/Block product is October 2032 (BPA fiscal year 2033).
2. Slice/Block allows for better representation of the output of the FCRPS than modeling a Load Following product. As a Load Following customer, BPA will cover CPU's load requirements. But, to cover their obligations, BPA will go through a similar IRP process to determine what are good resource additions to meet the needs of the customers. The resource additions in CPU's IRP will be similar to that of BPA's IRP, so it is just a matter of who is making these additions.

While CPU uses the Slice/Block product as the base case, the IRP also evaluates Clark's portfolio under the Load Following Contract.

5.1.2 BPA POST-2028 PRODUCT OPTIONS

Figure 12 shows BPA's Provider of Choice (POC) Timeline updated June 2024. Source: [BPA Provider of Choice]

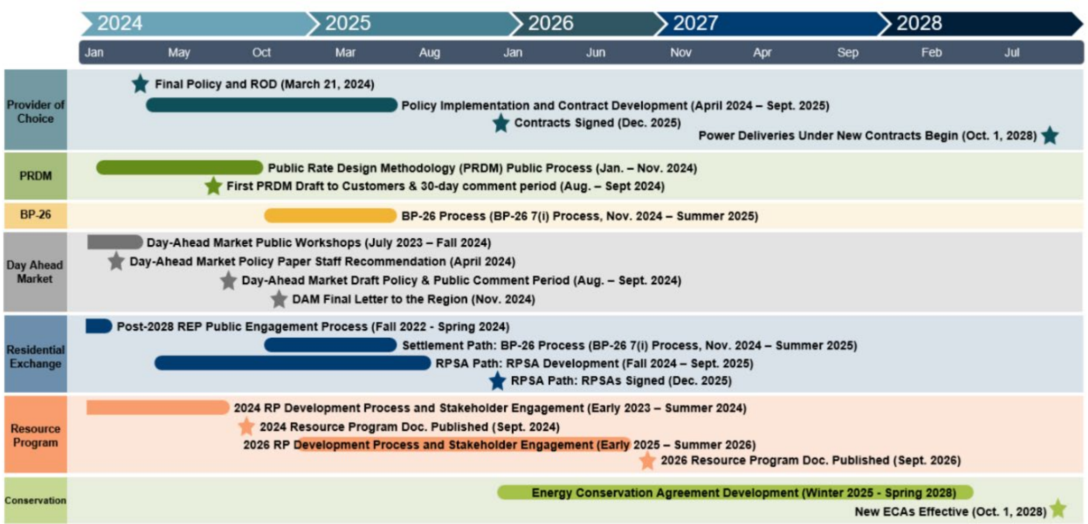


Figure 12. BPA's Provider of Choice (POC) Timeline

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.

Bonneville 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, Bonneville has suggested that they 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 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.

Section 5.2 provides a summary of the products BPA is, at the time of the IRP, considering offer to its customer utilities.

5.2 Product Comparison

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

Figure 13. BPA proposed 2028 product comparison.

5.2.1 Cost Comparison

At the time of the IRP, the Public Rate Design Methodology (PRDM) for the Provider of Choice contracts has yet to be finalized, so 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 will be the Load Responsible Entity (LRE) under WRAP. Alternatively, for planned product options such as Slice/Block and Block with Shaping, CPU 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 CPU. The Slice/Block product is anticipated to provide capacity based on the WRAP QCC of the FCRPS. CPU 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, CPU would need to add significant capacity resources (see Figure 14).

5.3 River Road Generating Plant

CPU owns and operates the River Road Generating Plant (RRGP), a combined cycle natural gas plant located in Vancouver, Washington. Connected to the grid in 1997, RRGP currently provides baseload generation for CPU' customers. Historically, CPU planned for RRGP to operate 11 months each year, allowing for a one-month maintenance outage. However, as conditions shift from planning to actual operations, opportunities sometimes arise to procure wholesale power from the market at prices lower than RRGP's hourly marginal cost. In these instances, CPU captures these savings through a process called "economic displacement." Between 2012 and 2021, RRGP was economically displaced for approximately nine weeks, or 2.25 months, per year. In alignment with CPU's CEIP, the IRP assumes four weeks of displacement in 2024 and six weeks of displacement in 2025 through 2027. Starting in October 2028, RRGP is expected to generate 102 aMW annually, or 20 percent of retail load, to serve load.

At the time of the IRP, CPU recently finished an upgrade to RRGP. This upgrade involves installing equipment to achieve a lower heat rate during baseload operation and to allow generation to ramp down to near 95 MW when economically advantageous. Historically, due to the risks associated with stopping and starting the plant, economic displacement has been limited to a minimum of one month. This recent upgrade enables the plant to reduce generation during hours when it is not economical to run or when energy is not needed, while still allowing for ramping up to maximum capacity during peak load hours. The growth of solar generation in the West is expected to create more economic displacement opportunities for RRGP, particularly in the fall and spring, when solar generation is strong, but energy demand is relatively low.

5.4 Columbia Generating Station

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

5.5 Packwood 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. CPU receives an 18% share of the output from the project, which averages a little more than 2 aMW annually. The project does not qualify as a renewable resource and does not help CPU meet its obligations under the EIA.

5.6 Combine Hills Wind Project

Combine Hills II is a 63 MW wind farm near Milton-Freewater, Oregon that began commercial operation in January 2010. CPU has a 20-year power purchase agreement with the project owners, Eurus Energy LLC. It is estimated that CPU will receive 160,308 MWh per year or 18 aMW from the Combine Hills II project. Past experience leads CPU to use 0 (zero) MW for the capacity contribution from Combine Hills II. The Power Purchase Agreement (PPA) expires on December 31, 2029. There are provisions in the current PPA that allow for the parties to extend the contract beyond 2029. However, CPU's contract with Eurus includes a first right of refusal for the project. Eurus is required to offer the project to CPU before any other counterparties and CPU has the right step in front of any offers that might be made to other counterparties and purchase project output at the contract price agreed to by Eurus and another counterparty.

Combine Hills I is a 41 MW wind farm located right next to Combine Hills II, which achieved commercial operation in 2003. This project, however, is connected to PacifiCorp's control area, which requires extra transmission to wheel the power into BPA's control area and to CPU load. The PPA signed in February 2024 was modeled after the Combine Hills II PPA previously signed between CPU and Eurus Energy LLC. The term of the Combine Hills I PPA is for 6 years (or through 2029) and has an option to extend by mutual agreement beyond 2029. It is estimated that CPU will receive approximately 100,000 MWh per year or 11 aMW from the Combine Hills I project.

Generation from both wind projects are 100 percent carbon-free and qualify as renewable energy under the EIA and CETA.

5.7 Box Canyon Hydro Project

In October 2021, CPU signed a term sheet that led to a PPA with Pend Oreille Public Utility District for the entire output of the Box Canyon Hydroelectric Project (Box Canyon). The PPA will add additional hydro generation to CPU's resource portfolio beginning in 2026. Box Canyon generation is 'run of river' and, based on historic inflows, generally flat across each week during each month. Under the WRAP, Box Canyon will provide a capacity planning value that will count towards meeting CPU's monthly peak loads. The generation will be 100 percent carbon-free and will qualify as renewable energy under CETA. Average generation from Box Canyon is expected to be 50 aMW.

5.8 Solar PPAs # 1 and #2

In the summer of 2024, CPU expects to finalize two PPAs for solar projects, one that will begin generating in December 2025, and the other in December 2026. PPA #1 is for a capacity of 74 MW and is expected to produce approximately 21 aMW in its first year, while PPA #2 is for a capacity of 60 MW and is expected to produce approximately 16 aMW in its first year. Since solar arrays degrade over time, it is assumed that the aMW of generation for each of the two projects will decrease by 0.45% annually. Generation from both solar projects are 100 percent carbon-free and qualify as renewable energy under the EIA and CETA.

5.9 Conservation

The EIA requires that qualifying utilities pursue all available cost-effective conservation. Between 2010 and 2023 CPU energy efficiency achievements totaled 102 aMW, or nearly 20 percent of its annual retail load. CPU will remain committed to providing a myriad of energy efficiency programs to its customers. For the sake of 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. CPU's 2023 Conservation Potential Assessment provides projected cost-effective conservation targets over a 20-year study period.

5.10 Existing Transmission

BPA Transmission Services (BPAT) as the Balancing Authority (BA) is the entity obligated to meet CPU's peak load. Each BPA Slice customer sets aside and cannot access its share of Slice capacity (900 to 1,300 MW for CPU) 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, CPU has handed over its obligation for these services to the BA and does not need to include capacity for these services in its capacity planning for the IRP. Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP.

5.11 Load/Resource Balance with Existing Resources

Figure 14 illustrates CPU's current resource qualifying capacity in relation to average energy consumption, peak demand load, and WRAP reserve margin requirements. CPU's existing resource capacity sufficiently meets the average energy consumption needs through the late 2030s. However, when comparing the existing resources capacity to peak load demand, there is a deficiency, resulting in a shortfall in capacity. Presently, energy to meet peak demand is acquired through market purchases. However, in the future with the introduction of the WRAP, this gap will need to be met through qualifying capacity resources.

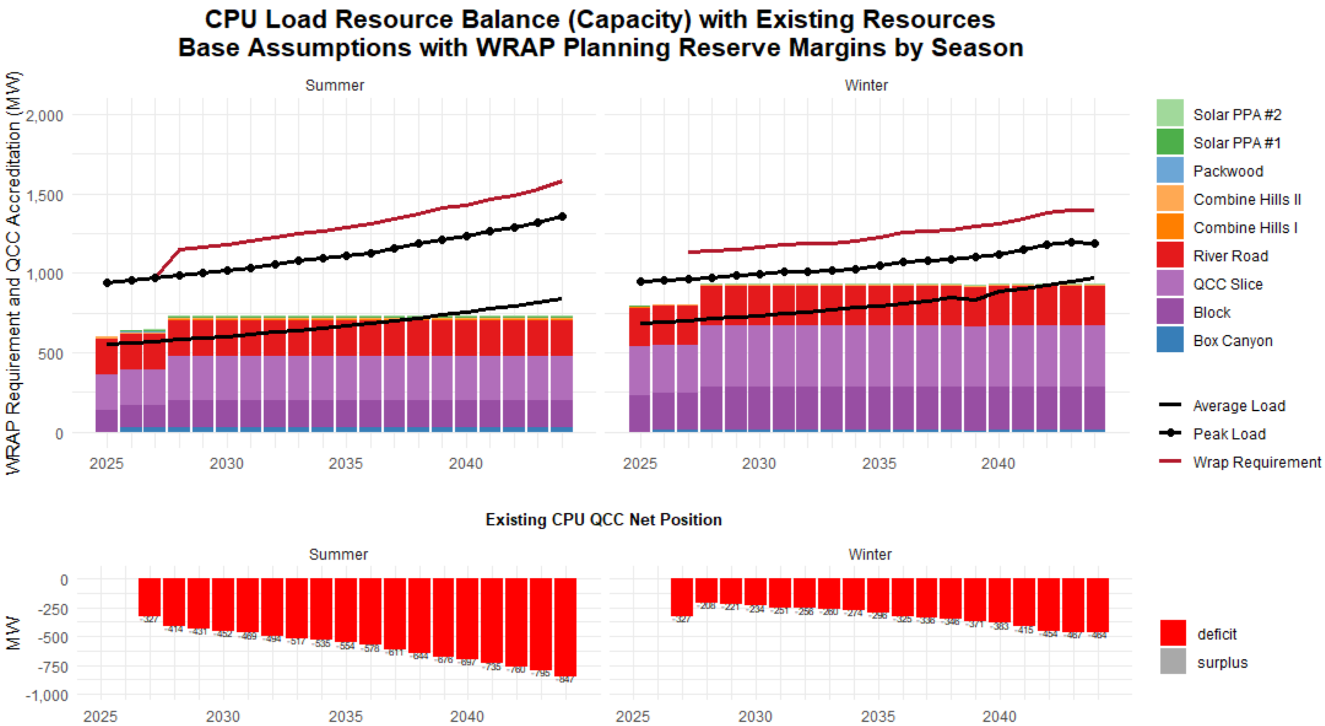


Figure 14. Existing Load Resource Balance

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 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 must supply carbon-neutral electricity by 2030. Although CPU 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 the 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, CPU 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

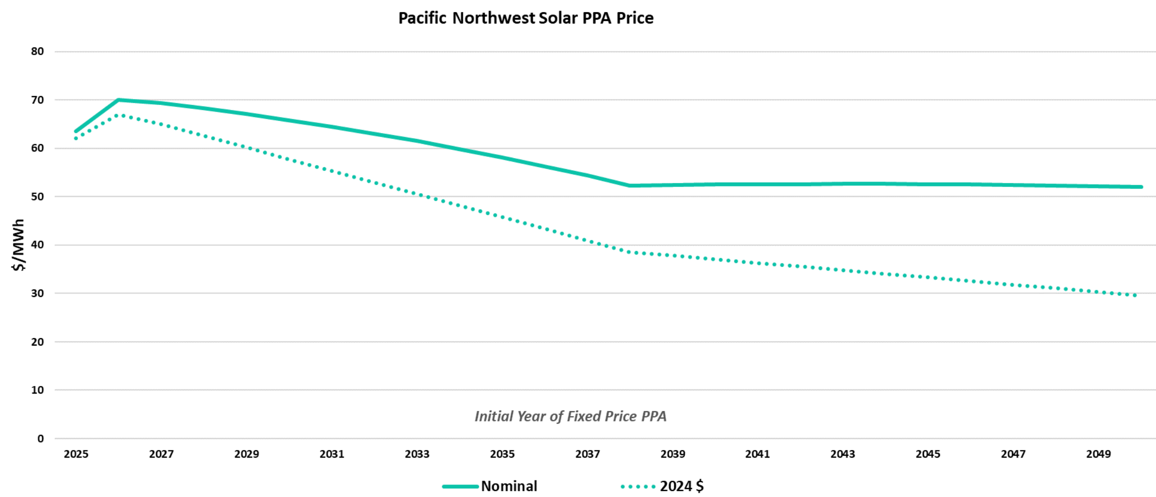
Solar resources were modeled as 20 MW PPAs based on large-scale solar photovoltaic projects. This option satisfies the long-term requirements of CETA. The rapid growth in electric generation from solar resources across the U.S. has been driven by declining costs, supportive governmental policies, and 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[7] by the end of 2023 and provided approximately 4%[8] of the total electric generation in the U.S. in 2023.

Solar resources considered by CPU 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 $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 The National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale solar capital costs to decline by an average of 2.9%/year in constant dollars

[7] 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.

[8] 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.

between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected solar PPA prices assumed in the study.



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[9] today. In 2023 wind generation provided over 10% of the total electric generation[10,11] in the US.

Wind resources considered by CPU 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,

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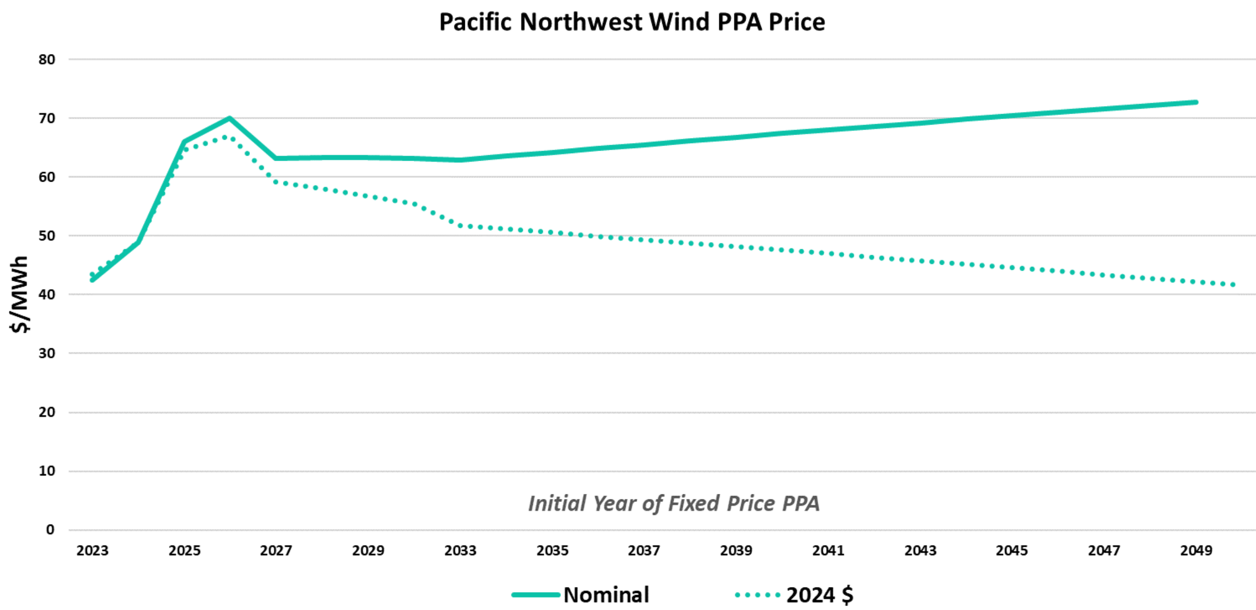
[9] Buttel, Lindsey. America's Electricity Generation Capacity 2024 Update, American Public Power Association. URL: America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[10] 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.

[11] 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.

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 The National Renewable Energy Laboratory's (NREL) 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. The following exhibit shows the projected wind PPA prices assumed in the study.



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. The following exhibit shows the projected battery storage PPA prices assumed in the study.

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, CPU 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 CPU beginning in 2035. A 2030 WRAP Portfolio Scenario includes Geothermal availability as early as 2030. The cost of energy from a 25-year PPA is assumed to be $90/MWh in 2024 dollars. The cost was 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, CPU 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. A 2030 WRP Scenario includes SMR availability as early as 2030. 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 market-based opportunities are modeled in the study.

- Long-Term Contract

  A long-term (10-year) contract for up to 650 MW of capacity and energy in 50 MW block sizes from a gas-fired combined cycle facility was assumed to be available in 2030. PPA pricing is based on fuel, variable operations and maintenance costs (VOM), and a fixed option premium.

- 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 8.

Table 8. 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 (%)
Solar PPA	NA	2027	15	20	70	0	Note[12]
Wind PPA	NA	2027	15	25	70	0	Note[12]
4-Hr Storage PPA	NA	2027	15	25	0	144	Note[12]
Geothermal PPA	25	2035	25	25	90	0	2.2%
LT Contract (2030 Only)	650	2030	10	50	Market	Market	2.2%
ST Contract (2026-34)	125	2026	1	25	90	0	0.0%
SMR	100	2035	25	25	130	0	2.2%

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

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 DERs. Understanding how DERs impact the grid itself, including reliability, is an important factor to be considered. Alternatively, understanding where, when, and how DER can benefit the grid is of equal value. While the economic signals may not yet be fully developed, technology has advanced to the point where consumers can respond to price changes, reduce (or increase) demand when useful to the system, or store electricity for later use.

DER are typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DER are being adopted at increasing rates due to favorable policies from both state and federal governments, improvements in technology, reduction in costs, and identifiable customer benefits, both at the individual and grid levels. Once DER adoption passes certain levels, DER can begin to cause significant issues for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of ratepayers. It is important for electric utilities to identify potential economic and grid issues and benefits from DER. DERs are becoming more widespread with increasing commercial availability, decreasing costs, and evolving consumer preferences. CPU 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 15 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 renewable portfolio standards. The second phase of the study uses the inputs from the first step to run a capacity expansion analysis. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 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.

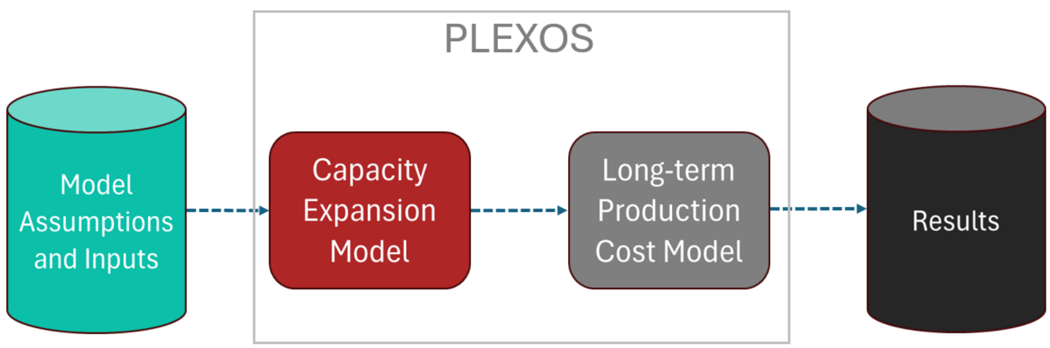


Figure 15. Modeling Approach

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.

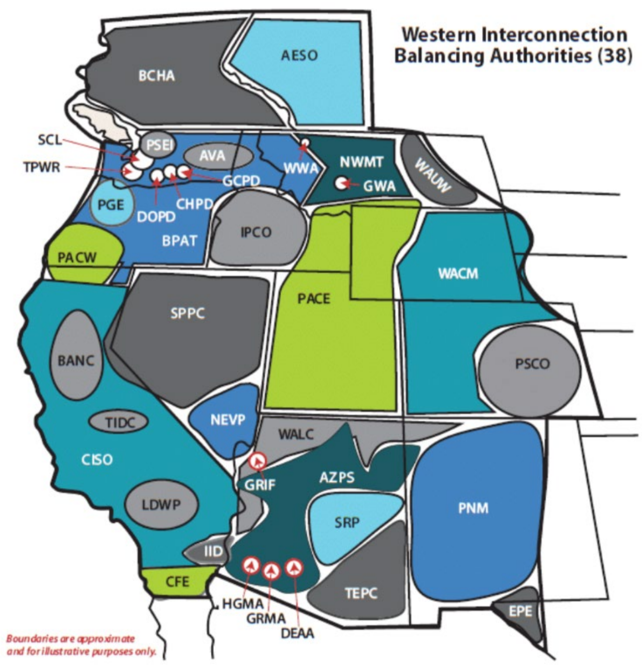
PLEXOS is utilized for three main purposes:

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 renewable portfolio standard 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 renewable portfolio standards. The resources that are chosen are the best economic performers – i.e. the resources which provide the most regional benefit for the lowest price 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 2020's through the 2040's 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.

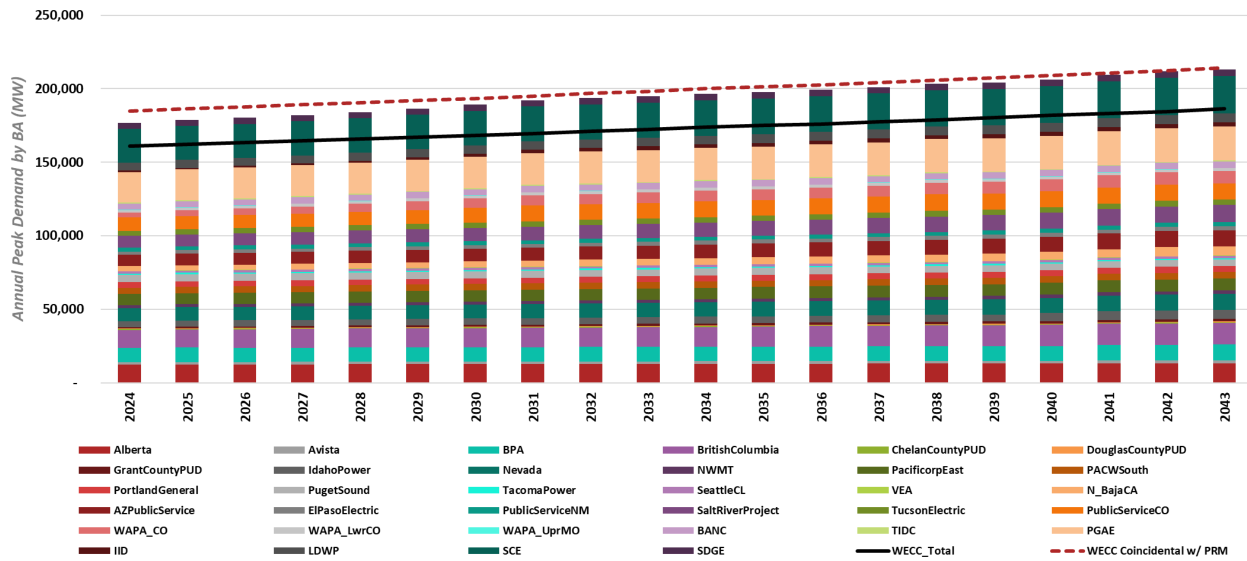


Figure 16. WECC Annual Peak Load Projections

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, is 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)

Renewable portfolio standards (RPS) are state-level requirements that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. 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 17 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 17. 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 Climate Commitment Act 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. Figure 18 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 18. 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 19. 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.

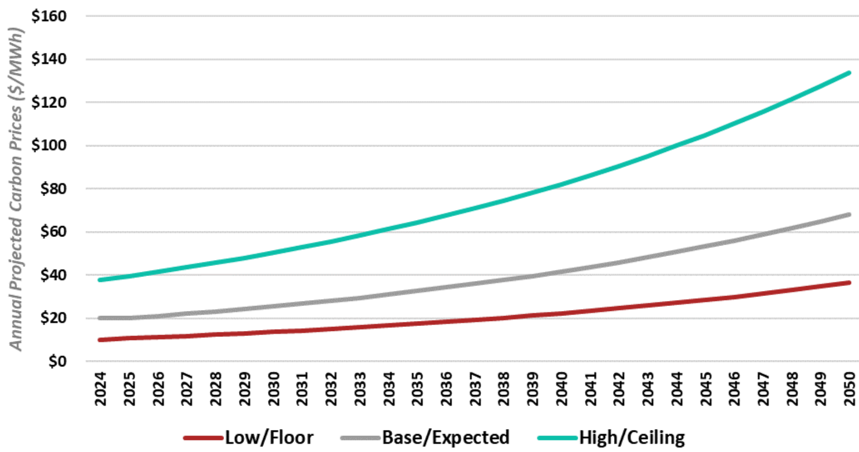


Figure 19. Washington Carbon Allowance Price Assumption in $/MWh in nominal dollars. Uses the $/MT CO2e price assumption multiplied by the unspecified per MWh emissions.

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 20.

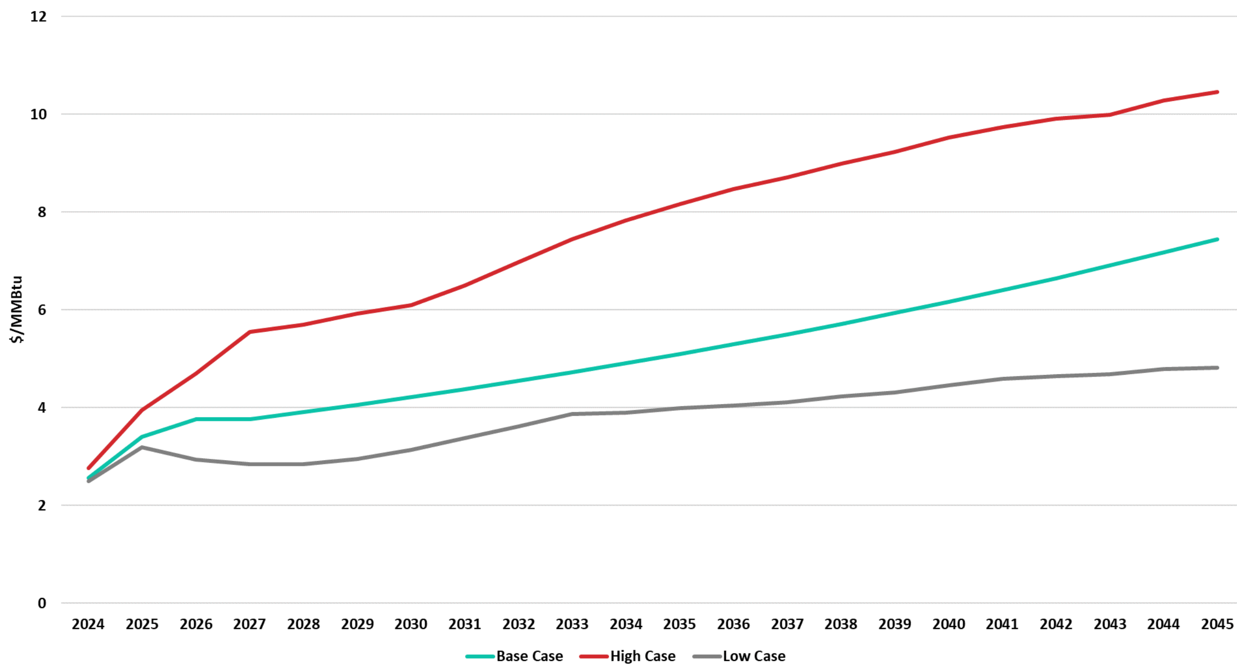


Figure 20 Annual average Henry Hub natural gas price, by price scenario.

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 21 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.

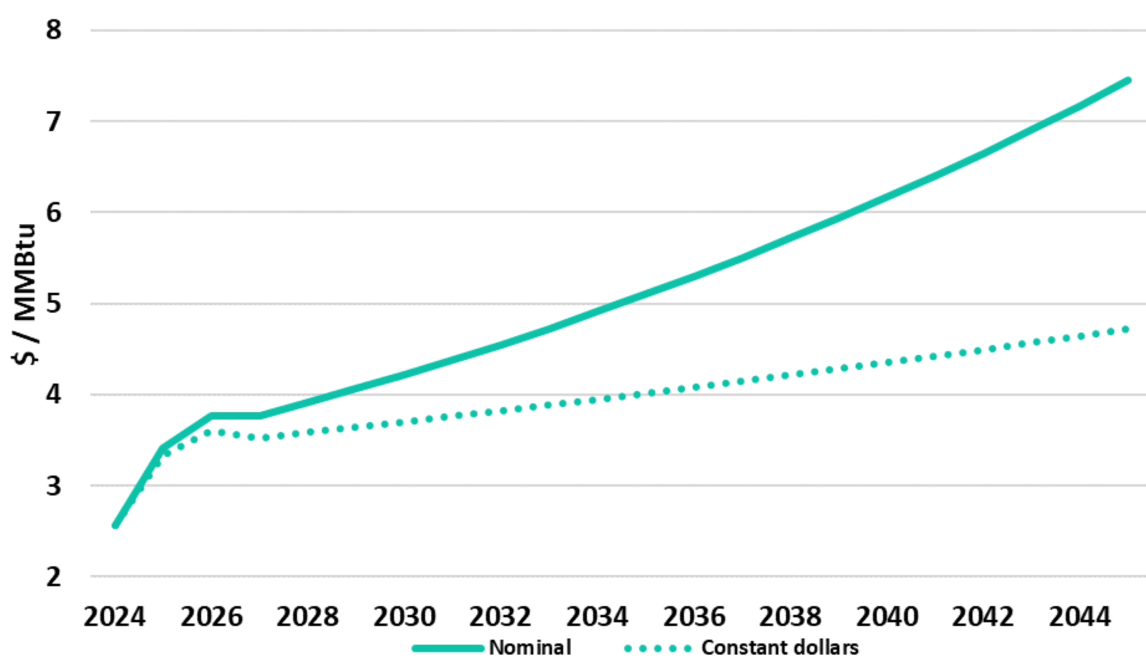


Figure 21 Natural gas prices at Henry Hub in nominal and constant 2024 dollars per mmBtu.

CPU currently receives natural gas for its River Road combined cycle facility from Canada through the Sumas Hub in northwest Washington and from the south through the Stanfield Hub in north central Oregon. TEA added a basis estimate to the Henry Hub price forecast to estimate future prices delivered to Washington and specifically to the River Road facility. 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 22 below.

