BONNEVILLE POWER ADMINISTRATION

2024 Resource Program

February 21, 2025

Contents

Section 1: Glossary of Terms

18-Hour Capacity – Metric used for evaluating capacity surplus/deficit over the six peak load hours per day during a simulated three-day extreme weather event, such as a cold snap or heat wave, and assuming median water conditions.
Available transfer capacity – Also "available transfer capability." Measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Balancing authority – The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing authority area – The collection of generation, transmission and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.
Balancing reserves – Incremental and decremental generation flexibility or demand response that is connected to BPA's Automatic Generation Control system and can respond to signals requesting Regulation Service and Within-hour Following Service in proportion to the AGC signal requirements.
Behind-the-meter generation – Energy generated on-site and on the consumer side of the meter facility.
Boardman to Hemingway (B2H) transmission line - A proposed 500-kilovolt transmission line that will run approximately 290 miles across eastern Oregon and southwestern Idaho. It will connect the proposed Longhorn Substation four miles east of Boardman, Oregon, to Idaho Power's existing Hemingway Substation in Owyhee County, Idaho.
Canadian Entitlement – The Canadian Entitlement is a quantity of power and capacity that has been agreed to between the US and Canadian Entities under the existing Columbia River Treaty; the values represent a sharing of the benefits of power coordination between the US and Canada.
Capacity – Capacity is defined and measured in various ways in the power industry. In the context of the Resource Program, BPA measures the capacity of its system by determining its maximum output in its 18-hour capacity studies, which represent the most stressful type of event BPA's power system could expect to experience approximately once in every 10 years under median water conditions.
Conservation – Any reduction in electric power consumption or peak load demand as a result of increases in the efficiency of energy use, production, or distribution.
Conservation Potential Assessment – Study conducted to assess the amount and costs of energy efficiency measures available from BPA's forecasted customer loads over the planning horizon.
Critical water – Also known as firm water or firm planning. It is the expected resource generation planning level to meet BPA's obligatory loads. The tenth percentile (p10) of the streamflow assumption distributions, given the current operations and constraints, is the current planning criteria.
Decentralization – Energy generated off the main grid and produced near to where it will be used, rather than at a large plant elsewhere and sent through the grid.
Demand response – Programs intended to reduce the use of electricity during times of peak demand.
Demand-side resources – Load management programs, such as energy efficiency, implemented by utilities. These resources can also include demand response, load shifting measures, and behind-the-meter generation and storage.
Distributed energy resources – Systems such as small-scale power generation or storage technologies – typically in the range of 1-10,000 kilowatts – used to provide an alternative to or an enhancement of the traditional electric power system.

Energy – The amount of electricity demanded, produced or required, over a specific period of time, sometimes measured in annual average megawatts, aMW, or in megawatt hours, MWh.
Energy efficiency (EE) – Using less energy to perform the same function or service.
Federal Columbia River Power System (FCRPS) - A series of multi-purpose, hydroelectric facilities in the Pacific Northwest region of the United States, constructed and operated by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation, and a transmission system built and operated by the Bonneville Power Administration (BPA) to market and deliver electric power.
Federal Energy Regulatory Commission (FERC) – An independent government agency delegated by Congress with the authority to regulate the energy infrastructure of the United States, including the transmission of electricity.
Fiscal Year (FY) – The federal government's fiscal year running from October 1 to September 30.
Heavy load hours – Times of highest electricity usage; for BPA, heavy load hours are hours ending at 7 a.m. to 10 p.m., Monday through Saturday, excluding North American Electric Reliability Corporation holidays.
Hub – Combination of the electrical grid and other networks, such as natural gas pipelines, for the production, conversion, storage and consumption of different energy generators.
Independent power producer – A non-utility producer of electricity that operates one or more generation plants under the 1978 Public Utility Regulatory Policies Act, PURPA. Many independent power producers are co-generators who produce power for their own use and sell the extra power to their local utilities.
Integrated Resource Plan – A long-term resource planning process conducted to help ensure a utility meets its expected future obligations at low cost and with minimum practical risk.
Intertie – A system of transmission lines permitting a flow of energy between major power systems. The BPA transmission grid has interties to British Columbia (Northern Intertie), California (Southern Intertie) and eastern Montana (Eastern Intertie).
Investor-owned utility – An investor-owned utility organized under state law as a corporation to provide power service and earn a profit for its shareholders.
Light load hours – Generally, times of low electricity usage; for BPA, light load hours are hours ending 11 p.m. to 6 a.m., Monday through Saturday, all day Sunday and holidays as designated in the North American Electric Reliability Corporation Standards.
Load – The amount of electric energy delivered or required at any specified point or points on a system.
Market depth limit – Result of a study used to determine how much energy BPA could reliably purchase from the wholesale market.
Market transformation savings – Associated with the Northwest Energy Efficiency Alliance's programs and initiatives that focus on long-term market change and push the region toward more efficient technologies.
Momentum savings – BPA tracks and reports momentum savings for select markets. Momentum savings are defined as all the energy efficiency occurring above the Northwest Power and Conservation Council's plan baseline that are not directly reported by utilities and not part of the Northwest Energy Efficiency Alliance's market transformation savings.
Net Resources – A forecast, under varying streamflow conditions, of firm power supply available to meet firm obligations from generating resources and contract purchases net of transmission losses.
Network transmission – A type of transmission contract or service described in a transmission provider's Open Access Transmission Tariff, OATT.
New Large Single Load (NLSL) – Any new load, or expansion of an existing load, at a single facility that grows by 10 average megawatts (aMW) or more in any consecutive 12-month monitoring period.
New Resource (NR) Rate – BPA's marginal resource cost-based rate at which customers requesting power from the federal system to serve large loads are served.

North American Electric Reliability Corporation (NERC) – A not-for-profit international regulatory authority appointed by the Federal Energy Regulatory Commission whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Northwest Energy Efficiency Alliance (NEEA) – A group of 140 Northwest utilities and energy efficiency organizations that fund activities and programs dedicated to accelerating energy efficiency in the region.

Outage – In a power system, an either scheduled or unexpected period during which the transmission of power stops or a particular power-producing facility ceases to provide generation.

p10 – The 10^{th} percentile of a distribution.

p10 heavy load hour – Criteria that evaluate the surplus/deficit over heavy load hours load obligations by month against the 10^{th} percentile, or p10, of net resources distribution from the corresponding streamflow assumptions.

p10 Super-Peak – Criteria that evaluate the surplus/deficit over the six peak hours per weekday load obligations by month against the 10^{th} percentile, or p10, of net resources distribution from the corresponding streamflow assumptions.

Peak load – The highest amount of load on the entire system in a stated period of time. It may be the maximum load at a given instant in the stated period or the maximum average load within a designated interval of the stated period of time.

Peak runoff – The period of time during which the maximum volume of precipitation, snowmelt or irrigation water that runs off the land into streams or other surface water within a watershed or basin. BPA forecasts the amount of water expected to enter the Federal Columbia River Power System based on winter snowpack measurements and historical volumes.

Ramp rates – 1) The amount of conservation or demand response that a program can acquire annually; 2) (Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.

Resource portfolio/stack – A set of resources used to provide power products. Demand side resources can also be in a resource portfolio.

Spill – Water that goes over the spillway of a dam rather than through its turbines, meaning it is not used to generate electricity.

SouthWest-East Diversity Exchange (SWEDE) – A subregion of the Western Resource Adequacy footprint comprised of zones including southeast Idaho, Nevada, Arizona, and New Mexico.

Supply-side – Generating resources or activities on the utility's side of the customer's meter used to supply electric power products or services to customers, rather than meeting load through energy-efficiency/conservation measures or on-site generation on the customer's side of the meter.

Western Interconnection – Synchronously operated interconnected electric transmission systems located in the Western United States, Baja California, Mexico, and Alberta and British Columbia, Canada.

Western Electricity Coordinating Council (WECC) – The Western Electricity Coordinating Council (WECC) is a non-profit corporation that exists to assure a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.

Western Resource Adequacy Program (WRAP) - An electricity planning and sharing agreement between electric utilities of the Western Power Pool.

Section 2: Introduction

2.1 Overview

The Bonneville Power Administration (BPA) began analyzing its resource needs with the Resource Program after passage of the 1980 Northwest Power Act. The purpose of the program—which is produced as needed on a roughly biennial basis since 2010—is to assess BPA Power Services' future needs for resources, i.e. power, to meet its firm power sales load obligations, and to inform the development of a strategy to meet those needs. The objective of the 2024 Resource Program is to develop a set of least-cost resource solutions to meet BPA's expected future energy and/or capacity needs to help inform:

- Integrated Program Review and budgeting process for Energy Efficiency (EE)
- BPA customer contract elections in Provider of Choice
- Long-term resource acquisition strategy
- Participation in Western Resource Adequacy Program (WRAP)

Findings from the Resource Program help BPA understand how it may fulfill its contractual obligations most cost-effectively by providing insights into the type, timing and amount of additional supply-side resources, demand-side resources and wholesale market purchases required to ensure resource adequacy under several long-term power planning metrics.

The 2024 Resource Program largely maintains the methodology used for both the 2020 and the 2022 Resource Programs with some significant updates to the optimization process and a refreshing of inputs to reflect new information or program accomplishments. As in other long-term power planning studies at BPA, the 2024 Resource Program assumes no material contract election or rate structure differences from current Regional Dialogue long-term power sales contracts in the study period following the expiration of these contracts on September 30, 2028. To study risks associated with variation in loads, resources and the wholesale power market, the 2024 Resource Program analyzes a suite of sensitivities that investigate how results are affected by changing individual input assumptions.

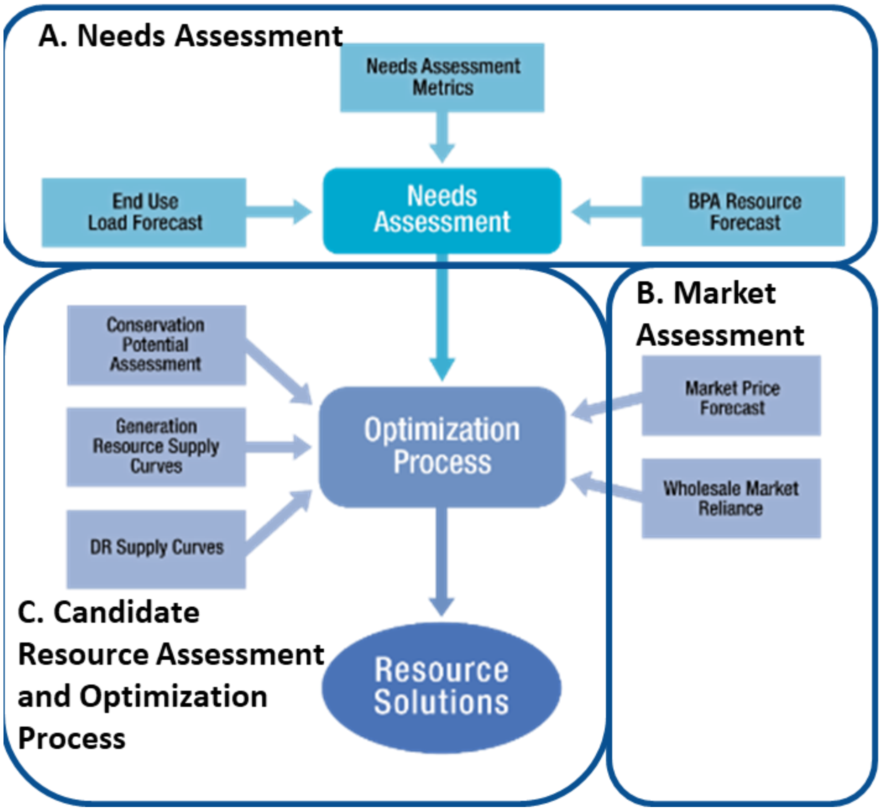
The Resource Program is neither a decision document nor a process required by any external entity. Rather, it is a body of work undertaken to inform acquisition strategies and provide valuable insight into how BPA can meet its obligations and strategic objectives at the least cost.

2.2 Methodology

Figure 2-1 provides a high-level diagram of the Resource Program process, which begins with the Needs Assessment. The Needs Assessment forecasts Power Services' total supply obligations specific to the expected loads of BPA utility customers and other BPA contractual and legal obligations, net of conservation achievements and the existing federal system's expected generating resource capabilities. These results are used to forecast long-term surplus/deficit inventory positions at the hourly level under various load and fuel (i.e., water) scenarios. These hourly positions are used to create a set of metrics that summarize BPA's power needs across various time periods within the study horizon.

Next, the Market Assessment simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load and economic conditions. The Candidate Resource Assessment and Optimization Process explores how the varying costs, performance and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs.

Figure 2-1: Resource Program Process



2.3 Conclusions

The points below summarize the main conclusions of the 2024 Resource Program:

- BPA Power Services tends to be energy short and capacity long with deficits between firm power supply obligations and existing federal system capabilities occurring under low-water conditions and in many time periods over the year with the largest deficits occurring in late winter (February) and just before the spring run-off begins (second half of April).
- The least-cost portfolio of resources to meet power needs includes a mixture of early investment in energy efficiency and demand response programs, the acquisition of the output of solar generators, and wholesale market purchases.
- Sensitivities studying the impact of increased firm power supply obligations and/or limitations on BPA's ability to rely on cost-effective purchases from the wholesale power market

demonstrate an increased reliance on more expensive demand-side programs as well as a greater diversity of generating resource acquisitions, with needs outstripping assumed technical potential in some of the most stressed cases.

2.4 Enhancements for the 2026 Resource Program

Based on feedback to the 2024 Resource Program, BPA will consider exploring a range of modeling enhancements for the 2026 Resource Program, including but not limited to:

- Assessing capacity metric under extreme weather and low water
- Reintroducing balancing reserves study to Needs Assessment
- Connecting resource solutions to WRAP forward showing position
- Including additional candidate resource options, such as natural gas generation and long duration energy storage
- Refining and refreshing characteristics for candidate resources, including performance of renewables
- Enhancing linkages between resource solutions, market assessment and needs assessment modeling

2.5 Report Overview

This report is organized as follows: Section 3 details the methods and results of the end-use load forecasts used in the 2024 Resource Program. Section 4 describes the various metrics by which BPA obligations and generating capabilities of the existing system are combined to summarize the needs under various scenarios and sensitivities across the 20-year study. Section 5 details the cost and performance characteristics of candidate generating resources, conservation and demand response measures, and the wholesale energy market which can be selected to meet needs. Section 6 reviews the methodology used by the 2024 Resource Program Solver to select least-cost portfolios of candidate resources which meet needs and describes the results of each scenario and sensitivity explored. Section 7 concludes.

Section 3: Load Forecasts

The Load Forecasting and Analysis team at Bonneville produces a variety of customized long-term load and resource forecasts for purposes such as setting power and transmission rates, revenue and operations planning, meeting compliance standards, and long-term transmission system planning[1]. The main forecast used to evaluate the resource choices is the Base Scenario. This scenario consists of the customer-level forecasts developed to reflect short-and medium-term Agency obligations with two significant adjustments. First, historical energy sales are reconstituted by adding the cumulative energy efficiency savings achieved in the past. The resulting forecast, called Frozen Efficiency, is one without future conservation programs, which allows Bonneville to evaluate conservation as another resource choice. The second adjustment accounts for changes expected to affect regional energy demand during the Resource Program planning horizon.

The individual utility forecasts are developed by BPA forecasters who meet with utility representatives at least once a year to discuss changes in local economic conditions, economic development efforts, conservation activities, construction and zoning, and individual point loads. The forecasting methodology varies depending on the characteristics and needs of each utility. A demand forecasting model for a small, rural utility might consist of an ordinary least-squares regression with only weather and economic-demographic factors as explanatory variables. A large, urban utility might require an end-use based econometric model with multiple load drivers for each customer class to achieve an unbiased and reasonable forecast. In aggregate, the individual customer forecasts are referred to as the Expected Case forecast, published in BPA's White Book, or the Agency Forecast.

The Resource Program Base Scenario forecast adds conservation to the Expected Case forecast and accounts for the expected load impact from weather and policies. To capture these long-term trends and to explore alternative economic and electrification futures, it is necessary to have the ability to affect the forecasts of underlying load drivers accordingly, which Statistically Adjusted End-use (SAE) models allow us to do. SAE models are a hybrid of the engineering end-use technology models and traditional econometric models, and as such they allow a detailed characterization of current and future electricity use. The use of aggregate, zonal SAE models is new in this Resource Program. Prior to 2024, all forecasts were produced using out-of-model adjustments to the Agency forecast.

The SAE framework estimates energy demand for heating, cooling, and for all other purposes (e.g. for wood product manufacturing or for clothes washing and drying) in the residential, commercial and industrial sectors. The estimation of energy use for each category requires data on all factors that affect consumption. Energy use for residential space heating, for example, depends on heating equipment saturation levels, equipment operating efficiency, thermal integrity and square footage of a home, household size, household income, and energy prices.

The data used in all SAE models created for the Resource Program come from external sources. End-use saturation and efficiency, thermal efficiency, and building square footage data are from the Residential and Commercial Building Stock Assessments (RBSA and CBSA) published by the Northwest Energy Efficiency Alliance (NEEA)[2] and from the Northwest Power and Conservation Council (the Council)[3]. The

[1] Forecasts are produced for BPA's power and transmission customers: 130+ public customers (cooperative, federal, municipal and political subdivisions), 8 investor-owned customers, 4 tribal customers, and 11 USBR customers. Customized forecasts are also produced for 36 WECC regions, including 13 Balancing Authorities.
[2] Available here: [Northwest Energy Efficiency Alliance (NEEA) | Regional Studies and…]()
[3] Available here: [The 2021 Northwest Power Plan]()

forecast data for selected end uses reflect laws and regulations at the time the study was run, including the Inflation Reduction Act (IRA), according to the Reference Case in the 2023 Annual Energy Outlook from the U.S. Energy Information Administration (EIA)[4]. Economic forecast data are from IHS S&P Global, an information services provider. The Base Scenario forecast uses projections from IHS S&P Global's baseline scenario, to which the consulting firm assigned a 55% probability in June of 2023.

Figure 3-1 Load Forecasting Process

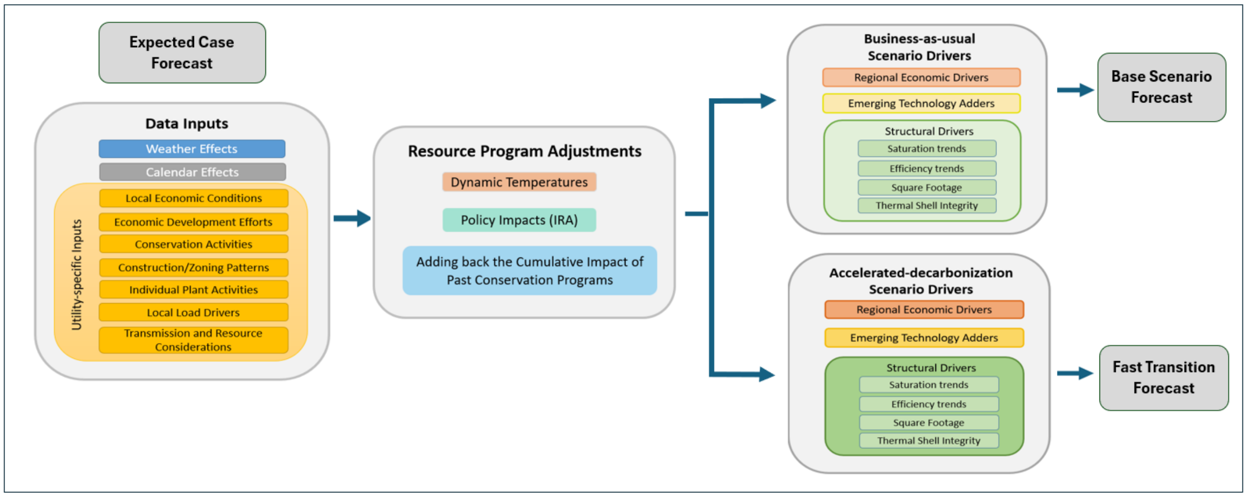


Figure 3-1 illustrates the steps involved in creating the Base Scenario forecast as well as an additional scenario, called Fast Transition, developed to quantify resource needs if the region follows an accelerated, policy-driven investment path.

The baseline scenario represents a business-as-usual scenario, in which economic trends follow their long-term trajectory: inflation returns to a 2% level, productivity grows at a rate of about 1.7%, household formation growth is between 0.8% and 1%, and industrial production growth remains between 1.1% to 1.5%. In the Fast Transition scenario, the consumer price level is 1% lower in the early years and 5.5% lower by 2040; the growth in real personal income increases by 15 to 70 basis points; industrial employment increases by 3.5% to 5%; and the number of households grows by 1% to 1.8%.

The Base Scenario makes no assumptions about future policy changes, as compared to the Fast Transition scenario that modeled potential policies at the time the study was run, including a 50% net-GHG emission reduction relative to 2005 and net-zero GHG emissions by 2050. [5] The emission reductions assumed in the Fast Transition scenario are the same as the EIA's High Macro, Low Zero-Carbon technology cost scenario[6] and the Pacific Northwest National Laboratories' (PNNL) Net Zero pathway[7]. The ambitious investment actions are reflected in our SAE models in the form of higher adoption of efficient end-uses. While no explicit assumption is made at the industrial end-use level, industrial sector

[4] Available here: U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

[5] The Fast Transition scenario is agnostic as to the source of these policy changes and makes no assumptions about whether they would be at the federal, state or local level.

[6] More information on this scenario can be found here: U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

[7] More information on this scenario can be found here: GODEEEP

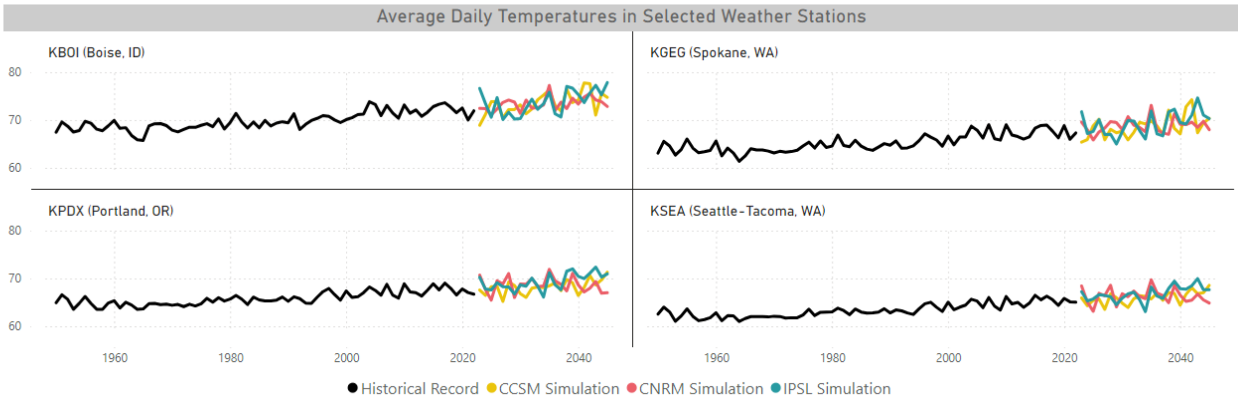
demand is most heavily influenced by economic growth assumptions, including higher industrial production.