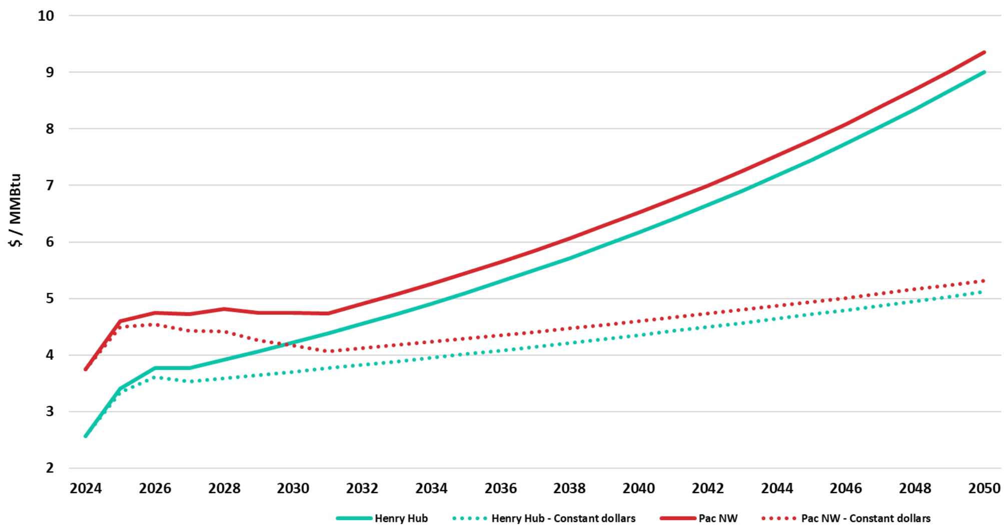


Figure 22. Annual natural gas prices delivered to the Pacific northwest for the 2024 through 2045 period.

Figure 23 below 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.

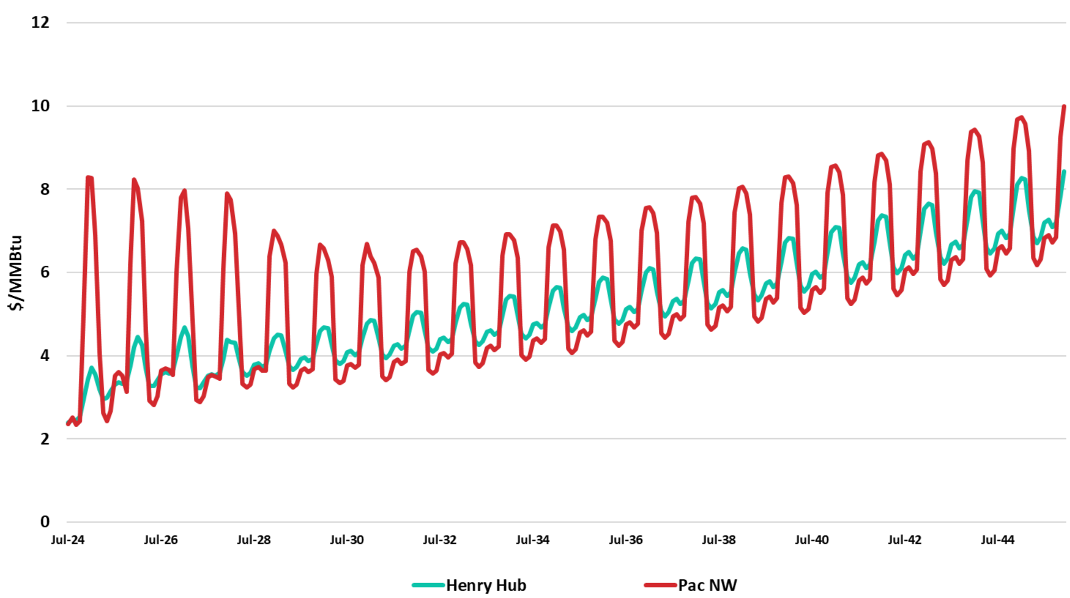


Figure 23. Henry Hub versus Delivered Pacific Northwest Natural Gas Prices.

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 options' such 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 24 details the base line 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.

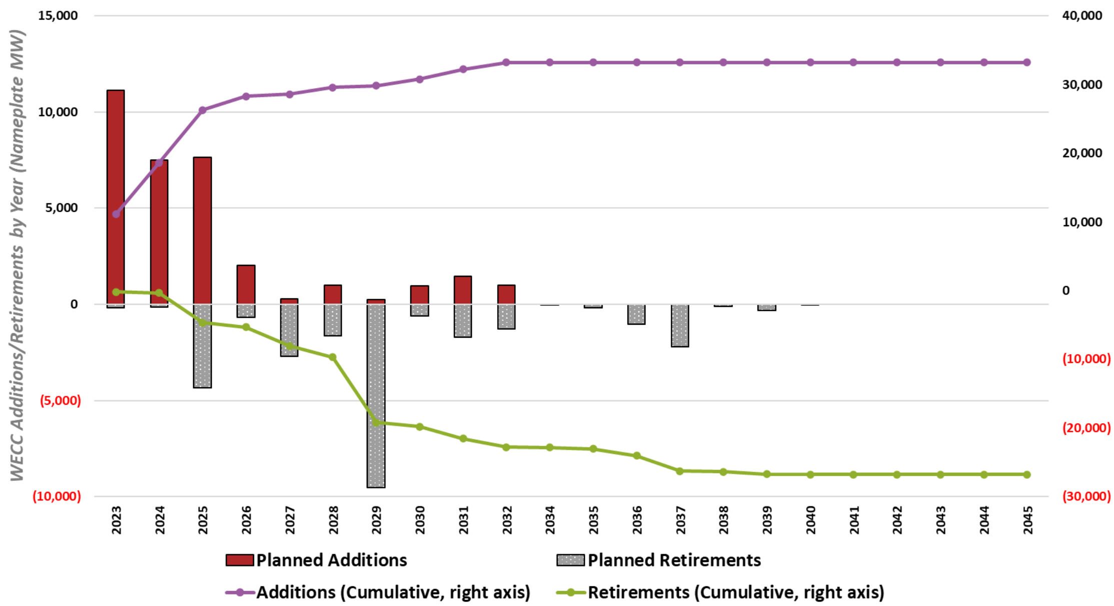


Figure 24. WECC Generation Additions and Retirements (pre-Capacity Expansion)

Based on the parameters outlined above, PLEXOS then determines the ideal mixture of new resource additions and further retirements to meet the inputs 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 25.

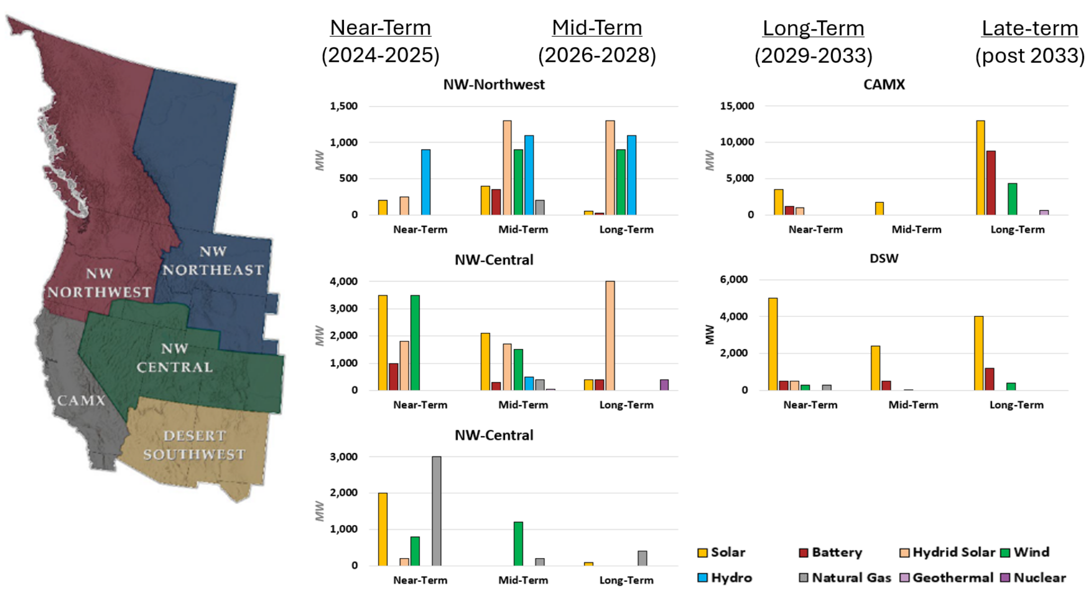


Figure 25. WECC Generation Additions and Retirements (post-Capacity Expansion)

Resources added post-2033 were done exclusively by PLEXOS for meeting either demand needs or RPS goals. Figure 26 illustrates the total additions, year by year, across the entire WECC capacity expansion simulation.

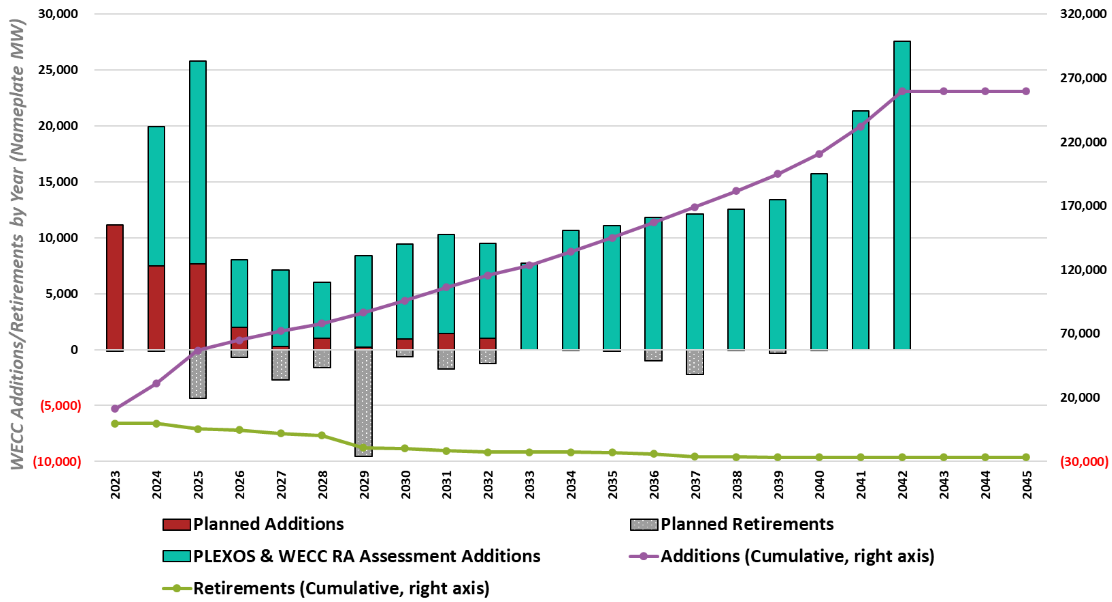


Figure 26. Annual nameplate capacity retirements and additions.

Over 90 GW of new generation is added to the WECC footprint by 2033 with Wind or Solar making up 53 GW and Batteries or 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 2040's. A breakdown in percentage of fuel type is represented in Figure 27.

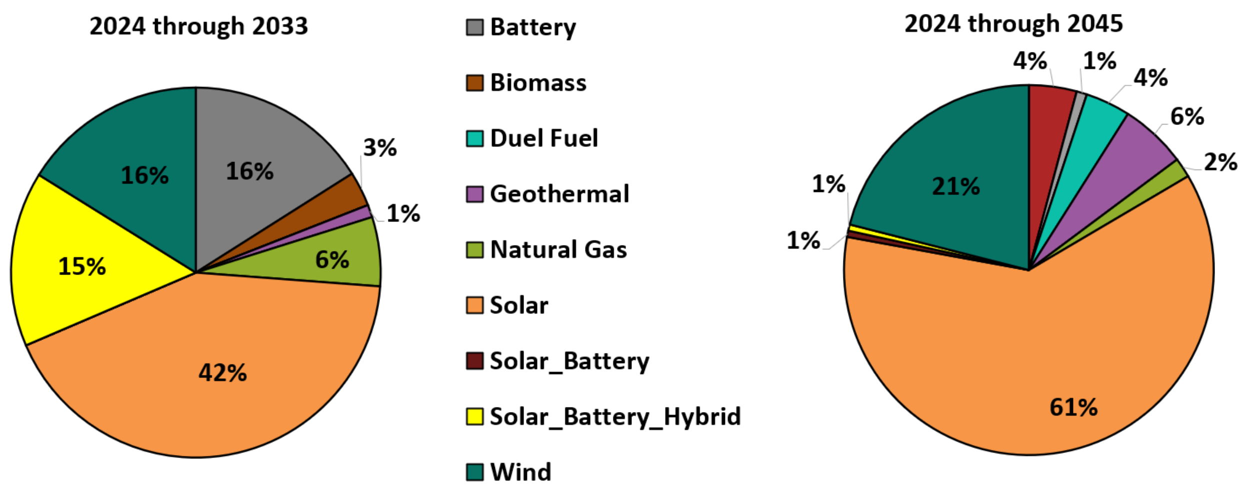


Figure 27. WECC Capacity Additions Percentages (Nameplate), by Fuel Type

Figure 28 and Figure 29 illustrate the expected new resource expansion and retirements through 2042 in the Pacific Northwest and California/Mexico regions.

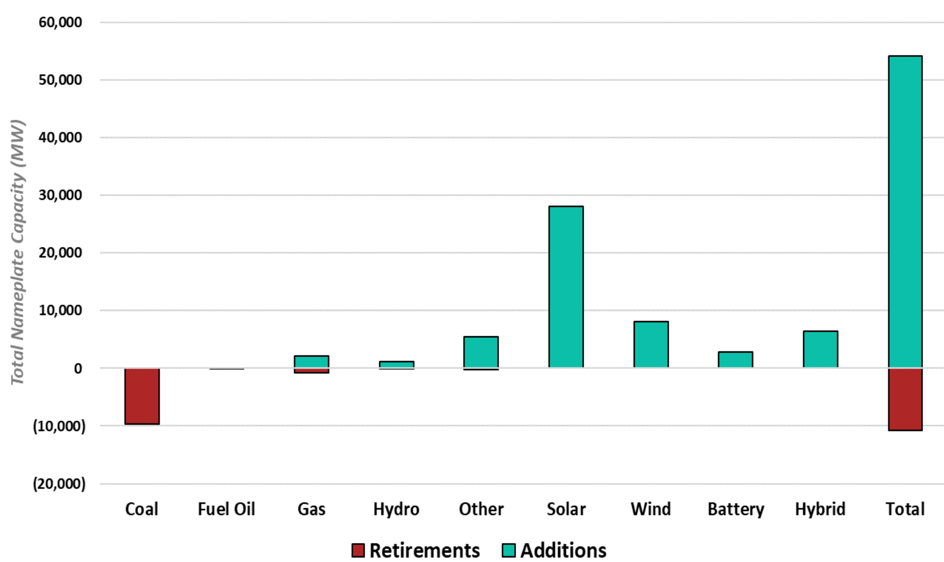


Figure 28. Forecasted Pacific Northwest Generation Capacity Retirements and Additions through 2042, by Fuel Source

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 does occur 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.

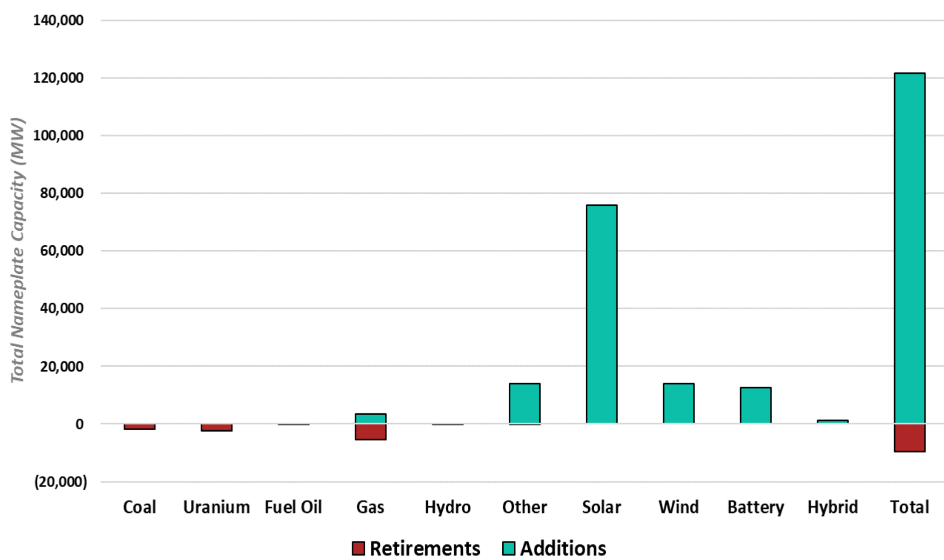


Figure 29. Forecasted California Generation Capacity Requirements and Additions through 2042, by Fuel Source

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. Like 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 30 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.

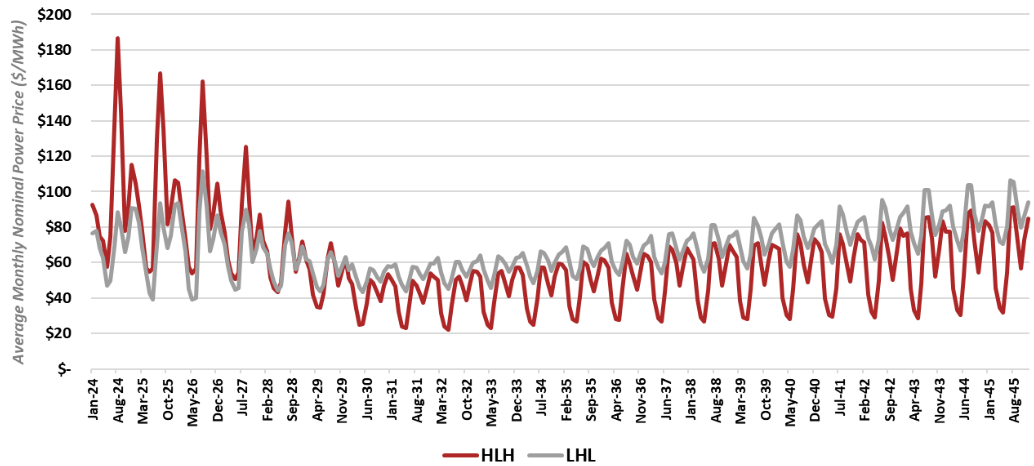


Figure 30. Forecast Mid-C Prices

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-2020's as seen in Figure 31.

Figure 31. Forecast Annual Mid-C Prices

Figure 32 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 2020's. 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 of the during the Spring season.

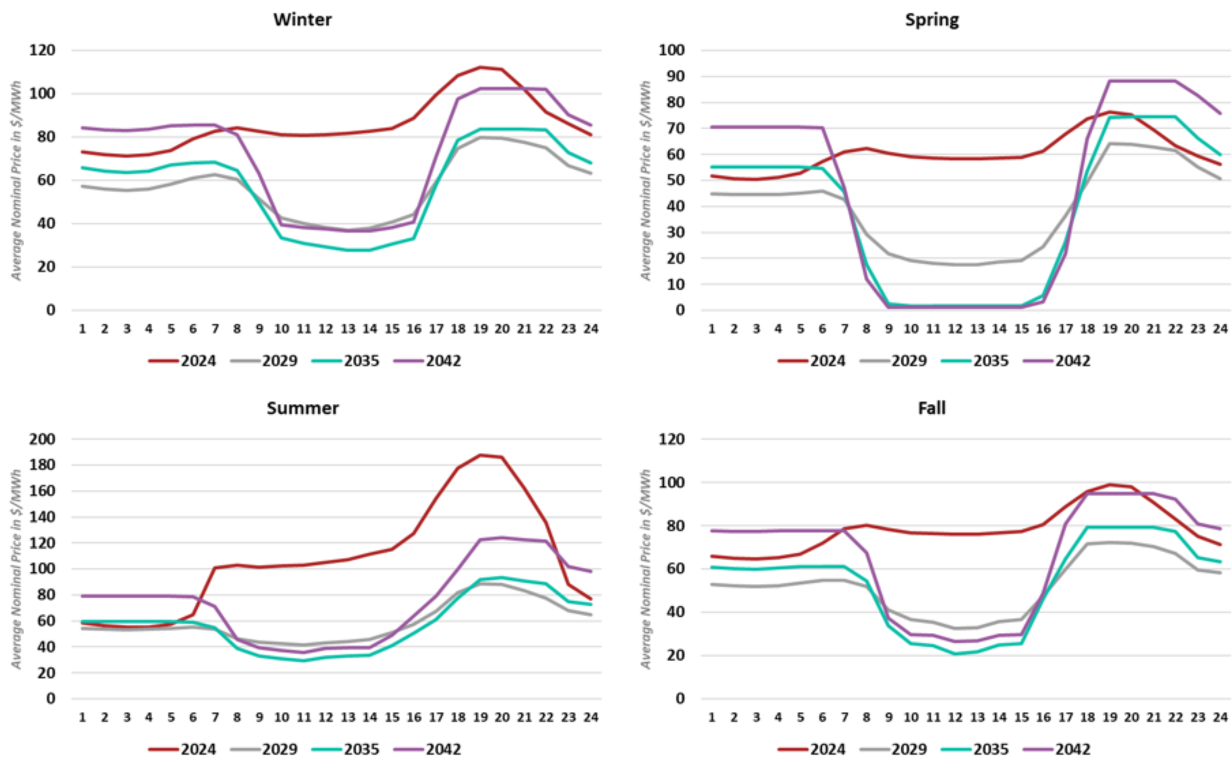


Figure 32. Forecast Mid-C Average Hourly Price Profile, by Season, for 2024, 2029, 2035, and 2042

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 become more progressive. A future where added pressure on natural gas production and usage is very plausible. In this future it is also believed in order 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: Although the retraction of state and province carbon goals is unlikely, the relaxing of those goals could happen. In a future where those goals are either reduced or pushed back in time the accompanying natural gas and carbon prices would be impacted. It is believed that in this scenario both prices would see a reduction in cost.

In Figure 33 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 takes hold.

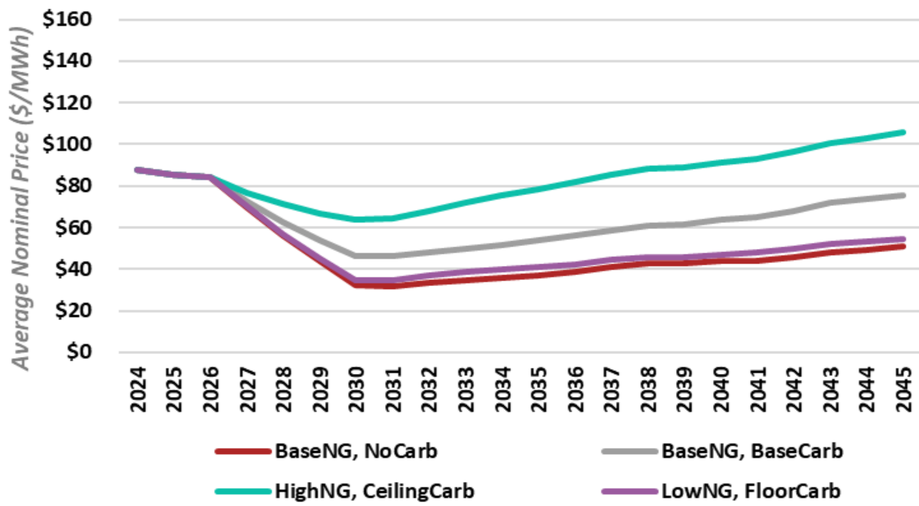


Figure 33. Forecast Mid-C Average Nominal Price, by Scenario

As expected, removing the carbon price and reducing the natural gas and carbon prices produces a change in market 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 34. Variance from Base Natural Gas and Base Carbon Scenario

Section 8 Risk Analysis and Portfolio Selection

CPU's objectives are to develop an optimal resource plan capable of managing uncertainties in projected monthly peak demand 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 CPU'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 CPU 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 CPU'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 CPU'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 CPU Scenario Cases and Results

CPU has considered two scenarios to help meet their objectives: the Reference Portfolio and a 2030 WRAP 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 Section 6.
- Base natural gas price and market price forecast as discussed in Sections 7.2.5 and 7.3.2 respectively.

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

Acknowledging the dynamic nature of the WRAP initiative, CPU also assumes a scenario with a less aggressive implementation date of January 2030 with increased supply option availability. Adjustments were made to the initial availability dates of geothermal and SMR technologies, both set to January 2030. The delay in WRAP is assumed to coincide with the earlier installation of geothermal and SMR technologies. Table 9 outlines how the scenarios are incorporated into the IRP.

Table 9. Scenario Analysis Assumptions

Scenario	Load	NG Price	Carbon	WRAP	Technology
Reference Portfolio	Base	Base	Base	11/2027	Base
2030 Wrap Portfolio	Base	Base	Base	01/2030	Geothermal & SMR available 01/2030

8.1.1 Reference Portfolio Results

The PLEXOS modeling software optimized a cost-effective portfolio, illustrated in Figure 35, to fulfill CPU'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. CPU's existing portfolio was tuned to supply average energy consumption throughout most of the study period, rendering baseload resources unnecessary for expansion. To achieve system balance for the WRAP requirement, the system needed resources demonstrating effective operation during peak demand periods and possessing capacity-enriched qualities. Batteries proved to be a suitable solution in the near term to fulfill this system need. Within the first 2 years of the WRAP implementation, 475 MW of battery storage is installed with additional 25MW battery storage increments added annually from 2029 through 2035. After 2035, wind and solar become necessary to meet average energy consumption as well as filling capacity needs. 60 MW (425 MW nameplate capacity) of qualifying wind capacity and 204 MW (1,650 MW nameplate capacity) of qualifying solar capacity is installed from 2036 through 2044 filling capacity needs. 60 MW (425 MW nameplate capacity) of qualifying wind capacity and 204 MW (1,650 MW nameplate capacity) of qualifying solar capacity is installed from 2036 through 2044. MW (425 MW nameplate capacity) of qualifying wind capacity and 204 MW (1,650 MW nameplate capacity) of qualifying solar capacity is installed from 2036 through 2044.

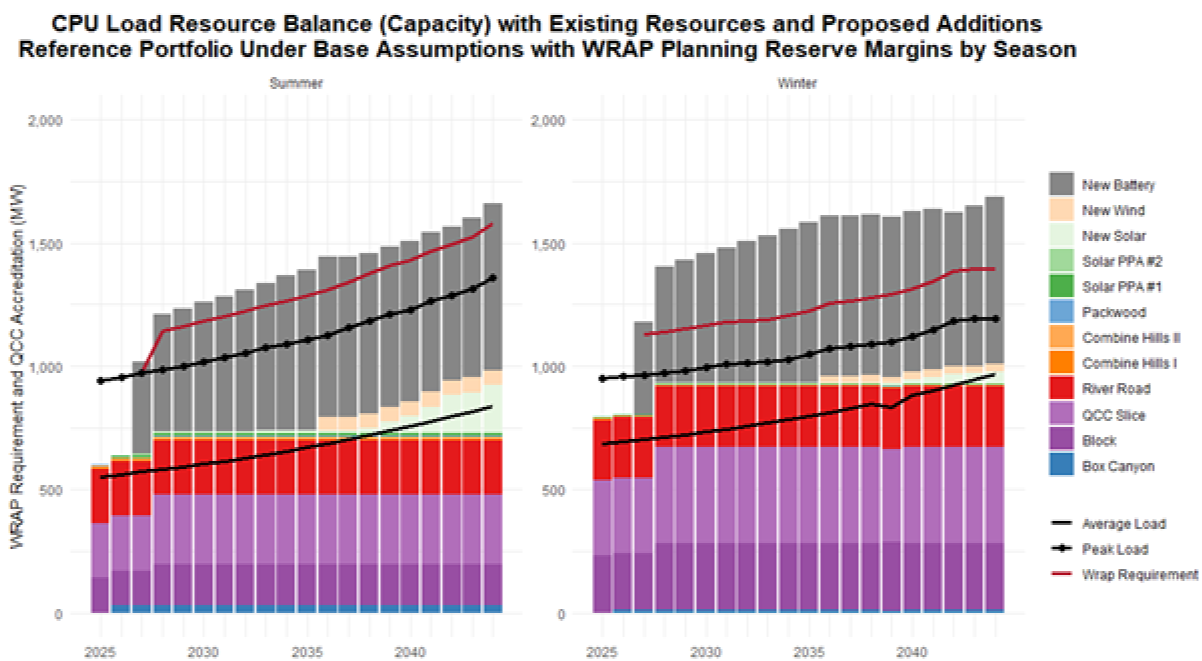


Figure 35. Demand and Resource Load Balance for Reference Portfolio

Figure 36 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. CPU's existing resources are able to meet the average energy consumption through 2035 with limited reliance on the market in early years of the study. From 2036 onward, there is a transition away from reliance on River Road towards solar and wind energy sources. The average summer contribution from River Road diminishes to nearly zero by the conclusion of the study period. The extensive expansion of solar and wind power integrates seamlessly into this portfolio due to the flexibility offered by the River Road resource.

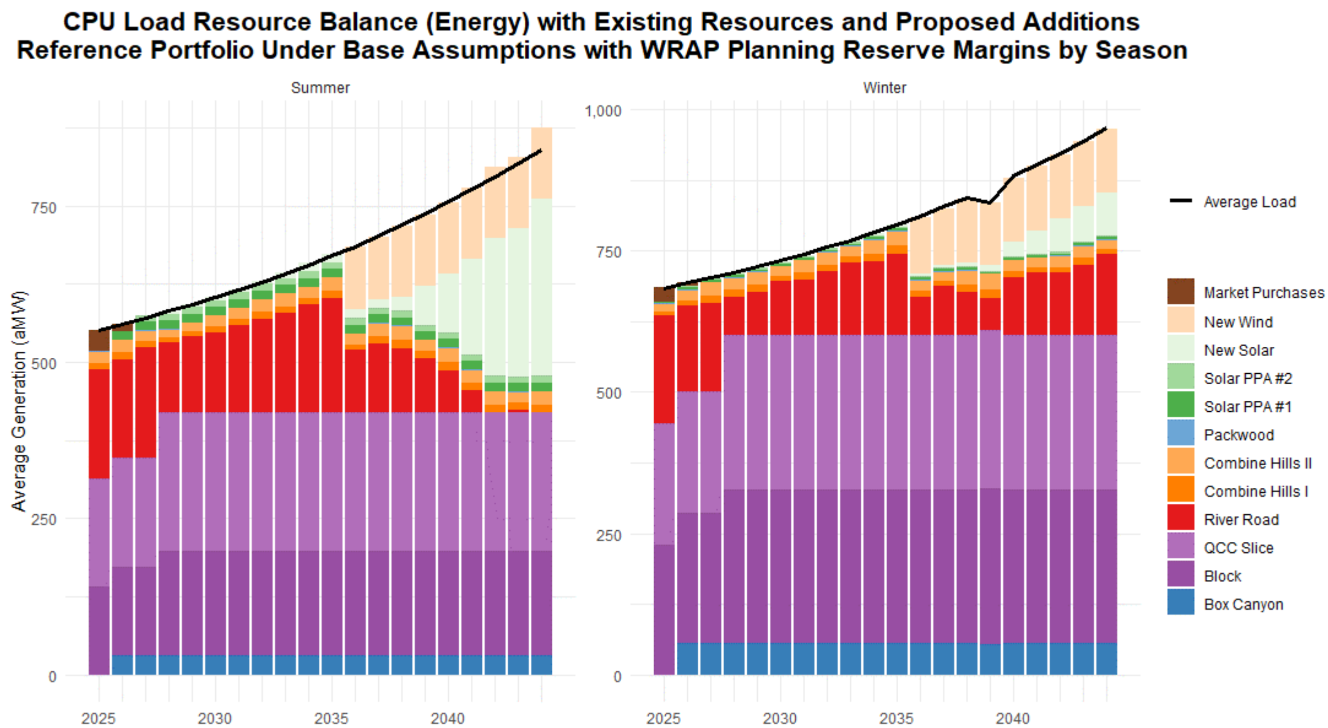


Figure 36. Energy Resource Load Balance for Reference Portfolio

Figure 37 shows the annual variable and incremental revenue requirements with qualifying capacity changes for the Reference Portfolio. It excludes existing debt service costs and sunk costs prior to the study period. VOM costs include the existing resource costs, which rise in 2026, when Box Canyon is introduced into the portfolio, and then stabilize for the remainder of the study period. Fixed Operations and Maintenance (FOM) costs pertain to the expenses linked to battery adoption. FOM costs rise steadily as additional batteries are integrated into the portfolio. The highest costs occur with the adoption of wind and solar starting in 2036, as intermittent energy quantities are added to the portfolio. The cumulative incremental NPVRR for the Reference Portfolio amounts to $2,230 million over the study period (see Figure 41). This amount serves as the benchmark for scenario comparisons and sensitivity analyses.