As in previous Resource Programs, an extreme weather scenario was developed to quantify the energy needs during stressed conditions. This forecast makes the same assumptions as the Base Scenario, but it uses the temperatures observed during the heat dome event of late June 2021 and the cold snap experienced in mid-January 2024. Temperature records were broken in many cities resulting in peak energy demand that tested the Pacific Northwest grid and required inter-regional support to maintain operations. Extreme weather events are happening more often and at more extreme temperatures during the summer months in the PNW. And while the same cannot be said for the winter months, winter extreme events pose complex challenges for a winter-peaking system like Bonneville's. This is especially true if these events occur during a low-water year and/or are preceded by abnormally cold temperatures. Regardless of whether extreme temperatures occur in the winter or summer months, they are expected to continue setting new peak demand records for the agency as a result of increasing adoption of electric heating and cooling (i.e. heat pumps and air conditioning, respectively), data center load growth, and a higher temperature sensitivity due to a shift in the composition of our area load away from industrial production and toward residential demand[8].

This Resource Program stands out not only because it uses zonal, scenario-specific SAE models to forecast the entirety of customers' total retail load and obligations, it is also the first to account for the evolving distribution of temperatures observed in BPA's service territory. The 2024 White Book forecast uses a recently updated set of normal temperatures that reflects temperatures that are representative of the period between 2004 to 2019. The Base Scenario, Fast Transition and Extreme Weather scenario further assume that the evolution of temperature dynamics of the last 30 years will continue in the coming decades. Assuming static temperatures during the Program's time horizon results in overestimating future heating needs and underestimating future cooling needs. Instead, the updated set of normal-weather temperatures are revised over time according to simulations created by the River Management Joint Operating Committee (RMJOC). The scenarios chosen most closely resemble the PNW's recent historical pattern of increasing temperatures, wetter winters, longer summer dry periods, declining snowpack, higher average fall and winter flows, earlier peak spring runoff, and longer periods of low summer flows. Figure 3-2 shows the simulated temperatures from the three climate scenarios used to calculate the future heating and cooling degree days used by the load forecasting models as well as the historical temperatures that precede them.

[8] When the temperature deviates from a comfortable level, residential customers respond by using more electricity to heat or cool their homes. In the last 10 years or so BPA has seen a faster growth in residential load relative to commercial and industrial loads causing the residential share of area load to increase and overall load to become more temperature sensitive. Higher AC saturation rates and greater adoption of electric heating (e.g. heat pumps) have also contributed to higher load responsiveness to temperature fluctuations.

Figure 3-2 Simulated Temperatures

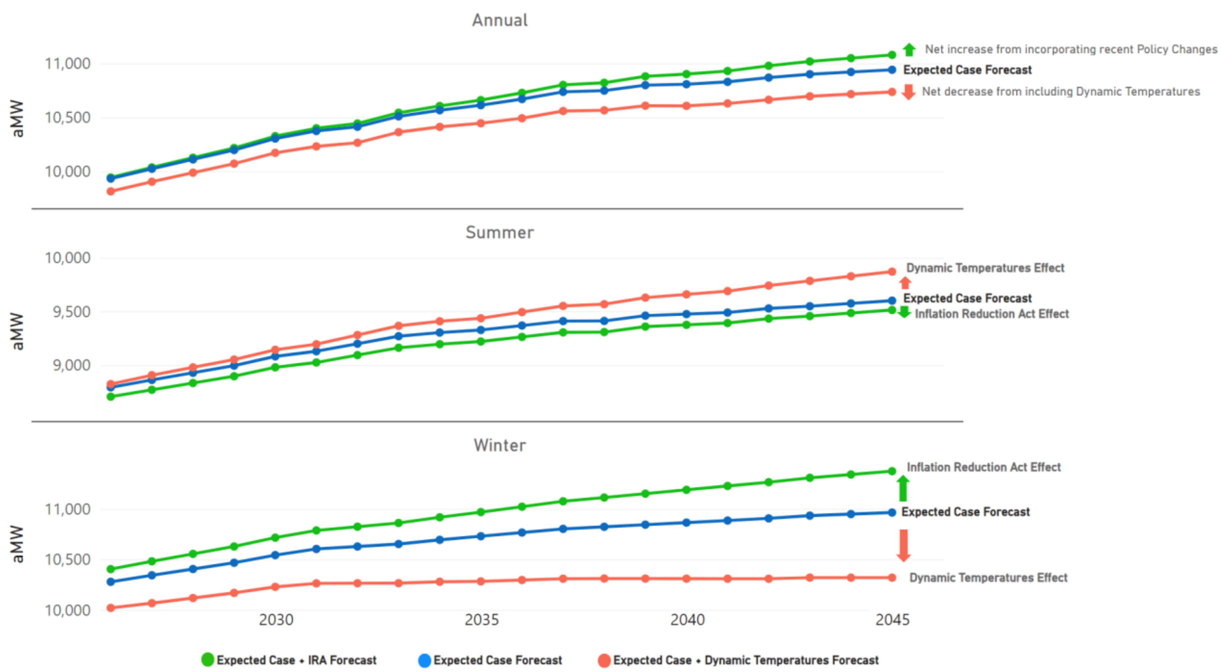


Despite these improvements, the work to adapt to a more uncertain future will continue in upcoming Resource Programs. The steady annual load growth of 0.3% observed in the decade following the Great Recession is no longer the norm. In the last 5 years, average load growth increased to 2.2%, and is expected to continue to rise. The magnitude and timing of the increase will be driven by several factors, including rising demand for cloud computing and artificial intelligence, households and policy makers' response to weather, the development and rate of adoption of emerging technologies, and the extent to which demand response programs affect peak levels. Cumulatively, these influences will require developing independent and increasingly complex models for forecasting average energy, peak energy, and load profiles, as well as ingenuity to produce robust results in the face of limited data.

3.1 Results

A detailed examination of the impact of the forecast drivers shows that the impacts from recent seasonal weather forecasts and behavioral responses to policy changes have counteracting effects on seasonal average energy. Rising temperatures increase load in the summer months and decrease it in the winter. These effects are accentuated over time but given the larger proportion of energy demanded during the winter months through the study horizon, the net load effect is negative. Including the impact of the Inflation Reduction Act has the opposite effect, reducing summer load and increasing winter load. The cost-reduction incentives on technologically effective end-uses drives consumers to substitute efficient cooling systems, like heat pumps or central air conditioning, lowering electric energy use during the summer. During the winter months, the incentives drive consumers to substitute natural gas-powered equipment with electric equipment at the margin, so electric energy use rises. The effect of fuel-switching dominates in BPA's service territory, so annual average energy demand is higher relative to the pre-IRA case. Figure 3-3 illustrates these effects on forecasted customer total retail load.

Figure 3-3 Annual and Seasonal Load Growths and Factor



The direction of the effect of transportation electrification within the region and specifically within BPA's customer service territories is the same across seasons, but load growth is slightly higher in the summer months given the increased use of electric vehicles during the busy driving season. Figure 3-4 shows the monthly forecast for the Base Scenario with and without transportation electrification, where summer seasons are shaded in light gray. The stock of light duty electric vehicles increases over the period considered, with the rate accelerating in the late 2020s and early 2030s as current tax credits expire. In the Fast Transition Scenario, another acceleration occurs in the following decades as emission target deadlines loom closer.

Figure 3-4 Monthly Load Growths

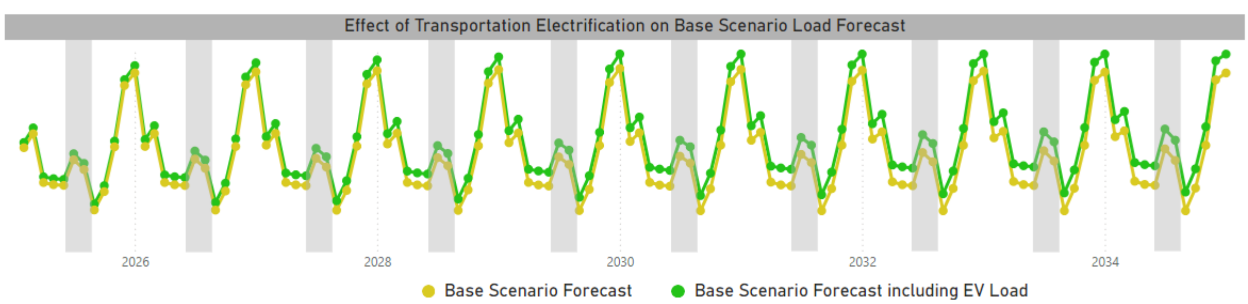
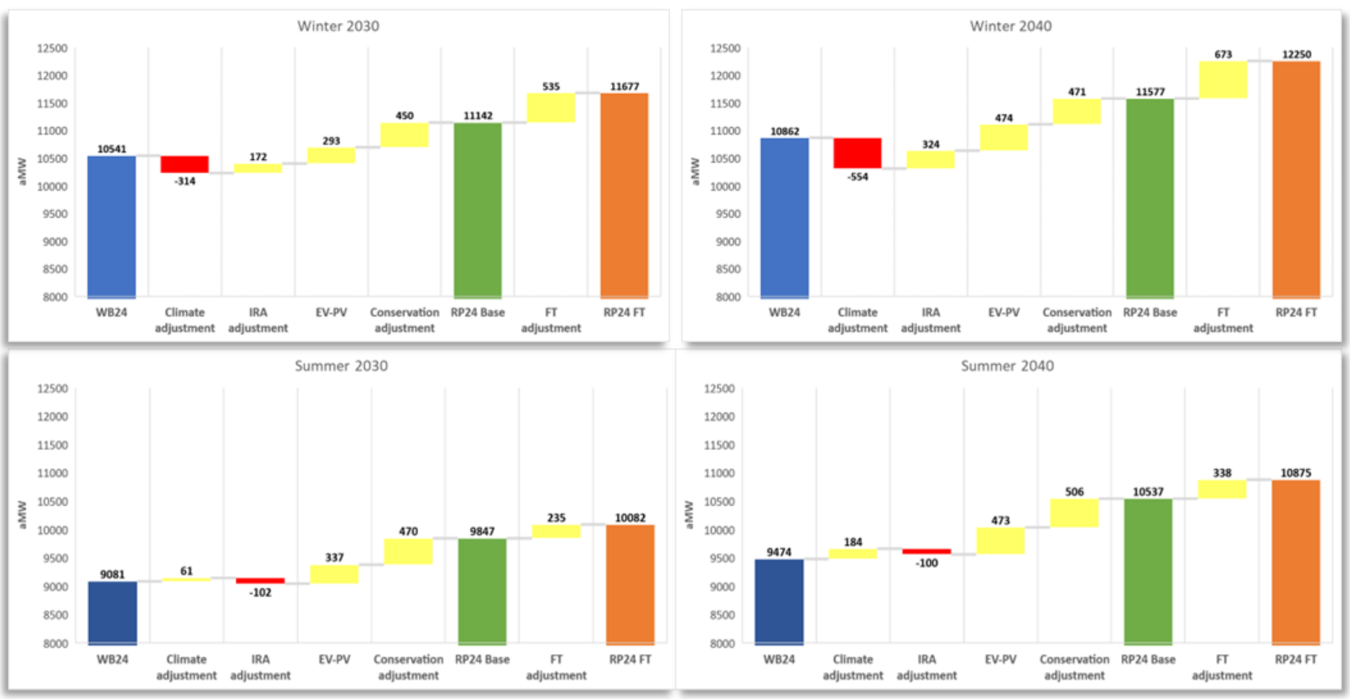


Figure 3-5 shows a summary of all load drivers and their relative magnitude at two points in time: 2030 on the left panel and 2040 on the right. The top two panels show the effect during the winter months and the bottom two panels show the effect during the summer months. The blue bar in the top left graph reflects the Expected Case load forecast of about 10,500 aMW created for use in the Agency's processes for medium term planning (1-3 years). The red bar represents the effect of incorporating the assumption of changing seasonal weather, which lowers the Expected Case load forecast by about 300 aMW as a result of the decrease in demand for heating. The adjustment to account for recent policy changes, including IRA, results in an additional 170 aMW as it accelerates adoption of electric heat. The green bar represents this year's Resource Program Base Scenario load forecast of about 11,000 aMW, which includes the energy savings that result from energy conservation. Adding conservation is necessary to allow the least-cost resource selection to include conservation. Finally, a set of policies that accelerates the transition to net-zero emissions results in an additional 500 aMW, which brings the level of energy demanded in the winter of 2030 to 11,677 aMW in the Resource Program Fast Transition (FT) Scenario.

Figure 3-5 Seasonal Load Forecast by Studies & Factors



Section 4: Needs Assessment

4.1 Overview

The Needs Assessment measures the federal system's[9] expected generating resource capabilities to meet projected load obligations under a range of conditions and timeframes. While the overall methodology remained largely the same from the 2022 Needs Assessment, the 2024 Needs Assessment:

- Increases the study horizon from 10 to 20 years, spanning fiscal years (FY) 2026 - 2045.
- Adjusts data inputs characterizing variation in streamflows and reflects updated agreements to longstanding litigation between interested parties over federal agencies' river operations.
- Adopts a zonal approach to separately assess resource adequacy in the Western Resource Adequacy Program (WRAP) Mid-C and Southwest-East Diversity Exchange (SWEDE) zones, as they pertain to the BPA Power Services load service territory.
- Includes a new month average energy metric based upon p10 generation levels to measure adequacy
- Considers planning risks associated with firm power obligations, new transmission infrastructure availability and resource capabilities through sensitivity analysis.

Hydro generation for the first nine years of the study are incorporated by analyzing streamflows from the most recent 30 water years, taken from the 2020 Level Modified Streamflow set. For the last 11 years of the study, generation values are based on streamflow sets derived from models developed in Part II of the RMJOC's research project (RMJOC-II). Further, fish operations are modeled after the Resilient Columbia Basin Agreement (RCBA) as adopted on December 14, 2023, until its current expiration in FY34, after which the model reverts to fish operations as specified by the Columbia River System Operations (CRSO) Environmental Impact Statement selected alternative.

In addition, the Needs Assessment explores the impact to long-term inventory positions from some amount of forecast regional load growth above existing Regional Dialogue contract levels being placed on Bonneville. It also provides insight into the needs associated with augmenting the capabilities of the existing Federal Columbia River Power System (FCRPS) to a higher fixed system size. The results of these sensitivities allow the Resource Program to consider the impacts of increased regional electricity demand on the BPA power system and inform BPA's decisions around how best to meet those needs, including through resource acquisitions.

Finally, inventory positions for all metrics are separately determined for the Mid-C and SWEDE zones with the assumption that transmission capabilities will be used to serve load in the SWEDE zone using resources from the Mid-C zone. One sensitivity explores the impact to the SWEDE zone from a delay in

[9] Details on the federal system's generating capacity can be found in the most recent version of BPA's Pacific Northwest Loads and Resources Study, often referred to as the "White Book," which is available at Resource Planning. In the 2024 White Book, the federal system's generation details can be found in Tables 2-6 and 2-7.

energization of the Boardman to Hemingway (B2H) transmission line combined with extreme weather events and potential curtailment of existing transmission rights.

4.2 Methodology

The Needs Assessment begins with forecasts of federal system load obligations and resource capabilities at the hourly frequency, with variation in both forecasts arising from the range of streamflow conditions evaluated. This analysis is used to produce forecast inventory positions for each hour and every water year. Hours are then aggregated to assess the average monthly surplus/deficit position during different hour categories and months, and a planning threshold (e.g., p10 or p50 hydro conditions) is used to select a single value for each planning month-year.

Load obligations and conservation adjustment: BPA's Agency Load Forecasting system (ALF) produces load forecasts, including power sales contract obligations to public and federal agency customers and to the U.S. Bureau of Reclamation, as well as other contract obligations. The load forecast beyond the terms of the current long-term power sales contracts assumes no material contract election or rate structure differences from Regional Dialogue.

The load reduction achieved through past energy efficiency programs is embedded into metered load data, so producing a Frozen Efficiency forecast is required to explicitly account for historical energy savings in demand forecasting models. This is achieved by including conservation as an independent variable, which improves the models' goodness of fit by explaining declining energy consumption over time and projecting historic energy savings forward. The Council's 2021 Northwest Power Plan targets are omitted from the load forecast since no assumption is made regarding future energy efficiency savings. Hence, the frozen efficiency adjustment effectively increases the firm power obligations being studied in the Resource Program relative to other studies (e.g., the White Book).[10]

Resources: BPA forecasts the resource capability of the federal system using two computer models: 1) HYDSIM (Hydro System Simulator) for monthly and annual energy; and 2) RiverWare for hourly energy and capacity. The models assess the resource capability to meet loads under expected load conditions and extreme temperature events over a range of possible water conditions while also meeting non-power requirements. To incorporate the federal system contract purchases and non-hydro generation in the study, the RiverWare model operates to an hourly Federal Residual Hydro Load. The Federal Residual Hydro Load is the hourly federal load obligations minus the hourly contract purchases and non-hydro generation in BPA's resource portfolio. Table 4-1 and Table 4-2 below show system generation under various streamflow conditions.

Consistent with the methodology employed by the Western Resource Adequacy Program (WRAP), this assessment splits BPA's service territory into two zones: the Southwest-East Diversity Exchange (SWEDE) and the Mid-Columbia (Mid-C). The Needs Assessment links the zones through a transmission constraint reflecting the challenge in getting electrical power generated or acquired in the Mid-C zone to loads in the SWEDE zone. Figure 4-1 sketches the SWEDE zone on the BPA Transmission System and Federal Dams map. Note that the Mid-C zone is everywhere outside of the SWEDE area.

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[10] The incremental conservation needed to meet the 2021 Northwest Power Plan targets and used to mitigate the deficits identified in this Needs Assessment is discussed in Section 6.3 – Results: Least Cost Portfolios.

Table 4-1 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[11] - OY2025, 2024 White Book

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity d/ (MW)	High c/ Energy (aMW)	Median c/ Energy (aMW)	Firm Energy a/c/ (aMW)	
Regulated Hydro								
1. Albeni Falls	1955	USACE	3	50	21.5	25.8	25.3	
2. Dworshak	1974	USACE	3	465	304	193	155	
3. Hungry Horse	1952	USBR	4	310	129	94	88	
4. Libby	1975	USACE	5	605	280	236	193	
5. Grand Coulee /	1941	USBR	27	6,684	3,063	2,306	1,872	
GCL Pumping	1973		6	314				
6. Chief Joseph	1955	USACE	27	2,614	1,780	1,372	1,106	
7. Lower Granite	1975	USACE	6	930	295	190	139	Lower Snake River Projects
8. Little Goose	1970	USACE	6	930	312	207	155	
9. Lower Monumental	1969	USACE	6	930	297	203	147	
10. Ice Harbor	1961	USACE	6	693	260	190	144	
11. McNary	1953	USACE	14	1,120	626	545	451	Lower Columbia River Projects
12. John Day	1968	USACE	16	2,480	1,374	994	787	
13. The Dalles	1957	USACE	22	2,080	1,081	817	642	
14. Bonneville b/	1938	USACE	18	1,221	722	527	387	
15. Total Regulated Hydro Projects			**169**	**21,426**	**10,546**	**7,901**	**6,291**	
Independent Hydro Projects								
16. Anderson Ranch	1950	USBR	2	40	16	12	13	
17. Big Cliff	1954	USACE	1	21	14	11	11	
18. Black Canyon	1925	USBR	2	8.5	8	6	7	
19. Boise Diversion	1908	USBR	3	2.5	1	1	1	
20. Chandler	1956	USBR	2	12.2	9	7	6	
21. Cougar	1964	USACE	2	28	9	5	5	
22. Cowlitz Falls	1994	LCPD#1	2	70	33	29	29	
23. Detroit	1953	USACE	2	115	33	26	23	
24. Dexter	1955	USACE	1	17	10	8	8	
25. Foster	1968	USACE	2	23	10	8	8	
26. Green Peter	1967	USACE	2	92	22	16	16	
27. Green Springs	1960	USBR	1	18	7	7	7	
28. Hills Creek	1962	USACE	2	34	24	19	17	
29. Lookout Point	1954	USACE	3	138	17	15	20	
30. Lost Creek	1975	USACE	2	56	42	37	31	
31. Minidoka	1909	USBR	4	28	19	14	11	
32. Palisades	1957	USBR	4	177	100	92	77	
33. Roza	1958	USBR	1	14	9	8	6	
34. Total Independent Hydro Projects			**38**	**894**	**381**	**320**	**296**	
Small Non-Federally Owned Hydro Projects								
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6	
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3	
37. Total Non-Federally Owned Hydro			**2**	**7**	**2.9**	**2.9**	**2.9**	
38. Total Hydro Generation *(line 15 + line 34 + line 37)*			**209**	**22,327**	**10,930**	**8,223**	**6,589**	

a/ Firm energy is the 12-month annual average for OY 2025 assuming 10th percentile (P10) water conditions
b/ Bonneville Dam generation totals include Bonneville Fishway
c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile
d/ Maximum Capacity represent full capacity of resource including overload.