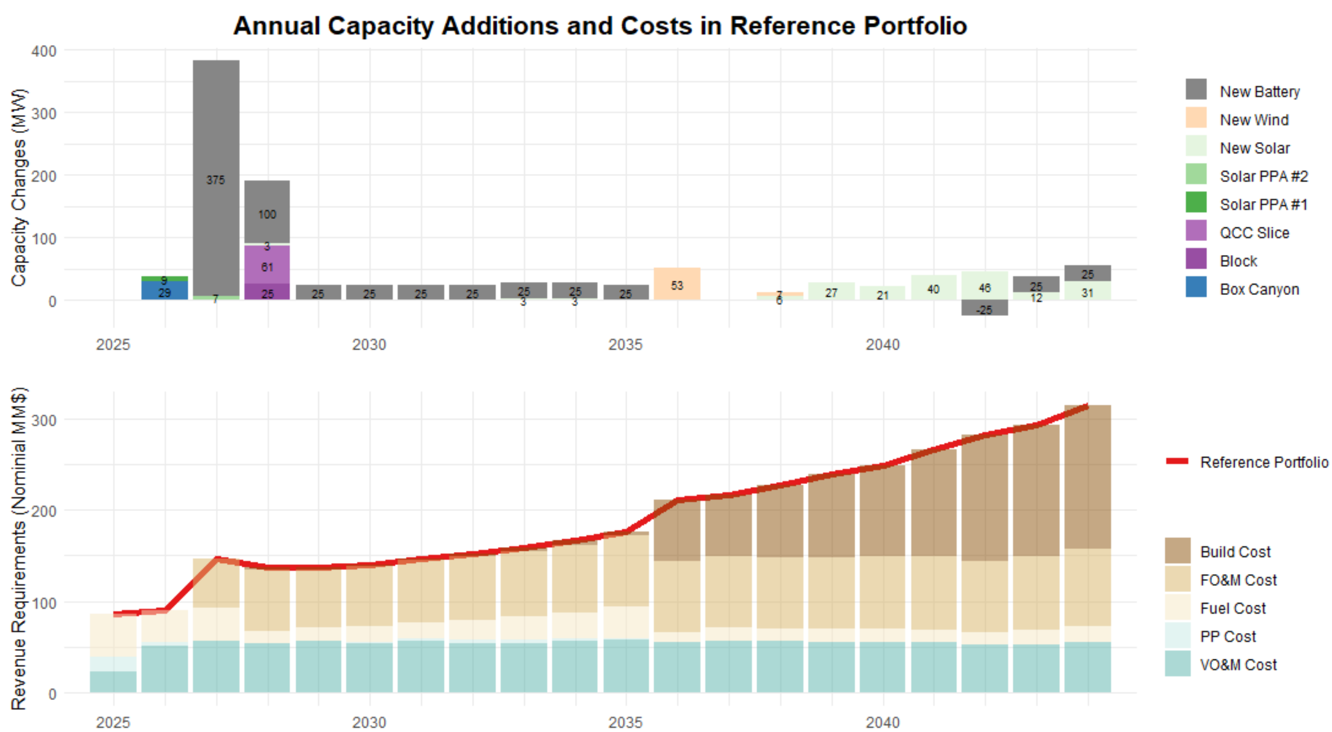


Figure 37. Nominal Revenue Requirements for Reference Portfolio

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 38Figure 38 provides a simulated view of how this is accomplished within CPU's portfolio after the adoption of significant amounts of renewable energy.

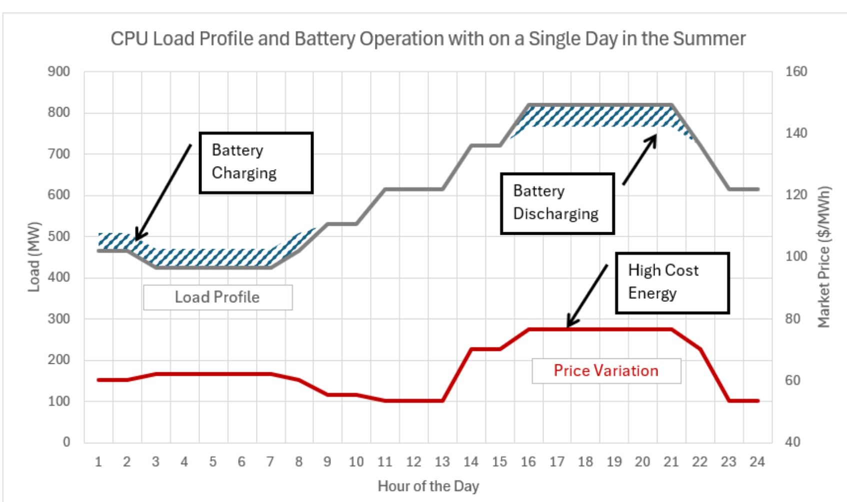


Figure 38. PLEXOS Simulated Output of Energy Shifting Within CPU Reference Portfolio

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. The flexibility of River Road's operation allows for effectively integrating over 2,000 MW of renewable energy into the portfolio, ensuring adaptive and sustainable energy management strategies.

8.1.2 2030 WRAP Portfolio Results

The 2030 WRAP Portfolio was developed in response to the uncertainty of the WRAP implementation date, allowing for WRAP requirements to be deferred until 2030 while leveraging early adoption of geothermal and SMR resources. Given high fixed and minimal variable costs, Geothermal and SMR were modeled as non-dispatchable baseload resources.

Figure 39 shows CPU's current energy portfolio is well-balanced and capable of meeting average energy consumption with minimal exposure to market price fluctuations. Before 2030, there are no economic opportunities for resource selection. However, with enforcement of WRAP requirements, the proposed additions to the resource mix closely resemble those in the Reference Portfolio. The main distinctions between the two portfolios lie in the quantity and timing of resource deployment. The 2030 WRAP Portfolio, over the study period, deployed 675 MW of battery storage, 60 MW (425 MW nameplate capacity) of qualifying wind capacity and 196 MW (1,575 MW nameplate capacity) of qualifying solar capacity.

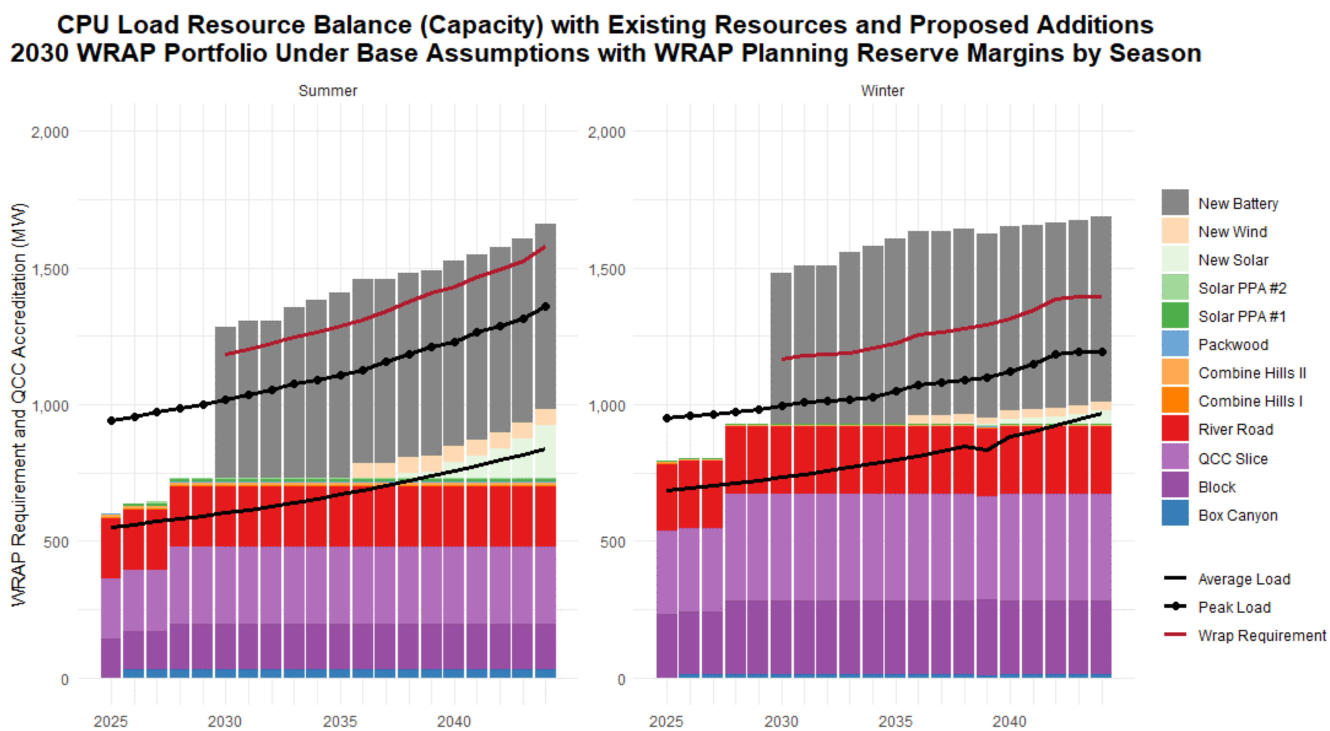


Figure 39. Demand and Resource Load Balance for 2030 WRAP Portfolio

Figure 40 displays the seasonal energy generated by the existing resources and proposed additions in average megawatts (aMW) per year for the 2030 Wrap Portfolio. CPU's current resources remain adequate to meet average energy consumption through 2035. Starting in 2036, there is a shift from relying on River Road to integrating solar and wind energy sources into the portfolio. The incorporation of wind and solar remains smooth, benefiting from River Road's flexibility.

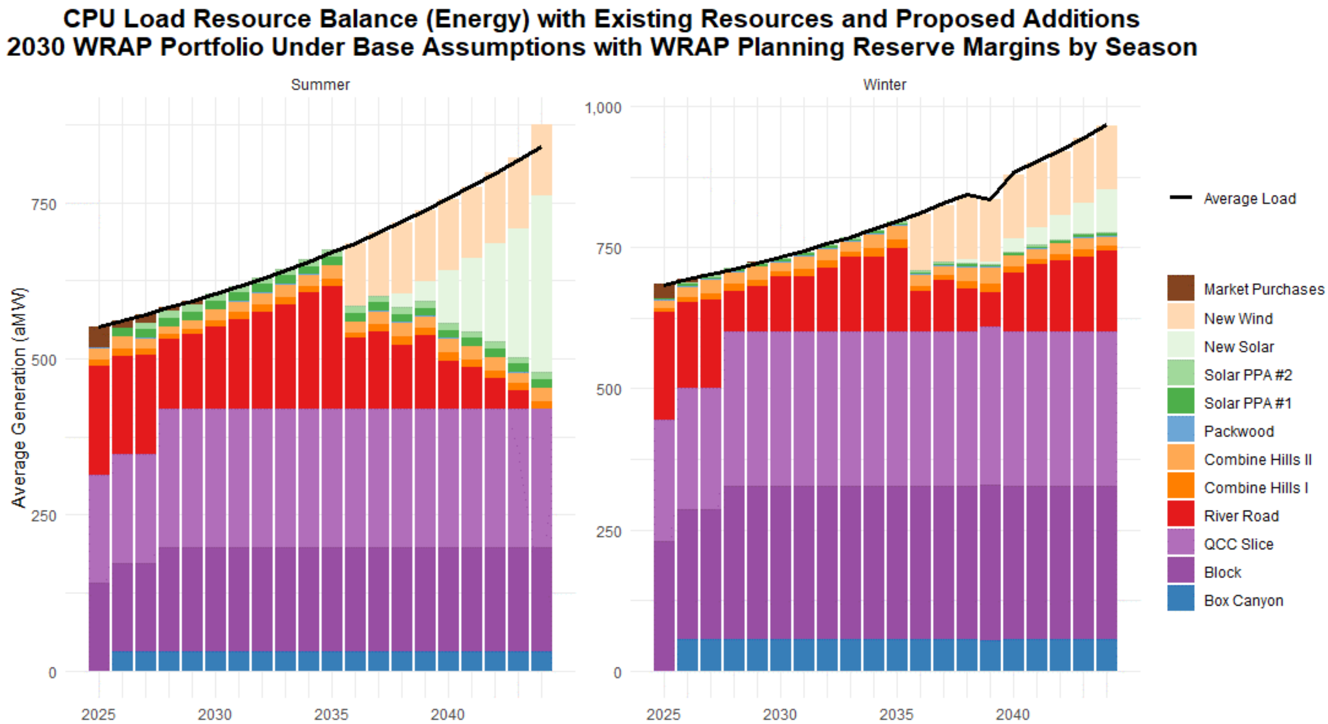


Figure 40. Energy Resource Load Balance for 2030 WRAP Portfolio

Figure 41 illustrates that the NPVRR of the 2030 WRAP portfolio is lower than that of the Reference Portfolio. This difference is driven by the delayed start of the WRAP program, which allows CPU to postpone additional capacity purchases required for compliance with the WRAP program Planning Reserve Margin (PRM). This delayed expense decreases costs in the additional years before the program starts (2027-2030). Moreover, any delay in the WRAP program implementation creates opportunities for new supply resource options to become available in the market and thereby allow CPU to meet its capacity requirements with lower cost solutions.

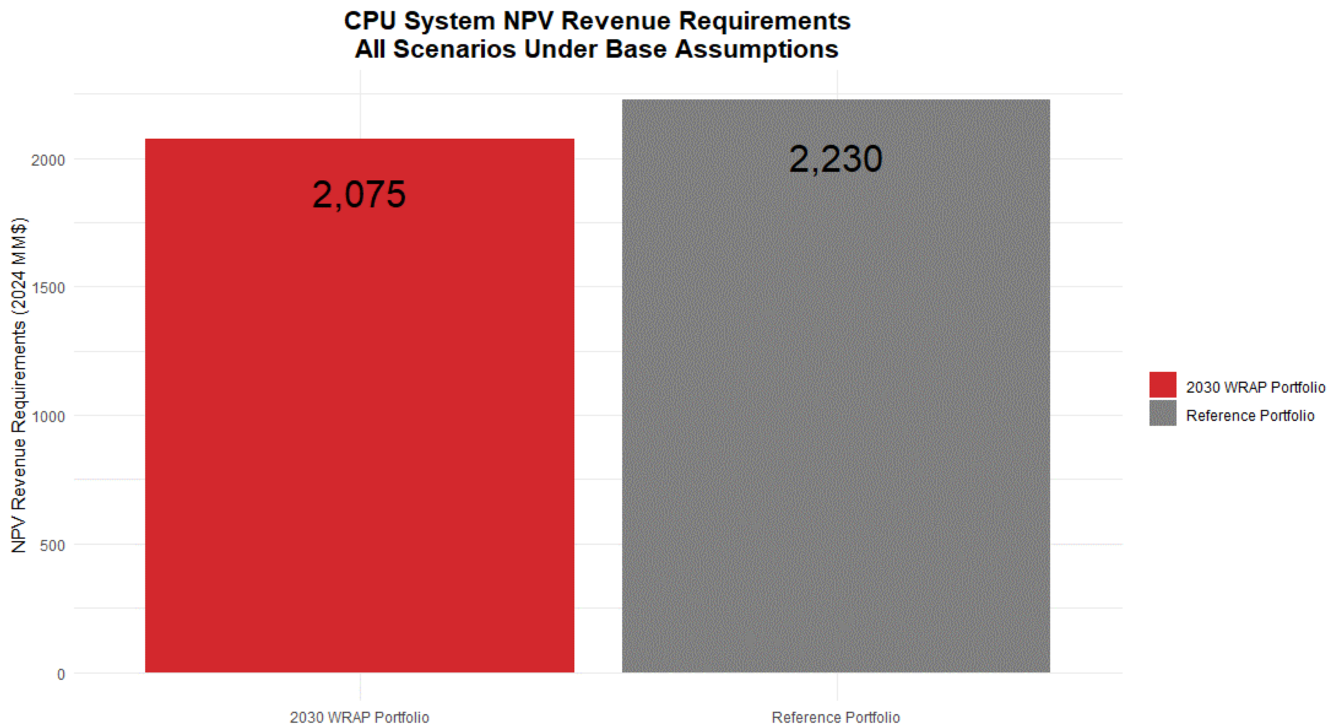


Figure 41. 20-Year NPVRR for All Scenarios

Battery storage plays a critical role in fulfilling capacity demands in both scenarios. Both require over 600 MW of battery storage to meet WRAP requirements. Its unique characteristics and qualifying capacity are essential for CPU to meet these requirements at least cost. From 2036 onward, solar and wind power become increasingly important as the gap widens between CPU's existing generation and average energy consumption. Meanwhile, River Road remains pivotal in providing flexibility for integrating renewable energy into the portfolio.

8.2 CPU Sensitivity Analysis and Results

CPU 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 1.2%), base (annual demand growth of 1.9%), and high (annual demand growth of 3%). Table 10 outlines how sensitivity analyses are incorporated into the IRP.

Table 10. 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 CPU's current and future resources will respond to WRAP requirements and future load growth.

Figure 42 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 the beginning 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 broad level, resource selection remains consistent across all scenario and sensitivity combinations. Battery storage continues to serve as the primary resource for meeting capacity requirements, while solar and wind gradually increase their contributions to meeting energy needs starting in the mid-2030s. The capacity quantities adjust with each study, demonstrating greater adoption in response to higher load levels.

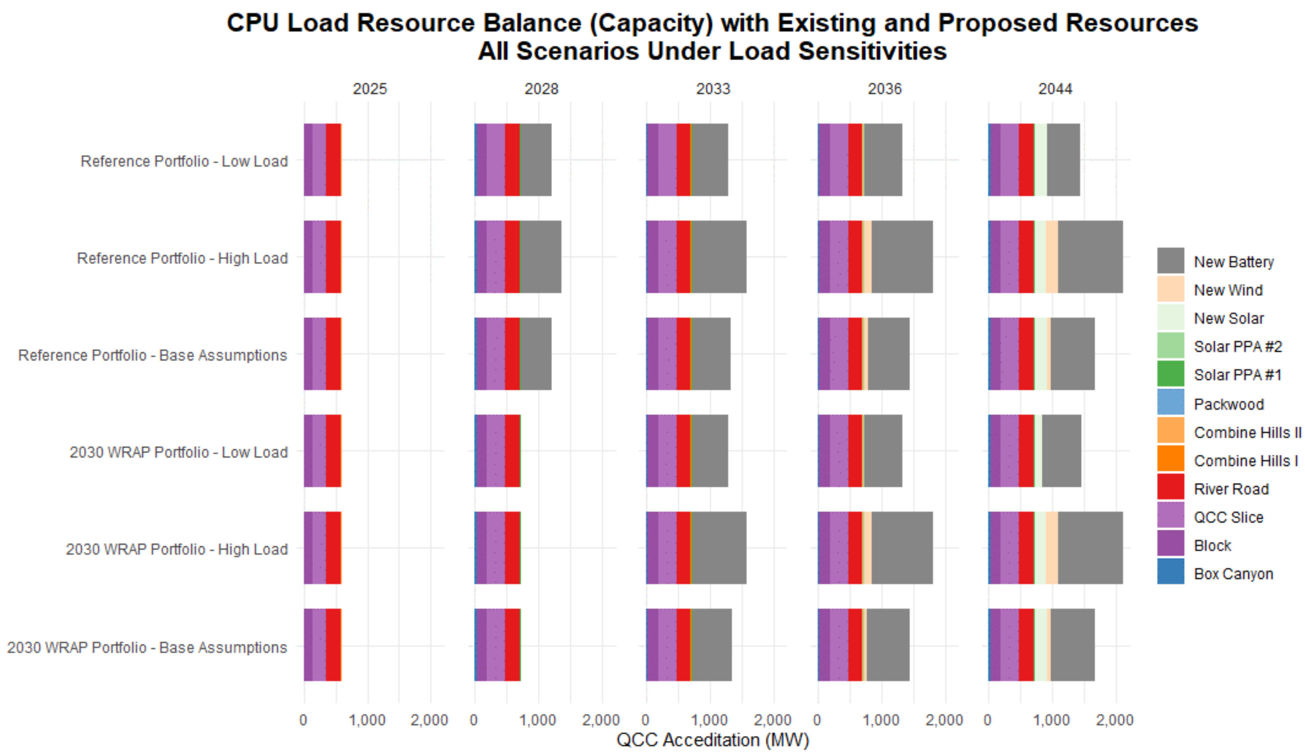


Figure 42. Sensitivity Load Resource Balance

Figure 43 compares the NPVRR of each of the sensitivities. The NPVRR sensitivity graph demonstrates that delaying the WRAP requirements by slightly over 2 years results in cost savings ranging from $145 to $191 million. The largest savings occurs in the high load sensitivity. The analysis also highlights a clear relationship: as load decreases, costs decrease accordingly, and conversely, as load increases, costs rise. While there are cost savings from a delay in WRAP implementation, there is greater variation in cost due to the load variations. This analysis highlights the critical impact of timing and load variations on financial outcomes.

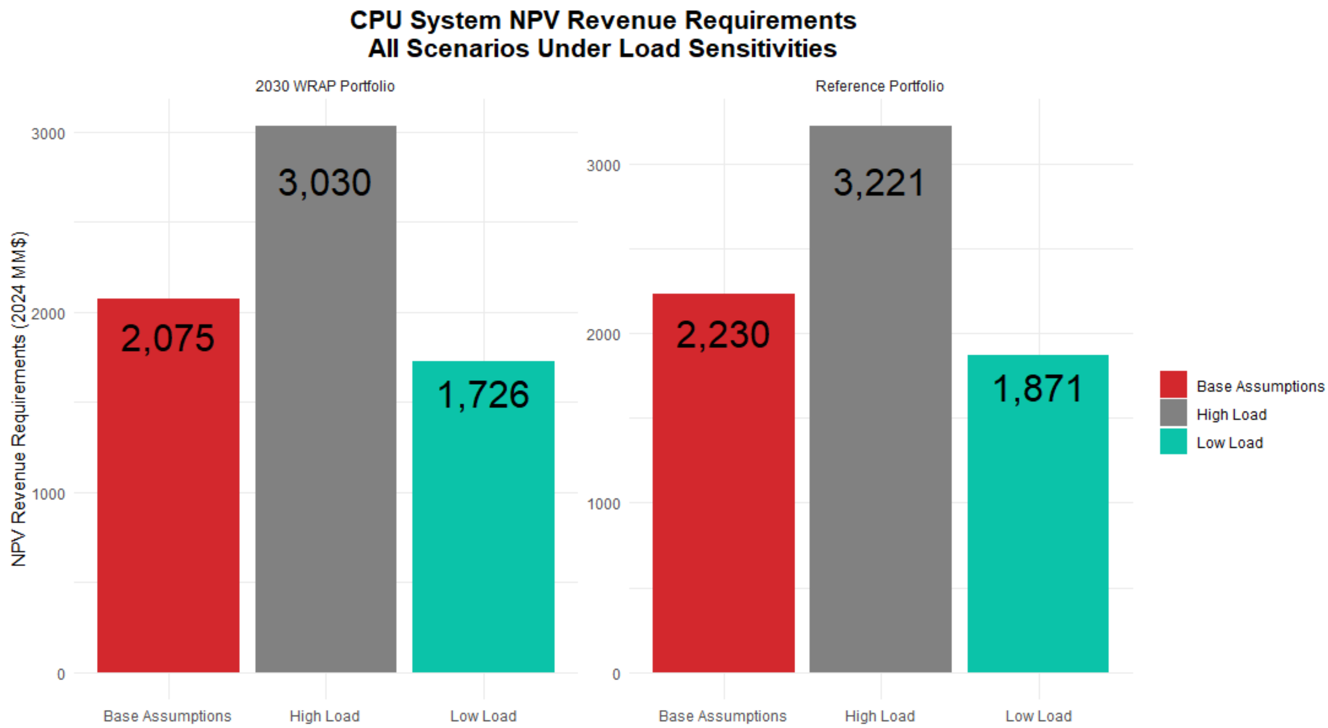


Figure 43. Sensitivity NPVRR

Battery storage remains essential for meeting WRAP capacity requirements, with at least 600 MW of storage needed even in low-load scenarios. Wind power deployment varies based on load; it is not selected in low-load scenarios, whereas solar is consistently chosen with over 1000 MW of installed nameplate capacity. River Road contributes crucial flexibility in integrating intermittent renewable energy sources.

8.3 BPA Load Following

In April 2024, BPA sent a letter to all Slice/Block customers informing them of an option to switch from the Slice/Block product to the Load Following product for the final 3-year rate period of the current BPA power contract (October 2025 through September 2028). **In June 2024, the CPU's Board of Commissioners authorized staff to send a letter to BPA formally requesting a change from the Slice/Block product to the BPA Load Following product beginning in October 2025.**

BPA completed a public process in July 2024 to determine the cost impacts of a product switch for CPU and the other utilities that have elected to change products. BPA's analysis did not find significant or unexpected cost impacts associated with the product switch. Based on the results of its analysis and public process BPA determined that it will allow CPU to switch to the Load Following contract effective October 1, 2025. **When CPU becomes a Load Following customer, BPA will supply CPU's hourly loads up to its**

monthly peak demands and CPU will not need to invest in any new resources to serve the capacity deficits shown in the load forecast section of this report.

CPU will have the option of continuing as a BPA Load Following customer under the next BPA power contract, known as the Provider of Choice (POC) contract. Neither the design of the Load Following product nor the rates applicable to Load Following customers under the POC have yet been finalized. However, at this time, we do know that BPA will continue to follow the hourly loads of Load Following customers under the POC contract. **As such, if CPU selects the Load Following product for the POC contract, BPA will serve CPU's hourly loads through the study period of this report (2044) and additional resources will not be needed to meet monthly peak demands.** However, as a Load Following customer, CPU will need to acquire additional resources to serve load growth beginning in the early to mid-2030s.

Section 9 Least Cost Action Plan

Below is a summary of near- and long-term action items that CPU intends to pursue.

- ✓ Acquire all cost-effective conservation consistent with NWPCC models and CPU's Conservation Potential Assessment (CPA)

  CPU has historically over-achieved compared to the energy efficiency targets included in its CPAs. In the 2022-2023 EIA compliance period CPU achieved 11.15 aMW of conservation or 1.78 aMW greater than its target of 9.37 aMW under the EIA. CPU will continue to endeavor to meet and, if possible, exceed the energy efficiency targets included in its CPA.

- ✓ Buy all available Bonneville Power Administration Tier 1 power in 2025-2044

  CPU worked with BPA and its preference customers on an agreement that will allow CPU to reduce the amount of RRGP generation that is dedicated to serve load in its post-2028 BPA power contract. Under the agreement, the RRGP resource declaration will, in the next BPA power contract that begins in October 2027, decrease by 123 aMW, from 225 aMW to 102 aMW, and CPU's allocation of BPA power will increase. CPU' allocation of BPA Tier 1 power under the current BPA power contract, known as its High-Water Mark, is currently 318 aMW. CPU' Contract High-Water Mark in the next BPA power contract is currently projected to be 391 aMW. CPU will evaluate the power products BPA proposes for post-2028 load service with a focus on which product will allow CPU to serve existing load and future load growth at the lowest cost and least risk to utility rate payers.

- ✓ Optimize River Road Generating Plant Generation using Flexibility Product Installed in May 2024

  In May 2024, CPU upgraded the RRGP plant with equipment that will a) result in a lower heat rate when the plant is operating at baseload generation, b) increase the plant's generating capacity and c) allow plant generation to be ramped down from its base generating level to near 95 MW when it is economic to do so. Historically CPU has had the ability to economically displace the plant for a minimum of two weeks as opportunities arose. The plant upgrade allows CPU to reduce generation in, for example, many off-peak hours when the plant is not economic to run and/or the energy is not needed to serve load. Reducing plant generation will also result in reduced carbon emissions as CPU will be looking for opportunities to displace RRGP generation with surplus carbon-free resources.

- ✓ Finalize Bonneville Power Administration Post-2028 Contract with the CETA requirements embedded

  CPU's staff and trade associations are currently engaged in BPA public process that will result in the signing of new BPA power contracts, known as Provider of Choice contracts, by the end of calendar year 2025. BPA's resource portfolio is currently 95 percent carbon-free. CPU and other BPA customer utilities have encouraged BPA to provide 100 percent carbon-free products to serve Tier 1 load, also known as High-Water Mark load, and load growth, also known as above-High Water Mark load.

- ✓ If load growth materializes, look for and acquire RECs to meet the EIA requirements, subject to EIA cost cap limits

As CPU prepares to comply with the renewable energy requirements included in the EIA and the carbon-free energy requirements included in CETA, it will continue to explore opportunities to purchase RECs. There will be years in which CPU is long energy but short on renewable and/or carbon-free energy. Rather than increase the amount of surplus energy in its portfolio and re-sell more energy into the wholesale market, potentially at a loss, in order to reduce its risk and costs, which are passed on to its customers through retail rates, CPU will explore options for purchasing RECs and/or offsets when available.

- ✓ Stay abreast of conservation and demand response programs, distributed generation, and renewable technologies and opportunities

Most of the DR measures included in the 2023 DRPA, including smart thermostats, require Advanced Metering Infrastructure (AMI) which CPU has yet to deploy. CPU’s Board of Commissioners has set aside funds to begin implementing AMI in CPU’s service territory, however, the rollout of AMI is expected to take several years.

CPU will continue to explore opportunities for adding both utility-scale renewable and behind-the-meter renewable resources, such as community solar projects, to its resource portfolio. Additional utility-scale renewables will only be added to the resource portfolio when the load/resource balance shows that new resources are needed from an energy perspective.

Section 10 Clean Energy Action Plan

This section of this Integrated Resource Plan is intended to meet the requirements of the CETA as it relates to obligations regarding the creation of a Clean Energy Action Plan. Below is a summary of the actions CPU has taken since the passage of CETA that will enable CPU to meet CETA's requirements.

10.1 BPA Power Purchases

As discussed in the previous section, CPU worked with BPA and its preference customers to finalize an agreement that will allow CPU to reduce the amount of RRGP generation that is dedicated to serve load in its post-2028 BPA power contract. Under the agreement, the RRGP resource declaration will decrease by 123 aMW, from 225 aMW to 102 aMW and CPU's allocation of BPA power will increase. CPU's allocation of BPA Tier 1 power under the current BPA power contract is currently 318 aMW. CPU's Contract High-Water Mark in the next BPA power contract is projected to be 391 aMW. Since BPA Tier 1 power is near 95 percent carbon-free power increasing CPU's access to BPA Tier 1 power will aid CPU in meeting its CETA obligations. As a BPA preference customer, CPU also has the right to place load growth on BPA through BPA's Tier 2 products. CPU and other BPA customer utilities will be working with BPA in the future to assure that BPA offers 100 percent carbon-free Tier 2 product choices.

10.2 Combine Hills Wind Contracts

CPU has been purchasing all the output of the 63 MW Combine Hills 2 wind project since January 2010. In February 2024 CPU began purchasing all the output of the 41 MW Combine Hills 1 wind project. In total these projects add 103 MW of wind capacity and 29 aMW of expected wind energy to CPU's resource portfolio. Both wind contracts expire at the end of the calendar year 2029.

CPU is currently in discussions with the owner of both the Combine Hills 1 and Combine Hills 2 wind projects to secure access to more wind generation from these projects after the current contracts expire. It is expected that the total generation of the two wind projects will increase when the projects are re-powered sometime around 2030. Total generation will increase when new, larger turbines, possibly as large as 4 MW, with higher capacity factors are installed. The existing turbines at both projects have capacities of 1 MW.

10.3 River Road Generating Plant Flexibility Product

As discussed in the previous section, CPU upgraded the RRGP plant in May 2024 with equipment that will reduce the plant's heat rate, resulting in less gas consumption, and allow plant generation to be ramped down from its base generating level to near 95 MW when it is economic to do so. Decreasing the plant's heat rate and reducing plant generation will result in reduced carbon emissions. CPU will be looking for opportunities to displace RRGP generation with carbon-free resources such as wind, solar and hydro generation when there is a surplus of these resources in the region. For example, if the forecast is for high wind generation overnight in the region, the plant could be ramped down to minimum generation for the night and ramped back up in time to serve morning peak demand.

10.4 Box Canyon hydroelectric Project

In 2022, CPU signed a power purchase agreement with Pend Oreille Public Utility District for the entire output of the Box Canyon Hydroelectric Project. Box Canyon is a run-of-the-river hydroelectric facility with little to no storage capacity. The power purchase begins in January 2026 and runs through December 2041 with rolling three-year evergreen terms continuing unless either party provides termination notice four years prior to the start of the corresponding evergreen term. The average annual generation from Box Canyon is expected to be 50 aMW. Box Canyon generation is 100 percent carbon-free and will CPU in meeting its non-emitting energy requirements under CETA.