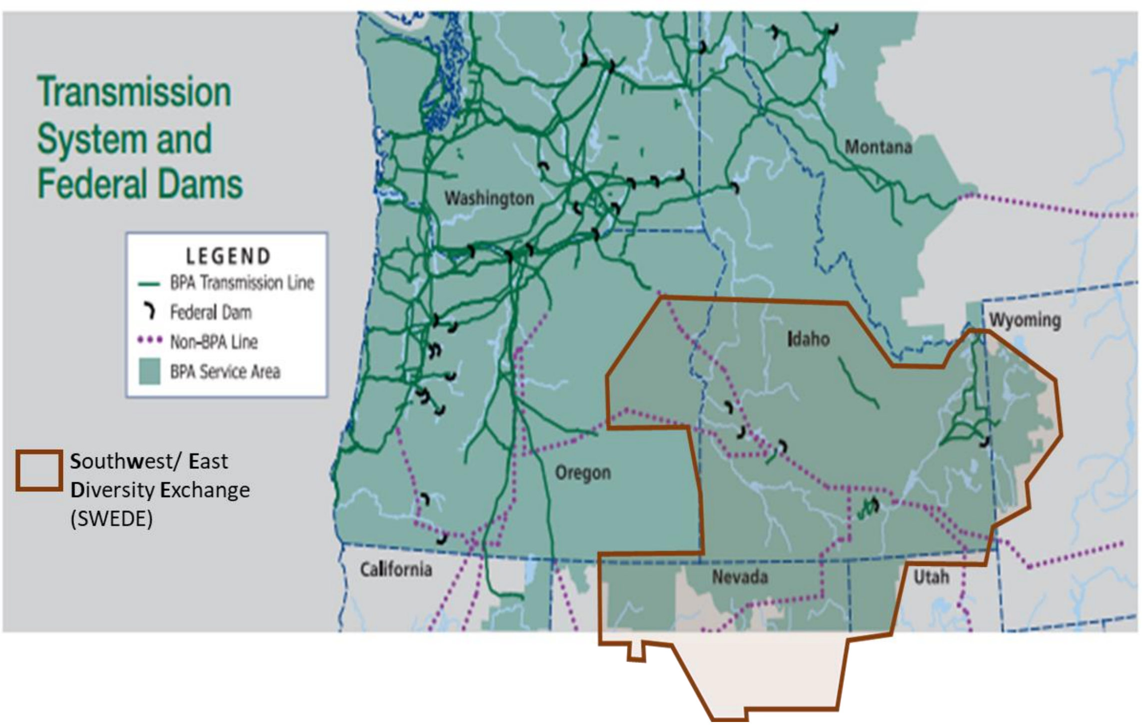
[11] Streamflow conditions do not always have a linear correlation with generation output. Projects with smaller head (head = forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head, this results in lower generation than in other lower flow conditions.

Table 4-2 Federal System Non-Hydro Project Generation Forecast and Contract Purchases - OY2025, [2024 White Book]

	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity a/ (Peak MW)	Firm Energy (aMW)
	Non-Hydro Resources					
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	994
2	Stateline Wind Project b/	2001	Wind	PPM, FLP	0	21.2
3	Klondike Phase III c/	2007	Wind	NW Wind Power	0	11.8
4	Fourmile Hill Geothermal d/	Not in Service	Geo.	Calpine	0	0
5	**Total Federal System Non-Hydro Resources**				**1,178**	**1,027**
	Contract Purchases					
6	Canadian Entitlement for Canada (non-Federal)				237	135
7	Canadian Imports				1	1
8	Pacific Southwest Imports				0	0
9	Intra-Regional Transfers In (Pacific Northwest Purchases)				175	69
10	Slice Transmission Loss Return				41	28
11	**Total Federal System Contract Purchases**				**454**	**233**
12	**Total Federal System Non-Hydro Resources and Contract Purchases**				**1,632**	**1,259**

a/ This is the maximum generation for January 2025
b/ Stateline Wind Project contract expiring in 2028
c/ Klondike Phase III Project expiring in 2029
d/ Fourmile Hill is not assumed to be in operation within the study period

Figure 4-1 SWEDE zone. [BPA Facts, Fiscal Year 2023, DOE/BP-5295, September 2024]



4.3 Metrics

The 2024 Needs Assessment relied on two sources for developing streamflow assumptions across the study horizon: the recent 30 years from the 2020 Level Modified Flows set (30WY) and a set of 30 water years for each of three models from RMJOC-II.

Depending on the study, up to four metrics, including annual energy and different capacity studies, were used to determine the ability of the federal system's generating capability to meet obligations.

- 30WY: The 30-year study uses streamflow data from the most recent 30 years, 1989-2018, of the 2020 modified streamflow records.

- RMJOC-II: Three RMJOC-II scenarios (CCSM, CNRM, and IPSL) were used for the out-years streamflow simulation. Additionally, two blocks of water-year (WY) (2021-2050 and 2030-2059) were used to provide more focused study periods. FY2035 to 2039 were evaluated using RMJOC-II WY 2021-2050, and FY2040 to 2045 were evaluated using RMJOC-II WY 2030-2059.

While data on firm power obligations and federal system capabilities are simulated at the hourly level for all water years, the Needs Assessment summarizes the long-term surplus/deficit position using a set of metrics based on averages over blocks of time:

1. Annual Energy: Evaluates the annual average energy surplus/deficit under p10-by-month critical water conditions.

2. Monthly p10 Average (AVG) Energy: Evaluates the monthly average surplus/deficit over all hours under p10-by-month critical water conditions.

3. Monthly p10 Heavy Load Hour (HLH) Energy: Evaluates the monthly average surplus/deficit over heavy load hours (hours ending 7-22, Monday-Saturday, excluding holidays) under p10-by-month critical water conditions.

4. Monthly p10 Superpeak (SPK) Energy: Evaluates the monthly average surplus/deficit over the six peak HLH each weekday (Monday-Friday) under p10-by-month critical water conditions. The roughly 120 superpeak hours per month are a subset of the roughly 384 heavy load hours per month.

5. 18-Hour Capacity: Evaluates the monthly average surplus/deficit over six peak load hours each day across three-day extreme weather load events under median water (p50) conditions. Winter events used actual temperatures from the January 2024 event for Dec/Jan/Feb, while summer events relied on actual temperature from the June 2021 event for July/August.

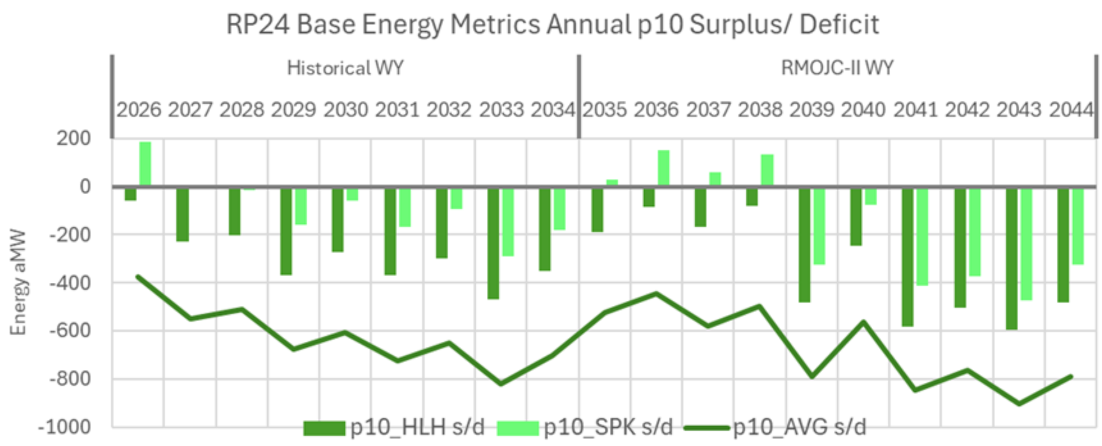
4.4 Results from Scenario Analysis

Results from studying BPA Power Services' total load obligations and generating capabilities net of conservation measures indicate deficits in all periods except for early summer months after runoff starts. The largest deficits tend to arise in late winter and just before the spring runoff begins due to a combination of particularly low water and non-power requirements.

4.4.1 Annual Energy

The following figures display the results from each scenario of the federal system's capability to meet energy loads on an annual basis, for all three energy metrics: p10 AVG, p10 HLH, and p10 SPK. Annual results are weighted monthly averages of 14 periods: 12 months plus two split months, April and August. Negative results (deficits) indicate shortfalls from resources to meet load obligations, therefore, those are identified as needs to be solved in Resource Solutions.

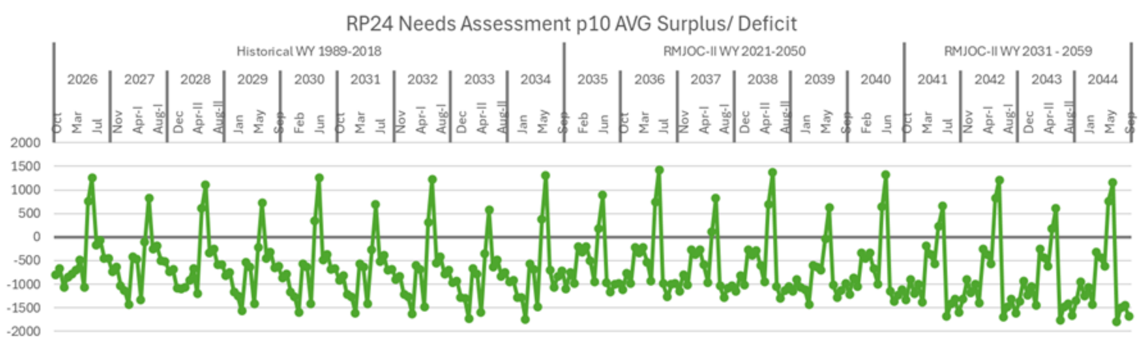
Figure 4-2 Base Scenario Annual Energy Metrics Surplus. Deficit Summary



4.4.2 Monthly p10 AVG Energy

This metric analyzes the ability of the federal system to meet energy loads across all hours under p10-by-month critical water conditions.

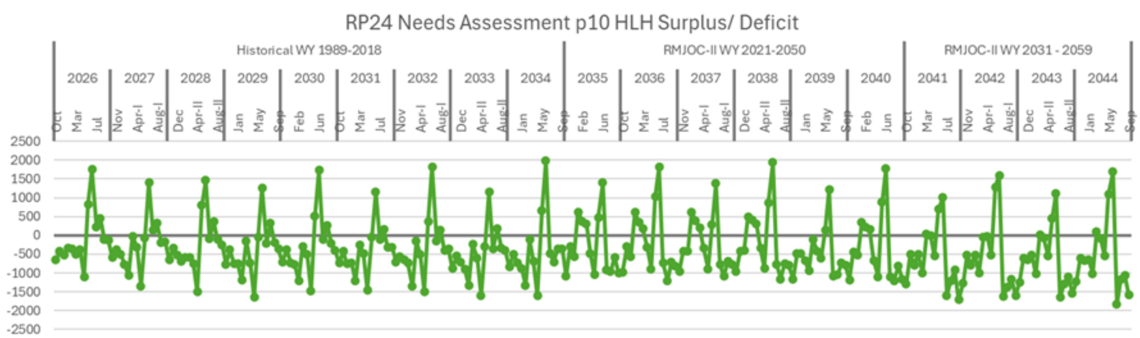
Figure 4-3 Monthly p10 AVG Energy Surplus/ Deficit, Base



4.4.3 Monthly p10 HLH Energy

This metric analyzes the ability of the federal system to meet HLH loads p10-by-month critical water conditions.

Figure 4-4 Monthly p10 HLH Energy Surplus/ Deficit, Base



4.4.4 Monthly p10 SPK Energy

This metric evaluates the ability of the federal system to meet loads over the six peak-load hours per weekday under p10-by-month critical water conditions.

Figure 4-5 Monthly p10 SPK Energy Surplus/ Deficit, Base

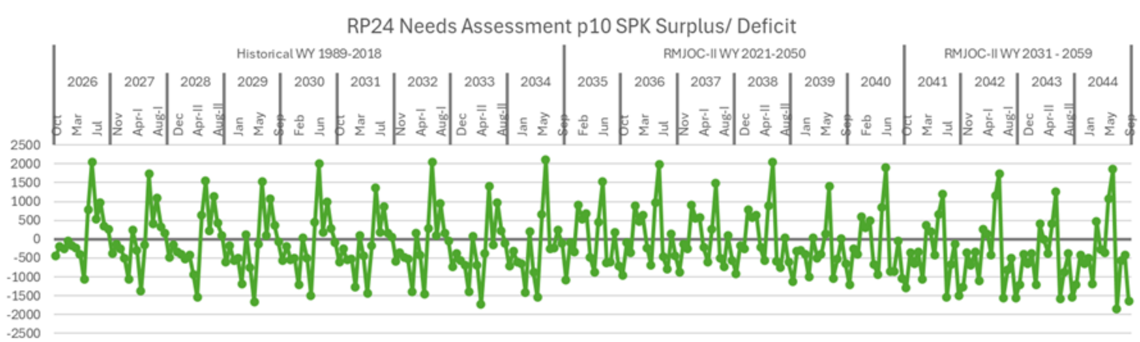
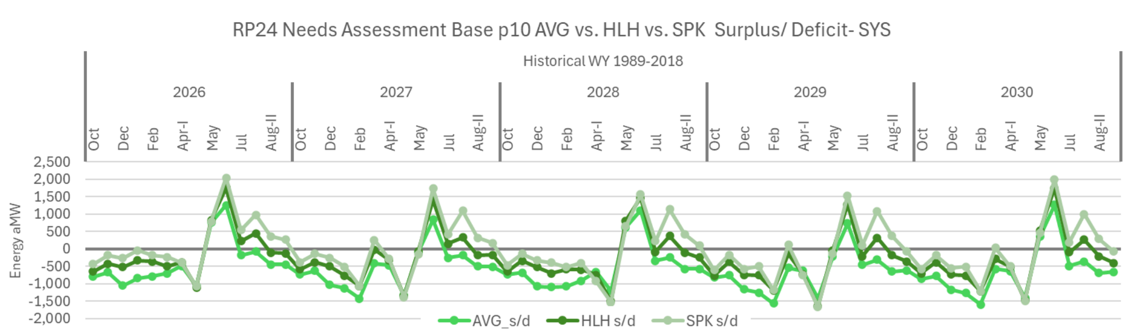


Figure 4-6 provides a close-up comparison across the energy metric surplus/deficit results and displays all three energy metrics for FY 2026-2030 under the Base scenario.

Figure 4-6 Monthly p10 Energy Surplus/ Deficit Summary, Base (FY2026-2030)



4.4.5 Fast Transition Scenario

In the Fast Transition (FT) scenario, load forecasts are adjusted to reflect more optimistic economic growth, net-zero by 2050, and an evolving load profile from changing household behaviors. As with the Base scenario, the FT load forecast assumes no change in the BPA customer base post-2028 and continues assuming Regional Dialogue product elections, resulting in a modest impact on BPA's firm power obligations. See FT loads in comparison with Base Scenario in Figure 4-11, for details. With the same resources as the Base scenario in the Needs Assessment study, the Energy metrics surplus/deficit results are very similar to that from the Base scenario. Figure 4-7 and Figure 4-8 present the annual and monthly surplus/deficit results from the FT scenario, respectively.

Figure 4-7 Fast Transition (FT) Scenario Annual Energy Metrics Summary

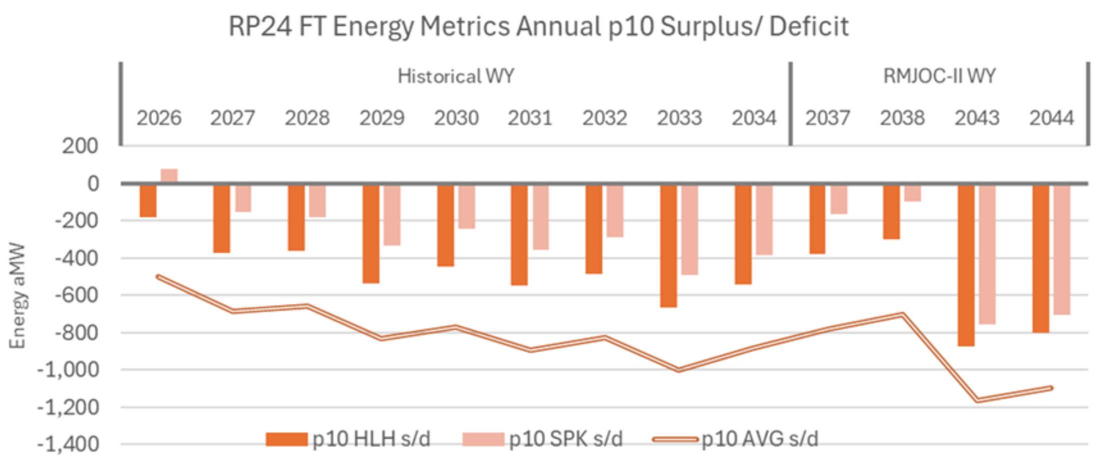
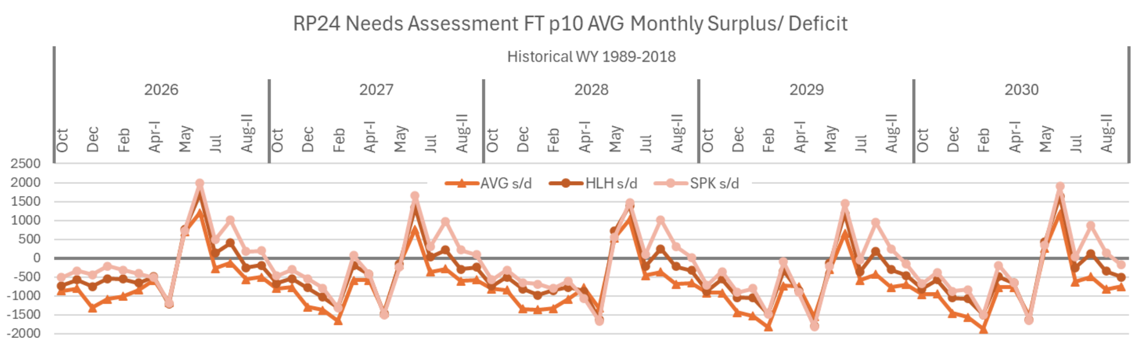


Figure 4-8 Monthly p10 Energy Metrics Surplus/ Deficit, Fast Transition (FT) FY2026-2030



4.4.6 <u>18-Hour Capacity</u>

The 18-Hour Capacity metric analyzes the ability of the federal system to meet loads over the six peak-load hours per day during a three-day extreme weather event under median water conditions. Two extreme weather events were studied: a heat event during summer and a cold event during winter. The months of December, January and February were analyzed for winter events; the months of July and August were analyzed for summer events. The 18-Hour Capacity study was conducted only in the sampling years: FY2026 to FY2028 and FY2031 to FY2032 for Historical Streamflow years, plus FY2037 to FY2038 and FY2043 to FY2044 for RMJOC-II streamflow years.

Figure 4-9 shows the resulting surplus/deficit for the 18-hour capacity metric under the Base and Fast Transition scenarios for all years, grouped by month. Under median water conditions the federal system is more than capable of supplying power during these extreme weather events in the winter. However, deficits begin to emerge in summer months of outyears. Figure 4-10**Error! Reference source not found.** presents the 18-hour capacity results for the SWEDE zone.

Figure 4-9 18-Hour capacity Surplus/Deficit, Base & Fast Transition (FT), System

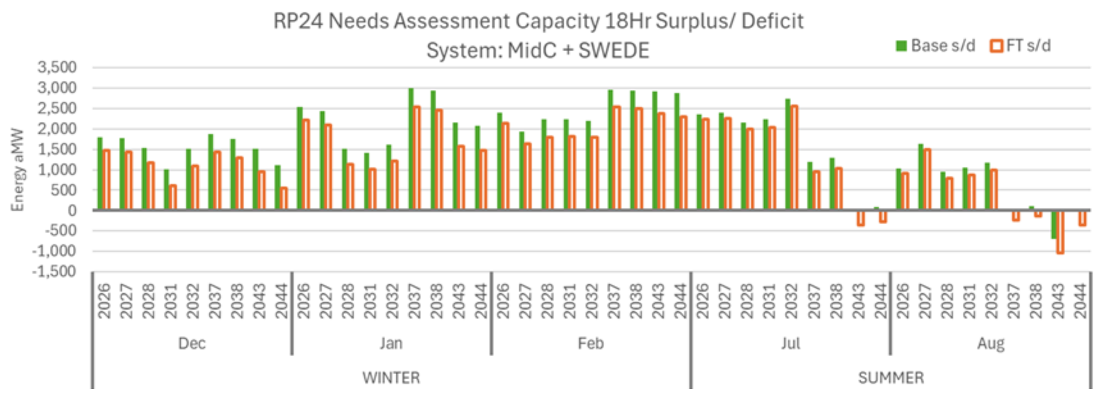
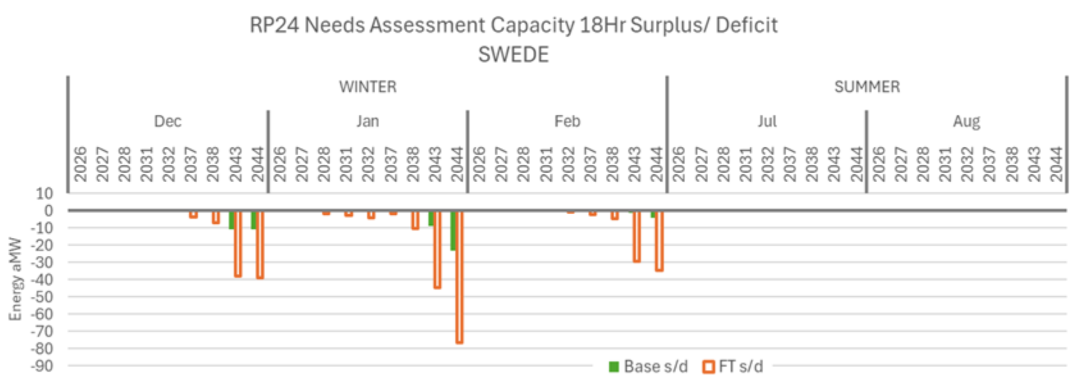


Figure 4-10 18-Hour Capacity Surplus/ Deficit, Base & Fast Transition (FT), SWEDE



4.5 Sensitivity Studies

In addition to the FT scenario, a number of sensitivities were studied to understand how BPA Power Services' needs are impacted by:

- Additional load service obligations that vary in timing, shape and size. (High and Medium Load Adders Sensitivities)
- Transmission infrastructure delay and constraints associated with curtailments limiting the ability to serve SWEDE load with Mid-C resources. (Boardman to Hemingway Delay Sensitivity)
- An increase in the generating capabilities of the existing system to a pre-specified fixed system level consistent with the Provider of Choice (POC) policy decisions. (Tier 1 System Size sensitivity)

In all cases, these adjustments were made relative to the hourly loads and resources studied in the Base scenario, leaving the FT scenario as a stand-alone study. Sensitivities exploring increased load service obligations (whether shaped or flat across the month) decrease expected surpluses and increase expected deficits relative to the Base scenario. Curtailments of transmission rights to deliver power in the SWEDE region can cause deficits in long-term planning. A modest annual augmentation of the FCRPS beyond its existing annual energy capabilities will require much larger increases in some months, particularly in the fall and winter due to existing large deficits in those periods.

4.5.1 Load Adders Sensitivity

To reflect the possibility that some amount of the region's expected load growth over the study horizon is placed on BPA Power Services, the 2024 Needs Assessment analyzed two potential load growth paths:

- Medium Load adder: Obligations increase relative to the Base scenario by 400 aMW starting in FY29, rising to an increase of 2,500 aMW by FY2045. The annual averages are shaped across the year based on current Slice customers' loads at the hourly level; and the adder is applied proportionally to every hour, which has the effect of making the increase in peaks more pronounced.[12] This resembles a future where customers place load growth on BPA Power Services at a Tier 2 rate.[13]

- High Load adder: Obligations increase relative to the Base scenario by 975 aMW starting in FY2026, rising to an increase of 4,800 aMW by FY 2045. The annual averages are applied additively to every hour, reflecting the impact of flat large loads with relatively high load factors being placed on BPA Power Services. This resembles a future where customers place load growth on BPA Power Services at the New Resource (NR) rate, such as for New Large Single Loads (NLSL).

Figure 4-11 presents the total obligations at the annual aMW level modeled for each of the Base and Fast Transition scenarios as well as the medium and high load adders. While it is possible for some or all of the load in the High and Medium Load Adders to both be placed on BPA, the 2024 Resource Program analyzed each adder independently.

[12] BPA's Slice product commits BPA to make a specific amount of power available to the purchaser in a shape the reasonably represents the storage and flexibility of Federal Base System (FBS) resources

[13] BPA utilizes a two-tiered rate design for sales of firm power, with a specified amount of power available for purchase at a cost-based rate (Tier 1) and purchases beyond that assessed at the Tier 2 rate reflecting the actual or forecast price paid to acquired the additional power requested.

Figure 4-11 Total Annual Average Obligations for Scenarios and Load Adder Sensitivities, Energy aMW

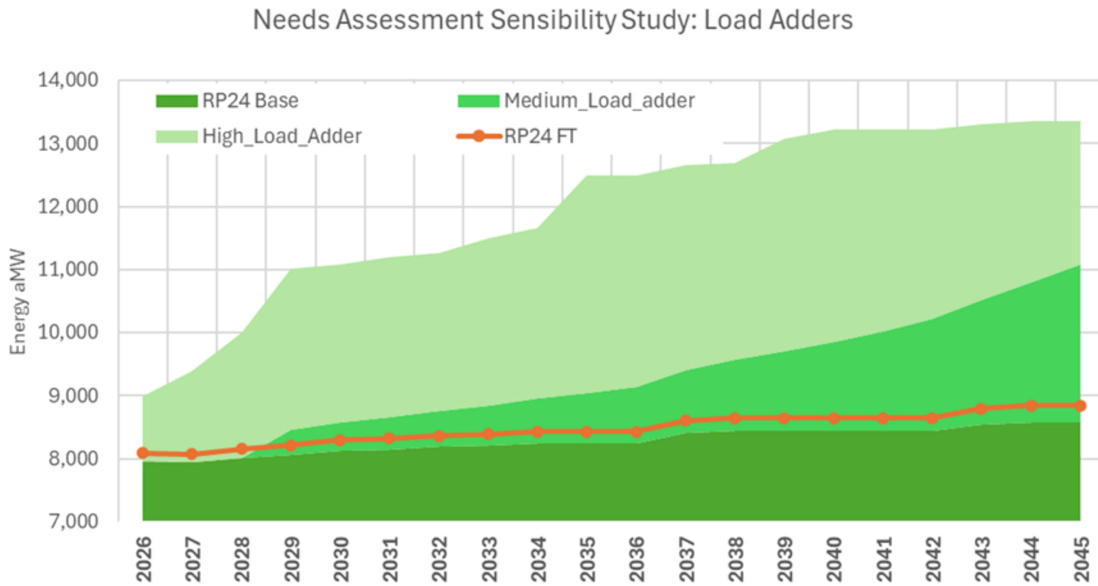
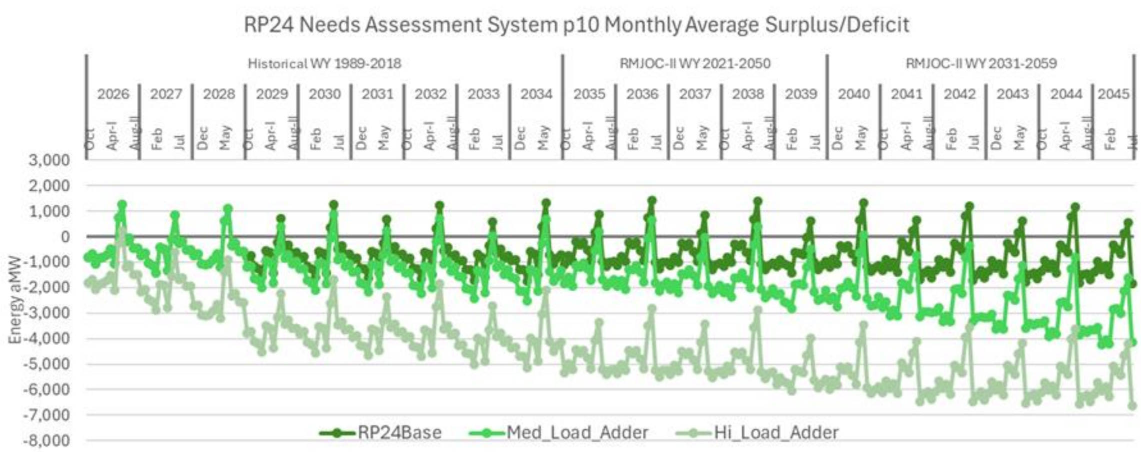


Figure 4-12 shows study results from the p10 Monthly Average Energy surplus/ deficit with both Load Adder sensitivity studies and Base case.

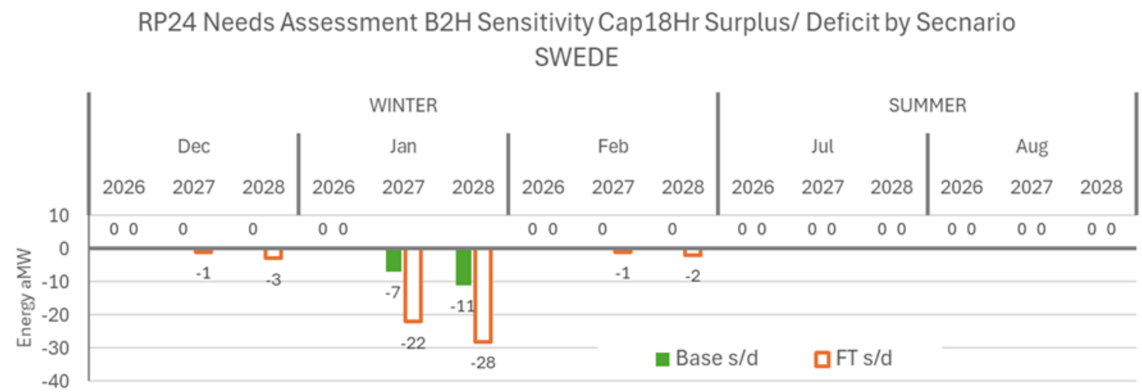
Figure 4-12 Monthly p10 Average Energy Surplus/ Deficit, Base vs. Medium & High Load Adder Sensitivities



4.5.2 B2H Delay Sensitivity

Under the 18-hour capacity metric, which pairs extreme weather loads with median resources, these results focused on the first three years of the study: 2026 to 2028. The sensitivity assumed that the B2H transmission project was delayed until July 2028 and assumed a reduction in existing transmission capability from 1,000 aMW to 900 aMW, limiting access to meet needs in the SWEDE zone. Figure 4-13 shows no SWEDE zone deficits occurred in the summer months under this sensitivity. The winter months, January in particular, show small levels of deficits in the SWEDE zone, meaning that loads exceed both local resources and the transmission capability.

Figure 4-13 18-Hour Capacity B2H Sensitivity, FY 2026-2028, SWEDE



4.5.3 Tier 1 System Size Sensitivity

As part of the Provider of Choice (PoC) long-term contract policy, BPA committed to fixing the amount of power available to be purchased by preference customers at a Tier 1 rate to 7,250 aMW annually. To support a shared understanding of the impact of the size and timing of this augmentation, the Needs Assessment includes a separate sensitivity in which the components of the Tier 1 System Firm Critical Output (T1FSCO) are calculated for all periods in the study and compared to the desired generation capability associated with the new fixed system, which is assumed to start in FY29 and shaped within-year based on BPA's existing Tier 1 firm obligations.

Figure 4-14 Annual T1SFCO forecast, Annual & Monthly T1 Needs

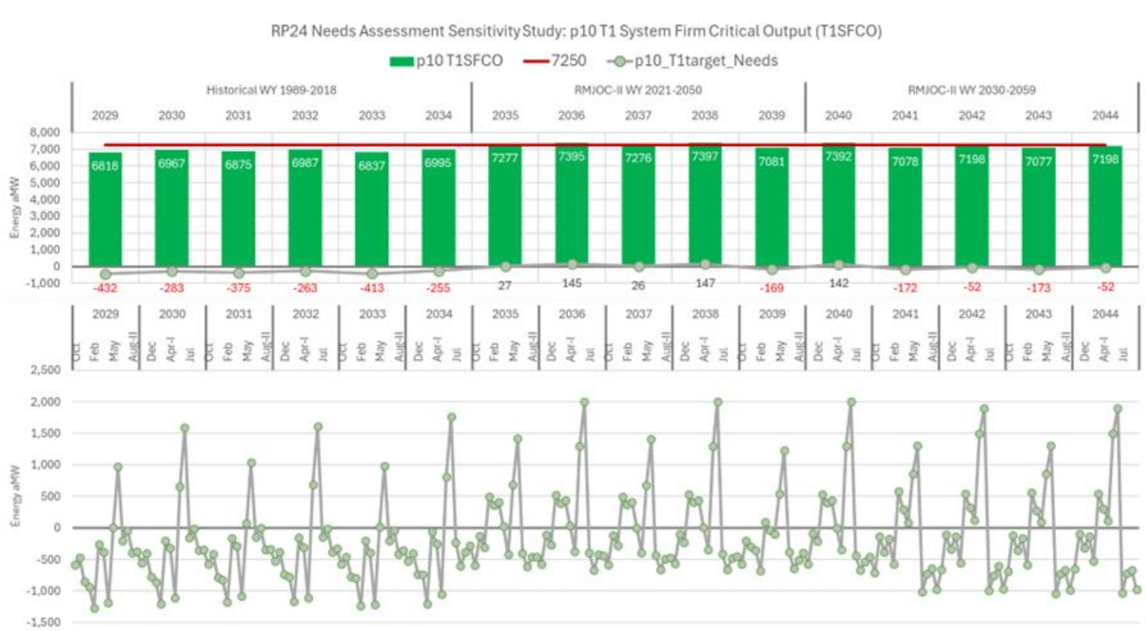


Figure 4-14 presents the size and timing of the T1SFCO. While average needs at an annual level range from around 250-400 aMW, augmentation needs at the monthly level are significantly larger in the late winter and before the spring runoff has begun.

4.6 Conclusions

Overall, the 2024 Needs Assessment results are generally consistent with prior Resource Program studies showing widespread average monthly surplus/deficit positions across many hour blocks, with the size of the deficits being largest when looking at the balance of energy across all hours. The deficits are relatively smaller in HLH and SPK due to FCRPS load factoring to capture economic value. In general, the largest of these deficits occur in late winter (February) and just before the runoff begins in the second half of April.

Deficits generally increased relative to the 2022 Resource Program due to increased load obligations and decreased resource generation. Impacts to varying resource generation depends highly on different streamflow assumptions, and recent fish operation updates, such as the RCBA. These results are exacerbated in sensitivities that consider the impact of large increases in load service obligations stemming from the possibility that customer load growth is ultimately placed on Bonneville.

As in prior Resource Programs, BPA's system has surplus capacity (as measured by its ability to meet obligations in the six peak load hours over three consecutive days during an extreme weather event) in the winter and the summer under average generation historical streamflows. Some deficits emerge in the summer months toward the second half of the study period (FY2035-FY2045) under RMJOC-II streamflows.

Section 5: Candidate Resource Assessment

5.1 Candidate Generating Resources

Guided by the Power Planning and Conservation Council's power plan and in accordance with the resource priorities of section 4(e)(1) of the Northwest Power Act, the analysis below identifies plant types considered herein. The 2024 Resource Program uses a set of technologies similar to the 2022 Resource Program, with some modifications, including the addition of 12-hour storage and traditional geothermal power.

Candidate resources are selected based on technical availability within the region and over the study horizon. All options are representative estimates with limited location information. Resources outside the Mid-C or SWEDE zones are not considered, and there are no specific project options included in the 2024 Resource Program. Other than Small Modular Reactors (SMR), there are no new emerging technology options. Candidate resources are not pre-screened based on relative levelized costs of energy or capacity.

The section below summarizes the resource plant types considered for the 2024 Resource Program. Natural gas-fired generation was also considered through analysis outside of the Solver and the characteristics and modeling approach for natural gas resources is discussed in detail in section 6.4.

- **Wind:** BPA models onshore wind in two locations – the Mid-C and SWEDE zones. BPA estimates wind output in the Mid-C zone using an hourly risk model designed for rate-setting evaluations that relies on historical BPA BA generation data. Wind output in the SWEDE zone relies on a representative, 8,760 hourly generation profile for Idaho wind included in the database of the production cost model Aurora[14].
- **Solar:** Single-axis tracking utility-scale solar resources are included with four representative solar generation shapes – southeast Idaho, eastern Oregon, western Oregon, and eastern Washington – to reflect different possible solar output profiles in the BPA region. The generation profiles consist of 8,760 hourly output levels that capture normal resource variability and align monthly output with generation of a typical weather year, using National Renewable Energy Laboratory data.
- **Paired solar and storage:** BPA includes two locations for alternating current (AC)-coupled solar and storage resources in the 2024 Resource Program. The representative generation shapes for eastern Washington and southeast Idaho described above are used for the solar portion of the resources. These solar resources are paired with a four-hour battery storage system, where the nameplate capacity of the storage resource is equal to half of the solar nameplate capacity.
- **Standalone six and twelve-hour battery storage:** These resources are modeled as lithium-Ion battery systems. Their dispatch is modeled using Aurora storage logic in the performance studies, described in Section 6.2.2.
- **Geothermal:** BPA includes traditional geothermal resources available in the Mid-C and SWEDE zones. These resources are assumed to have some flexibility to dispatch in response to prices. Their dispatch is modeled in the performance studies, described in Section 5.1.1.
- **Small modular reactor (SMR):** BPA models small, modular nuclear reactors available in the Mid-C and SWEDE zones. These resources are not based on a specific technology type, and are

[14] The Aurora model is described in Section 5.3.

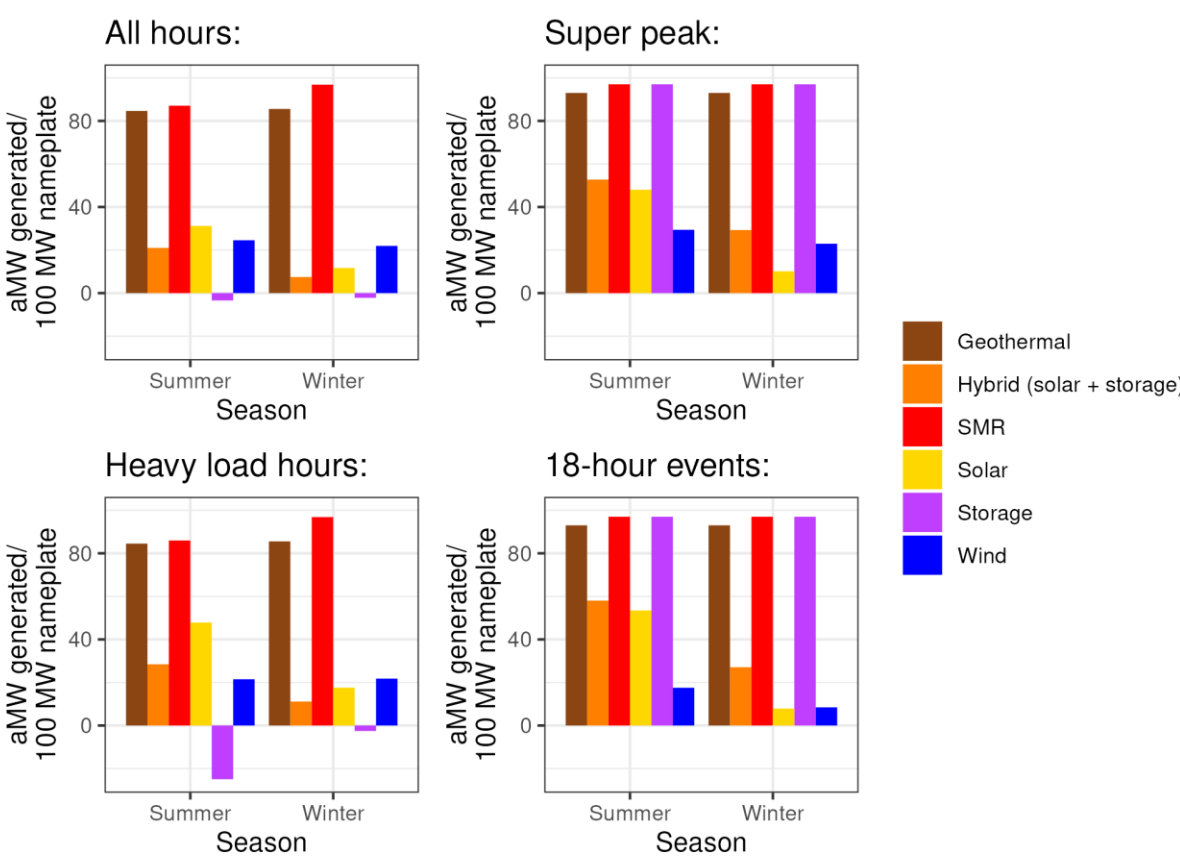
assumed to have substantial flexibility to commit and dispatch based on market prices. Their commitment and dispatch is modeled in the performance studies, described in Section 5.1.1.

5.1.1 Resource contributions to meeting needs

Figure 5-1 shows the representative contributions of each modeled resource type to meeting monthly average, HLH, superpeak, and 18-hour capacity needs. During superpeak hours and 18-hour events, SMR and geothermal resources are assumed to be running, and storage resources are assumed to be discharging, barring outages. Forced outage rates are assumed to be 3% for SMR and storage, and 7% for geothermal. To calculate contributions of wind generation to meeting 18-hour capacity and superpeak needs, BPA uses BPA system and Idaho Power Company BAA historical wind generation data during actual superpeak periods and 18-hour events.

Resource contributions to p10 flat and HLH energy needs are averages across the Aurora performance study runs (see Section 6.2.2 for more information about the performance study) with P85 to P95 monthly average energy prices. Using this subset of the performance study results for calculating contributions to p10 needs reflects the assumption that tight water conditions will result in high prices, supporting high generation levels.

Figure 5-1 Resource contributions to meeting needs



Values shown are averages for resources in the Mid-C region in FY2044 across the summer months of July and August and the winter months of December, January, and February. Actual modeled values vary across months and locations and between 6-hour and 12-hour storage.

5.1.2 Available capacities

Capacities available to the model are shown in Table 5-1. For modeling simplicity, only the following online years are considered as options: 2026, 2031, 2037, and 2043. Construction is assumed to occur prior to these dates, with construction times varying across resource types (Table 5-4). Capacities available to be built prior to 2035 are based on an assessment of resources currently in the BPA interconnection queue. The 2035 and later online dates for many resources incorporate the time required for construction and interconnection processes. In each location and start year, interconnection costs are set substantially higher for additions beyond a threshold nameplate capacity, which is 300 MW for solar, wind, and storage, and 450 MW for hybrid and SMR. The interconnection costs are described in more detail in section 5.1.4. Only very limited geothermal capacities are included as options in the Solver.[15]

Table 5-1: Supply-side resource options included in the 2024 Resource Program Solver

Types	Locations	MW nameplate capacity available per location and start year for each type	Special restrictions in 2026 or 2031
Solar	Western OR, Eastern OR, Eastern WA, SWEDE	300 MW + 1000 MW at higher interconnection cost	Only 600 MW available per location in 2026
Wind and 6- and 12-hour storage	Mid-C, SWEDE	300 MW + 1000 MW at higher interconnection cost	Only 600 MW available per location and type in 2026
Hybrid (solar + storage)	Mid-C, SWEDE	450 MW + 1500 MW at higher interconnection cost	Only 900 MW available per location in 2026
Geothermal	Mid-C, SWEDE	100 MW	Not available in 2026
Small modular reactor (SMR)	Mid-C, SWEDE	450 MW + 1000 MW at higher interconnection cost	Not available in 2026; only 450 MW available, in Mid-C only, in 2031

5.1.3 Resource costs

Cost calculations use two windows of time with substantially different assumptions, based on the earliest year a BPA-financed new resource could come online (Table 5-2). Resources coming online prior to 2034 are assumed to be power purchase agreements[16] for the full output of or partial stakes in projects that are already in development and in the transmission interconnection queue. Resources

[15] The Solver is a constrained optimization model described in Section 6.2.2 below.

[16] BPA's acquisition of any generating resource would be in the form of a power purchase agreement, because the Northwest Power Act prohibits BPA from ownership of "any electric generating facility." 16 U.S.C. § 839a(1).

coming online in 2035 or later are assumed to be greenfield or new projects that can fully benefit from BPA financing.

Resource-specific cost assumptions, including overnight capital costs, IRA treatment (production tax credit versus investment tax credit), fixed and variable operation and maintenance costs (FOM, VOM), plant life, and construction time, are shown in Figure 5-2, Table 5-3, and Table 5-4. Overnight capital costs for all resources other than the SMR are estimated from a blend of the 2023 EIA Annual Energy Outlook, 2023 NREL Annual Technology Baseline, and various consultant forecasts. The SMR overnight capital costs rely heavily on Idaho National Laboratory's 2023 review of SMR costs[17].