10.5 Solar Power Purchase Agreements

CPU is currently in negotiations with a renewable energy developer to purchase the entire output of two solar projects for 20-year contract terms. One project is scheduled to come on-line in January 2026 and add 74 MW of solar generation to CPU's resource portfolio. The second project is scheduled to come on-line in January 2027 and add 60 MW of solar generation to CPU's resource portfolio. Total projected annual generation from the two projects is near 37 aMW in 2027, degrading by 0.45 percent annually.

10.6 Energy Efficiency and Demand Response Programs

For years, CPU has followed numerous forums, policy groups, technical committees, and governmental efforts to provide the best energy efficiency programs and products to its customers. CPU will remain committed to providing a myriad of energy efficiency programs to its customers. Between 2010 and 2023 CPU energy efficiency achievements totaled 102 aMW, or nearly 20 percent of its annual retail load.

In 2024, CPU launched an industrial demand response pilot program that allows qualified customers the opportunity to make a one-time nomination of site load to be reduced during a demand response event. Demand response events are callable nine months of the year during the winter (January, February, March, November, and December) and summer (June, July, August, and September). Winter events have a maximum duration of four hours per day from 06:01 am to 10:00 am. Summer events have a maximum duration of four hours per day from 4:01 pm to 8:00 pm. Events may occur for a maximum of two consecutive days with no more than four events in a month. CPU notifies customers on the calendar day preceding the event when demand response is needed for load management or energy cost mitigation. For months during which the program is active a flat credit is applied based on the customer's nominated kW load multiplied by $4.40. Following an event, an energy credit is applied based on the difference between the actual load during the event and a site baseline energy load measured as the average hourly load during the previous ten business days. The kilowatt-hour differential is credited at $0.15 per kWh. The pilot program will be re-evaluated annually.

CPU will continue to expand demand response programs as they become more cost-effective and as more programs become achievable with the adoption of AMI.

10.7 Distributed Generation

CPU will continue to work with customers interested in installing distributed generation. The amount of rooftop solar on customers' homes has increased to near 23 MW of capacity. This distributed generation has been valuable in reducing peak summer demands. CPU looks forward to continuing to work with customers interested in installing distributed generation as it benefits both the customer and the utility.

In April 2024, CPU energized the 799 kW Community Solar East project, the second community solar project developed by the utility. The utility's first community solar project, the 319 kW Community Solar Orchards project, came on-line in 2015. Both projects are owned and operated by CPU.

CPU's Board of Commissioners allocated 5 percent, or approximately 15 kW, of the 319 kW Community Solar Orchards array to the utility low-income program, Operation Warm Heart. This design change allowed for many members of our most vulnerable populations to realize the benefit of local, renewable energy resources.

Community Solar East was conceived and developed in partnership with the site host, the Port of Camas Washougal, and is sited on the roofs of five Port buildings. The project will generate approximately 920,000 kWh of solar electricity annually and has an expected project life of 25 years. Community Solar East provides customer participants with annual "energy credits" on their utility account and are calculated using the utility's retail rates (similar to Net Metering).

Community Solar East includes customer participants from the residential, business and government agency sectors. 199 kW of the Community Solar East project is dedicated to CPU's low-income customers; in large part due to the WSU Energy Low Income Community Solar program created by HB 1814. The "energy credits" from this dedicated 199 kW piece of the project will be allocated annually to the utility's Operation Warm Heart energy assistance program that provides grants toward the heating bills of families in financial crisis. The remaining 600 kW of the project was sold to customers in "Solar Units" that represent 50 watts of the project capacity for $85 each. Participating customers are expected to realize a 12.5-year return-on-investment.

10.8 Electric Vehicle Demand Response Program

In 2024, CPU launched an Electric Vehicle (EV) managed charging pilot program in partnership with Optiwatt. Participants receive a $50 bill credit incentive for each EV that joins the program.

The EV Managed Charging Program works directly with EV's telematics and helps manage electric load and optimize the grid in Clark County. This program will help CPU better understand EV charging behavior in Clark County and help plan and prioritize system updates as EV adoption continues to grow. Participating EV owners are included in scheduled charging events. These events typically last four hours and are designed to be scheduled several times each month. Customers have the ability to opt out of events if participating in an event would cause an inconvenience. During winter months (November, December, January, February, and March) managed charging events are scheduled to run Monday through Friday from 6:01 a.m. to 10:00 a.m. Charging is restricted during events unless customers opt out of an event. During summer months (June, July, August, and September) managed charging events are scheduled Monday through Friday from 4:01 p.m. to 8:00 p.m. unless customers opt out. The program will be re-evaluated annually.

10.9 Small Modular Reactors

CPU has, over the past 3 to 4 years, engaged in preliminary discussions with SMR developers to investigate the progress being made and the potential viability of SMRs in the region. SMRs are carbon-free resources that could help CPU meet future CETA requirements. Since SMRs are carbon-free and dispatchable these resources may play an important role in the future resource portfolios of Washington utilities. If CPU were to pursue an SMR in the future it would be through a power purchase agreement, not through a consortium that would include an ownership interest in the project. CPU is a member of Energy Northwest which operates the Columbia Generation Station and has expressed interest in the development of an SMR. CPU will continue to stay engaged in the SMR arena.

Appendix A – Resource Adequacy Metrics Determination

CPU includes a planning margin in its incremental electric power requirements calculation as a means to account for resource adequacy (RA). CPU has historically used a 12 percent planning margin as the metric for RA. However, with the formation of the Western Resource Adequacy Program (WRAP) planning reserve margins have become more precise. The WRAP and CPU's role therein is described below.

The Western Power Pool (WPP) is a voluntary organization primarily consisting of major generating utilities serving the Pacific Northwest of the United States and the Pacific Southwest of Canada. The WPP primarily focuses on utility operations, planning, and operating reserve sharing. From these common interests, in late 2019 RA emerged as a topic of great interest to the WPP membership, the WPP began a journey toward developing an RA program for its members and, ultimately, developed the WRAP. Under the WRAP seasonal planning reserve margins are determined for summer and winter periods and expressed as a percentage of the 1-in-2-year seasonal peak load forecast. The first non-binding season was in winter 2022-23. The first mandatory binding season will be winter 2027-28. The first mandatory binding summer season will be summer 2028.

WRAP participants plan to a common RA standard. The program has developed common capacity counting methods for generating resources and allow the pooling of resources to meet the reliability needs of participants and unlock diversity benefits. The Southwest Power Pool administers and executes the RA program on behalf of WRAP members.

CPU has thus far elected to participate in the non-binding phase of the WRAP. CPU has joined with a group with four other Slice/Block customers that have chosen to participate in the WRAP as consortium of utilities whose RA requirements are managed by The Energy Authority. However, when CPU switches from the BPA Slice Block product to the BPA Load Following product, CPU would be part of the aggregated BPA load and will participate in the WRAP through BPA. CPU will not have any individual WRAP compliance obligations nor will it be subject to any individual non-compliance penalties.

Appendix B – Distributed Energy Resources

CPU anticipates substantial growth in customer owned distributed generation over the next twenty years. As of May 2022, CPU facilitates, integrates and provides the net metering benefit to 22.7 MW of installed distributed generation capacity. Our customers have installed 3,134 individual generating systems, primarily rooftop solar. Between 2015 and 2023 annual generation from net metered systems increased from 0.11 aMW to 2.70 aMW. Net metering customers receive a retail credit for their generation, which is predominantly rooftop solar, and, at times, the value of the energy is less than the retail energy rate. However, during stressful times, the value of energy is greater than the retail rate credit.

CPU has twice previously increased the allowable net metering for its customers to a level that exceeded the state's mandated threshold. The current maximum net metering capacity threshold is set by RCW 80.60.020 and is currently four percent of our historical 1996 peak load, or approximately 41.3 MW of installed capacity. Utilities must offer net metering to eligible customer-generators on a first-come, first-served basis until the earlier of either June 30, 2029 or the date upon which the cumulative generating capacity of net metering systems is equal to the threshold. CPU anticipates exceeding the threshold in 2028, which is before the June 30, 2029 date in the RCW. As such, CPU will need to address this issue for the third time in 2028.

The bars in Figure D-1 show net metering customers' total monthly energy production over a recent 12-month period. Distributed energy generation peaks in July and is at its lowest in January. The shaded area shows the percent of total production that was consumed by the homes and businesses that participate in the net metering program. As shown below, 40 percent of the energy generated during the peak month of July was consumed onsite and 60 percent was delivered to the distribution grid. In January 75 percent of the energy generated was consumed by the customer and only 25 percent was sent to the grid.

Figure D-1
Net Metering Customers' Total Energy Production
(Shaded area displays % of total production used in home/business)

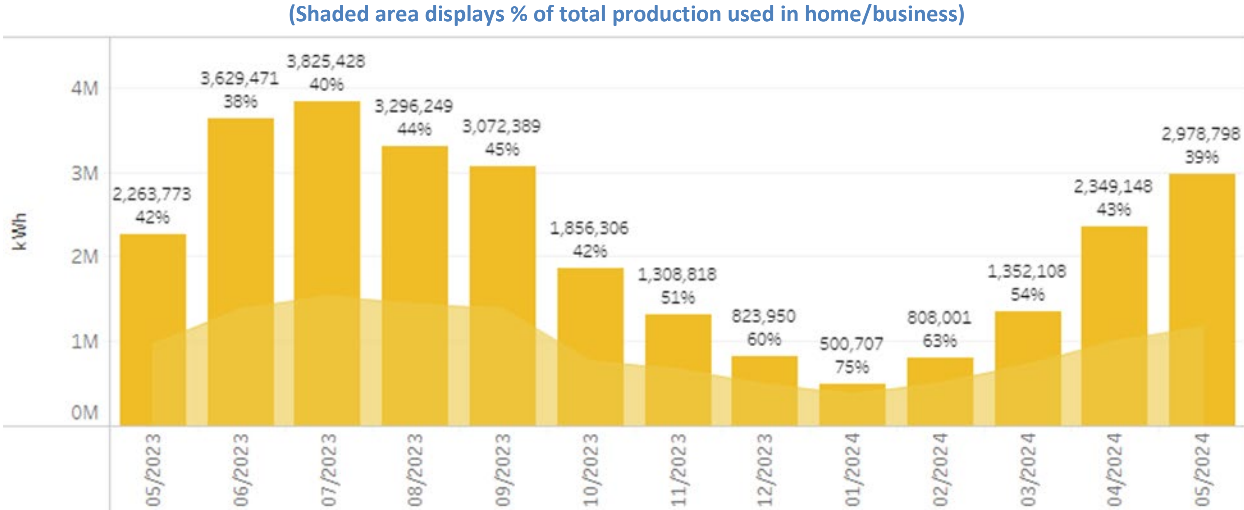
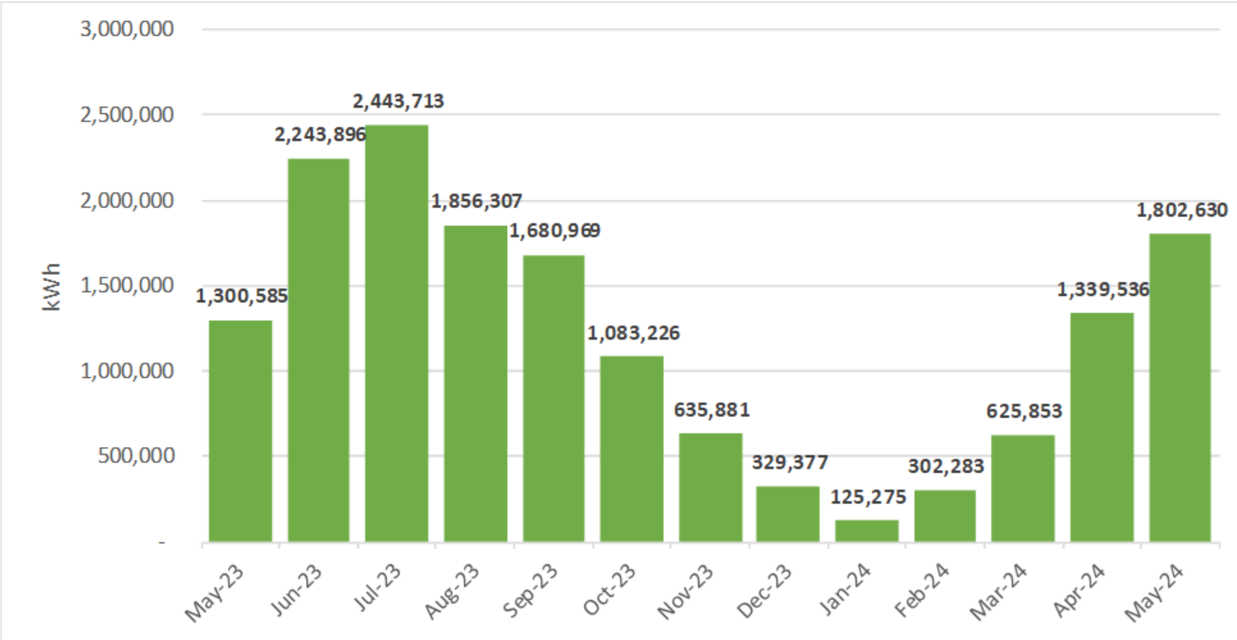


Figure D-2 shows the excess energy sent to the grid by net metered customers.

Figure D-2
Generation Received from Net Metered Customers



Customers are credited for the net excess energy generated during a given billing period with a kilowatt-hour credit on their bill for the following billing period. In accordance with state law, net metering accounts are re-set to zero each April 1st. Any remaining unused kilowatt-hour credits accumulated by customers between April and March are granted the utility without any compensation. At the end of the April 2023 through March 2024 operating year 119 net metering customers had excess generation that totaled 218,656 kWh, or 0.8 percent of the total energy generated by net metering customers.

In June through September, when solar generation is highest, CPU system loads peak during the 1800 hour, after solar generation has started to ramp down for the evening (see Figure 4.8).

Federal and state incentive programs drive higher adoption rates. Currently, the Washington state renewable incentive programs are closed to new participants, and in 2020 the federal tax credit started decreasing. Because of the uncertainty with respect to future federal and state incentives available to CPU's customers, the utility performed a distributed generation growth analysis that examined three different future scenarios. Historically, the overwhelming majority of installed capacity has been within CPU's residential customer sector. CPU anticipates that this trend will continue in the 2025 through 2044 study period.

CPU operates 1,118 kW of installed community solar sited in Clark County, WA.

The utility’s first community solar project, the 319 kW Community Solar Orchards project, came on-line in 2015. The utility’s second community solar project, the 799 Community Solar East project, came on-line in 2024.

CPU will continue to support any additional community solar opportunities that may arise. Any future community solar projects will count against the utility net metering threshold. There is sufficient capacity currently available that we do not anticipate any policy driven barriers that would preclude a new project, whether utility or privately administered, in Clark County.

Appendix C – Conservation Potential Assessment

2023 CONSERVATION POTENTIAL ASSESSMENT

Clark Public Utilities

November 15, 2023

Prepared by:

LIGHTHOUSE ENERGY CONSULTING

Table of Contents

List of Figures

List of Tables

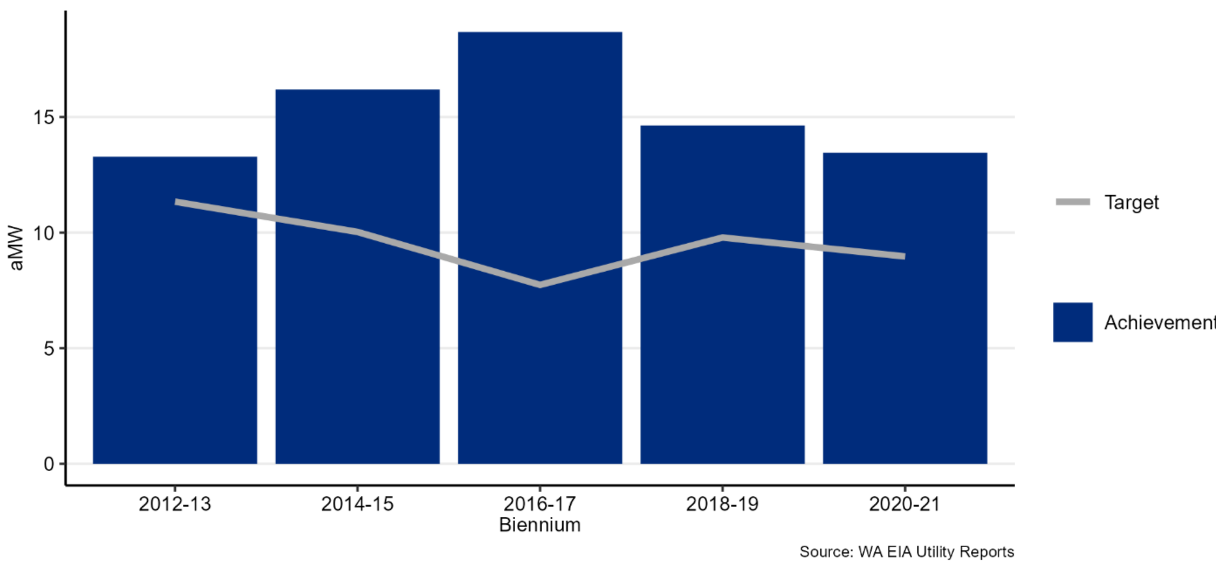
Executive Summary

Overview

This report describes the methodology and results of a conservation potential assessment (CPA) conducted by Lighthouse Energy Consulting (Lighthouse) for Clark Public Utilities. The CPA estimated the cost-effective energy efficiency savings potential for the period of 2024 to 2043. This report describes the results of the full 20-year period, with additional detail on the two- and 10-year periods that are the focus of Washington's Energy Independence Act (EIA). The initial two years of this study are also the final two years of the four-year period covered by Clark Public Utilities' first Clean Energy Implementation Plan (CEIP). If desired, the results of this study can be used to update the conservation target identified in that CEIP.

Clark Public Utilities provides electricity service to more than 225,000 customers across Clark County, Washington. The EIA requires that utilities with more than 25,000 customers identify and acquire all cost-effective energy efficiency resources and meet targets set every two years through a CPA. Clark Public Utilities' history of consistently exceeding its biennium conservation targets is shown in Figure 1, which is based on EIA compliance data reported to Washington's Department of Commerce.

Figure 1: Historic Targets and Achievements



The EIA specifies the requirements for setting conservation targets in RCW 19.285.040 and WAC 194-37-070 Section (5), parts (a) through (d). The methodology used in this assessment complies with these requirements and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in the 2021 Power Plan. Washington's Clean Energy Transformation Act (CETA) has additional requirements for CPAs; namely, that the assessment of cost-effectiveness make use of specific values for the social cost of carbon. Appendix III details these requirements and how this assessment fulfills those requirements.

This CPA used much of the 2021 Power Plan materials, with customizations to make the results specific to Clark Public Utilities' service territory and customers. Notable changes in this CPA relative to Clark Public Utilities' previous assessment include the following:

- Energy Efficiency Measures
  - This assessment uses the measure savings, costs, and other characteristics based on the measures included in the final 2021 Power Plan, with updates to dozens of measures based on new information from the Regional Technical Forum (RTF) and additional customizations to make the measures specific to Clark Public Utilities.
- Avoided Costs
  - A new market price forecast was incorporated, which has increased significantly from the 2021 CPA update
  - Lighthouse worked with Clark Public Utilities to estimate new values for summer and winter capacity
- Customer Characteristics
  - Updated counts of residential homes
  - Updated HVAC and other appliance saturations
  - New estimates of commercial floor area
  - New forecast of Clark Public Utilities' industrial sector loads
  - Updated customer growth rates
- Program Impacts
  - Consideration of Clark Public Utilities' recent conservation program achievements

Results

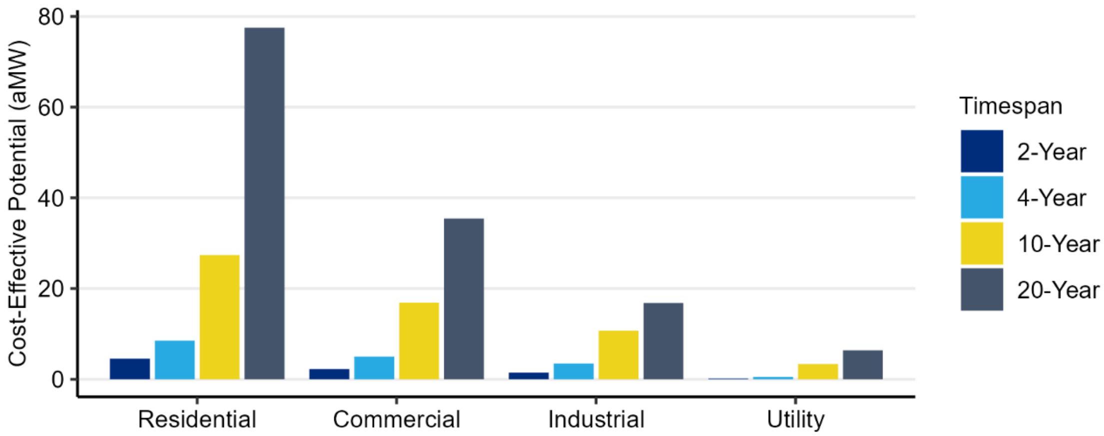
Table 1 and Figure 2 show the cost-effective energy efficiency potential by sector over two-, four-, 10-, and 20-year periods. Over the 20-year planning period, Clark Public Utilities has 136 aMW of cost-effective conservation available, which is approximately 18% of its projected 2043 load. The EIA focuses on the two- and 10-year potential, which are 8.43 aMW and 58.36 aMW, respectively.

Table 1: Cost-Effective Energy Savings Potential by Sector (aMW)

Sector	2-Year	4-Year	10-Year	20-Year
Residential	4.56	8.51	27.39	77.51
Commercial	2.24	5.01	16.90	35.44
Industrial	1.48	3.49	10.70	16.83
Utility	0.15	0.50	3.37	6.38
Total	**8.43**	**17.52**	**58.36**	**136.15**

Note: In this and all subsequent tables, totals may not match due to rounding.

Figure 2: Cost-Effective Energy Savings Potential by Sector



The residential sector has the largest potential, followed by the commercial and industrial sectors. This correlates with the loads of Clark Public Utilities' sectors. A much smaller amount of potential is available in the utility sector.

This assessment does not specify how the energy efficiency potential will be achieved. Possible mechanisms include:

- Clark Public Utilities' energy efficiency programs
- Clark Public Utilities' behavior program
- Market transformation driven by the Northwest Energy Efficiency Alliance (NEEA)
- State building codes
- State or federal product standards.

Often, the savings associated with a measure will be acquired by several of the above mechanisms over the course of its technological maturity. For example, heat pump water heaters started as one of NEEA's market transformation initiatives. Subsequently, they became a regular offering in utility programs across the Northwest and are starting to work their way into federal product standards.

Energy efficiency also contributes to reductions in peak demand. This assessment used hourly load and savings shapes developed by the Council to identify when the savings from each measure occur and estimate the demand savings at the time of Clark Public Utilities' system peak. The cost-effective energy savings potential identified in this assessment will result in nearly 253 MW of peak demand savings over the 20-year planning period, as shown in Table 2. This represents approximately 21% of Clark Public Utilities' estimated 2043 peak demand.

Table 2: Cost-Effective Peak Demand Savings Potential by Sector (MW)

Sector	2-Year	4-Year	10-Year	20-Year
Residential	10.56	19.63	65.31	185.08
Commercial	2.63	5.96	19.69	40.48
Industrial	1.76	4.16	12.69	20.03
Utility	0.17	0.57	3.81	7.22
Total	**15.13**	**30.32**	**101.51**	**252.81**

This CPA used ramp rates to identify the share of the potential available in each year that could be acquired. The ramp rates are based on those used by the Council for the 2021 Power Plan and reflect the market and program maturity of each measure. For this CPA, Lighthouse selected ramp rates that would align the near-term potential of each measure with Clark Public Utilities' recent and expected program achievements and the savings from NEEA's market transformation initiatives that are estimated to occur in Clark Public Utilities' service territory. Clark Public Utilities staff provided program achievement data for 2021 and 2022. Lighthouse assigned appropriate ramp rates for each measure so that the future acquisition of energy efficiency was aligned with this program data while allowing for the acquisition of all cost-effective energy efficiency over the 20-year planning period.

The estimate of annual energy efficiency potential by sector is shown in Figure 3. The available cost-effective potential starts at approximately 4 aMW in 2024 and grows to a maximum of 9 aMW in 2036. After that point, the annual potential declines through the remainder of the study period as the remaining available opportunities for energy efficiency are acquired. The higher residential potential in 2024-26 is due to savings expected as part of a behavior program offered in those years.

Figure 3: Annual Incremental Energy Efficiency Potential

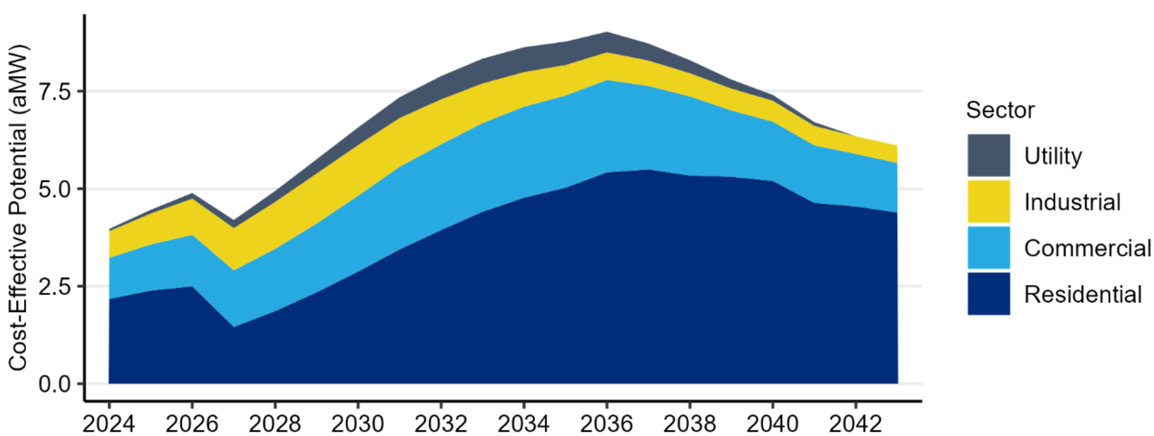
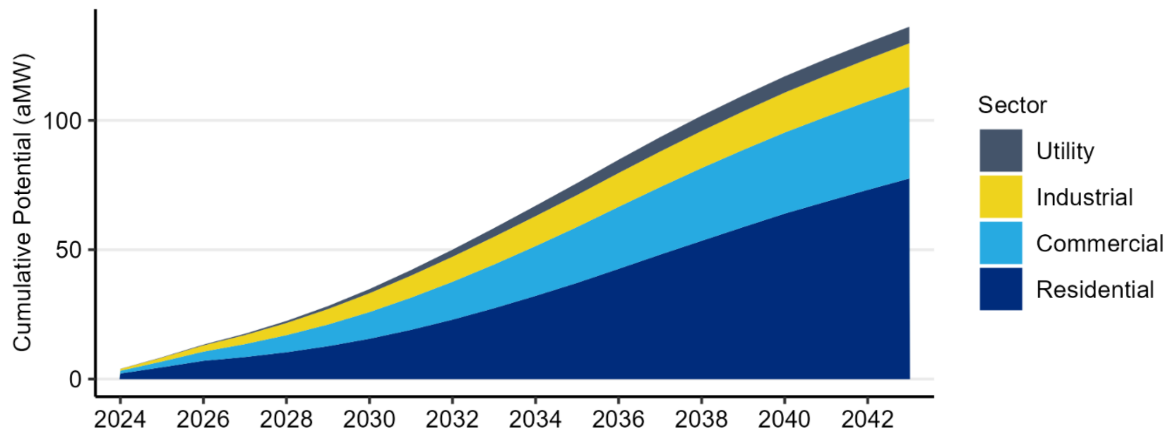


Figure 4 shows how the energy efficiency potential grows on a cumulative basis through the study period, totaling more than 136 aMW over the 20-year planning period.

Figure 4: Annual Cumulative Energy Efficiency Potential



Comparison to Previous Assessment

Table 3 shows a comparison of the two-, 10-, and 20-year cost-effective potential by sector as quantified by the previous 2021 CPA and this 2023 CPA. The two-year comparison shows a slight decrease in the overall potential with increases and decreases within the individual sectors. Over the longer term, the 10-year potential has increased by 17%, with even more potential over the 20-year period.

Table 3: Comparison of 2021 and 2023 CPA Cost-Effective Potential (MWh)

	2-Year Potential			10-Year Potential			20-Year Potential		
Sector	2021 CPA	2023 CPA	% Change	2021 CPA	2023 CPA	% Change	2021 CPA	2023 CPA	% Change
Residential	3.91	4.56	17%	19.81	27.39	38%	38.37	77.51	102%
Commercial	3.28	2.24	-32%	15.66	16.90	8%	27.78	35.44	28%
Industrial	2.13	1.48	-31%	12.43	10.70	-14%	19.67	16.83	-14%
Utility	0.05	0.15	213%	2.17	3.37	55%	6.38	6.38	0%
Total	**9.37**	**8.43**	**-10%**	**50.07**	**58.36**	**17%**	**92.20**	**136.15**	**48%**

Discussion of the factors leading to these changes is provided below.

Avoided Costs

The updated market prices used in this CPA have increased. The 20-year levelized value of the forecasted prices used in this CPA is approximately $52/MWh, an increase of 63% from the previous value of $32/MWh used in the prior CPA. In addition, Lighthouse worked with Clark Public Utilities staff to update the way that generation capacity is valued, including values for both summer and winter capacity.

These updated avoided costs have resulted in more measures passing the cost-effectiveness screening and additional cost-effective potential over the twenty-year period.

Customer Characteristics

This CPA used updated customer data for each sector. The initial count of homes is based on residential account data provided by Clark Public Utilities and has increased 5% from the number used in the 2021

CPA. In addition, the number of homes was forecast to grow 2.5% per year, an increase from the previous CPA.

Lighthouse also used the American Community Survey (ACS) and some early release data from the 2022 RBSA to update HVAC and appliance saturations. These updates resulted in higher saturations of heat pump technology, slightly reducing the remaining potential for these measures.

In the commercial sector, Clark Public Utilities provided updated load data by commercial building type. Lighthouse converted these loads to estimates of floor area by applying energy use intensities (EUI) from the 2019 Commercial Building Stock Assessment (CBSA). This updated data resulted in an increase of 7% in the estimated initial year floor area. Similar to the residential sector, the assumed future growth in commercial floor area is higher than the 2021 CPA.

The loads in the industrial sector have also increased slightly relative to the 2021 CPA. Similar to loads from the commercial sector, industrial loads have increased by 7% relative to the 2021 CPA. However, no growth was assumed for the industrial sector.

Program History & Forecasts

As described above, Lighthouse used ramp rates to align the cost-effective potential in the near term with Clark Public Utilities' recent and expected program achievements, as well as savings from NEEA's market transformation work. Clark Public Utilities' residential savings and expected savings from NEEA are higher than forecast in the 2021 CPA, resulting in an increase in the near-term residential potential. Expected savings from the commercial and industrial sectors are lower, however. Lighthouse also accounted for the recent program accomplishments in each sector by reducing the overall potential.

Conclusion

This report summarizes the CPA conducted for Clark Public Utilities for the 2024 to 2043 timeframe. The CPA identified slightly less potential available in the near-term relative to the 2021 CPA, but more potential available in the mid- and long-term.

The lower near-term potential in some sectors is due to alignment with recent program achievements, particularly in the commercial and industrial sectors. In the mid- and long-term, higher avoided costs and customer forecasts have resulted in additional cost-effective potential.

Introduction

Objectives

This report describes the methodology and results of a CPA conducted for Clark Public Utilities by Lighthouse. The CPA estimated the cost-effective energy savings potential available in Clark Public Utilities' service territory over the period of 2024 to 2043. This report describes the results of the full 20-year study period, with additional details on the two- and 10-year periods that are the focus of Washington's EIA.

This assessment was conducted in a manner consistent with the requirements of Washington's RCW 19.285, and WAC 194-37. As such, this report is part of the documentation of Clark Public Utilities' compliance with these requirements. The state of Washington's recently passed CETA includes an additional requirement for CPAs to use specific values for the social cost of carbon, which were incorporated into this analysis.