Table 5-2: Financing assumptions for supply-side resources

	2026-2034	2035+
Discount Rate (Nominal)	2.81%	
Weighted Average Capital Cost (Nominal)	7%	3.96%
Inflation Rate	~2.3%	
Investment Tax Credit (ITC)	30%	40% x 85% = 34%
Production Tax Credit (2020 $/MWh)	$23.89	$26.06 x 85% = $22.15

Figure 5-2: Overnight capital costs for supply-side resources

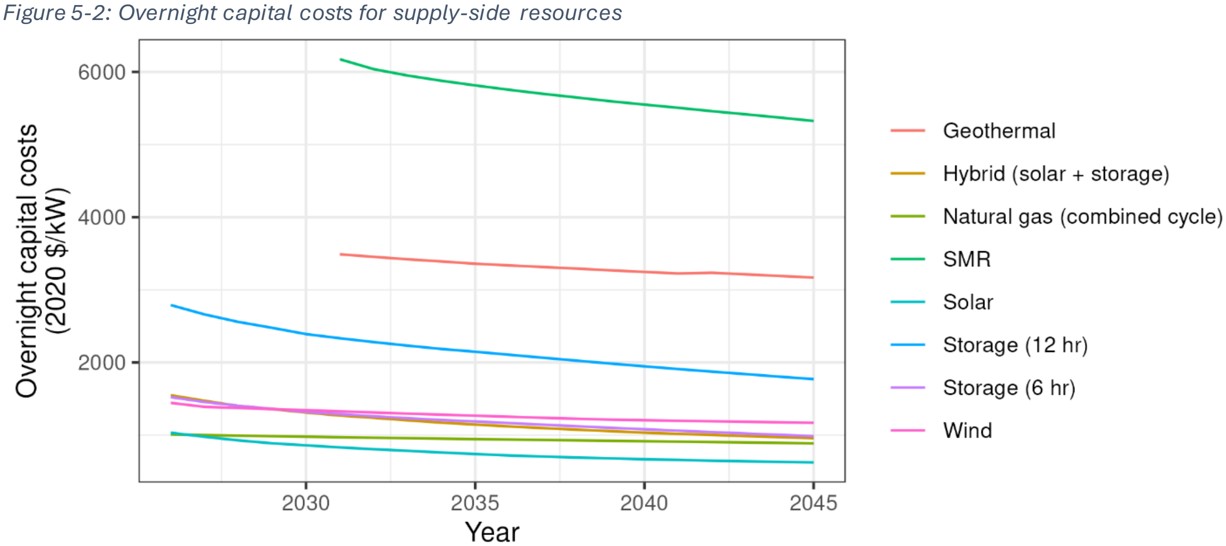


Table 5-3: Overnight capital costs for supply-side resources for the online dates used in 2024 Resource Program models, in 2020 $/kW

	2026	2031	2037	2043
Solar	1,033	831	705	639

[17] Literature Review of Advanced Reactor Cost Estimates, Abdalla Abou-Jaoude, Linyu Lin, Chandrakanth Bolisetti, Elizabeth Worsham, Levi M Larsen, Aaron Epiney. June 2023.

Wind	1,444	1,327	1,238	1,183
6-hour storage	1,523	1,288	1,144	1,022
12-hour storage	2,791	2,333	2,065	1,839
Hybrid solar + storage	1,548	1,269	1,097	986
Geothermal		3,489	3,314	3,213
SMR		6,174	5,698	5,416
Natural gas combined-cycle	1,009	970	933	899

Table 5-4: Resource-specific cost assumptions

	IRA Treatment	FOM (2020 $/kW-year)	VOM (2020 $/MWh)	Plant Life (years)	Construction Time (years)
Solar	PTC	19	0	30	1
Wind	PTC	33	0	30	3
6-hour storage	ITC	41	0	20	1
12-hour storage	ITC	65	0	20	1
Hybrid solar + storage	ITC	51	0	25	1
Geothermal	ITC	102	0	30	7
SMR	ITC	114	2.9	60*	6
Natural gas combined-cycle		29	1.8	30	3

*PTC = production tax credit; ITC = investment tax credit. * Presently, nuclear power licenses are approved for 40 years with the possibility of a 20 year extension. The 60-year plant life used for SMR in Resource Program 2024 is based on the assumption that the extension will be approved.*

Interconnection costs fall into two main categories: a small, low-cost set and a larger high-cost set. The low-cost set assumes some projects will not require substantial transmission upgrades or investments to connect to the system. These costs begin at $50/kW (real 2020$) for resources coming online in 2026 and escalate to $100/kW (real 2020$) for resources coming online in 2043. For the high cost set, interconnection costs begin at $400/kW (real 2020$) for resources coming online in 2026 and rise to $800/kW (real 2020$) for resources coming online in 2043. These costs are in addition to the overnight capital costs provided in tables 5-2 and 5-3.

Development of least-cost portfolios for meeting needs, described more fully in Section 6, is based on resource net costs over the full 20-year study horizon. Resource net costs are equal to fixed plus variable costs minus the value of the energy generated. Overnight capital costs and interconnection costs are converted into levelized fixed costs using the accounting assumptions summarized in Table 5-2 and Table 5-4. Fixed operations and maintenance costs are added to these levelized costs (Table 5-4).

Variable operations and maintenance costs, fuel costs, charging costs, and energy revenue (i.e., the value of the energy generated) are calculated in the performance studies and averaged across the full distribution of forecast market prices. Both storage costs and energy revenue are modeled on an hourly basis, so flexible resources are able to produce higher revenues by dispatching energy into more valuable hours. The study does not differentiate between whether the energy is avoiding a purchase or enabling a sale—all energy is valued at the forecast Mid-C price for the hour in which it is produced or consumed. Note that while energy needs and contributions to meeting those needs are modeled only for specific conditions (i.e., p10 water conditions), net costs represent expected values across the full range of possible conditions.

Net costs are discounted to net present value (NPV) and summed into a single net cost[18] for each resource option.

5.2 Conservation and Demand Response Supply Curves

5.2.1 Overview

The conservation and demand response (DR) measures that the Resource Program considers are identified and defined through studies conducted by BPA, the Council and the Council's Regional Technical Forum (RTF). The 20-year study period the Resource Program uses means that individual conservation or demand response programs can reach market saturation over the course of the study period. Accordingly, the Resource Program results are a picture of the currently achievable conservation and demand response resources selected as part of a least-cost portfolio of resources covering the 20-year time horizon.

BPA used updated conservation and demand response supply curves in the Solver which then compared and selected resources based on need, availability and cost. To determine the character of those supply curves, BPA relied on a Conservation Potential Assessment (CPA) and Demand Response Potential Assessment (DRPA). For the 2024 Resource Program, BPA updated the most recent CPA and DRPA studies and supply curves used for the 2022 Resource Program. More specifically, this involved updating supply curves developed in 2021 and aligning them with the 2024 Resource Program study assumptions (described in detail below).

5.2.2 Methods for Preparing Conservation and Demand Response Inputs

The CPA and DRPA are the primary conservation and demand response planning assessments that contribute to the Resource Program. These two efforts contribute standardized supply curves for analysis and selection within the Solver component of the Resource Program. Supply curves describe the availability of a conservation or demand response measure on an hourly basis and over a time horizon defined by the Resource Program. Supply curves account for the time required to start and implement a BPA utility customer program, known as a ramp rate, as well as the anticipated effectiveness of that program and its measures. There are too many conservation or demand response technologies for performance studies to model individually. Because of this, the Resource Program groups the CPA conservation measures into bundles based on price and sector (e.g. residential HVAC under $40/kw, industrial process under $60/kw) where a set of unrelated technologies produce energy savings. This bundling makes it difficult to independently evaluate the value proposition of a given conservation measure but does facilitate the review and interpretation of higher-level trends in the time-value of conservation or demand response and the types of programs that are most effective to fulfill a BPA resource need.

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[18] Cost calculations are based on the performance studies, which only explicitly model a representative subset of time periods from the 20-year study horizon: two weeks per month and 9 years out of the full 20 years. Net costs for the explicitly modeled periods are extrapolated to generate costs for the full 20 years, including all hours, weeks and years.

5.2.3 Conservation Potential Assessment

For this CPA Update, BPA kept the underlying methodology largely consistent with its prior CPA conducted for the 2022 Resource Program[19], except for some specific updates described below:

1. **Increased overall load forecasts**. BPA updated the individual sector-level supply curve unit forecasts, such as the number of residential homes or the square feet of regional commercial buildings, by combining various new market data with data from BPA's end-use forecast models. BPA incorporated sector-specific growth rates to project future growth in each sector based on data from BPA's load forecast team. Where growth data were unavailable from BPA's load forecast team, such as for the agricultural and industrial sectors, BPA used a growth rate consistent with the prior CPA.

2. **Modified the timeframe of the CPA analysis to match the timeframe of the Resource Program modeling efforts.** BPA updated the 20-year CPA study horizon to reflect the years 2026 through 2045. Since this new period of analysis is two years beyond the previous CPA, which was a 20-year study from 2024 through 2043, BPA developed an approach to adjust the prior CPA ramp rates to this new study period. The approach consisted of matching the calendar year ramp rates from the Council's 2021 Regional Power Plan to the prior CPA up to 2041 for lost opportunity and discretionary conservation ramp rates. These ramp rate decisions caused achievable potential to be further along the ramp rate in Year 1 of this CPA (calendar year 2026) when compared to Year 1 of the prior CPA (calendar year 2024). Therefore, these CPA results reach the market-achievable potential maximum cap quicker over the study period. Also, more conservation is often achieved in the early years of the study period.

3. **Updated certain measures to remain consistent with the most up-to-date calculations and assumptions made by the Regional Technical Forum (RTF).** For the purposes of this CPA update, RTF workbooks provided the primary savings, cost, and estimated useful life assumptions in the 2021 Power Plan supply curves. BPA developed and identified a list of prior CPA supply curves to update with the newest RTF measure characterization inputs. Depending on the update, measures may increase or decrease in achievable potential or become more or less cost-effective. Most of these updates focused on the residential building shell; heat pump HVAC technologies; heat pump water heaters; and commercial, agricultural, and industrial pump and fan measures.

4. **Revised the 2021 Power Plan future meteorological year (FMY) weather adjustments to typical meteorological years (TMY3) to align with the 2024 Resource Program's forecast methodology.** For the 2024 Resource Program, the BPA load forecast team accounted for the possible impacts to load that could result from potential changes in weather patterns. To apply these load impacts to the supply curve potential estimates, the CPA analysis team received the temperature forecasts used by the BPA forecast team for select weather stations. They mapped these BPA weather station forecasts to the Council's RTF's definitions of heating and cooling zones. Using documentation from the Council, the team aligned CPA measure inputs with BPA temperature forecasts. The overall impact of these newly developed adjustments relative to the prior CPA resulted in lower heating potential and increased cooling potential for all weather-dependent supply curves for this CPA.

[19] The Conservation Potential Assessment performed for the 2022 Resource Program can be found on the [BPA website at this location](). This Conservation Potential Assessment was updated to conform with the modeling needs of the 2024 Resource Program but the underlying methodology remains the same. The 2024 Conservation Potential Assessment Update will be published on this same site in February of 2025.

5.2.4 Demand Response Potential Assessment

For this 2023 DRPA Update, BPA kept the underlying methodology largely consistent with the prior DRPA conducted for the 2022 Resource Program[20], except for some specific updates described below.

1. **BPA assumed that programs would begin in 2026 and run through 2045.** The 2022 Resource Program assumed programs would begin operation in 2024. While some BPA customer utilities have begun planning and implementing their own demand response pilots and programs, overall, very few BPA customer utilities had demand response programs in operation at the time of the update. Thus, the new start date did not involve the ramp rate complications that had occurred with the conservation ramps. There was no in-progress ramp to account for.

2. **Analyzes demand response products that can be used frequently and for longer durations.** The 2021 DRPA considered two different use-case scenarios: a typical operations scenario that used demand response products in extreme peak demand conditions for capacity purposes (referred to as dispatchable DR in the results of the Resource Program), and the regular (e.g., daily) use of demand response products for energy savings purposes (referred to as non-dispatchable DR in the results of the Resource Program). For the 2023 DRPA, instead of considering different use-case scenarios, BPA grouped products into categories based on whether they could be used regularly. BPA's 2022 Resource Program and the Council's 2021 Power Plan identified that products could be used more frequently and for longer durations (e.g., for 10 hours each day) and could have high value for BPA and the region. Energy savings demand response products appeared to be more valuable than occasionally used short-duration peak reduction capacity-related products. Accordingly, to provide the most value to BPA, the team analyzed the frequently used, longer duration products separately in the 2024 Resource Program. BPA estimated their hourly impacts and value streams over all months of the year and across all hours of each day.

BPA assumes in the 2023 DRPA analysis that dispatchable demand response programs will be dispatched during 18-hour events[21] and estimates their contributions to meeting energy needs by assuming that the programs will be dispatched into the highest-priced hours of the day in the highest-priced month of each season.[22]

[20] The Demand Response Potential Assessment performed for the 2022 Resource Program can be found on the BPA website. This Demand Response Potential Assessment was updated to conform with the modeling needs of the 2024 Resource Program but the underlying methodology remains the same. The 2024 Demand Response Potential Assessment Update will be published on this same site in February of 2025.

[21] Demand response programs are assumed to consist of either five 8-hour blocks or 10 4-hour blocks per summer (July and August) or winter (December through February). In assigning capacity of 8-hour demand response blocks to meeting 18-hour capacity needs, BPA assumes that three of the five blocks will be used in July, leaving only two available for 18-hour capacity events in August. (The 8-hour demand response products are available only in the summer.)

[22] All hours of the 4-hour blocks and two-thirds of the hours in the 8-hour blocks are assumed to take place during superpeak hours (i.e., the highest-load 6 hours of the day). This may overestimate the value of these products, because the top load hours are often split between morning and evening peaks. The market price model described in section 5.3 is used to portion those hours across months. All the demand response capacity is assigned to the highest-priced month (based on average monthly price, not including weekends and holidays, of the 4- or 8-hour block during the day with the highest average price) in each model iteration and then averaged across model iterations.

5.2.5 Program costs

As is true for generating resources, net costs of energy efficiency and demand response programs are equal to fixed plus variable costs minus the value of the energy generated, across the full 20-year time horizon. Costs are represented as total resource costs (TRC), meaning they include costs and benefits without regard for which parties (e.g., BPA, customer utilities, end-use customers, etc.) experience those costs or benefits. For energy efficiency programs, TRC values are adjusted to incorporate Inflation Reduction Act tax credits and then decreased by 10% (or, if negative, increased by 10%) as required by the Northwest Power Act.[23]

Variable costs and energy revenue (i.e., the value of the energy generated) for energy efficiency programs and non-dispatchable demand response programs are calculated in the performance studies and averaged across the full distribution of market prices. Revenues for dispatchable demand response programs are calculated from the same distribution of market prices as used in the performance studies.[24]

Net costs are discounted to net present value (NPV) and summed into a single net cost for each resource option, representing the expected net cost across the full 20-year study horizon.

5.2.6 Conservation and Demand Response Findings

The Resource Program provides some insight into the changing time-value of conservation and demand response. As market conditions in the Northwest and West continue to shift, the value of energy efficiency may also change. The findings from the 2024 Resource Program suggest that off-peak resources such as industrial energy efficiency and voltage reduction might be more valuable than they have been in the past, in part because of changing market pricing conditions that change hydropower generation strategies.

The Resource Program selects a least-cost portfolio of resources from an inventory of available resources as defined by BPA. When those resources are stacked according to value, the Solver identifies those resources which best contribute to the least-cost mix of resources. The Solver optimizes for metrics beyond just cost. Thus, the model may not always select a low-cost resource as part of the least-cost portfolio of resources. Figure 5-3 illustrates those resources not selected by the resource program as well as their price points and amounts, with three distinct categories of resources not chosen identified in the figure:

1. **Low-cost resources with low-value features:** These resources have low-time-value of conservation, coincide particularly poorly with the generation profile of existing BPA assets or the load profile of BPA customers, or coincide with low-price market conditions.

[23] 16 U.S.C. §839a(4)(D).

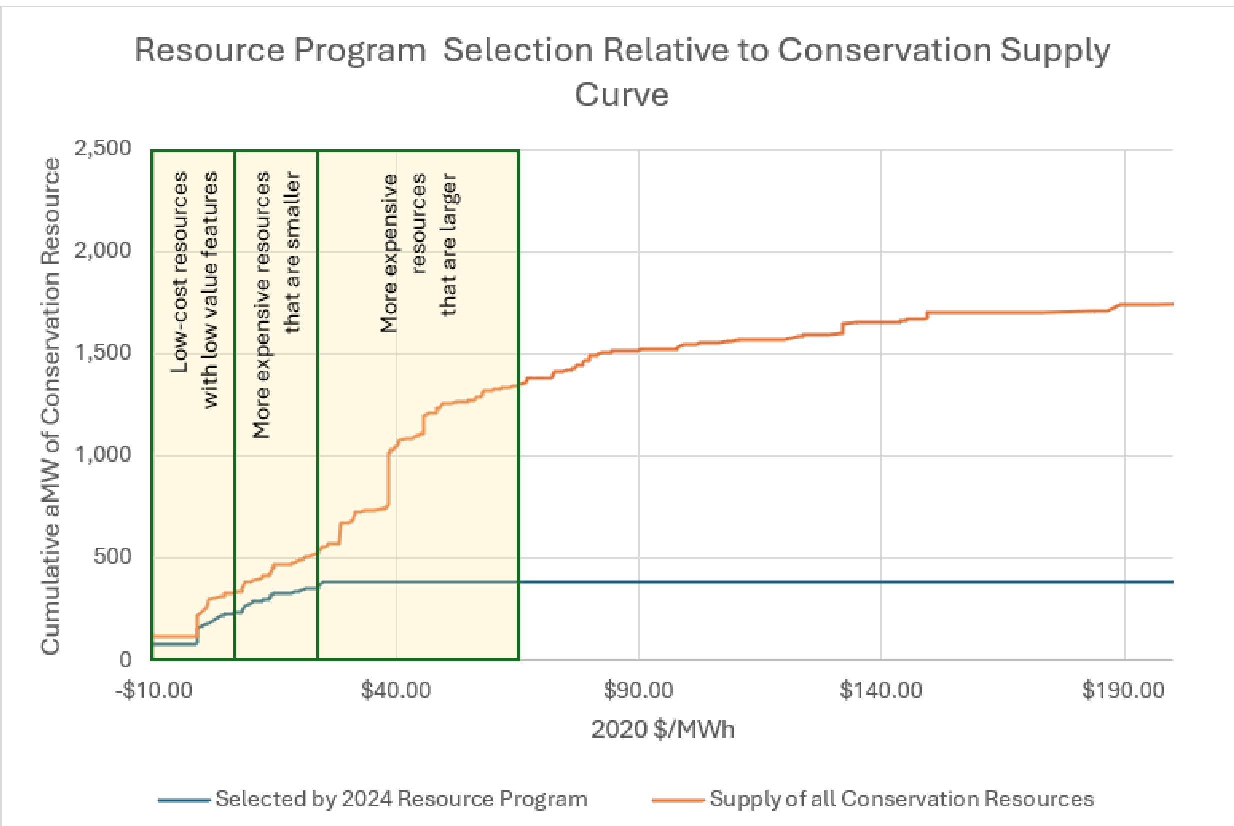
[24] As described in an earlier footnote, within each iteration of the market price model, all the 4- or 8-hour blocks of each dispatchable demand response program are assigned to the highest-priced month, based on average monthly price, not including weekends and holidays, of the 4- or 8-hour block during the day with the highest average price. That monthly average price (for the highest-priced 4- or 8-hour block of the day) is used to calculate the monetary value of the energy conserved (i.e., the revenue for the demand response program). These monetary values are then averaged across model iterations. This approach can be seen as approximating the revenues (or savings) achieved by dispatchers who know which month is going to be most expensive and which time of day is typically most expensive, but not which days in the month will be the most expensive.

2. **More expensive resources that are smaller:** These resources are slightly more expensive and are a low-volume opportunity for energy efficiency program expansion if needed to pick up unfilled shares of the resource pool due to decisions made after Resource Program completion.

3. **More expensive resources that are larger:** These resources cost more but are not altogether out of reach. Selected resources from this cost grouping could be sufficiently high-value for the Solver to include them in the least-cost portfolio of resources, but their cost may be too high. If BPA needs more energy efficiency programs, these are some of the swing resources that BPA could activate.

Depending on the scenario, different types and amounts of conservation and demand response resources may be selected by the Solver.

Figure 5-3: Illustrating the conservation resources selected by the Resource Program (blue) and the overall supply curve for conservation (orange). This figure shows the amount and price range of those resources not selected by the Resource Program between the two lines and identifies three distinct areas where these resources not chosen present value opportunities.



5.2.7 Conservation and Demand Response Analytical Approach

As a next step, BPA's energy efficiency and demand response planning team will examine the results of the 2024 Resource Program in further detail. This examination will include comparisons of the Resource Program base case results against:

- Other 2024 Resource Program sensitivity results
- 2022 Resource Program results

- BPA’s 2022-2027 EE Action Plan
- The Council’s 2021 Power Plan

These comparisons will help inform long-term planning work around energy efficiency and demand response. The results of the 2024 Resource Program have integrated a number of changes in modeling approach that the team needs to explore through review of the various sensitivity solution sets.

Consistent with statute, conservation and demand response are part of BPA’s overall resource acquisition strategy, and as the strategy evolves, BPA’s approach to these resources may change. In the near term, however, conservation and demand response work at BPA will continue as outlined in Bonneville’s 2022-2027 EE Action Plan. 2024 Resource Program results, along with upcoming resource planning exercises like the 2026 Resource Program and the Council’s Ninth Power Plan, will guide BPA’s long-term resource acquisition strategy and inform the development of BPA’s next EE Action Plan, where BPA will decide conservation and demand response goals and strategies for the future.

5.3 Wholesale Energy Market

5.3.1 Overview

BPA uses the production cost model Aurora[25] to forecast energy market prices and assess energy market depth on a fundamentals[26] basis for the 20-year horizon of the Resource Program. The model uses forecasts of key inputs to estimate resource additions and retirements, producing a resource buildout for the Western Interconnection. The buildout is combined with risk models to simulate hourly operations under a wide range of conditions to produce a distribution of future energy market prices. BPA makes further modifications to assess load curtailments and estimate market reliance limits. The market price forecasts are also used to evaluate the performance, energy revenues, variable costs and charging costs of all resource options on an hourly basis as described in Section 6.2.2.