The results of this assessment can be used to assist Clark Public Utilities in planning its energy efficiency programs by identifying the amount of cost-effective energy savings available in various sectors, end uses, and measures. The results of this CPA can also be used to update the four-year energy efficiency target included in Clark Public Utilities' CEIP, if desired. Finally, the results can be used to inform Clark Public Utilities' integrated resource planning.

Background

Washington State's EIA defines "qualifying utilities" as those with 25,000 customers or more and requires them to achieve all conservation that is cost-effective, reliable, and feasible. Since Clark Public Utilities serves more than 25,000 customers, it is required to comply with the EIA. The requirements of the EIA specify that all qualifying utilities complete the following by January 1 of every even-numbered year:[1]

- Identify the achievable cost-effective conservation potential for the upcoming 10 years using methodologies consistent with the Council's latest power plan.
- Establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for that two-year period of its cost-effective conservation potential for the subsequent 10 years.[2]

Appendix III further details how this assessment complies with each of the requirements specified for CPAs by Washington's EIA.

Study Uncertainties

There are uncertainties inherent in any long-term planning effort. While this assessment makes use of the latest forecasts of customers, loads, energy prices, and other variables, these are still subject to uncertainties and limitations, as recent global events have shown. These uncertainties include, but are not limited to:

[1] Washington RCW 19.285.040

[2] In CA No. 2011-03, the State Auditor's Office has defined "pro rata" as "a proportion of an exactly calculable factor" and expects utilities to have analysis and documentation to support their identified targets, which could be more or less than 20% of the 10-year potential.

- Customer Characteristic Data: This assessment used the best available data to reflect Clark Public Utilities' customers. In some cases, however, the assessment relied upon data beyond Clark Public Utilities' service territory due to limitations of available data and adequate sample sizes. There are uncertainties, therefore, related to the extent that this data is reflective of Clark Public Utilities' customer base.
- Measure Data: Estimates of measure savings and costs are based on values prepared by the Council and RTF. These estimates will vary across the region due to local climate variations and market conditions. Additionally, some measure inputs such as applicability are based on limited data or professional judgement.
- Market Price Forecasts: This assessment uses an updated market price forecast. Market prices and forecasts are continually changing.
- Utility System Assumptions: Measures in this CPA receive cost credits based on their ability to provide transmission and distribution system capacity. The actual value of these credits is dependent on local conditions, which vary across Clark Public Utilities' service territory. Additionally, a value for generation capacity is included, but the value of this credit is subject to the evolving need for capacity in the Northwest.
- Load and Customer Growth Forecasts: This CPA projects future customer growth over a 20-year period. Any forecast over a similar time period will inherently include a significant level of uncertainty.

Due to these uncertainties and the continually changing planning environment, the EIA requires qualifying utilities to update their CPAs every two years to reflect the best available data and latest market conditions.

Report Organization

The remainder of this report is organized into the following sections:

- Methodology
- Historic Conservation Achievement
- Customer Characteristics
- Results
- Scenario Results
- Summary
- References & Appendices

Methodology

This section provides an overview of the methodology used to develop the estimate of cost-effective conservation potential for Clark Public Utilities.

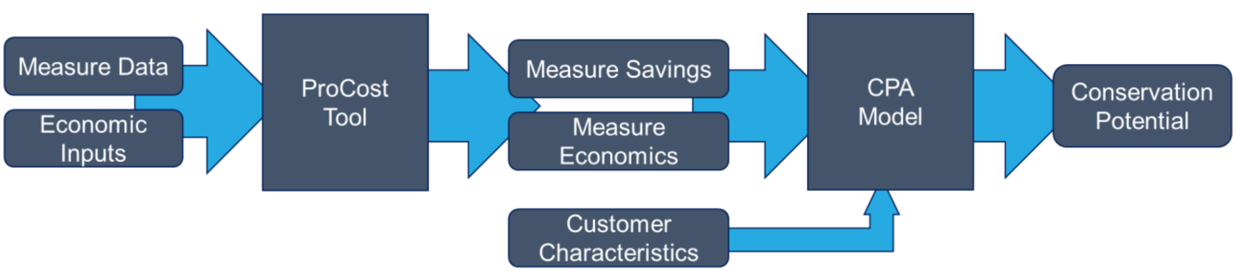
Requirements for this CPA are laid out in RCW 19.285.040 and WAC 194-37-070, Section 5 parts (a) through (d). Additional requirements are specified in the rules of Washington's CETA. The methodology used to produce this assessment is consistent with these requirements and follows much of the methodology used by the Council in developing its regional power plans, including the final 2021 Power Plan.

Appendix III provides a detailed breakdown of the requirements of the EIA and CETA and how this assessment complies with those standards.

High-level Methodology

The methodology used for this assessment is illustrated in Figure 5. At a high level, the process combines data on individual energy efficiency measures and economic assumptions using the Council's ProCost tool. This tool calculates a benefit-cost ratio using the Total Resource Cost (TRC) test, which is used to determine whether a measure is cost-effective. The TRC test includes all of the costs and benefits of energy efficiency measures, regardless of who receives the benefit or pays the cost. The measure savings and economic results are combined with customer data in Lighthouse's CPA model, which quantifies the number of remaining implementation opportunities. The savings associated with each of these opportunities are aggregated in the CPA model to determine the overall potential.

Figure 5: Conservation Potential Assessment Methodology



Economic Inputs

Lighthouse worked closely with Clark Public Utilities staff to define the economic inputs that were used in this CPA. These inputs include avoided energy costs, carbon costs, transmission and distribution capacity costs, and generation capacity costs. Each of these are discussed below.

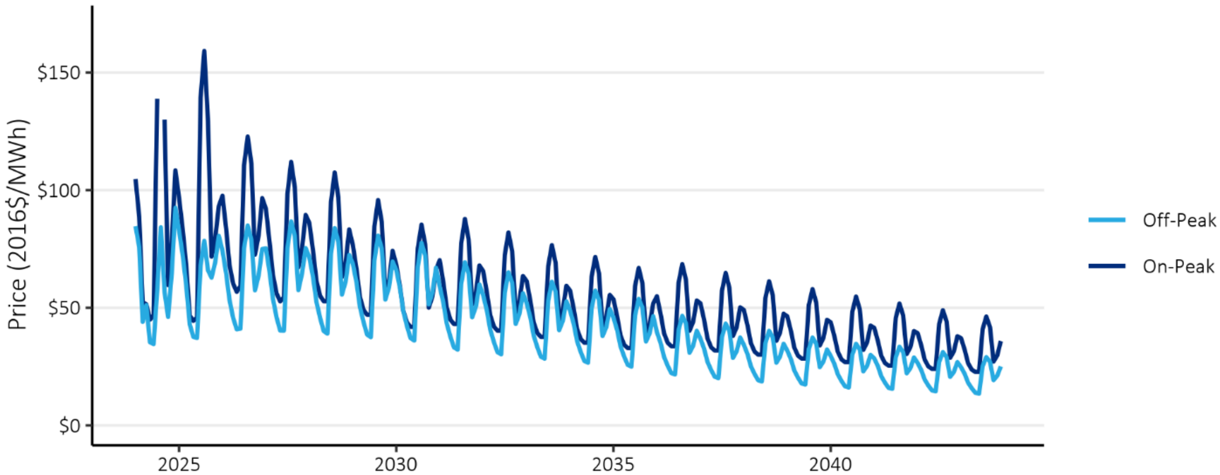
Avoided Energy Costs

Avoided energy costs represent the value of energy savings, either through the value of avoided energy purchases or the opportunity cost of additional sales made possible by reducing customer demands. The EIA requires utilities to "set avoided costs equal to a forecast of market prices."[3] For this CPA, Clark Public Utilities provided a forecast of avoided on- and off-peak energy prices at the Mid-Columbia trading hub from The Energy Authority. Figure 6 below shows the market price forecast that was used for the base

[3] WAC 194-37-070

case scenario of this assessment. Lighthouse also developed high and low variations of this forecast for the avoided cost scenarios, which are discussed later in this report and are discussed in Appendix IV.

Figure 6: Avoided Energy Costs



Social Cost of Carbon

In addition to avoiding purchases of energy, energy efficiency measures have the potential to avoid emissions of greenhouse gases like carbon dioxide. The EIA requires that CPAs include the social cost of carbon, which the U.S. EPA defines as "a measure of the long-term damage done by a ton of carbon dioxide emissions in a given year." It includes, among other things, changes in agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs, including increases in the costs of cooling and decreases in heating costs.[4] In addition to this requirement, Washington's CETA requires that utilities use the social cost of carbon values developed in 2016 by the Federal Interagency Workgroup using a 2.5% discount rate.

To implement the cost of carbon emissions, additional assumptions must be made about the intensity of carbon emissions. This assessment uses an updated forecast of marginal emissions rates developed by the Council in 2022, with modifications to reflect that CETA requires carbon-free energy beginning in 2030.

Renewable Portfolio Standard Compliance Costs

By reducing Clark Public Utilities' overall load, energy efficiency reduces the cost of complying with Washington's requirements for renewable and carbon-neutral energy. Currently, Clark Public Utilities is required to source 15% of its power from renewable energy resources, which it does through the purchase of renewable energy credits (RECs). In 2030, CETA requires all sales to be greenhouse gas neutral, while allowing up to 20% of the requirement to be met through REC purchases. Conservation can reduce the cost of complying with these requirements by reducing Clark Public Utilities' load. Further details are discussed in Appendix IV.

[4] See https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

Deferred Transmission and Distribution System Costs

Unlike supply-side resources, energy efficiency does not require capacity on transmission and distribution infrastructure. Instead, it frees up capacity by reducing the peak demands on these systems and can help defer future capacity expansions and the associated capital costs.

In the development of the 2021 Power Plan, the Council developed a standard methodology for calculating these values and surveyed Northwest utilities to update the values associated with these cost deferrals. This CPA uses the values developed by the Council through that process: $3.54 and $7.82 per kW-year (in 2016 dollars) for transmission and distribution capacity, respectively. These values are slightly higher than the values used in the Clark Public Utilities' 2021 CPA as they reflect small updates to the Council values as the 2021 Power Plan was finalized.

These values are applied to the demand savings coincident with the timing of the respective system peaks.

Program Administration Costs

In each of the past three power plans, the Council has assumed that program administrative costs are equal to 20% of the cost of each measure. This CPA uses that assumption, which is also consistent with Clark Public Utilities' previous CPAs.

Risk Mitigation

Investing in energy efficiency can reduce the risks that utilities face by the fact that it is made in small increments over time, rather than the large, singular sums required for generation resources.

This CPA follows the process used in Clark Public Utilities' previous CPAs. A scenario analysis is used to account for uncertainty, where present, in avoided cost values. The variation in inputs covers a range of possible outcomes and the amount of cost-effective energy efficiency potential is presented under each scenario. In selecting its biennial target from this range of outcomes, Clark Public Utilities is selecting its preferred risk strategy and the associated risk credit. This process is similar to the one used by the Council to identify the risk mitigation credit in the regional power plans.

Northwest Power Act Credit

The EIA requires that utilities give energy efficiency measures a 10% cost credit. This benefit is specified in the Northwest Electric Power Planning and Conservation Act and is included by the Council in their power planning work.

Other Financial Assumptions

In addition, this assessment makes use of an assumed discount rate to convert future costs and benefits to present-year values so that values occurring in different years can be compared. This assessment uses a real discount rate of 3.75%, which is the value developed for the 2021 Power Plan. Energy efficiency benefits accrue over the lifetime of the measure, so a lower discount rate results in higher present values for benefits occurring in future years.

Measure Characterization

Measure characterization is the process of defining each individual measure, including the savings, cost, lifetime, non-energy impacts, and a load or savings shape that defines when the savings occur. The

Council's 2021 Power Plan materials are the primary source for this information, although Lighthouse incorporated updated information from the RTF for many measures.

Measure savings are typically defined by a "last in" approach. With this methodology, each measure's savings is determined as if it was the last measure installed. For example, savings from home weatherization measures are determined based on the assumption that the home's heating system has already been upgraded. Similarly, the heating system measures are quantified based on the assumption that the home has already been weatherized. This approach is conservative but prevents over-counting savings over the long term as homes are likely to install both measures.

Measure savings also consider measure interaction. Interaction occurs when measures in one end use impact the energy use of other end uses. Examples of this include energy efficient lighting and other appliances. The efficiency of these appliances results in less wasted energy released as heat, which impacts the demands on heating and cooling systems.

These measure characteristics, along with the economic assumptions, are used as inputs to the Council's ProCost tool. This tool determines the savings at the generator, after factoring in line losses, as well as the demand savings that occur coincident with Clark Public Utilities' system peak. It also determines the levelized-cost and benefit-cost ratios, the latter of which is used to determine whether measures are cost-effective.

Customer Characteristics

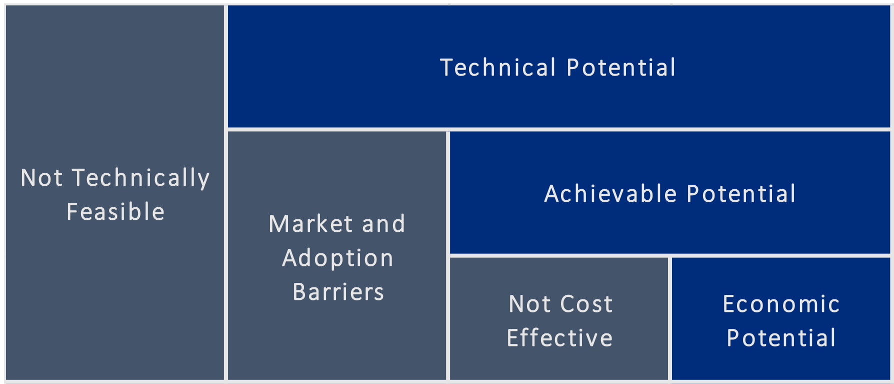
The assessment of customer characteristics is used to determine the number of available measure installation opportunities for each measure. This includes both the number of opportunities overall, as well as the share, or saturation, which have already been completed. The characterization of Clark Public Utilities' customer base was completed using data provided by Clark Public Utilities, NEEA's commercial and residential building stock assessments, U.S. Census data, and other data sources. Details for each sector are described subsequently in this report.

This CPA used baseline measure saturation data from the Council's 2021 Power Plan. This data was developed from NEEA's stock assessments, market research and other studies. This data was supplemented with Clark Public Utilities' conservation achievements, where applicable. This achievement is discussed in the next section.

Energy Efficiency Potential

The energy efficiency measure data and customer characteristics are combined in Lighthouse's CPA model. The model calculates the economic or cost-effective potential by progressing through the types of energy efficiency potential shown in Figure 7. Each is discussed in further detail below.

Figure 7: Types of Energy Efficiency Potential



First, technical potential is the theoretical maximum of energy efficiency available, regardless of cost or market constraints. It is determined by multiplying the measure savings by the number of remaining feasible installation opportunities.

The model then applies several filters that incorporate market and adoption barriers, resulting in the achievable potential. These filters include an assumption about the maximum potential adoption and the pace of annual achievements. Energy efficiency planners generally assume that not all measure opportunities will be installed; some portion of the technically possible measure opportunities will remain unavailable due to unsurmountable barriers. In the Northwest, planners have historically assumed that 85% of all measure opportunities can be achieved. This assumption came from a pilot program conducted in Hood River, Oregon, where home weatherization measures were offered at no cost. The pilot was able to reach over 90% of homes and complete 85% of identified measure opportunities. In the 2021 Power Plan, the Council took a more nuanced approach to this assumption. Measures that are likely to be subject to future codes or product standards have higher maximum achievability assumptions. This CPA follows the Council's new approach.

In addition to the factors that consider the maximum possible achievement, ramp rates are used to identify the portion of the available potential that can be acquired each year. The selection of ramp rates incorporates the different levels of program and market maturity as well as the practical constraints of what utility programs can accomplish each year.

Finally, economic, or cost-effective potential is determined by limiting the achievable potential to those measures that pass an economic screen. Per the EIA, this assessment uses the TRC test to determine economic potential. The TRC evaluates all measure costs and benefits, regardless of who pays the cost or receives the benefit. The costs and benefits include the full incremental capital cost of the measure, any operations and maintenance costs, program administrative costs, avoided energy and carbon costs, deferred capacity costs, and quantifiable non-energy impacts. Because the TRC test considers the full cost of energy efficiency measures, Clark Public Utilities could pay up to the full cost of measures with its incentives without needing to reevaluate the cost-effectiveness of the measure, although practical constraints such as program budgets may limit this.

Recent Conservation Achievement

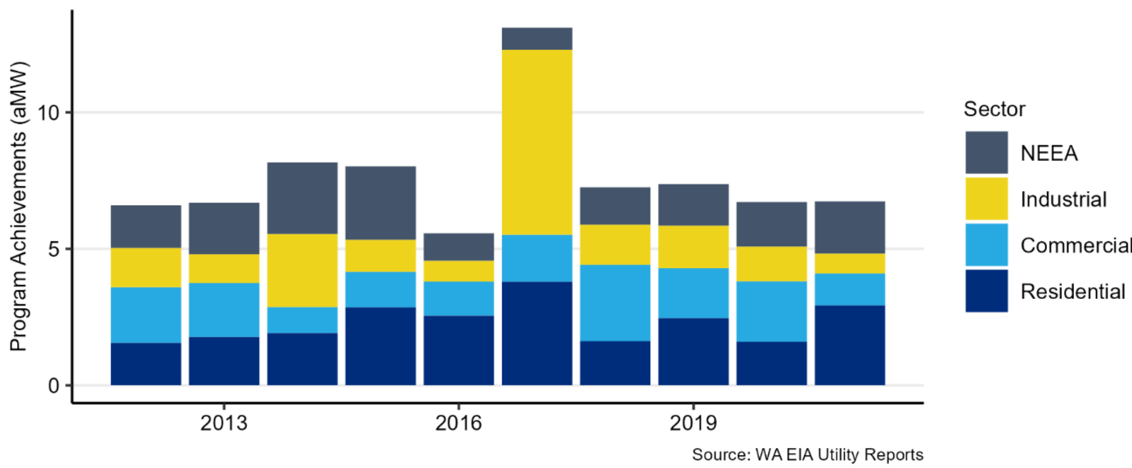
Clark Public Utilities has a long history of energy efficiency achievement and, according to the RTF's 2021 Regional Conservation Progress Report, has averaged savings equal to 1.2% of its retail sales in each year over the 2016-2021 time period, putting it among top saving utilities in the region.

Clark Public Utilities currently offers programs for its residential, commercial, and industrial customers. In addition to these programs, Clark Public Utilities receives credit for the market transformation initiatives of NEEA that occur within its service territory. NEEA's work has helped to bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters, to the Northwest.

Overall

Figure 8 summarizes Clark Public Utilities' conservation achievements from 2012-2021 by sector, as reported under Washington's EIA.

Figure 8: Recent Conservation Achievements by Sector



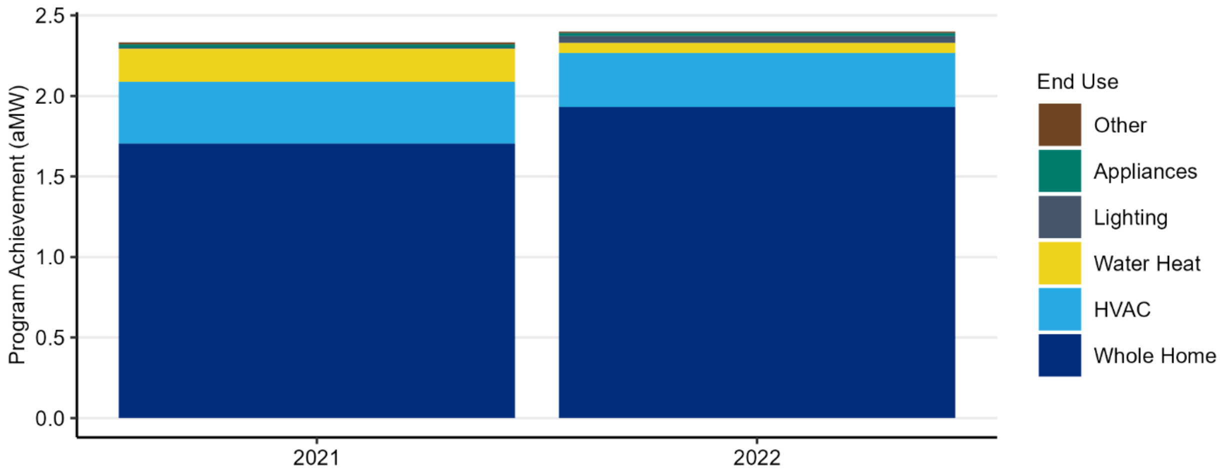
The average savings over this eight-year period is 7.62 aMW per year. Savings from NEEA's market transformation initiatives are primarily in the residential sector, so most of the historical savings are from Clark Public Utilities' residential sector.

Clark Public Utilities provided additional details on Clark Public Utilities' program savings for 2021 and 2022 for each sector, which are discussed below. In addition to counting past achievements against the available potential, these achievements also serve as a reference point for identifying rates of future acquisition.

Residential

The recent residential program achievements by end use are shown in Figure 9. Most of the savings are in the whole home end use, which are primarily savings from Clark Public Utilities' behavior program. Beyond that program, the primary sources of savings come from the HVAC and water heating end uses. Note that the HVAC end use includes both weatherization and heating system equipment. Smaller amounts of savings were achieved in the lighting, appliances, and other end uses. The other end use includes electronics and electric vehicle supply equipment. Residential savings averaged approximately 2.4 aMW per year over this two-year period.

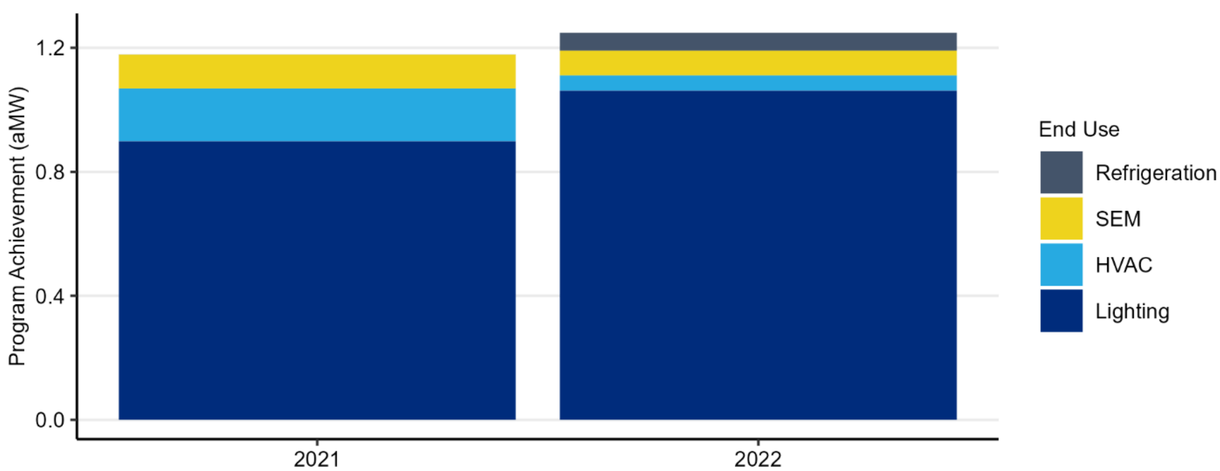
Figure 9: 2021-2022 Residential Program Achievements by End Use



Commercial

The majority of Clark Public Utilities' commercial savings are in the lighting end use, as shown in Figure 10. Smaller amounts of savings come from projects in the HVAC, strategic energy management (SEM), and refrigeration end uses. Commercial savings averaged 1.2 aMW per year over this two-year period.

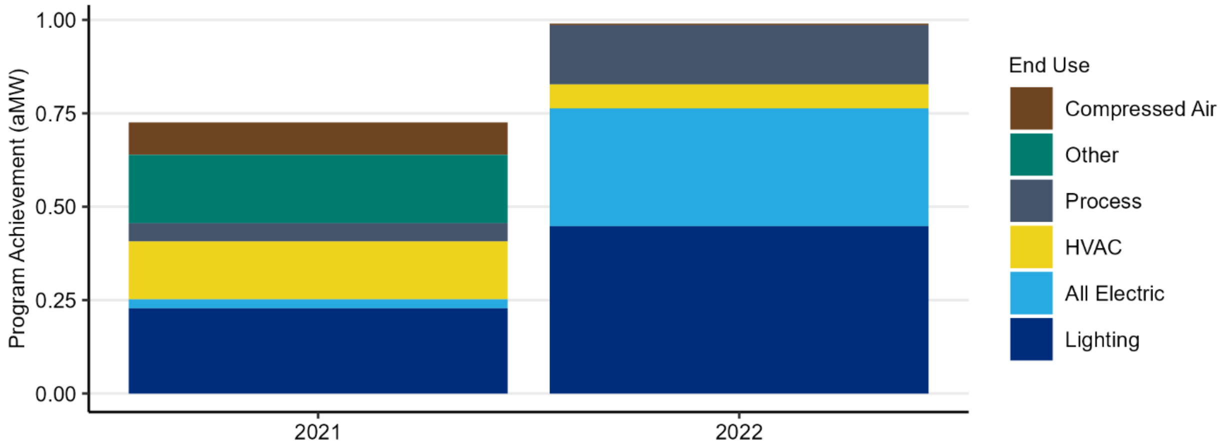
Figure 10: 2021-2022 Commercial Program Achievements by End Use



Industrial

In the industrial sector, lighting savings make up the largest historical source of savings while savings from numerous other end uses contribute additional savings. Savings from the industrial sector are often lumpy, with savings varying from year to year depending on the projects identified and chosen for capital investment by industrial facilities. These savings are summarized in Figure 11 below. Industrial savings averaged just under 0.9 aMW per year over this period.

Figure 11: 2021-2022 Industrial Program Achievements by End Use



Customer Characteristics

This section describes the characterization of Clark Public Utilities' customer base. This process includes defining the makeup and characteristics of each individual sector. Defining the customer base determines the type and quantity of remaining opportunities to implement energy efficiency measures. Information about the local climate and service territory population is used to characterize some measures. This information is summarized in Table 4.

Table 4: Service Territory Characteristics

Heating Zone	Cooling Zone	Total Homes (2022)	Total Population (2022)
1	1	207,817	516,779

The count of homes is based on residential account data provided by Clark Public Utilities and reflects a 5% increase from the 2020 value used in the 2021 CPA. Future residential growth was assumed to be 2.5% per year, based on Clark Public Utilities projections.

Lighthouse also applied a demolition rate based on assumptions for Washington State from the Council's 2021 Power Plan. The demolition rate quantifies the rate at which existing homes are converted to new homes through demolition or major renovation, where codes for new construction apply. The population is based on census data for Clark County.

Residential

Within the residential sector, the key characteristics are the number and type of homes as well as the saturation of end use appliances such as space and water heating equipment. Lighthouse updated the distribution of home types based on American Community Survey (ACS) data. HVAC and other appliance saturation data was based on a combination of data from the ACS and early data from NEEA's 2022 Residential Building Stock Assessment. Table 5 and Table 6 summarize the characteristics that were used for this assessment for existing homes and new homes, respectively.

Table 5: Residential Existing Home Characteristics

	Single Family	Low Rise Multifamily	High Rise Multifamily	Manufactured
Share of Homes	74%	6%	15%	4%
HVAC Equipment				
Electric Forced Air Furnace	6%	0%	0%	55%
Air Source Heat Pump	25%	5%	5%	26%
Ductless Heat Pump	14%	0%	0%	6%
Electric Zonal/Baseboard	9%	91%	91%	3%
Central Air Conditioning	44%	0%	0%	0%
Room Air Conditioning	15%	29%	29%	29%
Other Appliances				
Electric Water Heater	58%	95%	95%	90%
Refrigerator	131%	104%	104%	126%
Freezer	44%	5%	5%	39%
Clothes Washer	96%	35%	35%	94%
Electric Clothes Dryer	83%	29%	29%	94%
Dishwasher	98%	60%	60%	77%
Electric Oven	80%	98%	98%	100%

	Single Family	Low Rise Multifamily	High Rise Multifamily	Manufactured
Desktop	81%	27%	27%	65%
Laptop	87%	29%	29%	29%
Monitor	104%	31%	31%	65%

Table 6: Residential New Home Characteristics

	Single Family	Low Rise Multifamily	High Rise Multifamily	Manufactured
HVAC Equipment				
Electric Forced Air Furnace	6%	0%	0%	55%
Air Source Heat Pump	25%	5%	5%	26%
Ductless Heat Pump	14%	0%	0%	6%
Electric Zonal/Baseboard	9%	91%	91%	3%
Central Air Conditioning	44%	0%	0%	0%
Room Air Conditioning	15%	29%	29%	29%
Other Appliances				
Electric Water Heater	58%	95%	95%	90%
Refrigerator	131%	104%	104%	126%
Freezer	44%	5%	5%	39%
Clothes Washer	96%	35%	35%	94%
Electric Clothes Dryer	83%	29%	29%	94%
Dishwasher	98%	60%	60%	77%
Electric Oven	80%	98%	98%	100%
Desktop	81%	27%	27%	65%
Laptop	87%	29%	29%	29%
Monitor	104%	31%	31%	65%

In the tables above, numbers greater than 100% imply an average of more than one appliance per home. For example, the single-family refrigerator saturation of 131% means that single family homes average approximately 1.3 refrigerators per home.

Commercial

In the commercial sector, building floor area is the primary variable in determining the number of conservation opportunities, as many of the commercial measures are quantified based on the applicable amount of floor area. To estimate the commercial floor area in Clark Public Utilities' service territory, Clark Public Utilities provided 2022 sales by commercial building type. The sales were converted to estimates of floor area by applying energy use intensities (EUIs) from the 2019 CBSA. Based on the updated sales data, the estimated floor area increased by 7% from the 2021 CPA. The commercial floor area was assigned a growth rate of 1.6% based Clark Public Utilities' forecast.

Table 7 summarizes the resulting floor area estimates for each of the 18 commercial building segments.

Table 7: Commercial Floor Area by Segment

Building Type	2022 Floor Area (square feet)
Large Office	6,706,376
Medium Office	6,374,120
Small Office	9,230,160
Extra Large Retail	7,120,887
Large Retail	2,141,653
Medium Retail	3,371,346
Small Retail	5,150,362
School (K-12)	14,771,674
University	1,230,061
Warehouse	3,647,076
Supermarket	1,380,173
Mini Mart	618,871
Restaurant	2,125,828
Lodging	7,274,195
Hospital	2,510,489
Residential Care	954,046
Assembly	11,572,614
Other Commercial	10,691,877
Total	96,871,807

Industrial

The methodology used to estimate potential in the industrial sector is different from the residential and commercial sectors. Instead of building a bottom-up estimate of the savings associated with individual measures, potential in the industrial sector is quantified using a top-down approach that uses the annual energy consumption within individual industrial segments, which is then further disaggregated into end uses. Savings for individual measures are calculated by applying the assumed savings, expressed as a percentage, to the applicable end use consumption within each industrial segment.

To quantify the industrial segment loads, Clark Public Utilities provided 2022 energy consumption data for its industrial customers categorized by industry. The overall industrial consumption totals 1,017,457 MWh, as summarized in Table 8. This represents a 7% increase over the 2021 CPA.

Lighthouse assumed no load growth in the industrial sector, consistent with Clark Public Utilities' forecasts.

Table 8: Industrial Sector Sales by Segment

Segment	2022 Sales (MWh)
Water Supply	48,866
Sewage Treatment	36,591
Other Food	74,482
Wood - Lumber	8,625
Wood - Other	8,858
Pulp and Paper Mills (Kraft)	1,813
Paper Conversion Plants	13,872
Refinery	912
Chemical Manufacturing	125,018
Silicon Growing/Manufacturing	205
Cement/Concrete Products	4,101
Primary Metal Manufacturing	2,848
Fabricated Metal Manufacturing	36,686
Semiconductor Manufacturing	493,183
Transportation Equipment	25,771
Misc. Manufacturing	104,453
Refrigerated Warehouse	7,625
Fruit Storage	8,363
Indoor Agriculture	15,185
Total	**1,017,457**

Utility Distribution System

The 2021 Power Plan used a new approach for quantifying the potential energy savings in measures that improve the efficiency of utility distribution systems. The Council's new approach estimates potential savings based on the 2018 sales within each sector and estimates costs from estimates of the number of distribution substations and feeders for each utility. Table 9 summarizes the assumptions used for this sector.

Table 9: Utility Distribution System Efficiency Assumptions

Characteristic	Count
Distribution Substations*	42
Residential/Commercial Substations*	35
Urban Feeders*	68
Rural Feeders*	29
2018 Residential Sales (MWh)	2,364,873
2018 Commercial Sales (MWh)	1,335,558
2018 Industrial/Other Sales (MWh)	764,602

**Note that these are estimates from the Council and may not reflect Clark Public Utilities' actual system*

Results

This section discusses the results of the 2023 CPA. It begins with a discussion of the high-level achievable and cost-effective conservation potential and then covers the cost-effective potential within individual sectors and end uses.

Achievable Conservation Potential

The achievable conservation potential is the amount of energy efficiency available without considering the cost-effectiveness of measures. It considers market barriers and the practical limits of acquiring energy savings by efficiency programs, but not the cost.

Figure 12 shows the supply curve of achievable potential over the 20-year study period. A supply curve depicts the cumulative potential available against the levelized cost of energy savings, with the measures sorted in order of ascending cost. No economic screening is applied. Levelized costs are used to make the costs comparable between measures with different lifetimes as well as supply-side resources considered in utility integrated resource plans. The costs include credits for deferred transmission and distribution system costs, avoided generation capacity, avoided periodic replacements, and non-energy impacts. With these credits, some of the lowest-cost measures have a net levelized cost that is negative, meaning that the credits exceed the measure costs.

Figure 12: 20-Year Supply Curve

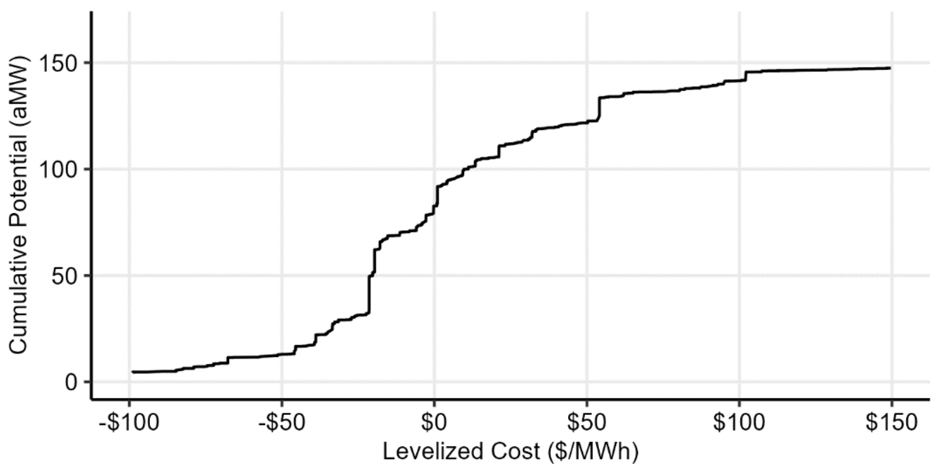


Figure 12 shows that approximately 75 aMW of potential are available at a levelized cost at or below $0/MWh. As discussed above, these are measures where benefits such as the deferral of capacity costs and non-energy benefits exceed the measure costs. Clark Public Utilities could acquire approximately 125 aMW of savings at costs of $50/MWh or below. A total of 169 aMW is available in Clark Public Utilities' service territory over the 20-year period, but only potential below $150/MWh is shown in the supply curve. After a cost just above $50/MWh, the supply curve flattens and any increases in potential come at increasingly higher costs.

Supply curves based on levelized cost are limited in that not all energy savings are equally valued. For example, two measures could have the same levelized cost but provide different reductions in peak demand. An alternative to the supply curve based on levelized cost is one based on the benefit-cost ratio. This is shown below in Figure 13.

Figure 13: 20-Year Benefit-Cost Ratio Supply Curve

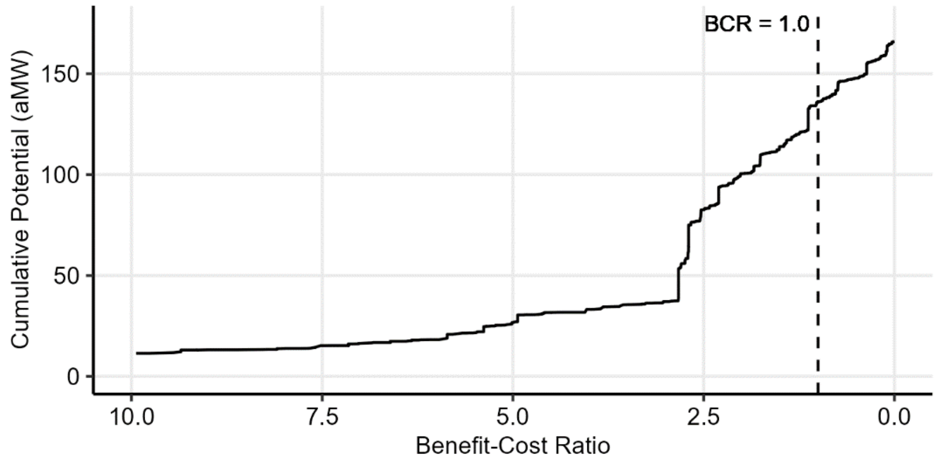


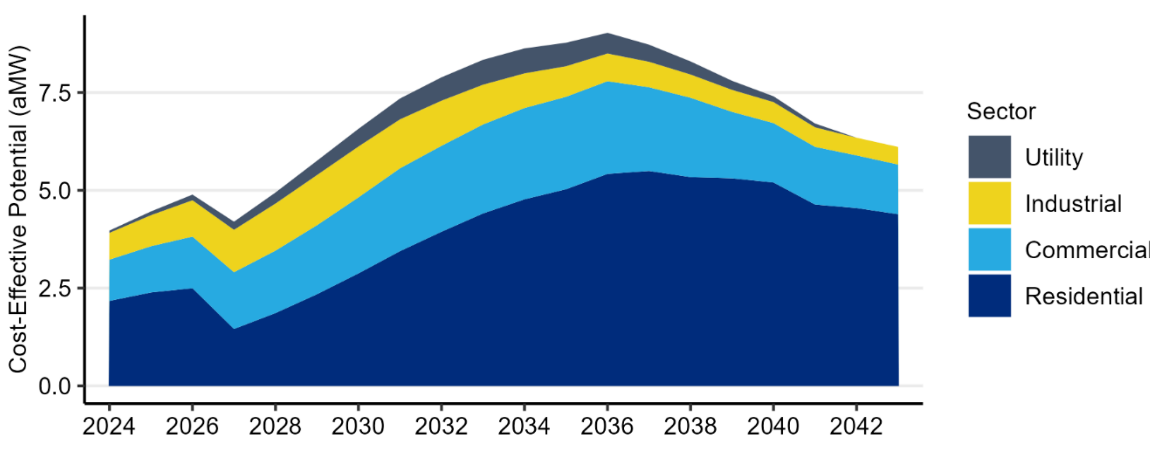
Figure 13 includes a dashed line where the benefit-cost ratio is equal to one. There are 136 aMW of cost-effective savings potential to the left of this line, with benefit-cost ratios greater than one. This is the 20-year cost-effective potential identified earlier in this report. Although there are steps in the line, the slope of the line is fairly consistent from the point where the benefit-cost ratio is equal to 2.5 to 0. This suggests approximately equal sensitivities to higher and lower avoided costs, which would effectively shift the dashed line to the right or left, respectively. However, more than 80% of the achievable potential is already cost-effective, so there is a limited amount of achievable potential that could become cost effective with higher avoided costs.

The economic or cost-effective potential is described further below.

Cost-Effective Conservation Potential

Figure 14 shows the cost-effective potential by sector on an annual basis. Most of the potential is in Clark Public Utilities' residential sector, followed by the commercial and industrial sectors, with smaller amounts available in the utility sector.

Figure 14: Annual Cost-Effective Potential by Sector



Lighthouse used the ramp rates from the 2021 Power Plan were used to establish reasonable rates of acquisition for all sectors. This included making modifications to the assigned ramp rates for some measures to align the near-term potential with recent and expected savings in each sector. Appendix VII has more detail on the alignment of ramp rates with program expectations.

Sector Summary

The sections below describe the cost-effective potential within each sector.

Residential

Relative to the 2021 CPA, the cost-effective potential in the residential sector has increased moderately in the near term, with more significant increases in the long-term.

Figure 15 shows the cost-effective potential by end use for the first 10 years of the study period. There is a large chunk of savings from Clark Public Utilities' behavior program expected in the near term, which are part of the "whole home" end use. Lighthouse only included savings from this program through 2026. Beyond these savings, measures in the HVAC (which includes both equipment and weatherization) and water heating end uses make up the largest share of residential potential in the initial 10 years. Savings in the other end use includes savings from the cooking and lighting end uses.

The savings potential grows during the initial 10 years of the study as the expected market share of efficient equipment and adoption of other energy efficiency measures increases.

Figure 15: Annual Residential Potential by End Use

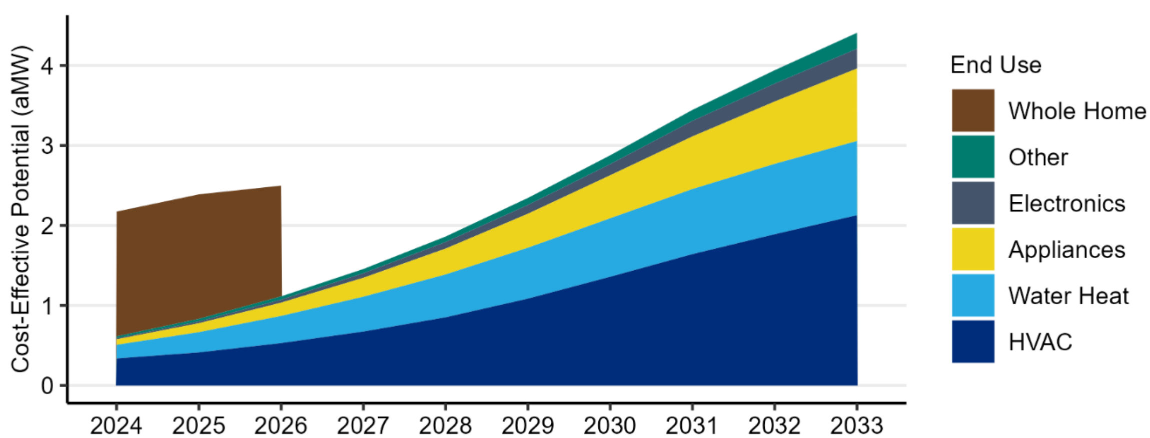
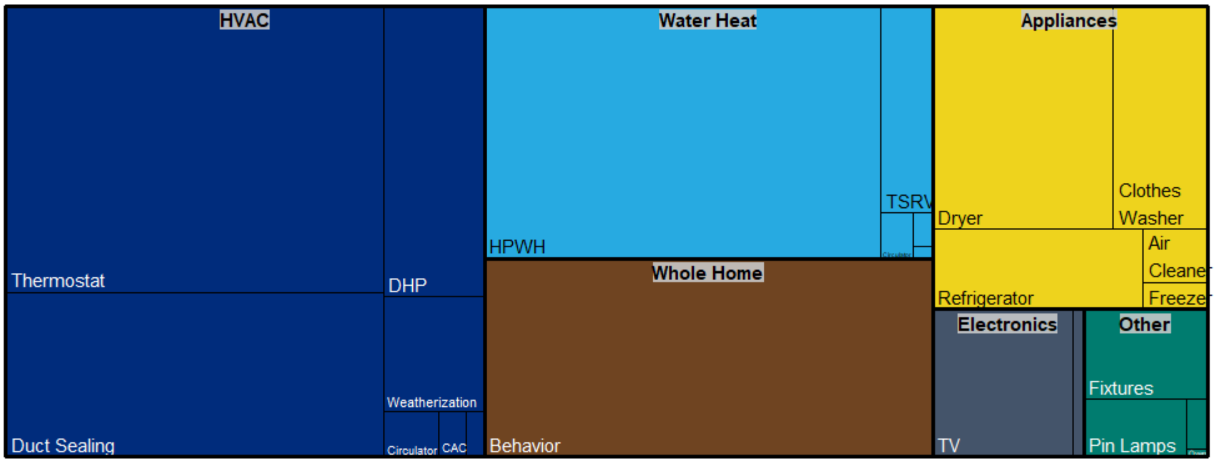


Figure 16 shows how the 10-year potential breaks down into end uses and measure categories. The area of each block represents its share of the total 10-year residential potential. Smart thermostats, ductless heat pumps, and duct sealing make up most of the potential in the HVAC end use, while heat pump water heaters (HPWH) and thermostatic restriction valves (TSRV) are the key measures within the water heating end use. The potential from some weatherization measures as well as most air source heat pump measures did not pass the cost-effectiveness screening in this CPA, even with the higher avoided costs and updated capacity values.

Figure 16: Residential Potential by End Use and Measure Category

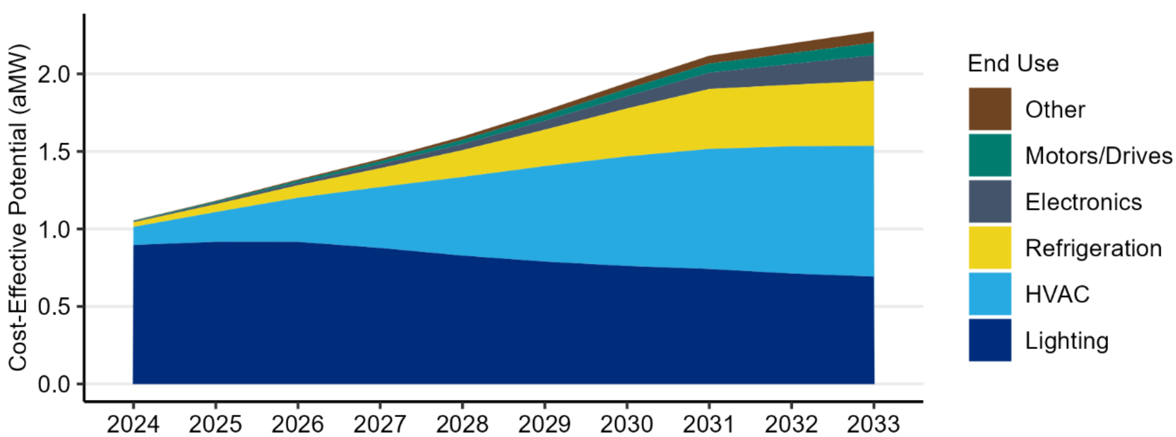


Note that some residential measures, such as smart thermostats and heat pump water heaters, can provide benefits as both energy efficiency and demand response resources. Any demand response benefits were not included in this CPA, although energy efficiency programs can help build a stock of equipment that could be called upon by demand response programs. Lighthouse assessed the demand response potential of these measures in Clark Public Utilities' *2023 Demand Response Potential Assessment*.

Commercial

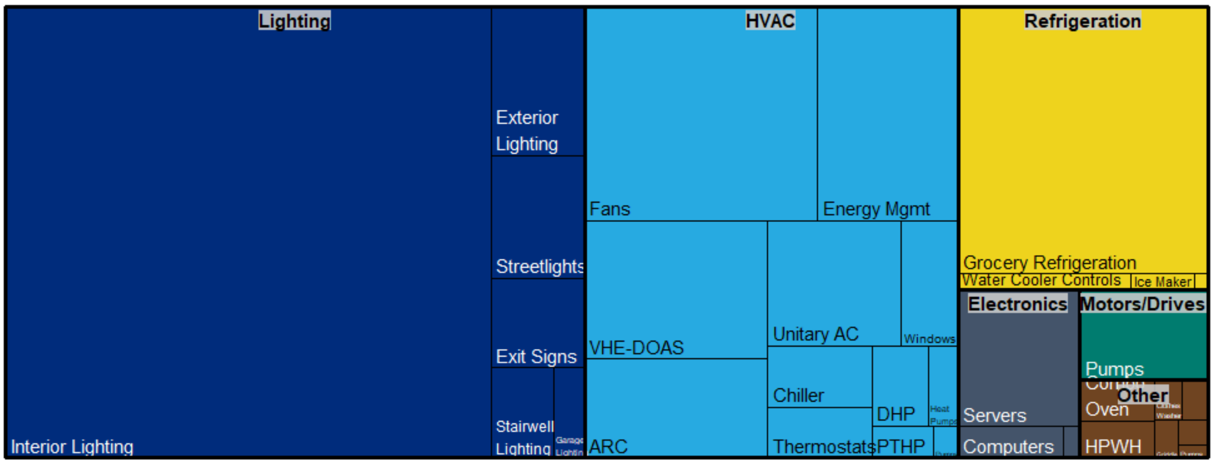
In the commercial sector, lighting, HVAC, and refrigeration measures are the end uses with the highest potential. The potential in the lighting end use declines over time, a reflection of the limited lighting potential remaining after being mainstay of commercial programs for many years. In contrast, the potential in the HVAC and refrigeration end uses grows, showing opportunities for program growth in these areas. In Figure 17, the other category includes measures in the compressed air, food preparation, and water heating end uses.

Figure 17: Annual Commercial Potential by End Use



The key end uses and measure categories within the commercial sector are shown in Figure 18. The area of each block is proportional to its share of the 10-year commercial potential. The potential in the lighting end use includes measures applicable to both interior and exterior lighting as well as other lighting applications. In the HVAC end use, the potential is distributed across a range of equipment types, which reflects the range of building sizes and HVAC equipment types used across the sector.

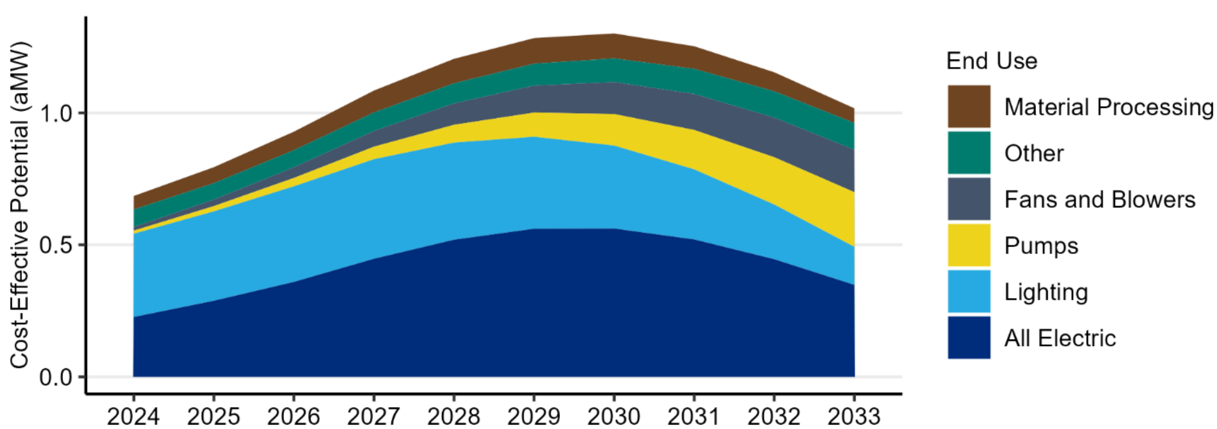
Figure 18: Commercial Potential by End Use and Measure Category



Industrial

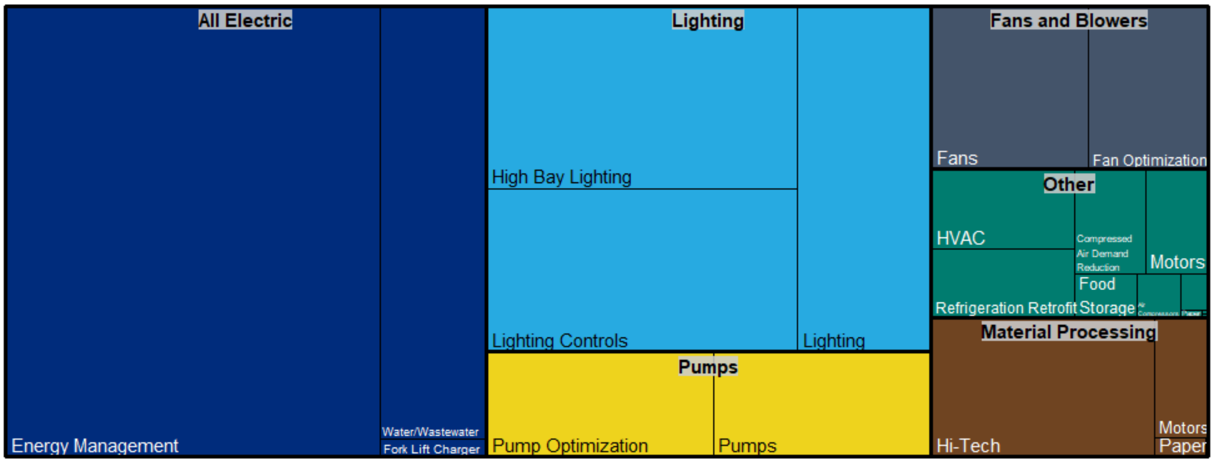
The annual industrial sector potential is shown in Figure 19. The all electric and lighting end uses have the most potential, although, like the commercial sector, the available lighting potential decreases over time. The all electric end use includes measures applicable to all end uses, such as strategic energy management programs. Smaller amounts of potential are available through measures in the pumps, fans and blowers, and material processing end uses. The other category in Figure 19 includes a variety of end uses, including material handling, HVAC, refrigeration, compressed air, and several other small end uses.

Figure 19: Annual Industrial Potential by End Use



The breakdown of 10-year industrial potential into end uses and measure categories is shown in Figure 20.

Figure 20: Industrial Potential by End Use and Measure Category

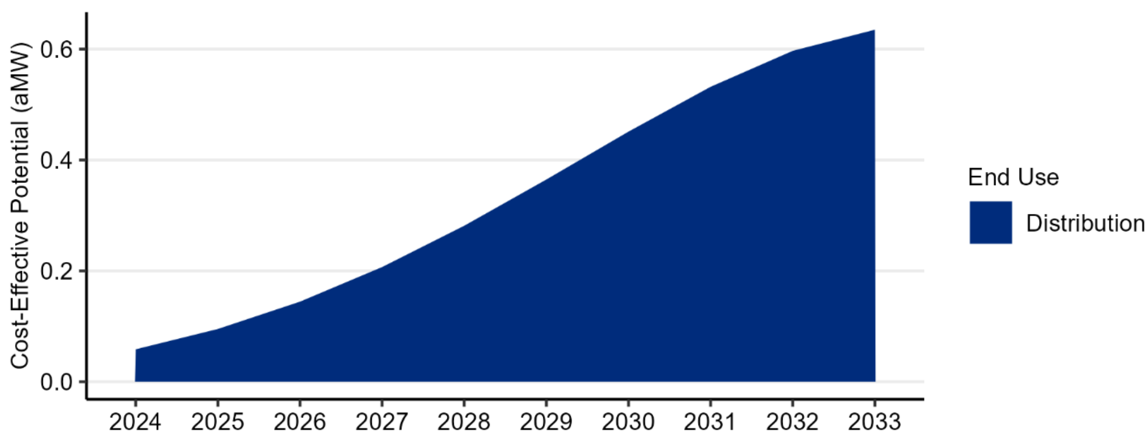


Utility

Measures in the utility sector involve the regulation of voltage to improve the efficiency of the distribution system. This CPA includes the measures characterized for the 2021 Power Plan, which are based on Clark Public Utilities' load and estimates of the number of distribution substations and feeders.

The annual distribution system potential is shown in Figure 21. The Council characterized three measures in the draft 2021 Power Plan, which use increasingly sophisticated control systems. Note that the scale for this figure has changed relative to the figures above, as the potential in this sector is much smaller than those sectors.

Figure 21: Annual Distribution System Potential



Savings Shape

This section provides further details on the shape of the cost-effective potential identified in this CPA, including breakdowns of energy savings by on- and off-peak periods and month, as well as further detail on the peak demand savings.

Methodology

Each of the measures included in this CPA have one or more savings components. While most measures have just a single savings component, numerous measures have more than one. Efficient heat pumps, for example, can provide both heating and cooling savings, each of which are quantified as a separate savings component. Water-saving measures often have two distinct savings components: the reduction of water heating loads in homes and buildings, and the reduced loads at wastewater treatment plants through the reduction of wastewater influent. Each measure savings component was assigned a load profile and a ratio that allocated the total measure savings to each savings component. These ratios and load profiles were applied to the annual potential results, enabling the calculation of more detailed breakdowns in the savings potential. Lighthouse used the load shapes that were developed by the Council for the 2021 Power Plan for this analysis.

Results

Figure 22 shows the shape of the monthly savings for on- and off-peak energy savings. Like the annual results discussed above, most of the savings in each period are in the residential sector. This sector also contributes a larger share of its savings during the winter months, while the savings from other sectors are more consistent across the months of the year.

Figure 22: On- and Off-Peak Savings by Month and Sector

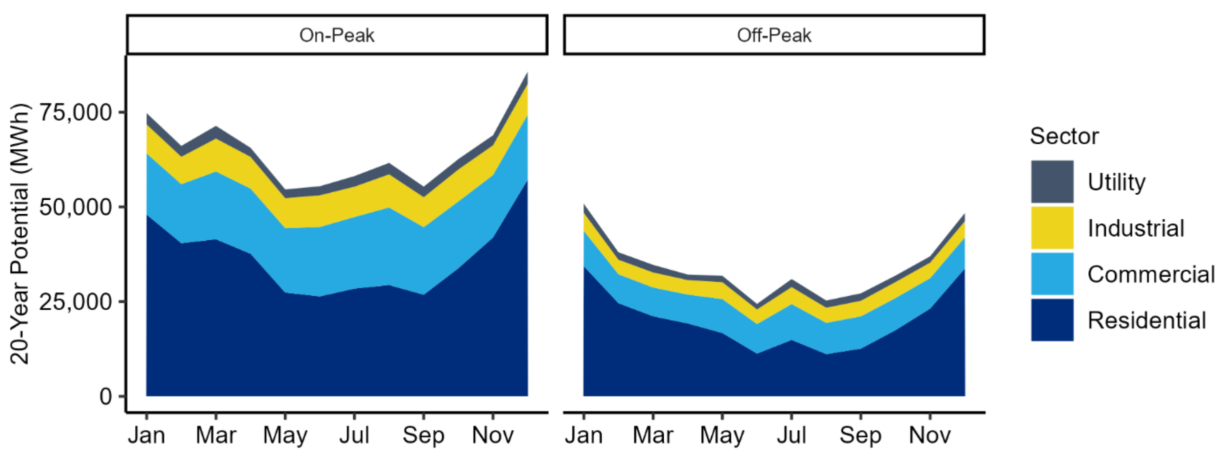


Figure 23 shows a similar breakdown as above, only by end use instead of sector. While each of the end use categories contributes more on-peak savings, the HVAC end use is a primary contributor to on-peak savings in the winter months while the savings from other end uses are more evenly spread across the year.

Figure 23: On- and Off-Peak Savings by Month and End Use

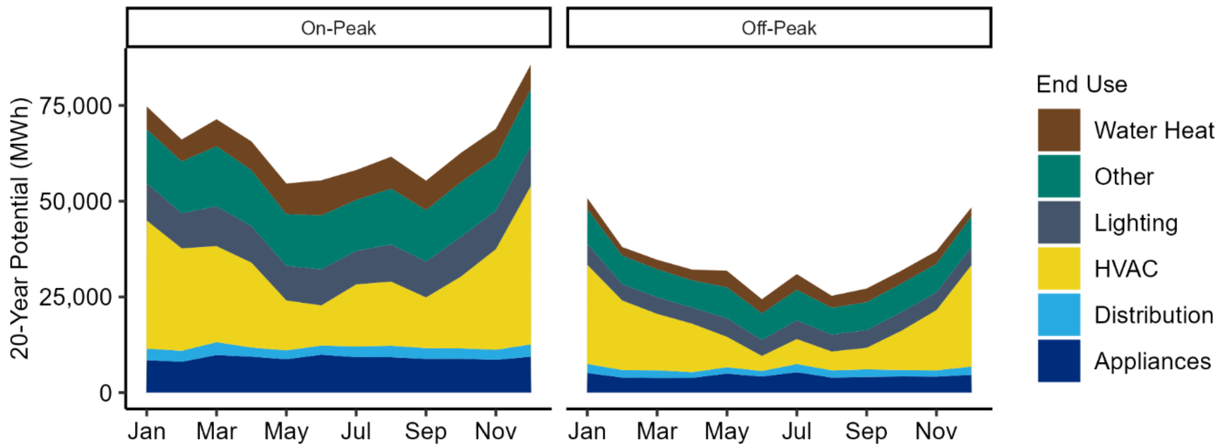


Figure 24 and Figure 25 show the monthly peak demand savings by sector and end use, respectively. Like above, the residential sector and HVAC end use contribute the most to reductions in peak demand. For this breakdown, Lighthouse assumed morning peaks in the winter and shoulder season months with evening peaks in the summer.

Figure 24: Monthly Peak Savings by Sector

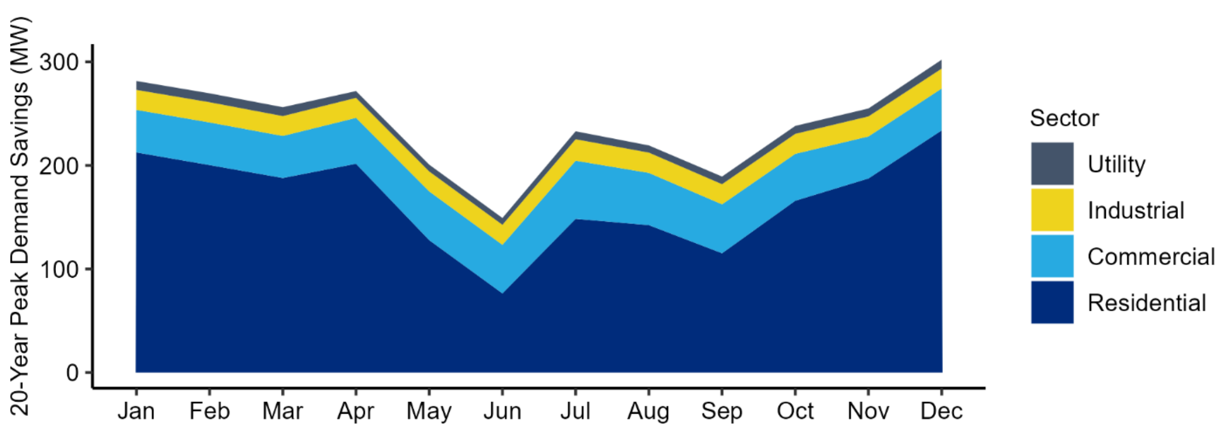


Figure 25: Monthly Peak Savings by End Use

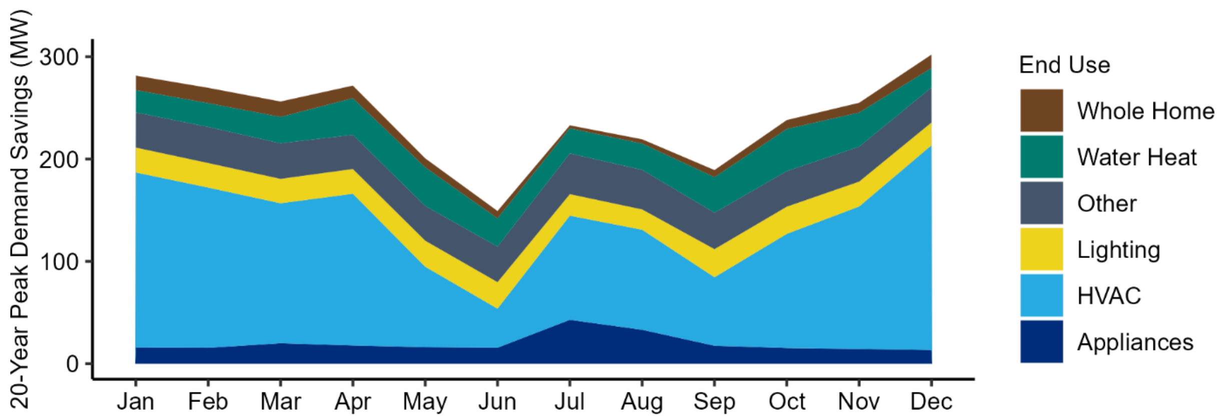
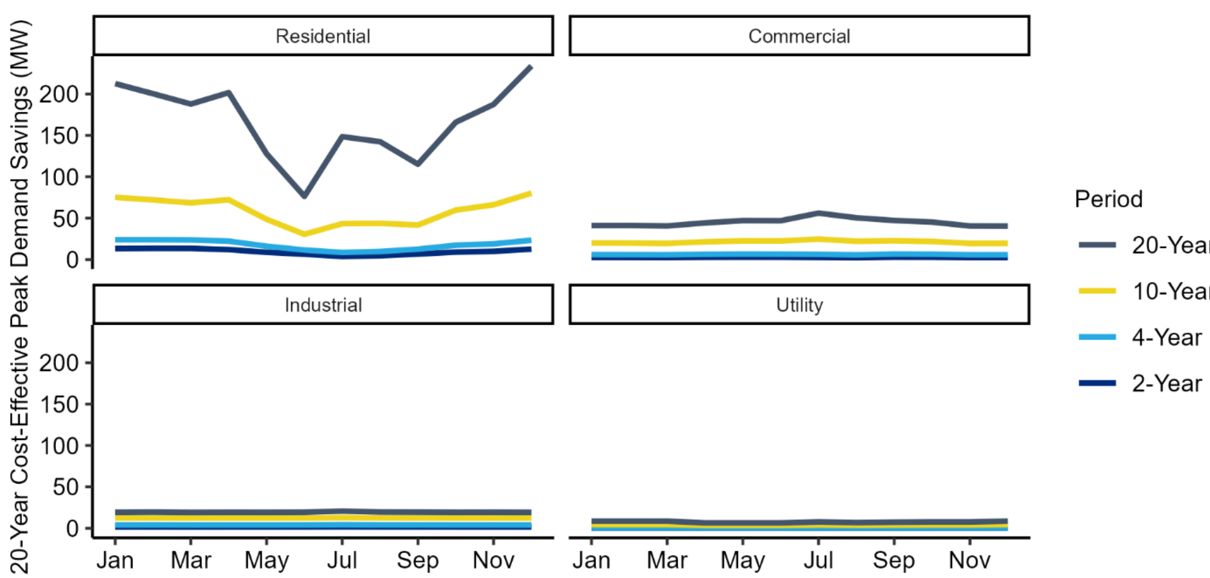


Figure 26 shows the monthly peak demand savings by sector, month, and time period. Like the figures above, the residential sector shows the highest levels of peak demand savings, but the month-to-month shape of the residential begins fairly flat but takes on a more seasonal profile over time, including a more pronounced increase in summer peak demand savings. This highlights the fact that much of the peak demand savings in the residential sector are in measures that were given slower ramp rates and are projected to be acquired more slowly. In the commercial sector, the savings take on a slightly more summer-oriented savings shape over time.