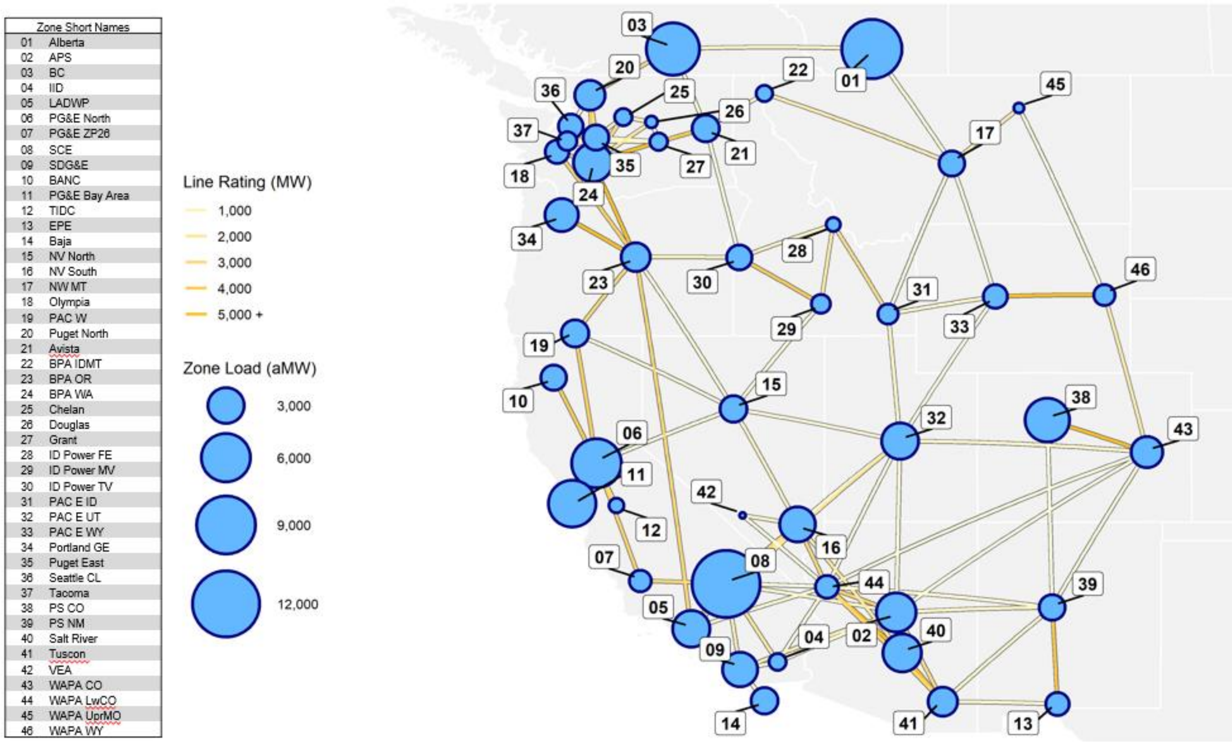
The Base Scenario reflects current policy and input values that align with current, mid-range expectations around costs and technology availability. In addition to the Base Scenario analysis, BPA created a Western Interconnection resource buildout and associated price forecast for the Fast Transition Scenario. The Fast Transition Scenario reflects more rapid and coordinated efforts throughout the Western Interconnection to meet relatively higher loads with non-emitting resources.

5.3.2 Key Inputs and Assumptions

The model uses a 46-zone topography of the Western Interconnection that is mostly aligned with balancing authorities (Figure 5-4). In addition to the interconnections shown, the following six new transmission projects are included (online years are in parentheses): Gateway South (2025), Gateway West (2026 to 2030), North Gila-Imperial Valley (2026), Boardman to Hemingway (2027), SunZia (2027), and TransWest Express (2028).

[25] Aurora is a registered trademark of Energy Exemplar Proprietary Limited (ACN 120 461 716), the software developer.
[26] “Fundamentals basis” means that the model creates a price forecast by simulating grid operations and assuming the cost of meeting loads under the resource and system constraints will be a good estimate of prices.

Figure 5-4. Aurora zonal topology.



The model includes impacts on the supply side from Washington's Renewable Portfolio Standard (RPS), Clean Energy Transformation Act, and carbon prices; Oregon's Renewable Portfolio Standard (RPS) and clean energy requirements; California carbon prices and Senate Bill (SB) 100; Alberta's Renewable Portfolio Standards (RPS) and carbon prices; and best estimates of all WECC state, utility, and municipal RPS and clean standards.[27]

Inflation Reduction Act incentives are modeled as a production tax credit at the base level for solar and wind (because preliminary analysis showed that production tax credits tend to yield more benefits than investment tax credits for these resources) and 30% investment tax credits for other eligible resources. Benefits are assumed to taper off in 2035.

For the Fast Transition Scenario, all states in the Western Interconnection are assumed to target 100% net zero emissions in the electric sector by 2050.

For the 2024 Resource Program, the Base Scenario WECC-wide load forecast has been updated to include increased electrification in loads. Consistent with the BPA load obligation forecast used in the needs assessment, WECC load forecasts are adjusted to account for increased electrification (Figure 5-5). These load increases are based mainly on the Energy Information Administration's 2023 Annual Energy Outlook, which leverages National Renewable Energy Laboratory (NREL) electrification studies to help capture Inflation Reduction Act impacts. The NREL Electrification Futures Study includes increased

[27] State policy requirements within the WECC enacted as of July 1, 2023. Additional clean energy goals and policies at the municipal and utility level are included but have been discounted by 20% to represent uncertainty about the extent to which these commitments will be upheld over the forecast horizon.

loads due to electrification from four sources: transportation, commercial, residential and industrial. The electrification adders used by BPA are flat increases to load and do not include modifications for hourly shaping. The fast transition model uses the increased load values from the 2024 Resource Program, plus an adjustment factor to capture higher load forecast values, consistent with BPA load forecasts in the Needs Assessment.

Figure 5-5: Average annual load increases due to electrification used in the base scenario

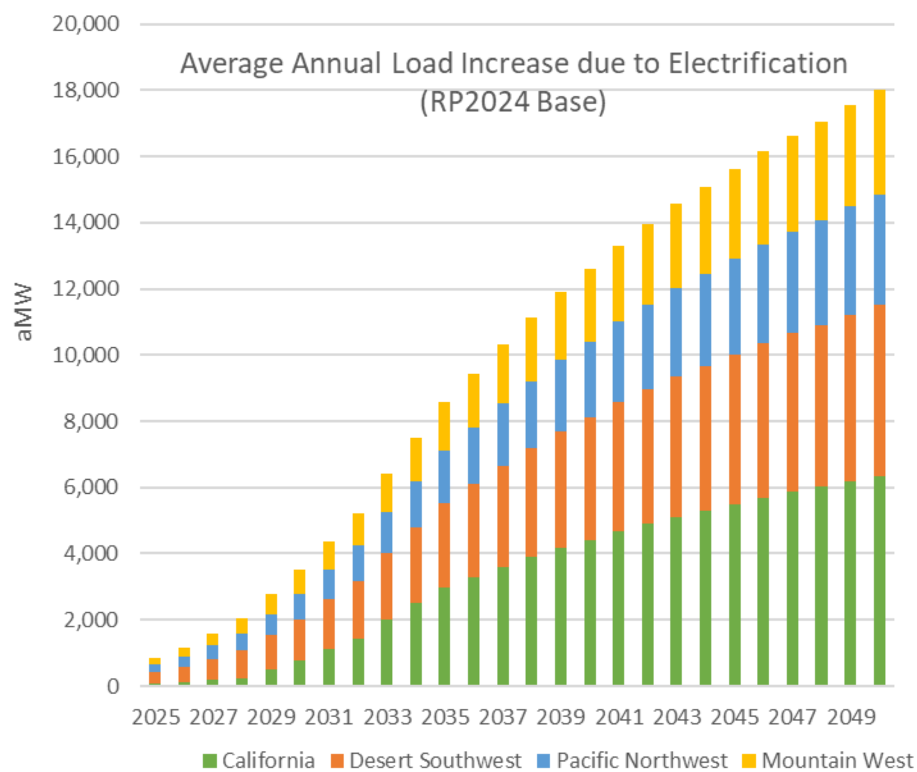
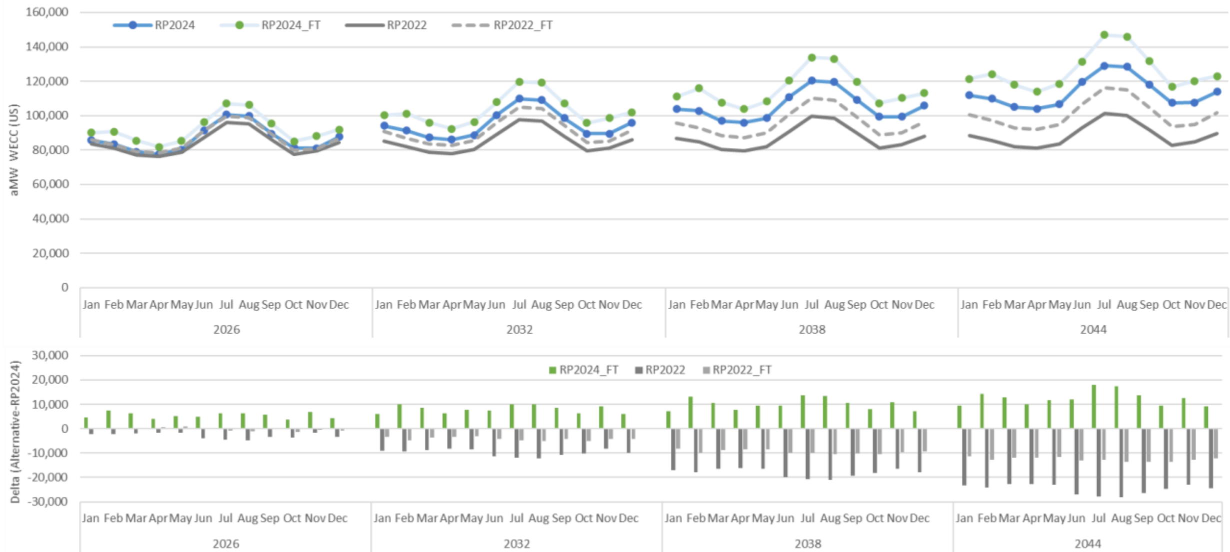


Figure 5-6: Forecast WECC loads compared between 2024 and 2022 Resource Programs

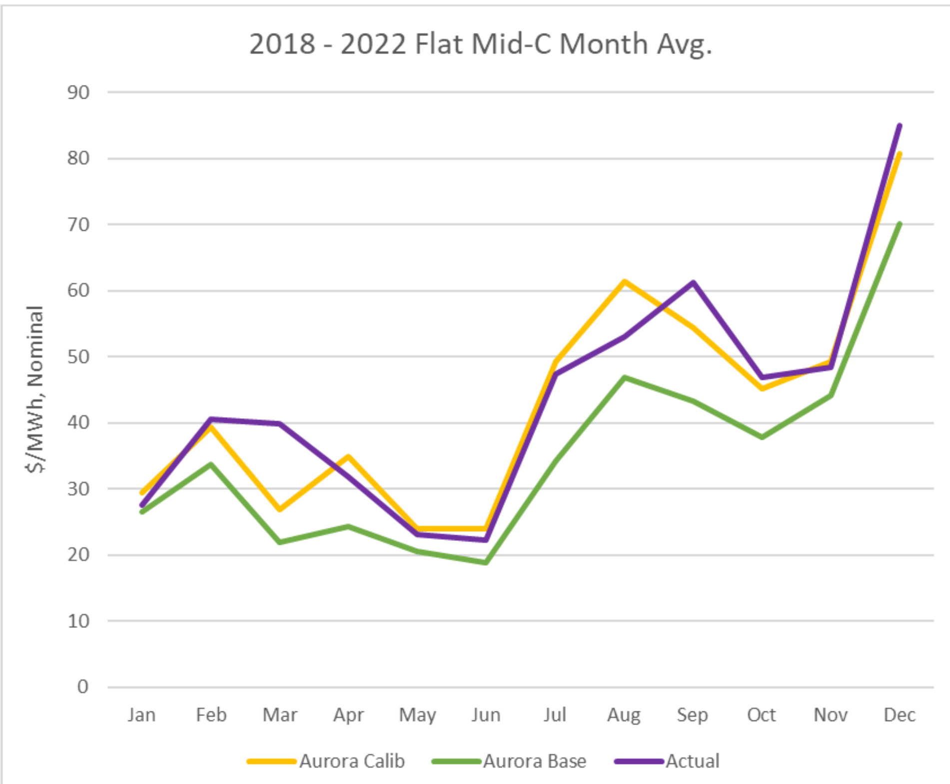


Natural gas prices are typically a significant determinant of electricity prices because gas generators tend to be the marginal unit, or the least-cost generator available to supply an incremental unit of energy; and the price of natural gas is the predominant factor affecting the dispatch cost, or production cost, of natural gas-fired generators. Relative to the 2022 Resource Program, the 2024 Resource Program reflects substantial increases in forecast gas prices, especially in the base scenario (Figure 5-7). This increase is primarily driven by an update to the natural gas risk model that substantially increases gas price risk on the higher end.

Figure 5-7: Natural gas price forecasts in 2024 and 2022 Resource Programs

BPA's Aurora price forecast includes two adjustments to resource bidding behavior[28] that have substantial impacts on the resulting distributions of price forecasts. First, BPA runs Aurora using a recent historical period, i.e., 2018-2022 and calibrates thermal resource bidding behavior to better align Aurora prices with actual day-ahead hub prices during the period (Figure 5-8). Second, BPA includes a simplistic depiction of negative bid behavior for renewable resources that are driven, for instance, by federal production tax credits for wind resources, renewable energy credits and power purchase agreements. WECC renewable resources bid at about -$23 (nominal) per megawatt-hour, except for BPA wind, which curtails at $0 per megawatt-hour. BPA hydropower is modeled to limit spill to current total dissolved gas limits, and other hydropower bids at -$25 per megawatt-hour so that it will curtail after other renewables.

Figure 5-8: Calibration of Aurora to better align with historical day-ahead prices



5.3.3 Western Interconnection Resource Buildout

Several processes inform BPA's forecast of the Western Interconnection resource retirements and builds used in the price forecast and market depth studies. First, data from the EIA's database of planned and sited resource additions and retirements over the horizon of the BP-24 rate period[29] were referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's

[28] In Aurora, resource bidding behavior (the minimum price level a resource is willing to sell its energy to the system) can change simulated commitment, dispatch and resulting prices when bids differ from marginal costs.
[29] BPA conducted a consolidated power and transmission rate proceeding, BP-24, to set rates for the FY 2024-2025 rate period (Oct. 2023-Sept. 2025). The rate case began with the Federal Register notice on Nov. 18, 2022, and concluded when BPA issued the Final Record of Decision on July 28, 2023.

Transmission Expansion Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission and third-party consultant reports to update the default Aurora resource stack. Additionally, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast and from integrated resource plans of utilities in the Southwest.

Finally, the Aurora long-term capacity expansion model is used to build and retire additional resources based on economics to satisfy pool planning reserve margins and meet all relevant state, municipal and utility policies, including renewable portfolio standards, zero emission targets and electric sector emission caps.

For the long-term capacity expansion model, BPA continues to include two types of firm flexible resources that allow the region to achieve clean policy goals while maintaining system reliability:

a) Clean Firm Flexible (CFF) Base: a very high fixed cost, low variable cost resource, modeled after SMR, but also comparable to traditional fossil fuel-based resources with carbon capture and storage.
b) CFF Peaker: a low fixed cost, high variable cost resource, modeled after an H_2 combustion turbine with onsite electrolysis and storage, but also roughly comparable to a combustion turbine running on other bio/renewable fuels or a traditional peaking resource with carbon capture and storage.

Compared to the 2022 Resource Program, the 2024 Resource Program Western Interconnection buildout shows significant increases in wind, solar and battery energy storage system (BESS) additions. The 2024 base scenario shows almost as many additions as the 2022 Fast Transition scenario. The increase in modeled additions is driven primarily by impacts from the IRA, both decreases to new resource costs as well as increases to loads from electrification.

Figure 5-11: Base and Fast Transition scenario cumulative resource additions and retirements from the 2024 Resource Program compared to the 2022 Resource Program (US share of the Western Interconnection additions and retirements, only).

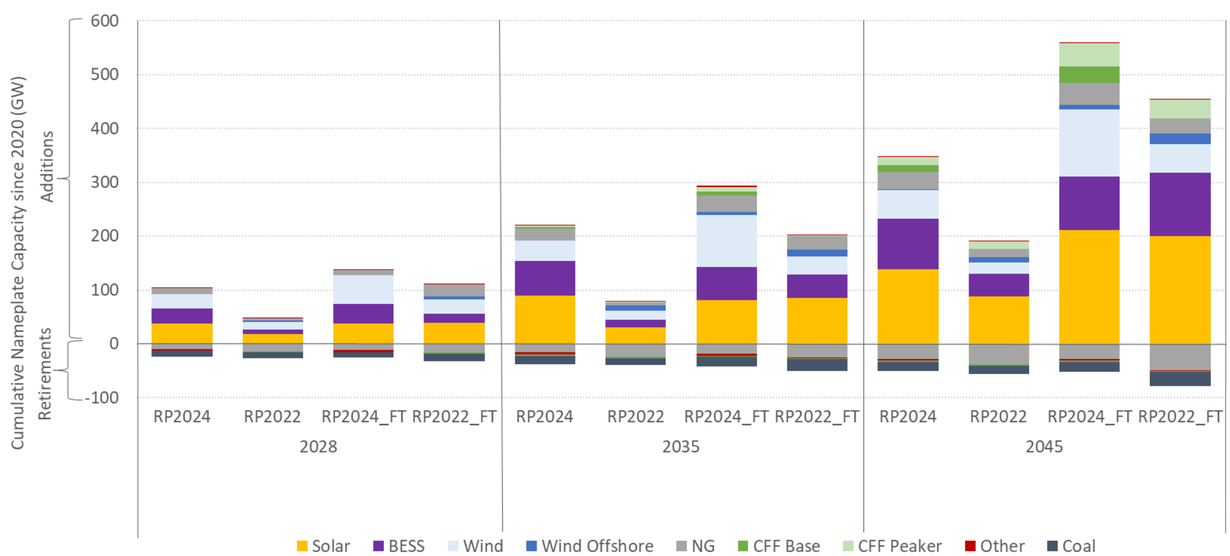
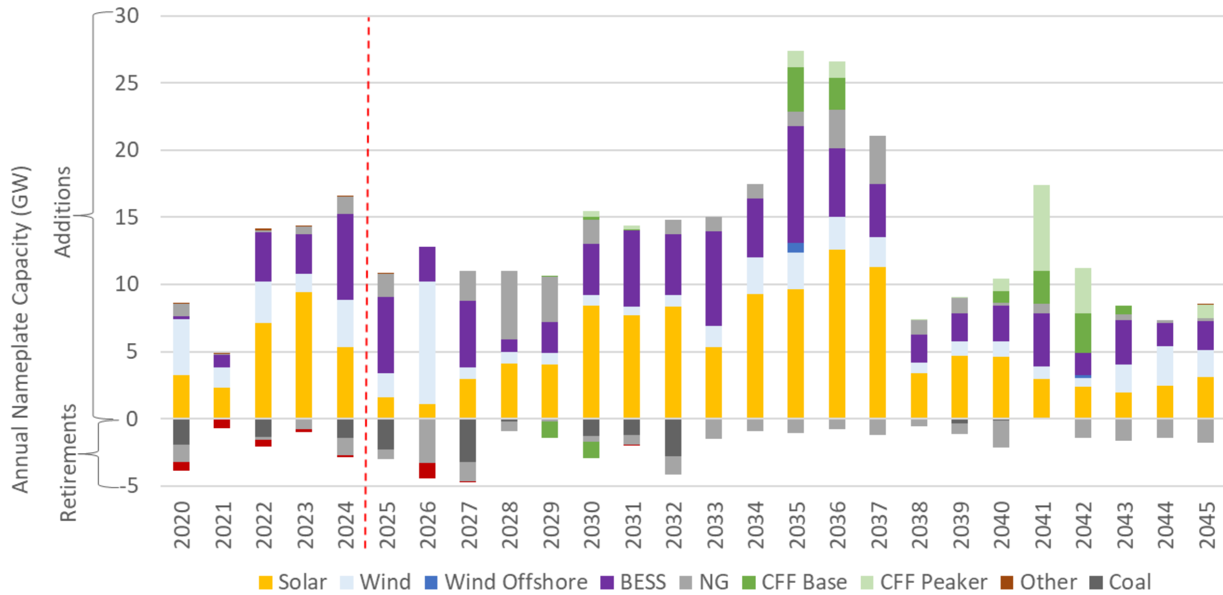


Figure 5-12 shows the additions and retirements by year from the 2024 Resource Program Base scenario. The forecast has a total of about 100 GW of new resources being built by 2028. Of these, more than half have already been constructed and begun operating. A significant portion of the remaining forecast resource additions expected to be online by 2028 have already begun construction, and the BPA forecast shows a moderate decrease in the rate of resource additions relative to what has been added from 2020 to 2024.

Figure 5-12: Base scenario cumulative resource additions and retirements from the 2024 Resource Program (US share of the Western Interconnection additions and retirements, only).



5.3.4 Wholesale Market Price Forecast

The Base Scenario price forecast consists of a distribution of 630 risk-informed hourly forecasts sampled two weeks per month.[30] Aurora itself is deterministic, but the inputs to Aurora are sampled from distributions based on historical variation using a Monte Carlo process. Each of the 630 forecasts is therefore based on a unique combination of water year sequence, natural gas price forecast, Western Electricity Coordinating Council-wide load forecast, hourly wind generation pattern, Columbia Generating Station outage schedule and hourly transmission path rating, as applied to the alternating current, direct current and British Columbia-United States interties. The price at a given energy hub is determined by the cost of delivering an incremental megawatt of energy to load, including transmission costs and energy losses, provided by the least-cost available resource.

Compared to the 2022 Resource Program, the 2024 Resource Program average prices are moderately higher, and price variability is substantially higher (Figures 5-13, 5-14, and 5-15). The 2024 Resource Program also adds a second decade to the study horizon. Spring and summer prices decline in the

[30] For more information about Aurora and the risk models used to produce this forecast, see the Power Market Price Study and Documentation, BP-24-FS-Bonneville-04.

second half of the study horizon because of the projected build-out of renewable resources, with expected average May and June prices becoming negative by 2038.

Figure 5-13: Forecast average Mid-C flat prices from the 2024 Resource Program compared to the 2022 Resource Program.

Figure 5-14: Comparison of forecast distributions of monthly flat Mid-C prices in the 2022 and 2024 Resource Program base scenarios and the 2024 Resource Program fast transition scenario.