Figure 26: Monthly Peak Demand Savings by Sector, Month, and Time Period



Scenario Results

This section discusses the results of two additional scenarios that were considered in addition to the base case scenario covered in the previous section. These scenarios feature low and high variations in the avoided costs values, covering a range of possible outcomes to reflect uncertainty in future values. These scenarios allow Clark Public Utilities to understand the sensitivity of the cost-effective potential to variations in avoided cost. All other inputs were held constant.

Table 10 summarizes the avoided cost assumptions used in each scenario, which are discussed further in Appendix IV.

Table 10: Avoided Cost Assumptions by Scenario

		Low Scenario	Base Scenario	High Scenario
Energy Values	Avoided Energy Costs (20-Year Levelized Price, 2016$)	Market Forecast minus 20%-80% ($27/MWh)	Market Forecast ($52/MWh)	Market Forecast plus 20%-80% ($77/MWh)
	Social Cost CO_2	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values
	RPS Compliance	WA EIA & CETA Requirements	WA EIA & CETA Requirements	WA EIA & CETA Requirements
Capacity Values	Distribution Capacity (2016$)	$7.82/kW-year	$7.82/kW-year	$7.82/kW-year
	Transmission Capacity (2016$)	$3.54/kW-year	$3.54/kW-year	$3.54/kW-year
	Generation Capacity (2016$) Winter Summer	$57/kW-year $49/kW-year	$69/kW-year $59/kW-year	$84/kW-year $72/kW-year
	Implied Risk Adder (2016$)	-$25/MWh -$10-12/kW-year	N/A	25$/MWh $13-15/kW-year
	NW Power Act Credit	10%	10%	10%

Instead of using a single risk adder applied to each unit of energy, the two alternate scenarios consider potential futures with higher and lower values for the avoided cost inputs where some degree of uncertainty exists, including variations in the value of both energy and capacity. The implied risk adder is calculated for the low and high scenarios by totaling the differences in both energy and capacity-based values relative to the base scenario. Further discussion of these values is provided in Appendix IV.

Table 11 summarizes the cost-effective potential across each avoided cost scenario. As discussed above, the results show roughly equal sensitivities to both higher and lower avoided cost scenarios over all but the 20-year timeframe.

Table 11: Cost Effective Potential (aMW) by Avoided Cost Scenario

Scenario	2-Year	4-Year	10-Year	20-Year
Low Scenario	7.92	16.30	53.26	117.11
Base Case	8.43	17.52	58.36	136.15
High Scenario	9.82	19.52	61.77	141.38

Overall, energy efficiency remains a low-risk resource for Clark Public Utilities since it is purchased in small increments over time, making it unlikely that the significant amounts of the resource be acquired that were over-valued.

Summary

This report has summarized the results of the 2023 CPA conducted for Clark Public Utilities. The assessment provided estimates of the cost-effective energy savings potential for the 20-year period beginning in 2024, with details on the first ten years per the requirements of Washington State's EIA. The assessment considered a wide range of measures that are reliable and available during the study period.

Compared to Clark Public Utilities' 2021 CPA, the potential has decreased slightly in the near term but increased over the mid- and long-term. Near term savings were aligned with recent program achievements, which decreased in the commercial and industrial sectors.

In the mid to longer term, this assessment found significantly higher amounts of cost-effective potential. This additional potential was driven by higher energy and capacity values in the avoided costs as well as higher projections of customer counts and loads.

Compliance with State Requirements

The methodology used to estimate the cost-effective energy efficiency potential described in this report is consistent with the methodology used by the Council in determining the potential and cost-effectiveness of conservation resources in the 2021 Power Plan. Appendix III provides a list of Washington's EIA requirements and a description of how each was implemented. In addition to using a methodology consistent with the Council's 2021 Power Plan, the assessment used assumptions from the 2021 Power Plan where utility-specific inputs were not used. Utility-specific inputs covering customer characteristics, previous conservation achievements, and economic inputs were used. The assessment included the measures considered in the 2021 Power Plan materials, with additional RTF updates since its publication.

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Appendix I: Acronyms

aMW	Average Megawatt
BPA	Bonneville Power Administration
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CPA	Conservation Potential Assessment
EIA	Energy Independence Act
EUI	Energy Use Intensity
HPWH	Heat Pump Water Heater
HVAC	Heating, Ventilation, and Air Conditioning
IRP	Integrated Resource Plan
kW	kilowatt
kWh	kilowatt-hour
LED	Light-Emitting Diode
MW	Megawatt
MWh	Megawatt-hour
NEEA	Northwest Energy Efficiency Alliance
O&M	Operations and Maintenance
RPS	Renewable Portfolio Standard
RTF	Regional Technical Forum
SEM	Strategic Energy Management
TRC	Total Resource Cost

Appendix II: Glossary

Achievable Technical Potential	Conservation potential that includes considerations of market barriers and programmatic constraints, but not cost effectiveness. This is a subset of technical potential.
Average Megawatt (aMW)	An average hourly usage of electricity, measured in megawatts, across the hours of a day, month, or year.
Avoided Cost	The costs avoided through the acquisition of energy efficiency.
Cost Effective	A measure is described as cost effective when the present value of its benefits exceeds the present value of its costs.
Economic Potential	Conservation potential that passes a cost-effectiveness test. This is a subset of achievable potential. Per the EIA, a Total Resource Cost (TRC) test is used.
Levelized Cost	A measure of costs when they are spread over the life of the measure, like a car payment. Levelized costs enable the comparison of resources with different useful lifetimes.
Megawatt (MW)	A unity of demand equal to 1,000 kilowatts (kW).
Renewable Portfolio Standard	A requirement that a certain percentage of a utility's portfolio come from renewable resources. In 2020, Washington utilities with more than 25,000 customers are required to source 15% of their energy from renewable resources.
Technical Potential	The set of possible conservation savings that includes all possible measures, regardless of market or cost barriers.
Total Resource Cost (TRC) Test	A test for cost-effectiveness that considers all costs and benefits, regardless of who they accrue to. A measure passes this test if the present value of all benefits exceeds the present value of all costs. The TRC test is required by Washington's Energy Independence Act and is the predominant cost effectiveness test used throughout the Northwest and U.S.

Appendix III: Compliance with State Requirements

This Appendix details the specific requirements for Conservation Potential Assessments listed in WAC 194-37-080. The table below lists the specific section and corresponding requirement along with a description of how the requirement is implemented in the model and where the implementation can be found.

Table 12: CPA Compliance with EIA Requirements

WAC 194-37-080 Section	Requirement	Implementation
(5)(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 calculates technical potential by multiplying the quantity of stock (number of homes, building floor area, industrial load) by the number of measures that could be installed per each unit of stock. The model further constrains the potential by the share of measures that have already been completed. See calculations in the "Units" tabs within each of the sector model files.
(5)(b)	**Achievable technical 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 model applies maximum achievability factors based on the Council's 2021 Power Plan assumptions and ramp rates to identify how the potential can be acquired over the 20-year study period. See calculations in the "Units" tabs within each of the sector model files. The complete set of the ramp rates used is on the "Ramp Rates" tab.
(5)(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.	Lighthouse used the Council's ProCost model to calculate TRC benefit-cost ratios for each measure after updating ProCost with utility-specific inputs. The ProCost results are collected through an Excel macro in the "ProCost Measure Results-(scenario).xlsx" files and brought into the CPA models through Excel's Power Query. See Appendix IV for further discussion of the avoided cost assumptions.
(5)(d)	**Total resource cost**. In determining economic achievable potential as provided in (c) of this subsection, perform a life-cycle cost analysis of measures or programs to determine the net levelized cost, as described in this subsection.	A life-cycle cost analysis was performed using the Council's ProCost tool, which Lighthouse configured with utility-specific inputs. Costs and benefits were included consistent with the TRC test. The measure files within each sector folder are used to calculate the ProCost results. These

WAC 194-37-080 Section	Requirement	Implementation
		results are then rolled up into the ProCost Measure Results files, which are linked to each sector model file through Excel's Power Query functionality.
(5)(d)(i)	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.	The costs considered in the economic analysis included measure capital costs, O&M costs, periodic replacement costs, and any non-energy costs. Benefits included avoided energy, T&D capacity costs, avoided generation capacity costs, non-energy benefits, O&M savings, and periodic replacement costs. Measure costs and benefits can be found in the individual measure files as well as the "ProCost Measure Results" files.
(5)(d)(ii)	Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes.	Assumed savings, cost, and measure lifetimes are based on 2021 Power Plan and subsequent RTF updates, where applicable. Measure costs and benefits can be found in the individual measure files as well as the "ProCost Measure Results" files.
(5)(d)(iii)	Calculate the value of the 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.	Lighthouse used a 20-year forecast of monthly on- and off-peak market prices and the load shapes developed for the 2021 Power Plan as part of the economic analysis conducted in ProCost. The "MC and Loadshape" file contains both the market price forecast as well as the library of load shapes. Individual measure files contain the load shape assignments.
(5)(d)(iv)	Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures.	Measure analyses include changes to O&M costs as well as periodic replacement costs, where applicable. These assumptions are based on the 2021 Power Plan and/or RTF. Measure assumptions can be found in the individual measure files.
(5)(d)(v)	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	Clark Public Utilities provided a forecast of on- and off-peak market prices at the mid-Columbia trading hub, which Lighthouse extrapolated to cover the 20-year period evaluated by this CPA. Further discussion of this forecast can be found

WAC 194-37-080 Section	Requirement	Implementation
	efficiency measures to which it is compared.	in Appendix IV. See the "MC and Loadshape" file for the market prices. These prices include the value of avoided REC purchases as applicable.
(5)(d)(vi)	Include deferred capacity expansion benefits for transmission and distribution systems.	Deferred transmission and distribution system benefits are based on the values developed by the Council for the 2021 Power Plan. These values can be found on the "ProData" tab of the ProCost files, cells C50 and C54.
(5)(d)(vii)	Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure.	Deferred generation capacity expansion benefits are based on BPA's monthly demand charges scaled to reflect a price differential between winter and summer months that Clark Public Utilities was finding for call options. The development of these values is discussed in Appendix IV. These values can be found on the "ProData" tab of the ProCost files, cells C60.
(5)(d)(viii)	Include the social cost of carbon emissions from avoided non-conservation resources.	This assessment uses the social cost of carbon values determined in 2016 by the federal Interagency Workgroup using a 2.5% discount rate, as required by the Clean Energy Transformation Act. The emissions intensity of energy savings is based on a Council analysis of the regional marginal emissions intensity updated subsequent to the 2021 Power Plan. Beginning in 2030, an emissions intensity of 0 lbs./kWh is assumed based on the CETA requirements for GHG neutral energy. The carbon costs and emissions intensities can be found in the MC and Loadshape file.
(5)(d)(ix)	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.	This analysis uses a scenario analysis to consider risk. Avoided cost values with uncertain future values were varied across three different scenarios and the resulting sensitivity and risk were analyzed. The Scenario Results section of this report discusses the inputs used and the implicit risk

WAC 194-37-080 Section	Requirement	Implementation
		adders used in the analysis.
(5)(d)(x)	Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized.	All quantifiable non-energy benefits were included where appropriate, based on values from the Council's 2021 Power Plan materials and RTF. Measure assumptions can be found in the individual measure files.
(5)(d)(xi)	Include an estimate of program administrative costs.	This assessment uses the Council's assumption of administrative costs equal to 20% of measure capital costs. Program admin costs can be found in the "ProData" tab of the ProCost files, cell C29.
(5)(d)(xii)	Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure.	This assessment utilizes the financing cost assumptions from the 2021 Power Plan materials, including the sector-specific cost shares and cost of capital assumptions. Financing assumptions can be found in the ProData tab of the ProCost files, cells C37:F46.
(5)(d)(xiii)	Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating non-conservation resources.	This assessment uses a real discount rate of 3.75% to determine the present value of all costs and benefits. This is the value developed for the 2021 Power Plan. The discount rate used in this analysis can be found in the ProCost files, on cell C27 of the ProData tab.
(5)(d)(xiv)	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 is applied consistent with the Northwest Power Act. The 10% credit used in the measure analyses can be found in the ProCost files, on cell C29 of the ProData tab.

Appendix IV: Avoided Costs

The methodology used to conduct conservation potential assessments for electric utilities in the state of Washington is dictated by the requirements of the Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA). Specifically, WAC 194-37-070 requires utilities to determine the economic, or cost-effective, potential by "comparing the total resource cost of conservation measures to the total cost of other resources available to meet expected demand for electricity and capacity."[5] This CPA will determine the cost-effectiveness of conservation measures through a benefit-cost ratio approach, which uses avoided costs to represent the costs avoided by acquiring efficiency instead of other resources. The EIA specifies that these avoided costs include the following components:

- Time-differentiated energy costs equal to a forecast of regional market prices
- Deferred capacity expansion costs for the transmission and distribution system
- Deferred generation capacity costs consistent with each measure's contribution to system peak capacity savings
- The social cost of carbon emissions from avoided non-conservation resources
- A risk mitigation credit to reflect the additional value of conservation not accounted for in other inputs
- A 10% bonus for energy and capacity benefits of conservation measures, as defined by the Pacific Northwest Electric Power Planning and Conservation Act

In addition to these requirements, Washington's CETA requires specific values be used for the social cost of carbon. [6] Lighthouse has also included the value of avoided renewable portfolio standard compliance costs in the avoided costs.

Each of these inputs is covered in detail in the following sections.

Avoided Energy Costs

Avoided energy costs are the energy costs avoided by Clark Public Utilities through the acquisition of energy efficiency instead of supply-side resources. For every megawatt-hour of conservation achieved, Clark Public Utilities can either avoid the purchase or sell one additional megawatt-hour of energy.

For this CPA, Clark Public Utilities provided a forecast of avoided on- and off-peak energy prices at the Mid-Columbia trading hub from The Energy Authority (TEA). The forecast was provided on April 25, 2023, and includes prices by month for a seven-year period (2024-2030).

To benchmark this forecast, Lighthouse compared the TEA forecast to prices published by the CME Group[7] that were pulled on April 7, 2023. The comparisons of on- and off-peak prices are shown in Figure 27 and Figure 28 below. While the prices available from the CME Group cover a more limited timeframe, the prices are nearly identical.

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[5] WAC 194-37-070. Accessed January 20, 2021. https://app.leg.wa.gov/wac/default.aspx?cite=194-37-070

[6] WAC 194-40-100. Accessed March 7, 2023. https://app.leg.wa.gov/WAC/default.aspx?cite=194-40-100

[7] See https://www.cmegroup.com/trading/energy/electricity/mid-columbia-day-ahead-peak-calendar-month-5-mw-futures.html and https://www.cmegroup.com/trading/energy/electricity/mid-columbia-day-ahead-off-peak-calendar-month-5-mw-futures.html

Figure 27: Comparison of On-Peak Prices

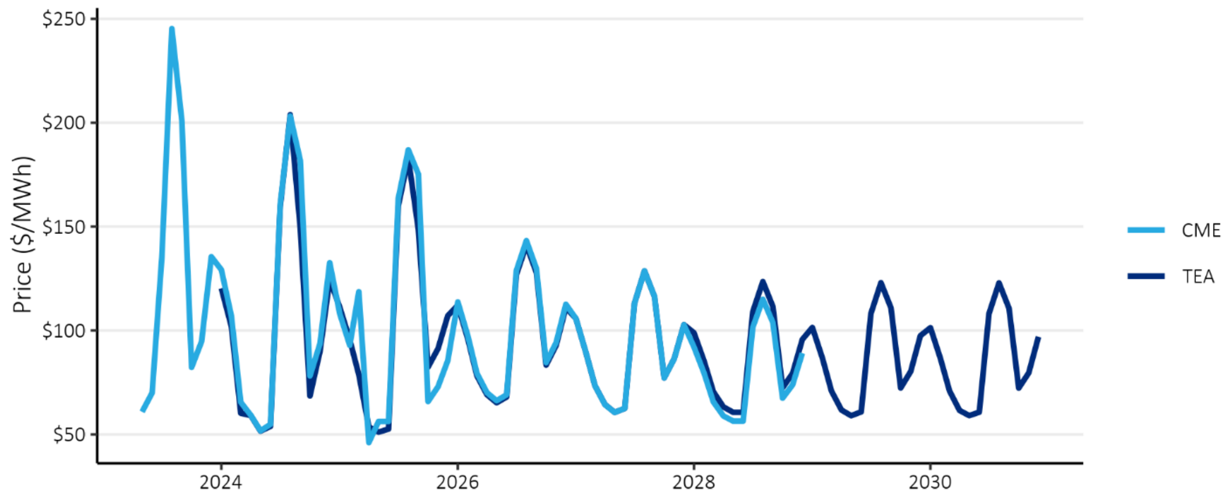
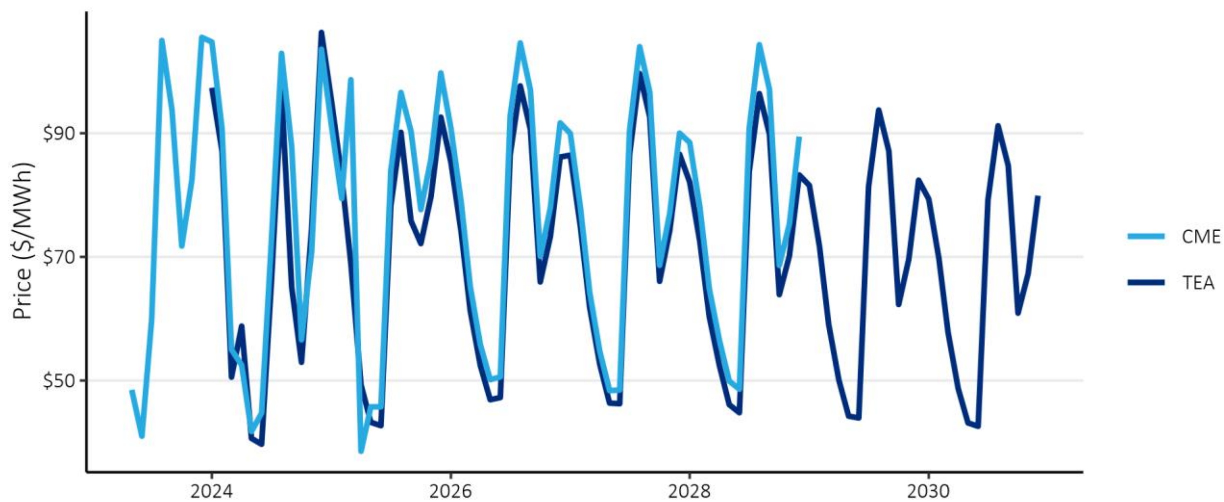


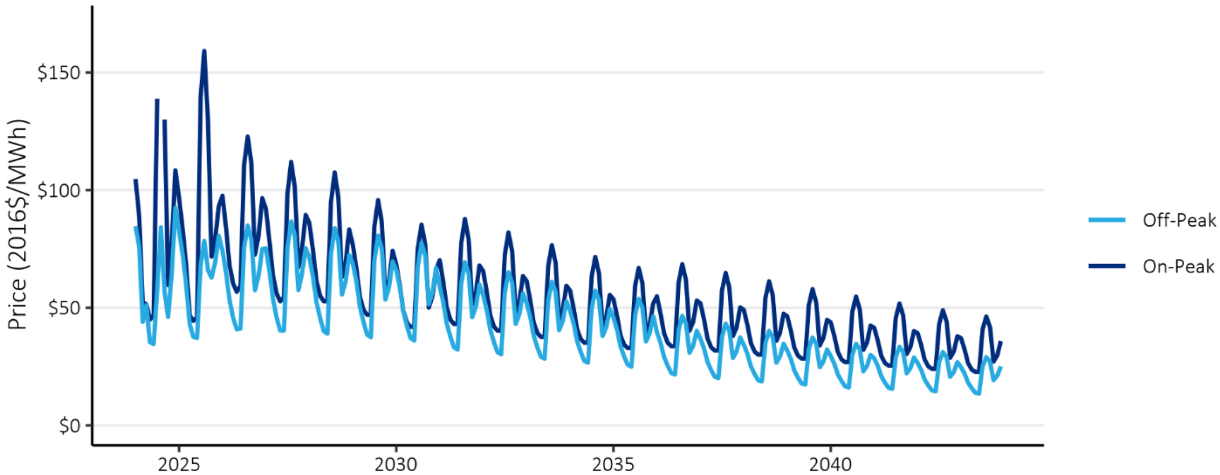
Figure 28: Comparison of Off-Peak Prices



To develop a forecast that covers the full 20-year study period of this CPA, Lighthouse developed a set of multipliers that would transition from the prices in 2028 to the mid-range of longer-term prices expected in the Northwest Power & Conservation Council's most recent market price forecast. [8] Lighthouse identified this approach as a balance that reflected both the near-term high prices and month to month volatility while also including the longer-term forecast based on market fundamentals from the Council. Figure 29 shows the resulting on- and off-peak prices resulting from this process.

[8] https://www.nwcouncil.org/fs/18190/2023_02_p3.pdf. Accessed March 3, 2023.

Figure 29: CPA Price Forecast



The levelized value of the 20-year price forecast is $52/MWh (2016$), a notable increase from the price forecast used in the 2021 CPA, which also had a levelized value of $32/MWh (2016$).

Lighthouse also created high and low variations of this forecast to be used in the avoided cost scenarios, which are described more subsequently. To develop the forecast variations, Lighthouse assumed that the high and low prices would vary by approximately 20% in the near term and 80% in the long term, relative to the base case price forecast. A similar approach was used in Clark Public Utilities' 2021 CPA based on the variation observed in the price forecasts developed for the 2021 Power Plan. Lighthouse applied this variation to the forecast described above to create high and low scenario forecasts. The resulting forecasts for on- and off-peak prices are shown in Figure 30 and Figure 31 below.

Figure 30: Comparison of On-Peak Price Scenarios

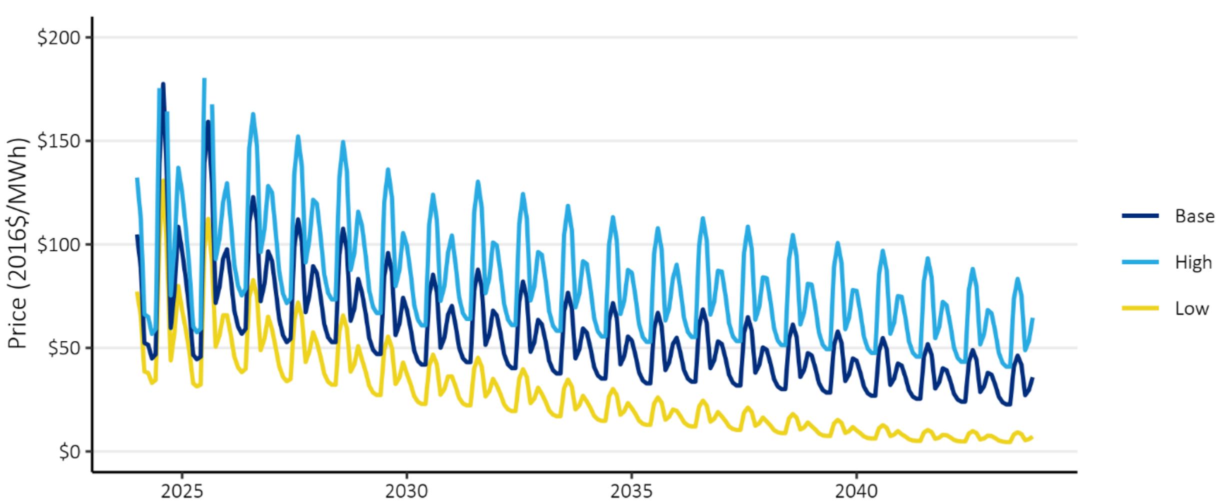
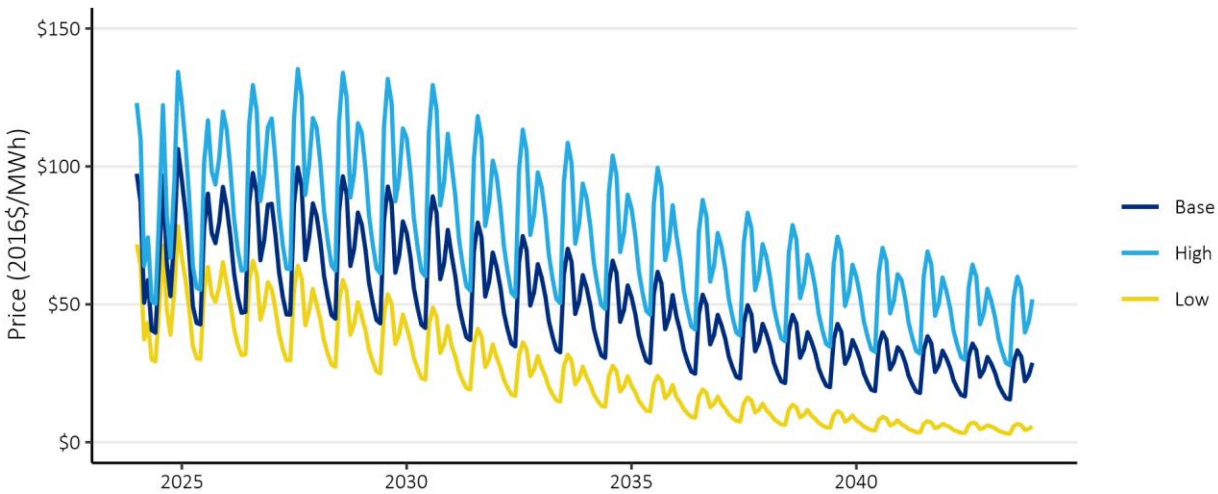


Figure 31: Comparison of Off-Peak Price Scenarios



Deferred Transmission and Distribution Capacity Costs

Unlike supply-side resources, energy efficiency does not require transmission and distribution infrastructure. Instead, it frees up capacity in these systems by reducing the peak demands and over time can help defer future capacity expansions and the associated capital costs.

In the development of the 2021 Power Plan, the Council developed a standardized methodology and surveyed the region to calculate these values. This CPA uses the values developed by the Council through that process: $3.54 and $7.82 per kW-year (in 2016 dollars) for transmission and distribution capacity, respectively. These values are slightly higher than the values used in the Clark Public Utilities' 2021 CPA and reflect small updates to the Council's values as they finalized the 2021 Power Plan.

These values for deferred transmission and distribution capacity are applied to demand savings coincident with the timing of the respective transmission and distribution system peaks. These values were used in all scenarios of the 2023 CPA. These capacity values were also applied to the demand savings quantified in the Demand Response Potential Assessment.

Deferred Generation Capacity Costs

Similar to the transmission and distribution systems discussed above, acquiring energy efficiency resources can also help defer or eliminate the costs of new generation resources built or acquired to meet peak demands for electricity.

For this CPA, Lighthouse and Clark Public Utilities staff collaborated to quantify generation capacity values that would be based on the sum of BPA demand charges across a calendar year, but scaled to reflect a price differential between winter and summer months that Clark Public Utilities was finding for capacity call options. This resulted in winter values of $67/kW-year and summer values of $57/kW-year in current year dollars.

In the base case, Lighthouse assumed that these values would increase by 2% each year and calculated a 20-year levelized cost in 2016 dollars, which is required in ProCost. The resulting base case values were

$69/kW-year for winter and $59/kW-year for summer. Lighthouse used these base cases values to quantify the value of demand savings in the Demand Response potential assessment as well.

For the low case, no price escalation was assumed, resulting in values of $57/kW-year for winter and $49/kW-year for summer. In the high scenario, 4% growth was assumed, resulting in values of $84/kW-year for winter and $72/kW-year for summer.

Social Cost of Carbon

In addition to avoiding purchases of energy, energy efficiency measures avoid emissions of greenhouse gases like carbon dioxide. Washington's EIA requires that CPAs include the social cost of carbon, which the EPA defines as a measure of the long-term damage done by a ton of carbon dioxide emissions in a given year. The EPA describes it as including, among other things, changes in agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs, including increases in the costs of cooling and decreases in heating costs.[9] In addition to this requirement, Washington's CETA requires that utilities use the social cost of carbon values developed by the federal Interagency workgroup using a 2.5% discount rate.

Washington's recently enacted Climate Commitment Act (CCA) requires all electricity imported into the state, including energy purchased from the Mid-Columbia trading hub, to be carbon-free or include emissions allowances. Based on this, the price forecasts discussed above may already include some cost of carbon embedded in the prices. Electric utilities also receive free emissions allowances under the CCA based on their forecasted emissions. These free allowances could be considered to offset any carbon costs included in the market prices. Because the CCA made no changes to CETA's requirement to include specific social cost of carbon values, this CPA used the CETA-required values in all scenarios.

To implement the cost of carbon emissions, additional assumptions must be made about the intensity of carbon emissions. This assessment uses an updated forecast of marginal emissions rates developed by the Council in 2022. The values from this analysis are used for years before 2030. Beginning in 2030, the marginal emissions rate is set to zero to reflect that CETA requires carbon-free energy. The Council's updated values generally follow those used in the 2021 Power Plan and Clark Public Utilities' 2021 CPA, but are now available on a more granular basis, reflecting variations by month and on- and off-peak periods. Table 13 shows the forecasted marginal emissions rates by month and year.

[9] https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf. Accessed January 21, 2021.

Table 13: Council Forecast of Marginal Emissions Rates (lbs./kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2023	1.0	1.1	1.0	1.0	1.0	0.9	1.2	1.2	1.2	1.0	1.2	1.1
2024	1.1	1.0	0.8	0.8	0.6	0.9	0.9	1.0	1.0	0.9	1.1	1.1
2025	0.6	0.4	0.6	0.6	0.4	0.6	0.8	1.0	1.0	0.9	0.8	0.8
2026	0.5	0.6	0.4	0.4	0.4	0.5	0.6	0.9	0.9	0.7	0.8	0.6
2027	0.6	0.6	0.4	0.6	0.3	0.5	0.7	0.9	0.9	0.7	0.8	0.7
2028	0.3	0.4	0.4	0.2	0.3	0.5	0.6	0.9	0.8	0.7	0.6	0.6
2029	0.4	0.4	0.3	0.3	0.4	0.4	0.9	0.9	0.8	0.7	0.7	0.8
2030	0.6	0.5	0.5	0.5	0.3	0.4	0.7	0.8	1.0	0.8	0.7	0.8
2031	0.6	0.5	0.4	0.5	0.4	0.5	0.7	0.9	1.1	0.9	0.5	0.9
2032	0.6	0.4	0.3	0.3	0.3	0.4	0.7	1.0	0.9	0.6	0.5	0.7
2033	0.4	0.4	0.5	0.4	0.3	0.5	0.8	1.0	1.0	0.9	0.7	0.9
2034	0.5	0.5	0.4	0.3	0.3	0.8	0.7	1.0	1.1	0.9	0.6	0.7
2035	0.5	0.5	0.4	0.5	0.3	0.5	0.8	1.0	0.8	0.6	0.5	0.7
2036	0.6	0.3	0.5	0.4	0.2	0.6	0.5	0.9	1.1	0.7	0.7	0.7
2037	0.4	0.4	0.5	0.4	0.3	0.5	0.8	0.9	0.9	0.8	0.5	0.8
2038	0.5	0.5	0.4	0.3	0.3	0.4	0.7	0.9	0.9	0.7	0.5	0.8
2039	0.5	0.5	0.5	0.3	0.3	0.5	0.7	0.9	1.0	0.8	0.7	0.8
2040	0.3	0.4	0.3	0.2	0.1	0.3	0.7	0.9	0.8	0.6	0.4	0.7
2041	0.2	0.1	0.1	0.1	0.1	0.1	0.4	0.4	0.4	0.2	0.1	0.2
2042	0.4	0.2	0.2	0.1	0.1	0.1	0.3	0.6	0.5	0.2	0.2	0.2

Renewable Portfolio Standard Compliance Costs

The renewable portfolio standard established under Washington's EIA requires that utilities source 15% of retail sales from renewable resources throughout the study period of this CPA. The subsequently passed CETA furthers these requirements, mandating that 100% of sales be greenhouse gas neutral in 2030, with an allowance that up to 20% of the requirement can be achieved through other options, such as the purchase of RECs.

Energy efficiency can reduce the cost of complying with these requirements by reducing Clark Public Utilities' overall load. In 2024, a reduction in load of 100 MWh through energy efficiency would reduce the number of RECs required for compliance by 15. This equates to a value of 15% of the cost of a REC for every megawatt-hour of energy savings. In 2030, it was assumed that marginal energy purchases would also include the purchase of a REC, thus the full price of a REC was added to the energy price after 2030.

Lighthouse developed a forecast of REC prices based on input from several clients.

Risk Mitigation Credit

Any purchase of a resource involves risk. The decision to invest is based on uncertain forecasts of loads and market conditions. Investing in energy efficiency can reduce the risks that utilities face by the fact that it is made in small increments over time, rather than the large, singular sums required for generation resources. A decision not to invest in energy efficiency could result in exposure to higher market prices than forecast, an unneeded infrastructure investment, or one that cannot economically dispatch due to low market prices. While over-investments in energy efficiency are possible, the small and discrete amounts invested in energy efficiency limit the scale of any exposure to this risk.

In its power planning work, the Council develops a risk mitigation credit to account for this risk. This credit accounts for the value of energy efficiency not explicitly included in the other avoided cost values, ensuring that the level of cost-effective energy efficiency is consistent with the outcomes of the power planning process. The credit is determined by identifying the value that results in a level of cost-effective energy efficiency potential that is equivalent to the regional targets set by the Council.

In the 2021 Power Plan, the Council determined that no risk credit was necessary after including carbon costs and a generation capacity value in its avoided cost.

This CPA follows the process used in Clark Public Utilities' previous CPAs. A scenario analysis is used to account for uncertainty, where present, in avoided cost values. The variation in energy and capacity avoided cost inputs covers a range of possible outcomes and the sensitivity of the cost-effective energy efficiency potential is identified by comparing the outcomes of each scenario. In selecting its biennial target based on this range of outcomes, Clark Public Utilities is selecting its preferred risk strategy and the associated risk credit.

Northwest Power Act Credit

Finally, this CPA includes a 10% cost credit for energy efficiency. This credit is specified in the Pacific Northwest Electric Power Planning and Conservation Act for regional power planning work completed by the Council and by Washington's EIA for CPAs completed for Washington utilities. This credit is applied as a 10% bonus to the energy and capacity benefits described above.

Summary

Table 14 summarizes the avoided cost assumptions used in each of the scenarios in this CPA update.

Table 14: Avoided Cost Assumptions by Scenario

		Low Scenario	Base Scenario	High Scenario
Energy Values	Avoided Energy Costs (20-Year Levelized Price, 2016$)	Market Forecast minus 20%-80% ($27/MWh)	Market Forecast ($52/MWh)	Market Forecast plus 20%-80% ($77/MWh)
	Social Cost CO_2	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values
	RPS Compliance	WA EIA & CETA Requirements	WA EIA & CETA Requirements	WA EIA & CETA Requirements
Capacity Values	Distribution Capacity (2016$)	$7.82/kW-year	$7.82/kW-year	$7.82/kW-year
	Transmission Capacity (2016$)	$3.54/kW-year	$3.54/kW-year	$3.54/kW-year
	Generation Capacity (2016$) Winter Summer	$57/kW-year $49/kW-year	$69/kW-year $59/kW-year	$84/kW-year $72/kW-year
	Implied Risk Adder (2016$)	-$25/MWh -$10-12/kW-year	N/A	25$/MWh $13-15/kW-year
	NW Power Act Credit	10%	10%	10%

Appendix V: Measure List

This appendix provides a list of the measures that were included in this assessment and the data sources that were used for any measure characteristics. The assessment used all measures from the draft 2021 Power Plan that were applicable to Clark Public Utilities. Lighthouse customized these measures to make them specific to Clark Public Utilities' service territory and updated several with new information available from the RTF. The RTF continually updates estimates of measure savings and cost. This assessment used the most up to date information available when the CPA was developed.

This list is high-level and does not reflect the thousands of variations for each individual measure. Instead, it summarizes measures by category. Many measures include variations specific to different home or building types, efficiency level, or other characterization. For example, attic insulation measures are differentiated by home type (e.g., single family, multifamily, manufactured home), heating system (e.g., heat pump or furnace), baseline insulation level (e.g., R0, R11, etc.) and maximum insulation possible (e.g., R22, R30, R38, R49). This differentiation allows for savings and cost estimates to be more precise.

The measure list is grouped by sector and end use. Note that all measures may not be applicable to an individual utility service territory based on the characteristics of individual utilities and their customer sectors.

Table 15: Residential End Uses and Measures

End Use	Measure Category	Data Source(s)
Appliances	Air Cleaner	2021 Power Plan, RTF
	Clothes Washer	2021 Power Plan, RTF
	Clothes Dryer	2021 Power Plan, RTF
	Freezer	2021 Power Plan
	Refrigerator	2021 Power Plan
Cooking	Electric Oven	2021 Power Plan
	Microwave	2021 Power Plan
Electronics	Advanced Power Strips	2021 Power Plan, RTF
	Desktop	2021 Power Plan
	Laptop	2021 Power Plan
	Monitor	2021 Power Plan
	TV	2021 Power Plan
EVSE	EVSE	2021 Power Plan
HVAC	Air Source Heat Pump	2021 Power Plan
	Central Air Conditioner	2021 Power Plan
	Cellular Shades	2021 Power Plan
	Circulator	2021 Power Plan
	Circulator Controls	2021 Power Plan
	Ductless Heat Pump	2021 Power Plan, RTF
	Duct Sealing	2021 Power Plan, RTF
	Ground Source Heat Pump	2021 Power Plan
	Heat Recovery Ventilator	2021 Power Plan
	Room Air Conditioner	2021 Power Plan
	Smart Thermostats	2021 Power Plan, RTF
	Weatherization	2021 Power Plan, RTF
	Whole House Fan	2021 Power Plan
Lighting	Fixtures	2021 Power Plan, RTF
	Lamps	2021 Power Plan, RTF
	Pin Lamps	2021 Power Plan, RTF
Motors	Well Pump	2021 Power Plan
Water Heat	Aerators	2021 Power Plan, RTF
	Circulator	2021 Power Plan
	Circulator Controls	2021 Power Plan
	Dishwasher	2021 Power Plan
	Gravity Film Heat Exchanger	2021 Power Plan
	Heat Pump Water Heater	2021 Power Plan, RTF
	Pipe Insulation	2021 Power Plan
	Showerhead	2021 Power Plan
	Thermostatic Restrictor Valve	2021 Power Plan, RTF
Whole Home	Behavior	2021 Power Plan

Table 16: Commercial End Uses and Measures

End Use	Measure Category	Data Source(s)
Compressed Air	Air Compressor	2021 Power Plan, WA Code
Electronics	Computers	2021 Power Plan
	Power Supplies	2021 Power Plan
	Smart Power Strips	2021 Power Plan, RTF
	Servers	2021 Power Plan
Food Preparation	Combination Ovens	2021 Power Plan, RTF
	Convection Ovens	2021 Power Plan, RTF
	Fryers	2021 Power Plan, RTF
	Griddle	2021 Power Plan, RTF
	Hot Food Holding Cabinet	2021 Power Plan, RTF
	Overwrapper	2021 Power Plan
	Steamer	2021 Power Plan, RTF
HVAC	Advanced Rooftop Controller	2021 Power Plan, RTF
	Chiller	2021 Power Plan
	Circulation Pumps	2021 Power Plan, RTF
	Ductless Heat Pump	2021 Power Plan
	Energy Management	2021 Power Plan
	Fans	2021 Power Plan
	Heat Pumps	2021 Power Plan
	Package Terminal Heat Pumps	2021 Power Plan
	Pumps	2021 Power Plan, RTF
	Smart Thermostats	2021 Power Plan
	Unitary Air Conditioners	2021 Power Plan
	Very High Efficiency Dedicated Outside Air System	2021 Power Plan
	Variable Refrigerant Flow Dedicated Outside Air System	2021 Power Plan
	Windows	2021 Power Plan
Lighting	Exit Signs	2021 Power Plan
	Exterior Lighting	2021 Power Plan
	Garage Lighting	2021 Power Plan
	Interior Lighting	2021 Power Plan
	Stairwell Lighting	2021 Power Plan
	Streetlights	2021 Power Plan
Motors & Drives	Pumps	2021 Power Plan, RTF
Process Loads	Elevators	2021 Power Plan
	Engine Block Heater	2021 Power Plan, RTF
Refrigeration	Freezer	2021 Power Plan
	Grocery Refrigeration	2021 Power Plan, RTF
	Ice Maker	2021 Power Plan, RTF
	Refrigerator	2021 Power Plan, RTF
	Vending Machine	2021 Power Plan, RTF
	Water Cooler Controls	2021 Power Plan
Water Heating	Commercial Clothes Washer	2021 Power Plan, RTF
	Heat Pump Water Heater	2021 Power Plan, RTF
	Pre-Rinse Spray Valve	2021 Power Plan, RTF
	Pumps	2021 Power Plan, RTF
	Showerheads	2021 Power Plan

Table 17: Industrial End Uses and Measures

End Use	Measure Category	Data Source(s)
All Electric	Energy Management	2021 Power Plan
	Forklift Charger	2021 Power Plan
	Water/Wastewater	2021 Power Plan
Compressed Air	Air Compressor	2021 Power Plan, WA Code
	Air Compressors	2021 Power Plan, WA Code
	Compressed Air Demand Reduction	2021 Power Plan
Fans and Blowers	Fan Optimization	2021 Power Plan
	Fans	2021 Power Plan, RTF
HVAC	HVAC	2021 Power Plan
Lighting	High Bay Lighting	2021 Power Plan
	Lighting	2021 Power Plan
	Lighting Controls	2021 Power Plan
Low Temp Refer	Motors	2021 Power Plan
	Refrigeration Retrofit	2021 Power Plan
Material Handling	Motors	2021 Power Plan
	Paper	2021 Power Plan
	Wood Products	2021 Power Plan
Material Processing	Hi-Tech	2021 Power Plan
	Motors	2021 Power Plan
	Paper	2021 Power Plan
	Pulp	2021 Power Plan
	Wood Products	2021 Power Plan
Med Temp Refer	Food Storage	2021 Power Plan
	Motors	2021 Power Plan
	Refrigeration Retrofit	2021 Power Plan
Melting and Casting	Metals	2021 Power Plan
Other	Pulp	2021 Power Plan
Other Motors	Motors	2021 Power Plan
Pollution Control	Motors	2021 Power Plan
Pumps	Pulp	2021 Power Plan
	Pump Optimization	2021 Power Plan
	Pumps	2021 Power Plan, RTF

Table 18: Utility Distribution End Uses and Measures

End Use	Measure Category	Data Source
Distribution	Line Drop Control with no Voltage/VAR Optimization	2021 Power Plan
	Line Drop Control with Voltage Optimization & AMI	2021 Power Plan

Appendix VI: Energy Efficiency Potential by End Use

The tables in this appendix document the cost-effective energy efficiency savings potential by end use for each sector.

Table 19: Residential Potential by End Use (aMW)

End Use	2-Year	4-Year	10-Year	20-Year
Appliances	0.18	0.58	4.21	18.36
Cooking	0.00	0.01	0.06	0.37
Electronics	0.04	0.13	1.13	2.51
EV Supply Equipment	-	-	-	-
HVAC	0.75	1.95	10.91	34.29
Lighting	0.05	0.14	0.86	3.70
Motors	-	-	-	-
Water Heat	0.42	1.20	5.72	13.78
Whole Home	3.12	4.50	4.50	4.50
Total	**4.56**	**8.51**	**27.39**	**77.51**

Table 20: Commercial Potential by End Use (aMW)

End Use	2-Year	4-Year	10-Year	20-Year
Compressed Air	0.00	0.00	0.00	0.00
Electronics	0.01	0.06	0.64	1.46
Food Preparation	0.00	0.02	0.18	0.63
HVAC	0.31	0.99	5.25	13.01
Lighting	1.81	3.61	8.13	12.61
Motors/Drives	0.01	0.04	0.36	1.23
Process Loads	-	-	-	-
Refrigeration	0.08	0.28	2.20	5.81
Water Heat	0.00	0.01	0.13	0.69
Total	**2.24**	**5.01**	**16.90**	**35.44**

Table 21: Industrial Potential by End Use (aMW)

End Use	2-Year	4-Year	10-Year	20-Year
All Electric	0.52	1.32	4.28	5.03
Compressed Air	0.02	0.06	0.18	0.30
Fans and Blowers	0.04	0.14	0.89	2.56
HVAC	0.08	0.14	0.23	0.26
Lighting	0.65	1.39	3.04	3.24
Low Temp Refrigeration	0.01	0.02	0.13	0.31
Material Handling	0.00	0.01	0.09	0.37
Material Processing	0.11	0.26	0.76	1.02
Med Temp Refrigeration	0.02	0.04	0.16	0.36
Melting and Casting	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00
Other Motors	0.00	0.00	0.02	0.06
Pollution Control	0.00	0.00	0.01	0.01
Pumps	0.03	0.11	0.93	3.31
Total	**1.48**	**3.49**	**10.70**	**16.83**

Table 22: Utility Distribution System Potential by End Use (aMW)

End Use	2-Year	4-Year	10-Year	20-Year
LDC with no VVO	0.04	0.12	0.78	1.48
LDC with VVO & AMI	0.12	0.39	2.58	4.89
Total	**0.15**	**0.50**	**3.37**	**6.38**

Appendix VII: Ramp Rate Alignment Documentation

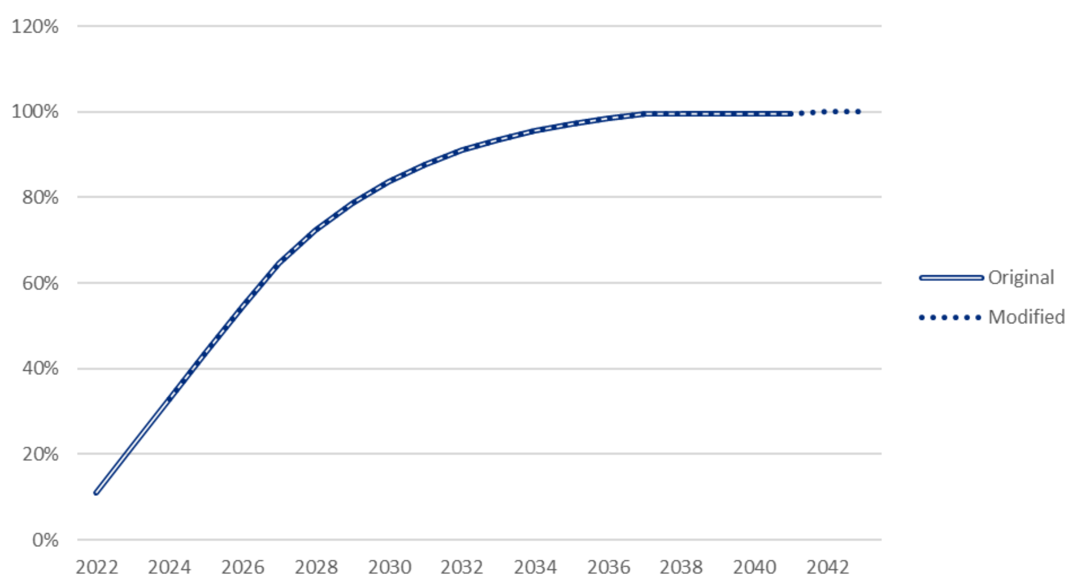
This appendix documents how Lighthouse adjusted the ramp rates from the 2021 Power Plan to be applicable to the 2024-43 time period of this CPA and then selected the appropriate adjusted ramp rate to ensure alignment between the near-term potential quantified in the CPA and the recent achievements of Clark Public Utilities' (Clark Public Utilities) energy efficiency programs. Ramp rates are the annual values that describe the share of technical potential available in a given year that is achievable. Aligning the potential with recent achievements ensures that the near-term potential is feasible for Clark Public Utilities' programs as energy efficiency programs take time to ramp up and are subject to local and dynamic market conditions.

Ramp Rate Adjustments

The CPA model used for this assessment uses the ramp rates developed by the Northwest Power and Conservation Council for the 2021 Power Plan. The 2021 Power Plan, however, covers an earlier time period and so the ramp rates require adjustment to correspond to the 2024-43 time period of this CPA.

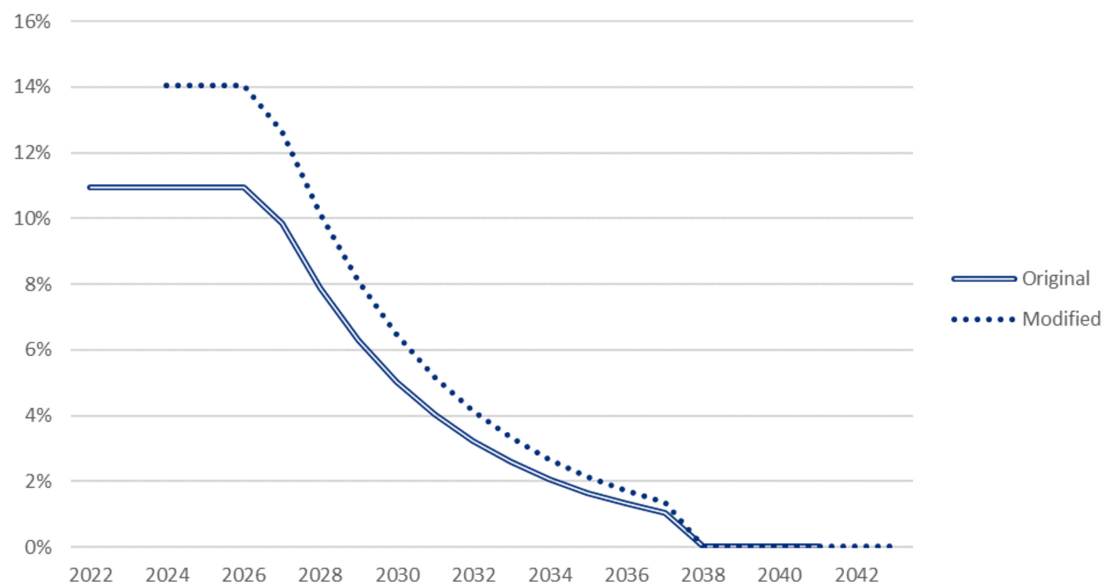
There are two different types of ramp rates, which correspond with the two types of measure under consideration. For lost opportunity measures that are associated with equipment replacement cycles or new construction, the ramp rate values reflect the amount of energy efficiency potential captured among the equipment being purchased in a given year. These ramp rates typically approach 100% in the later years and were adjusted to cover the timeline of the CPA by simply extending the final value of the ramp rate an additional two years. Figure 32 shows how one lost opportunity ramp rate was modified to cover the 2024-43 timeline of this CPA. The original ramp rate reaches 100% at approximately 2037 and the modified ramp rate simply extends this trend for another two years.

Figure 32: Lost Opportunity Ramp Rate Adjustment



For retrofit measures, the ramp rate values reflect the portion of the total available potential that is achieved in a given year. Because retrofit measures can be achieved in any year, the ramp rate values typically sum to 100% over a 20-year time period. To adjust the ramp rates for retrofit measures, Lighthouse assumed that the potential associated with the first two years of the 2021 Power Plan had been achieved and the remaining potential was distributed across the 18 remaining years of the original 2021 Power Plan timeline, in proportion to the original ramp rate projection. This results in higher ramp rate values relative to the original 2021 Power Plan, but equivalent amounts of potential after program achievements have been accounted for. Figure 33 shows the original and modified versions of one retrofit measure ramp rate.

Figure 33: Retrofit Ramp Rate Adjustment



For this ramp rate, nearly 100% of the remaining potential is captured by 2038 in both the original and modified versions of the ramp rate.

Ramp Rate Alignment Process

Clark Public Utilities provided program achievement data for 2021-22, which Lighthouse summarized by sector and end use. Lighthouse also summarized the residential program achievements by high-level measure categories.

Clark Public Utilities also receives credit for savings from market transformation that the Northwest Energy Efficiency Alliance (NEEA) estimates has occurred in Clark Public Utilities' service territory. Measure-level detail provided by Clark Public Utilities allowed Lighthouse to allocate these savings to end uses and measure categories.

Lighthouse compared the recent savings from Clark Public Utilities' programs and NEEA's market transformation initiatives with the cost-effective energy efficiency potential identified in the 2023 CPA. Lighthouse started with the ramp rates that were assigned to each measure in the 2021 Power Plan and compared the resulting cost-effective potential in the first few years of the assessment with Clark Public Utilities' recent programmatic achievements. Lighthouse then made changes to the ramp rate assignments for each measure to accelerate or decelerate the pace of savings acquisition to align with recent programmatic achievements. In areas where there were no recent program achievements, Lighthouse typically assigns a ramp rate that is slower than the applicable 2021 Power Plan ramp rate unless one is already assigned. This accounts for the fact that a program may need to start from scratch and build momentum over several years.

NEEA resets the baseline against which it quantifies its market transformation savings with every new Power Plan. This happened in 2022 with the publication of the 2021 Power Plan. For consistency in projecting future savings, Lighthouse used NEEA's projected 2023 savings for both 2021 and 2022. This level of savings best represents the expected level of savings going forward with the 2021 Power Plan baseline.

The following tables show how Clark Public Utilities' recent achievements compare to the potential after Lighthouse adjusted the ramp rates to align. Color scaling has been applied to highlight the larger values. Discussion follows each table with additional detail.

Residential

The table below shows how residential potential was aligned with recent achievements by measure category.

Table 23: Alignment of Residential Program History and Potential by Measure Category (MWh)

		Program History		CPA Cost-Effective Potential		
End Use	Category	2021	2022	2024	2025	2026
Appliances	Air Cleaner	23	23	13	25	45
Appliances	Clothes Washer	253	253	247	372	510
Appliances	Dryer	111	111	141	274	474
Appliances	Freezer	-	-	6	11	20
Appliances	Refrigerator	193	193	198	298	408
Cooking	Microwave	-	-	4	7	12
Cooking	Oven	-	-	1	1	2
Electronics	Advanced Power Strips	93	18	-	-	-
Electronics	Laptop	-	-	4	7	13
Electronics	TV	129	129	109	196	314
EVSE	EVSE	6	52	-	-	-
HVAC	ASHP	1,687	1,393	27	34	37
HVAC	CAC	-	-	4	8	13
HVAC	Circulator	54	54	44	64	82
HVAC	Circulator Controls	-	-	0	0	1
HVAC	DHP	1,583	1,573	2,087	2,075	2,063
HVAC	Duct Sealing	3	6	225	407	702
HVAC	Room AC	4	4	-	-	-
HVAC	Thermostat	65	48	274	659	1,289
HVAC	Weatherization	349	236	299	372	454
Lighting	Lighting	-	-	201	268	346
Water Heat	Aerators	103	14	-	-	-
Water Heat	Circulator	54	54	25	36	46
Water Heat	Circulator Controls	-	-	2	4	7
Water Heat	Dishwasher	-	-	1	2	3
Water Heat	HPWH	1,886	779	1,399	2,061	2,734
Water Heat	Showerhead	48	-	-	-	-
Water Heat	TSRV	4	-	65	113	181

Whole Home	Behavior	14,690	16,079	13,662	13,627	12,123
NEEA	NEEA	-	-	*n/a*	*n/a*	*n/a*
	Total	**21,340**	**21,019**	**19,037**	**20,923**	**21,879**

Note: For clarity, measure categories with no program achievements and no cost-effective potential have been removed. In addition, note that some measures have savings values that are small and cannot be shown at this level of resolution. These values show as 0 in this and following tables while a true zero value is shown as a dash.

The following sections discuss the alignment within each residential end use.

Appliances & Cooking

While there are no Clark Public Utilities program achievements in these end uses, NEEA's market transformation work includes an initiative for retail products and appliances that contributes savings. The ramp rate assignments for these measures were slowed slightly from the default 2021 Power Plan assignments to align with recent NEEA savings.

Electronics

In this category, Clark Public Utilities has achieved some savings through advanced power strips. However, the Regional Technical Forum (RTF) has recently deactivated the measure due to a lack of data and confidence in the savings, so the measure was removed from this CPA. Additional potential is available through TVs, which is part of NEEA's Retail Product Portfolio, similar to the appliance end use discussed above. Lighthouse slowed the ramp rate for laptops since there is no current program or NEEA initiative that would address this category of measures.

Electric Vehicle Supply Equipment (EVSE)

While Clark Public Utilities has recently started offering an incentive for qualifying EV chargers, after updating this measure with new data from the RTF, it did not pass the cost effectiveness screening. EV chargers may provide additional value as a future demand response resource, however.

HVAC

In the HVAC category, as with Clark Public Utilities' 2021 CPA, only a limited number of applications of air-source heat pumps (ASHP) were cost-effective, limiting the ability to closely match program achievement and potential. However, the tax credits and incentives provided for heat pumps through the federal Inflation Reduction Act have the potential to make these measures cost-effective, especially the more generous incentives provided to income-qualified households. The measures in this category were accelerated to align with recent program activity as much as possible.

The potential with ductless heat pumps (DHP) was accelerated to slightly exceed recent achievements, as there is some crossover with ASHP measures. Some weatherization measures were accelerated while duct sealing measures were slowed from the default 2021 Power Plan ramp rates. The potential with smart thermostats was slowed to be more consistent with current program levels.

Lighting

The lighting end use is now subject to Washington state standards that took effect in 2020 and cover many screw-in lamps. The potential that remains is in fixtures with integrated LEDs and less common bulb types. There is not currently a program to incentivize LED fixtures, so these measures were given a slower ramp rate.

Water Heat

The program history in the water heating category consists mostly of savings from heat pump water heaters. The potential for heat pump water heaters was left at the 2021 Power Plan ramp rates, which resulted in reasonable alignment with recent achievement from Clark Public Utilities programs and NEEA savings.

Washington's recent HB 1444 specifies standards for showerheads and aerators, so there is no potential in these categories. Lighthouse applied slower ramp rates to the initial potential for circulator pumps and controls. Lighthouse also applied a slower ramp rate for thermostatic restrictor valves to match recent program activity more closely.

Whole Home

This category includes a residential behavior program. The ramp rates were adjusted to align with Clark Public Utilities' planned behavior program as much as possible.

Table 24 below summarizes the residential measure category results in Table 23 by end use. In addition, this table incorporates savings from several NEEA initiatives that do not align with categories included in the CPA but could be grouped in the end uses listed below.

Table 24: Alignment of Residential Program History and Potential by End Use (MWh)

	Program History		CPA Cost-Effective Potential		
End Use	2021	2022	2024	2025	2026
Appliances	581	581	605	981	1,457
Cooking	-	-	4	8	13
Electronics	243	169	113	204	327
EVSE	6	52	-	-	-
HVAC	3,788	3,356	2,960	3,619	4,641
Lighting	-	-	201	268	346
Motors	-	-	-	-	-
Water Heat	2,096	847	1,492	2,216	2,971
Whole Home	14,690	16,079	13,662	13,627	12,123
NEEA	-	-	*n/a*	*n/a*	*n/a*
Total	**21,404**	**21,083**	**19,037**	**20,923**	**21,879**

Commercial

In the commercial sector, most of the potential is in the lighting end use, which was given some of the fastest ramp rates available in the 2021 Power Plan. Lighthouse made no change to these ramp rates, which resulted in near-term potential that is aligned with recent program history.

Potential in the HVAC end use, which includes energy management programs, was slowed slightly.

Lighthouse applied slightly slower ramp rates to measures in the other end uses, including compressed air, electronics, food preparation, refrigeration, and water heating. These end uses have smaller amounts of potential and are not a focus of current programs.

Table 25 below shows the alignment of program history and potential in the commercial sector.

Table 25: Alignment of Commercial Program History and Potential by End Use (MWh)

	Program History		CPA Cost-Effective Potential		
End Use	2021	2022	2024	2025	2026
Compressed Air	-	-	0	0	0
Electronics	54	54	45	85	146
Food Preparation	20	20	13	25	46
HVAC	2,524	1,210	1,020	1,681	2,492
Lighting	7,899	9,329	7,854	8,031	8,029
Motors/Drives	-	-	40	68	109
Process Loads	-	-	-	-	-
Refrigeration	6	501	259	444	707
Water Heat	7	7	9	17	30
NEEA	-	-	-	-	-
Total	**10,511**	**11,122**	**9,239**	**10,352**	**11,557**

Industrial

Most of the Clark Public Utilities' recent savings, as well as the future potential, in the industrial sector are in the lighting and energy management end uses. Lighthouse applied slightly slower ramp rates across the industrial sector end uses to align the future potential with recent program achievements.

Table 26 shows the alignment of industrial potential and recent program history by end use.

Table 26: Alignment of Industrial Program History and Potential by End Use (MWh)

	Program History		CPA Cost-Effective Potential		
End Use	2021	2022	2024	2025	2026
Energy Management	1,337	2,762	1,987	2,526	3,151
Compressed Air	760	35	100	118	139
Fans and Blowers	-	-	119	216	353
HVAC	1,355	565	388	302	265
Lighting	1,998	3,924	2,763	2,965	3,171
Motors	-	-	5	8	10
Refrigeration	-	-	79	100	128
Process	428	1,388	456	544	637
Pumps	480	-	103	175	278
Other	-	-	2	2	3
NEEA	-	-	*n/a*	*n/a*	*n/a*
Total	**6,358**	**8,674**	**6,001**	**6,957**	**8,135**

Utility Distribution System

The amount of potential in the utility distribution system is limited compared to other sectors. The 2021 Power Plan assumes that the potential in this sector will be acquired slowly. No changes were made to the default ramp rate assigned in the 2021 Power Plan.

Table 27: Alignment of Distribution System Program History and Potential by End Use (MWh)

	Program History		CPA Cost-Effective Potential		
End Use	2021	2022	2024	2025	2026
Distribution System	-	-	512	834	1265