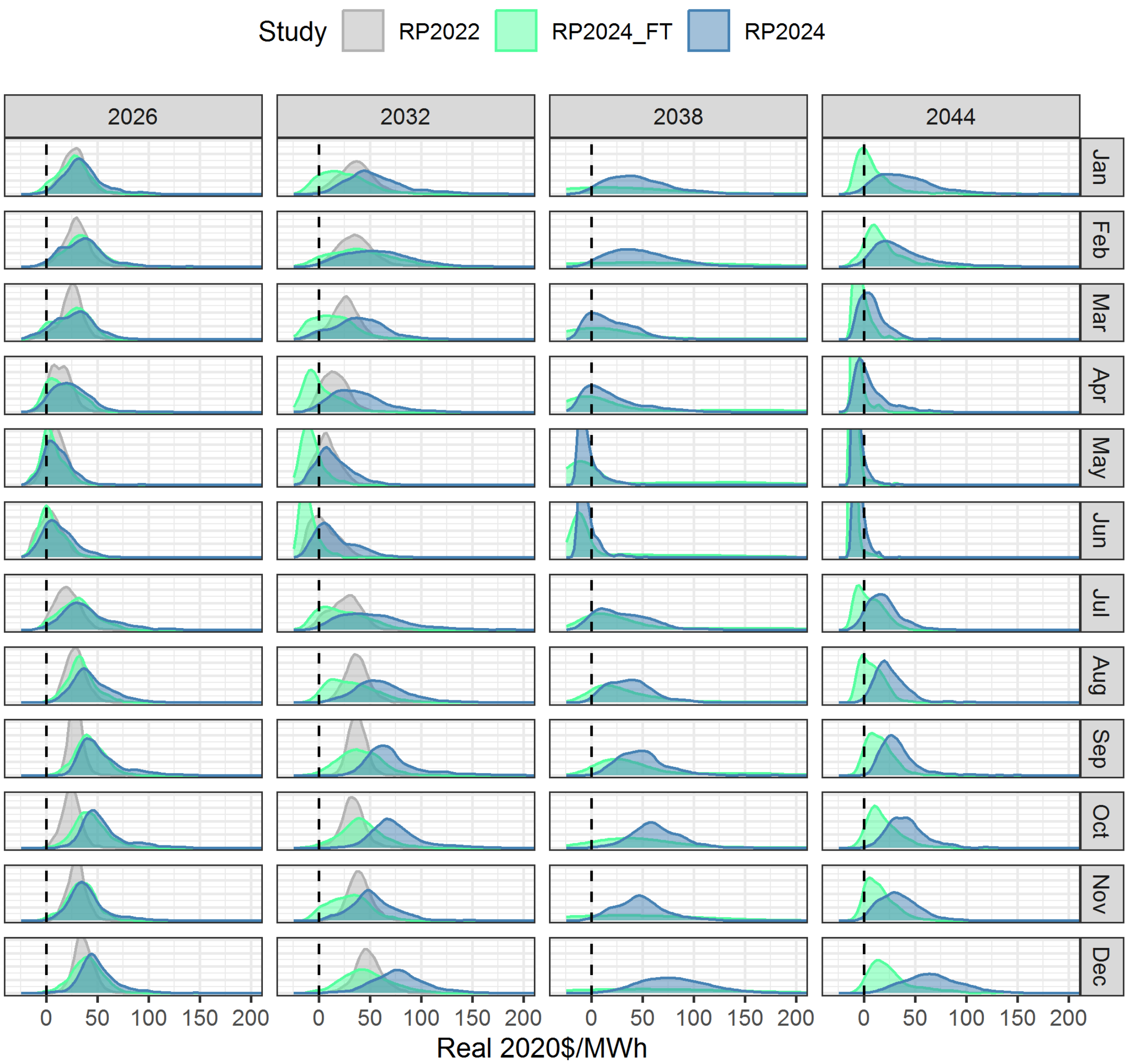
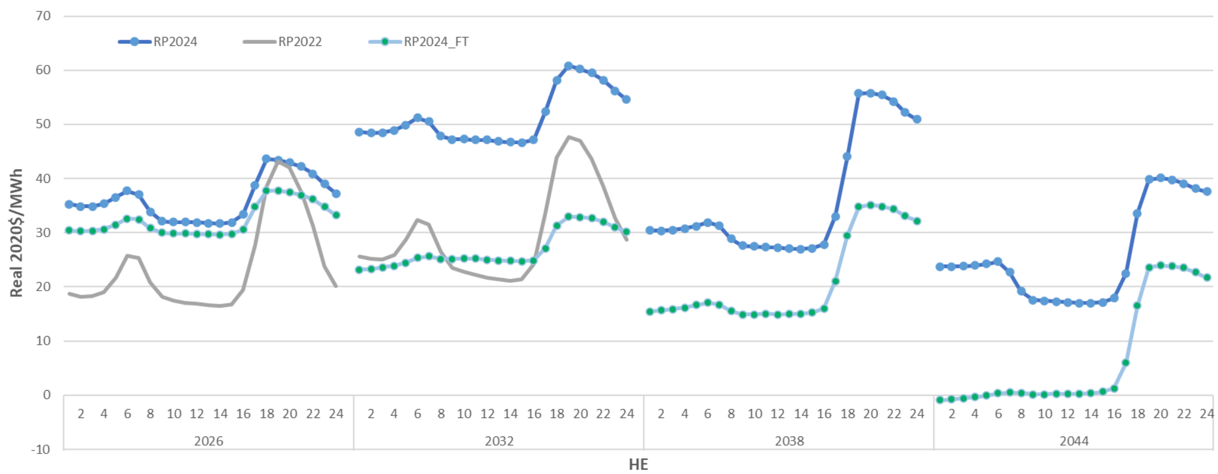


Figure 5-15: Forecast average Mid-C hourly prices from the 2022 and 2024 Resource Programs



5.3.5 Market Contributions to Meeting Needs

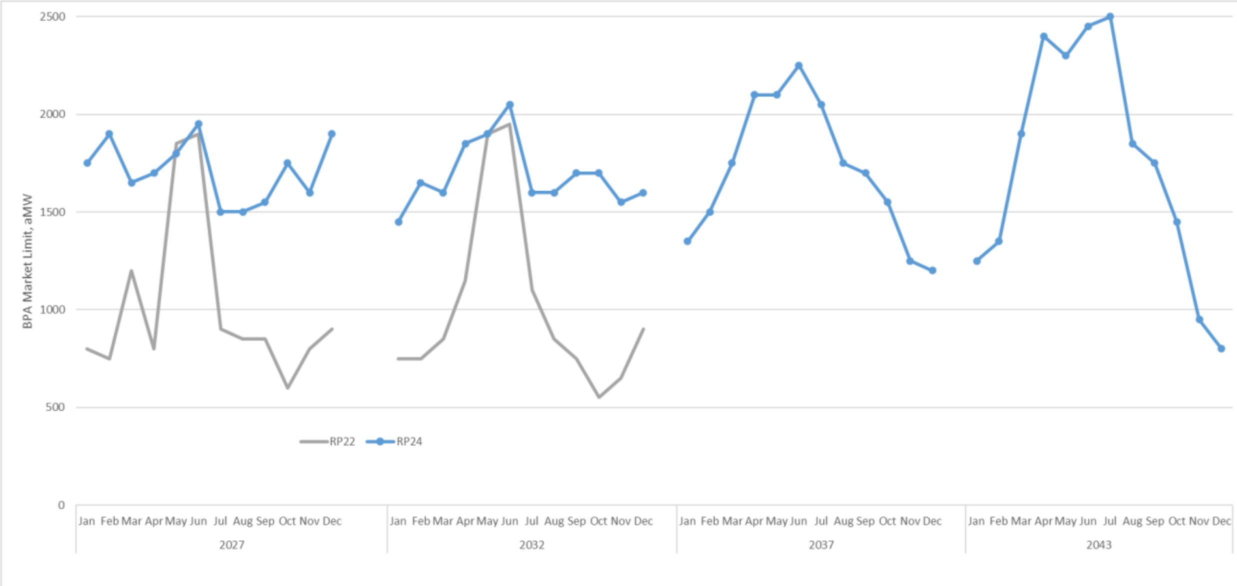
The price forecasts are used to assign costs of meeting BPA energy needs in MIDC and in SWEDE under a wide range of future conditions. Market purchases are agnostic to timing (they do not include adjustments to account for differences stemming from Real-Time vs Day-Ahead vs forward timing of purchases/sales), do not include capacity premiums, and do not contribute to meeting 18-hour capacity needs. The following section describes BPA's method for estimating how much energy may be available for the 2024 Resource Program.

5.3.6 Market Reliance Limit

Given expected fundamental changes in energy markets across WECC driven by growth in zero-emission resources, BPA uses Aurora to assess future energy availability and establish monthly market reliance limits for the 20-year planning horizon. The process begins with the base scenario resource build described above, which is assumed to reflect zero market reliance, i.e., all balancing authorities meet their reliability needs individually, without relying on other BAs or regions. Next, BPA uses incremental reductions in regional resources[31] to represent increases in market reliance. Higher levels of market reliance are tested until the exceedance of a 1 day in 10 years (2.4 hours/year) loss of load expectation (LOLE) threshold. Up until that point, it is assumed that the region can rely on market exchanges to meet energy needs rather than building or maintaining additional resources. BPA is then allocated a share of the market availability proportional to its share of regional load. This sets BPA's market reliance limit, expressed in terms of monthly average heavy-load-hour megawatts. It should be noted that this methodology does not anticipate or account for evolving market structures, such as wider adoption of an energy imbalance market, a day ahead market or a Western Interconnection-wide Independent System Operator. The estimate simply reflects expected physical energy availability given projections of WECC load-resource balance and transmission capabilities.

[31] Testing all combinations of resource removal would be computationally prohibitive; instead, BPA uses monthly flat load increases to represent the loss of resource availability.

Figure 5-14: Forecast market limits in the 2024 Resource Program compared to corresponding limits in the 2022 Resource Program



Section 6: Resource Optimization

6.1 Overview

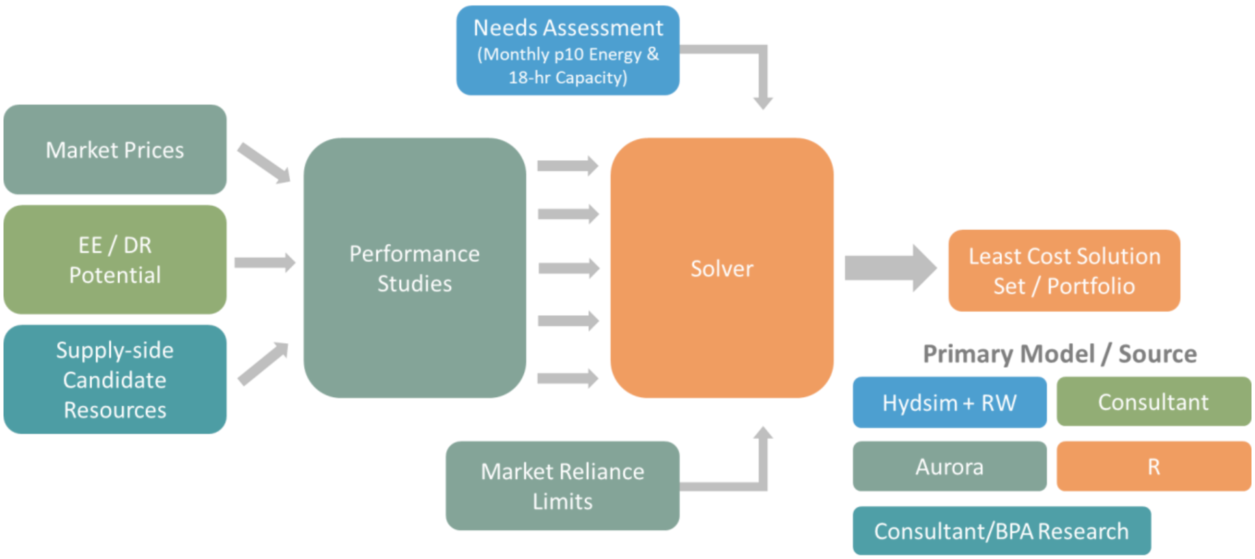
BPA uses a combination of performance studies carried out in Aurora and constrained optimization models to identify least-cost resource options that satisfy its needs throughout the 20-year planning horizon (Figure 6-1).

6.2 Portfolio Selection

6.2.1 Model Structure

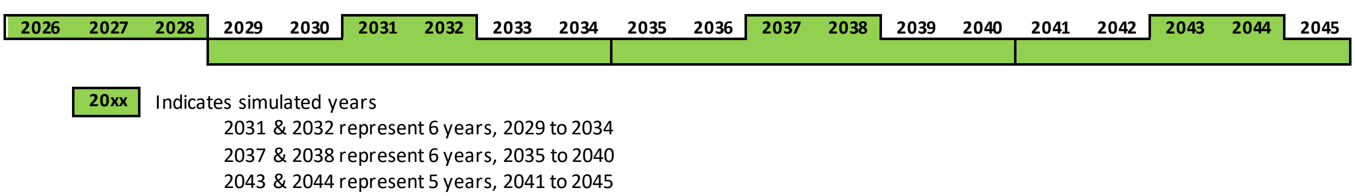
Figure 6-1 summarizes the modeling framework used to generate least-cost resource portfolios. Performance studies carried out in Aurora model resource performance (including hourly generation, costs, and revenues) under a variety of price conditions, based on inputs generated by the candidate resource assessment described in Section 4. Output from the performance studies and the Needs Assessment, along with market purchase limits determined by the Market Assessment, feed into the Solver, a constrained optimization model that identifies least-cost resource portfolios.

Figure 6-1: Resource Program 2024 modeling framework



Nine years out of the 20-year study horizon are explicitly modeled in the performance studies and the Solver (Figure 6-2). Needs are only explicitly modeled in these 9 sample years. Resource net costs are extrapolated from the sample years to estimate costs over the full 20-year study horizon.

Figure 6-2: Time horizon and sample years



The Mid-C and Southwest/East Diversity Exchange (SWEDE) regions are represented by modeling needs and resources in both zones, and by only allowing the resources in each zone to meet that zone's needs.

6.2.2 Performance Studies

Performance studies carried out in Aurora model the hourly performance of each candidate resource (including demand side and supply side resource options) to estimate generation output, variable costs (including charging costs of storage resources), and energy revenues under a wide range of system conditions reflected in the full distribution of forecast prices generated by the wholesale energy market assessment (see Section 5.3). The hourly price forecasts are exogenous inputs—these prices do not respond to differing levels of generation in the performance studies. For resources that have flexibility in their dispatch, Aurora simulates operations to generate power when prices are higher than variable costs of generating, given the operational constraints of the resources. Resources that lack dispatch flexibility are still included in the performance study to assess their energy revenues and any variable generation costs.

6.2.3 Constrained Optimization Model: The Solver

For portfolio selection, the 2024 Resource Program replaces the Aurora portfolio optimization process that was previously used with a constrained optimization model carried out in R software, referred to as the Solver. Implementing the constrained optimization in R offers greater flexibility, better accommodating BPA-specific needs that were difficult or impossible to include in the Aurora portfolio optimization process. It also has much faster run times, facilitating exploratory and follow-up analyses that would not be feasible in the Aurora platform.

Constrained optimization models adjust a set of decision variables to either minimize or maximize the value of an equation, known as the objective function, subject to a set of constraints. In the 2024 Resource Program Solver, the decision variables are proportions of each available resource to be acquired (Table 6-1). The objective function, which the Solver minimizes, calculates the total net cost of acquired resources. Linear constraints include meeting all energy and capacity needs identified by the Needs Assessment, limits on market purchases based on BPA's assessment of market liquidity, and rules to prevent impossible outcomes such as the same energy efficiency or demand response program being selected twice, in two different years.

Table 6-1: Mathematical structure of the 2024 Resource Program Solver

Objective function: sum of resource net costs	$\min\left(\sum_{i=1}^{r} c_i x_i\right)$	x_i = proportion of the ith resource acquired c_i = net cost of the ith resource r = number of resource options p = number of market purchase options e_{ij} = contribution of the ith resource to the jth need m_{ik} = contribution of the ith market purchase to the kth market purchase limit N_j = the jth need e_{ik} = contribution of the ith market purchase to the kth market purchase limit L_k = the kth market purchase limit
Linear constraints*:		
Energy and capacity needs	$\sum_{i=1}^{r} e_{ij} x_i > N_j$ for all j	
Market purchase limits	$\sum_{i=1}^{p} m_{ik} x_i < L_k$ for all k	
Restrictions on decision variables	$0 < x_i < 1$	

*Linear constraints also include rules to prevent impossible outcomes such as the same energy efficiency or demand response program from being selected more than once.

Resources available to meet needs in the 2024 Resource Program Solver include energy efficiency bundles, demand response programs, supply-side resources and market purchases.[32] Resources are modeled in both SWEDE and Mid-C zones. The supply-side resources available to the model are described in section 5.1. Energy efficiency and demand response resources are summarized in Section 5.2. Three possible start dates are allowed for each energy efficiency bundle and demand response program: 2026, 2031, and 2037. For dispatchable demand response programs, the Solver can acquire just summer, just winter or both seasons. Each decision variable in the Solver is the proportion of a

[32] In addition, to allow the Solver to generate a partial solution when resources are insufficient to meet needs, the Solver is allowed to select flat blocks of energy available separately in Mid-C and SWEDE regions in FY2026-2028, 2029-2034, 2035-2040, and 2041-2045, with net cost set at $10 million (2020 $) per MW per year.

particular resource type acquired at a particular time in a particular zone: for example, the proportion of the 300 MW of wind capacity available in the MIDC zone in 2026 or the proportion of the total available capacity of a utility demand voltage reduction program starting in 2031.

As described in Section 5, net costs of supply-side, energy efficiency and demand response resources include the value of the energy generated or conserved. This value could manifest as avoided market purchases or revenue from sales of surplus power. For the purposes of selecting least-cost portfolios, there is no need to distinguish between those two outcomes.

Wholesale market purchases are included in the model as resources for the purpose of enforcing market purchase limits. The Solver can select flat, HLH, LLH, and superpeak market purchases for each month that contribute to meeting energy needs and are counted when applying market purchase limits. Market purchases are not allowed to contribute to meeting 18-hour capacity needs. Market purchases are treated as zero-cost because the value of avoided market purchases is included in the net costs of other resources.

Resources that have total costs lower than the value of the energy they provide have negative net costs. For example, for solar power acquired in eastern Oregon in 2031, forecast energy revenue plus IRA production tax credits exceed total costs, resulting in a negative net cost (Table 6-2). In a constrained optimization that minimizes total resource costs, negative-cost resources will always be selected. To prevent the Solver from selecting supply-side resources beyond what is required to meet BPA needs, supply-side resources with negative net costs enter the model with very low positive costs. (However, this adjustment is not applied to energy efficiency and demand response resources, so the least-cost portfolios include all energy efficiency and demand response programs that can supply energy at lower cost than market purchases.) Market purchases are given slightly higher positive costs so that they will be selected only after negative net-cost resources are acquired.

Table 6-2: Net cost calculation for first 300 MW of solar power acquired in eastern Oregon in 2031

	Cost (millions of $, NPV)*
Total costs	474
IRA production tax credits	-214
Value of energy generated**	-262
Net cost	-2

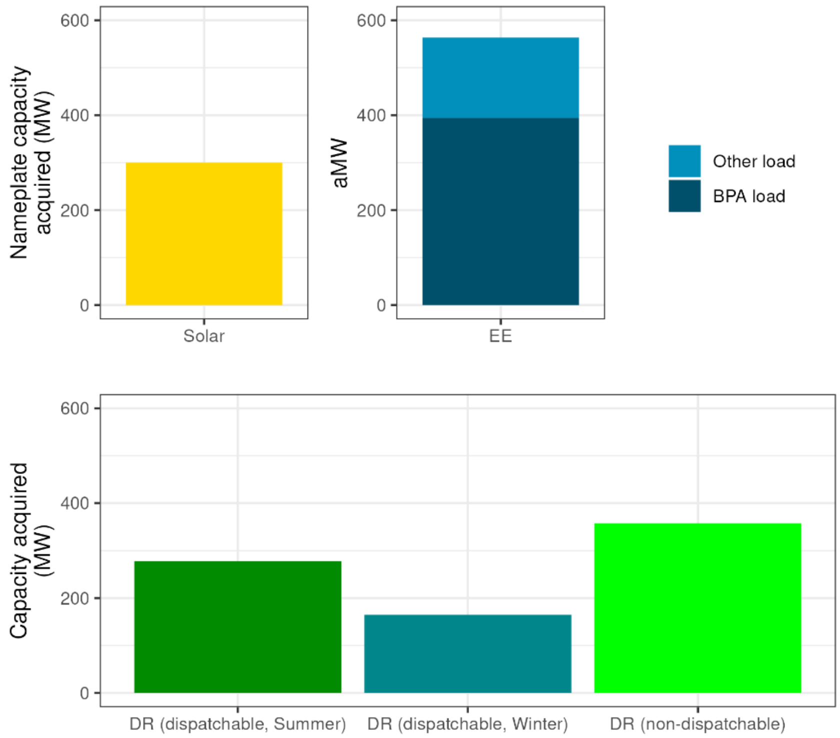
** Net costs are net present value, 2024 dollars, although costs are shown as positive values and revenues as negative values. ** Energy is valued at the forecast market price for the hour when it is generated.*

6.3 Results: Least-Cost Portfolios

6.3.1 Base Scenario

In the Base Scenario, needs are met primarily with energy efficiency, demand response and market purchases, similar to results from the 2022 Resource Program. However, energy efficiency acquisitions are considerably smaller than in the 2022 Resource Program, and the least-cost portfolio includes a 300 MW solar acquisition.

Figure 6-3: Resources acquired by 2045, in the Base Scenario least-cost portfolio.



Energy efficiency values are cumulative over the 20 years. The model assumes that 70% of energy efficiency achieved through each program reduces BPA's load obligations, and that the other 30% reduces customer obligations. Actual percentages vary by EE measure and by customer. Capacity shown for non-dispatchable demand response programs is the sum of maximum capacities across all products acquired. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity.

Table 6-3: Demand response products included in the Base Scenario least-cost portfolio

Category	Product	2045 capacity (MW)			
		Mid-C		SWEDE	
Non-dispatchable	Residential time-of-use (TOU) pricing	130		11.4	
	Utility demand voltage reduction (DVR)	197		19.4	
Dispatchable		Summer	Winter	Summer	Winter
	Residential critical peak pricing (CPP)	153	59	13.4	5.2
	Commercial critical peak pricing (CPP)	75	65	8.1	7.1
	Industrial critical peak pricing (CPP)	27	27	1.4	1.4

Dispatchable products are assumed to be available for 10 4-hour blocks during each season. Non-dispatchable products influence loads throughout the year. Capacities of non-dispatchable products represent the highest 1-hour capacity across the year.

Demand response products included in the least-cost portfolio are demand voltage reduction (DVR), time-of-use (TOU) pricing, and critical peak pricing (CPP) programs (Table 6-3). The energy efficiency bundles included in the least-cost portfolio were all under $30/MWh (2020 $).

All energy efficiency and demand response programs included in the least-cost portfolio begin in 2026, but these programs are assumed to require multiple years to ramp up to their full potential (Figure 6-4). The solar resource included in the least-cost portfolio is acquired in eastern Oregon in 2031.

Figure 6-4: Base Scenario: Mid-C Annual aMW contributed by energy efficiency, demand response, and supply-side resources

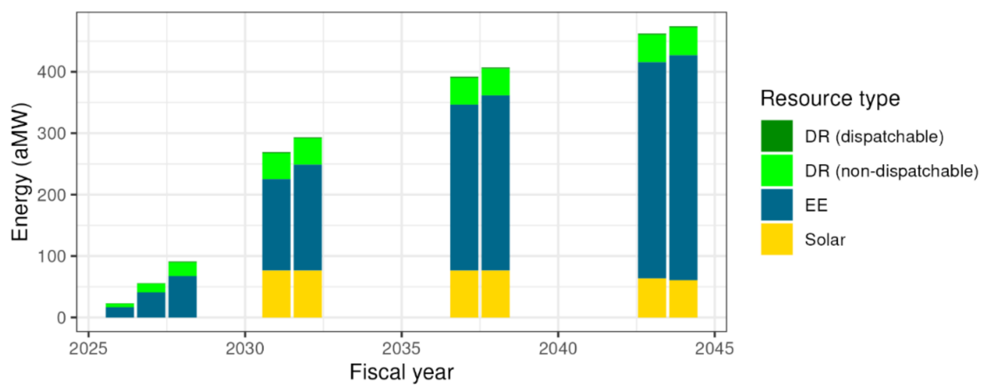


Figure 6-5: Resource contributions to meeting monthly needs in the Base Scenario

Needs represented in the top three rows assume p10 water conditions. Needs remaining after contributions by resources shown here are met with market purchases.

Substantial market purchases are needed to meet p10 energy needs in the Mid-C region, but these purchases remain well below the limits set by BPA's market liquidity assessment throughout the modeled period. As a result, the selection of other resources in the Mid-C region depends only on whether they meet energy needs at a lower cost than market purchases.

The total portfolio cost, including the net cost of meeting needs as well as net costs of the energy efficiency, demand response and solar resources, is $772 million (NPV, 2024 dollars) (Table 6-4).

Table 6-4: Base Scenario total portfolio cost

Resource	Base scenario net cost (millions of $, NPV)*	
Net cost of meeting needs		2,576
Purchases to fill deficits	4,732	
Sales of surplus power	-2,156	
Energy efficiency and demand response		-1,802
Energy efficiency	-1,425	
Dispatchable demand response	-89	
Non-dispatchable demand response	-288	
Supply side		-2
Solar	-2	
TOTAL		772

* Net costs are net present value, 2024 dollars, although costs are shown as positive values and revenues as negative values.

6.3.2 Market Limits Sensitivities

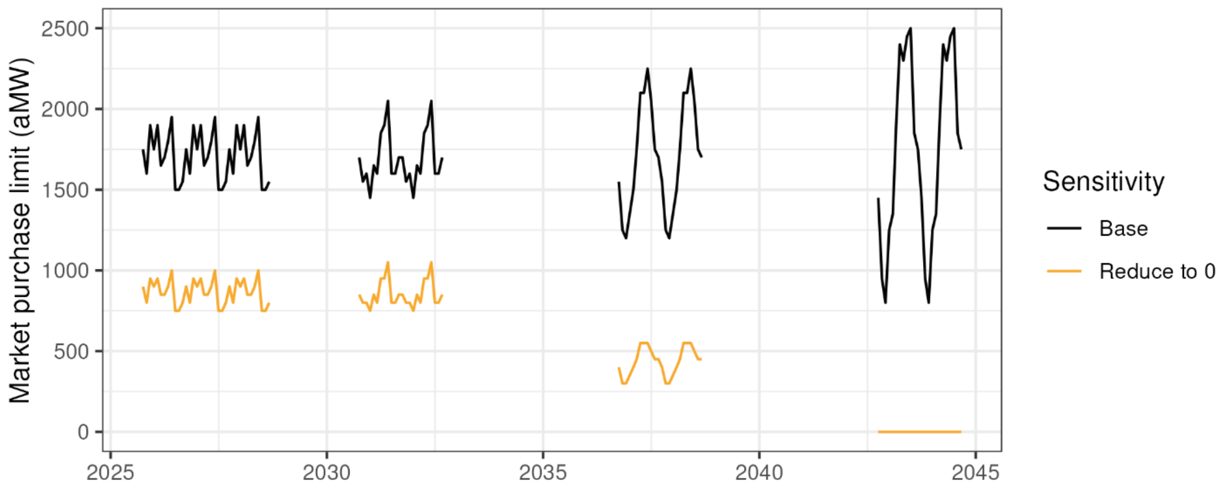
The market limits sensitivities reduce the quantity of market purchases that can used to meet needs. These sensitivities can be seen as modeling reduced market liquidity or as strategies to reduce risk associated with reliance on the market.

The 2024 Resource Program includes five market limits sensitivities, listed in Table 6-5. They differ both in terms of the scale of reduction in market purchase limits and in whether those limits are applied to LLH. Whereas the Base Scenario sets maximum aMW market purchases during HLH (and superpeak) at the forecast market depth from the Market Assessment, the market limits sensitivities reduce maximum purchases below that level. Some of the sensitivities also apply limits to purchases during LLH. Market purchase limits are compared between the Base Scenario and the 'Reduce to 0' market limits sensitivity in Figure 6-6.

Table 6-5: Market limits sensitivities

Sensitivity	Limits apply to…	Market purchases limited to…
Base Scenario	HLH	Forecast market depth
Reduce HLH by 25%	HLH	75% of forecast market depth
Reduce HLH by 50%	HLH	50% of forecast market depth
Reduce all by 50%	All hours	50% of forecast market depth
Reduce to 0	All hours	50% of forecast market depth in 2026-2033, reducing to 0 by 2043
No market	All hours	No market purchases allowed

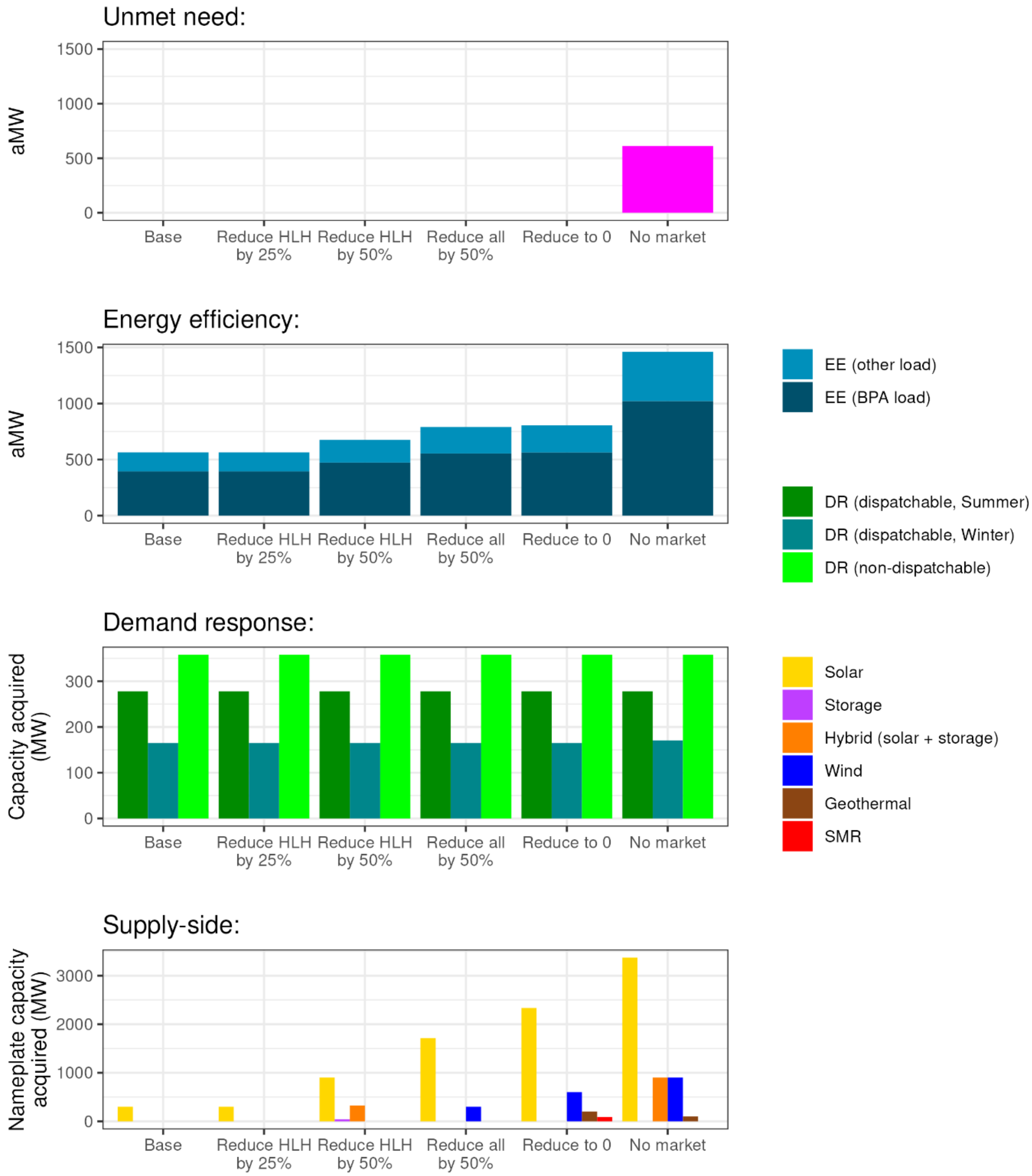
Figure 6-6: Market purchase limits in the Base Scenario and the 'Reduce to 0' market limits sensitivity



In the least-cost portfolios of the market limits sensitivities, market purchases are replaced primarily by solar and wind power (Figure 6-7). Acquisitions are driven mainly by flat energy needs, and needs in 2026-2028 are particularly influential. In all sensitivities, most resources are acquired in 2026, and in the absence of market purchases, modeled resources are not sufficient to meet all needs in the winter and early April of 2026-2028.

The 'Reduce HLH by 25%' market limits sensitivity has identical results to the Base Scenario (Figure 6-7). Each additional reduction in market purchase limits increases solar acquisitions, and sensitivities limiting LLH market purchases include wind acquisitions in their least-cost portfolios. Energy efficiency programs also contribute to replacing market purchases. Other resource acquisitions vary greatly across sensitivities.

Figure 6-7: Resources acquired by 2045 in the Base Scenario and the market limits sensitivities



In the ‘Reduce to 0’ sensitivity, 1,100 MW solar and 300 MW of wind are acquired in 2026, along with all demand response programs and nearly all energy efficiency bundles included in the least-cost portfolio. An additional 1,200 MW of solar and 300 MW of wind are acquired in subsequent years. All available geothermal resources (100 MW per start year) are acquired in 2037 and 2043, and 85 MW of SMR is added in 2043 (Figure 6-8).

In the ‘No market’ sensitivity, the least-cost portfolio includes all the solar, hybrid (solar + storage) and wind resources available in the Mid-C region in 2026, as well as 79% of the 75 aMW of energy efficiency available to serve BPA load that year. However, energy generated still falls short of needs during the winter months and early April of 2026-2028 (Figure 6-9). An additional 1,600 MW of solar resources are acquired in 2031, along with 300 MW of wind and 100 MW of geothermal resources, and the energy efficiency and demand response programs acquired in 2026 ramp up substantially over time. These large resource acquisitions, required to meet needs in the early part of the study period, are sufficient to meet needs in all subsequent years, which is why the least-cost portfolio for the ‘No market’ sensitivity does not include the 2037 and 2043 acquisitions of geothermal and SMR resources seen in the ‘Reduce to 0’ sensitivity.

Figure 6-8: ‘Reduce to 0’ sensitivity: Mid-C Annual aMW contributed by energy efficiency, demand response, and supply-side resources

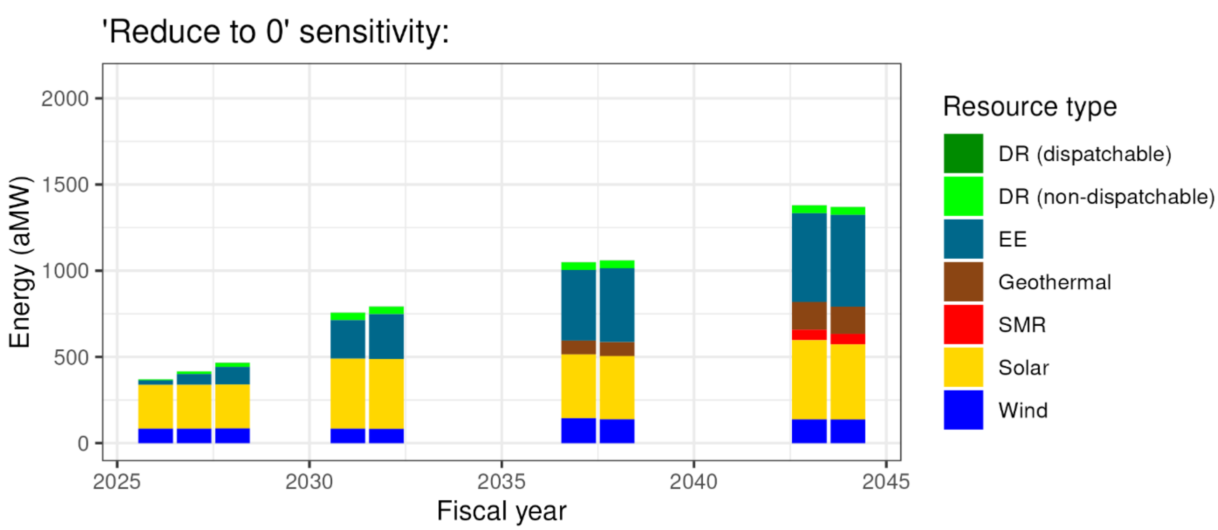
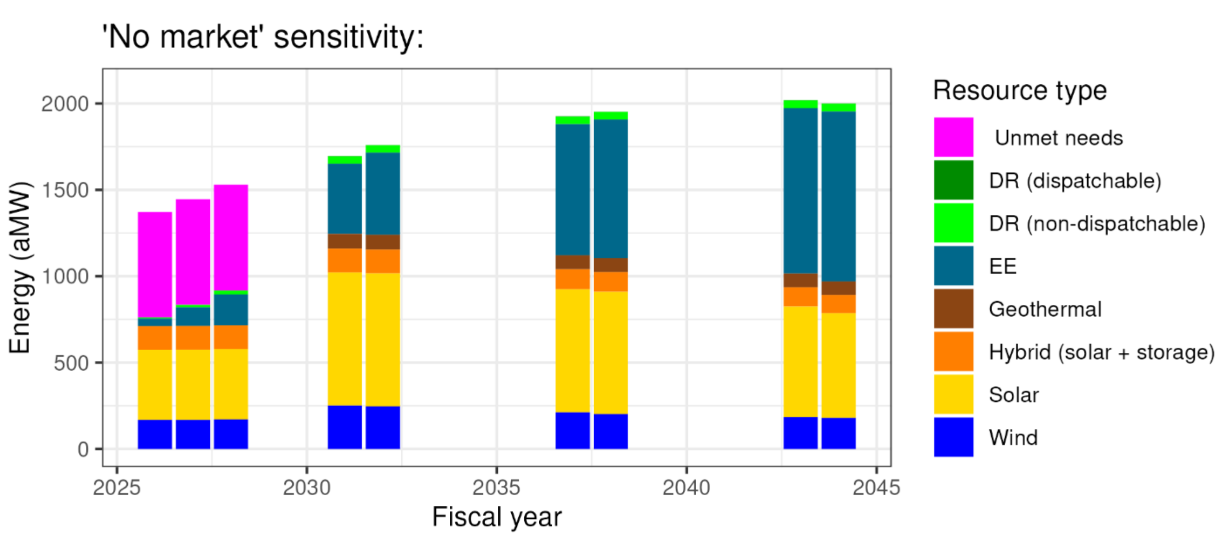


Figure 6-9: ‘No market’ sensitivity: Mid-C Annual aMW contributed by energy efficiency, demand response, and supply-side resources



6.3.3 Market Price Sensitivity

The high market price sensitivity explores the impacts of increasing market prices compared to those assumed in the Base Scenario. Higher market prices, not surprisingly, increase the range of energy efficiency and supply-side resources that are lower cost than market purchases. With doubled market prices, energy efficiency acquisitions in the least-cost portfolio approximately double, solar acquisitions increase by more than 12-fold, and wind and geothermal resources are also acquired (Figure 6-10). Reliance on market purchases to meet p10 needs drops to zero by 2037.

Figure 6-10: Resources acquired by 2045 in the Base Scenario and the high market price sensitivity

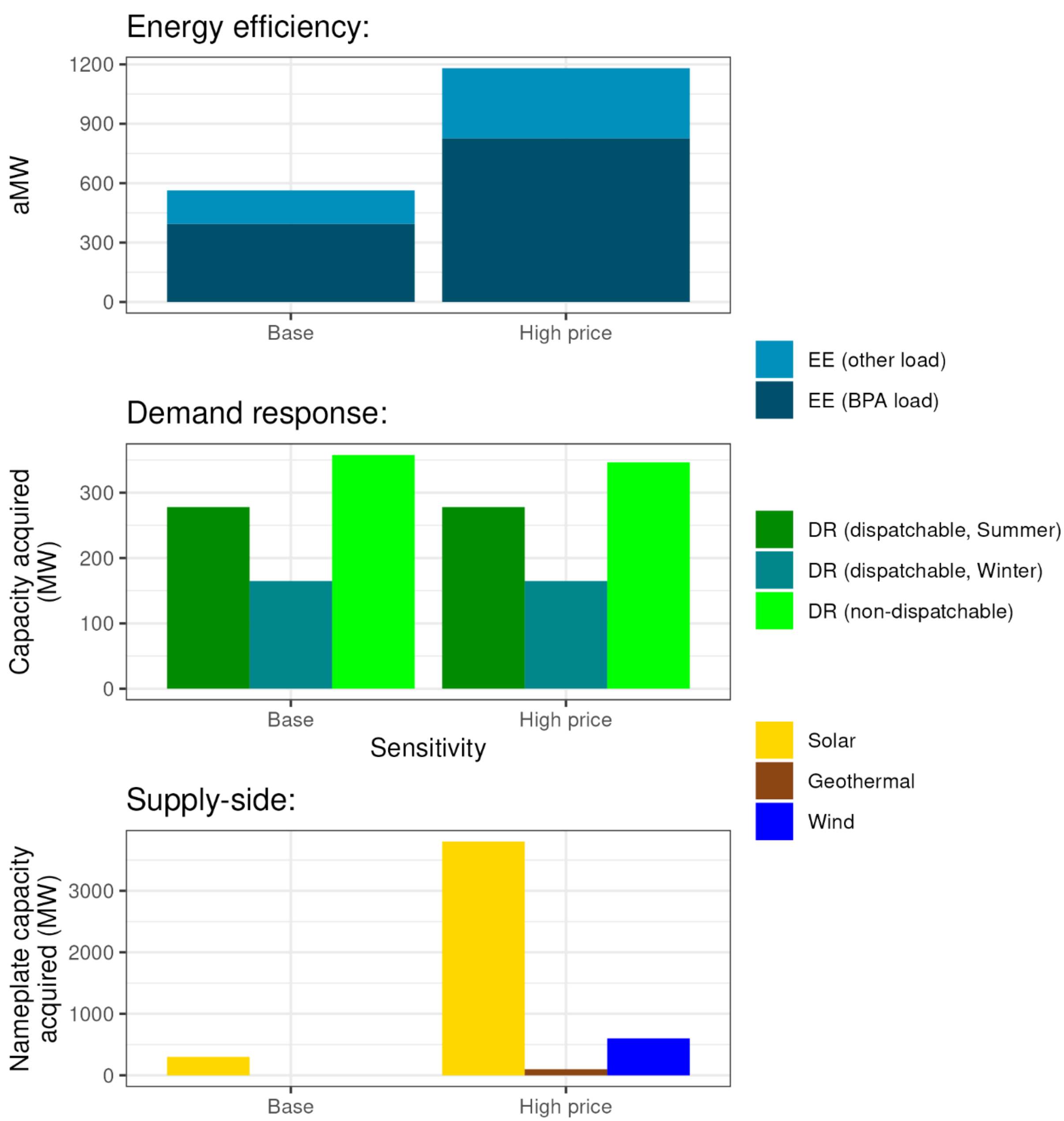
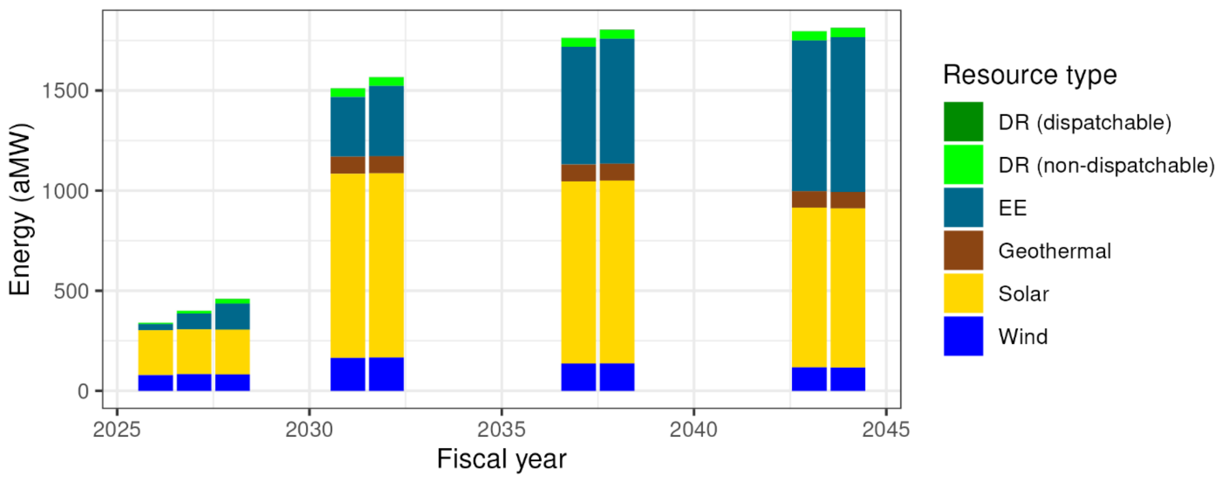


Figure 6-11: High market price sensitivity: Mid-C Annual aMW contributed by energy efficiency, demand response and supply-side resources



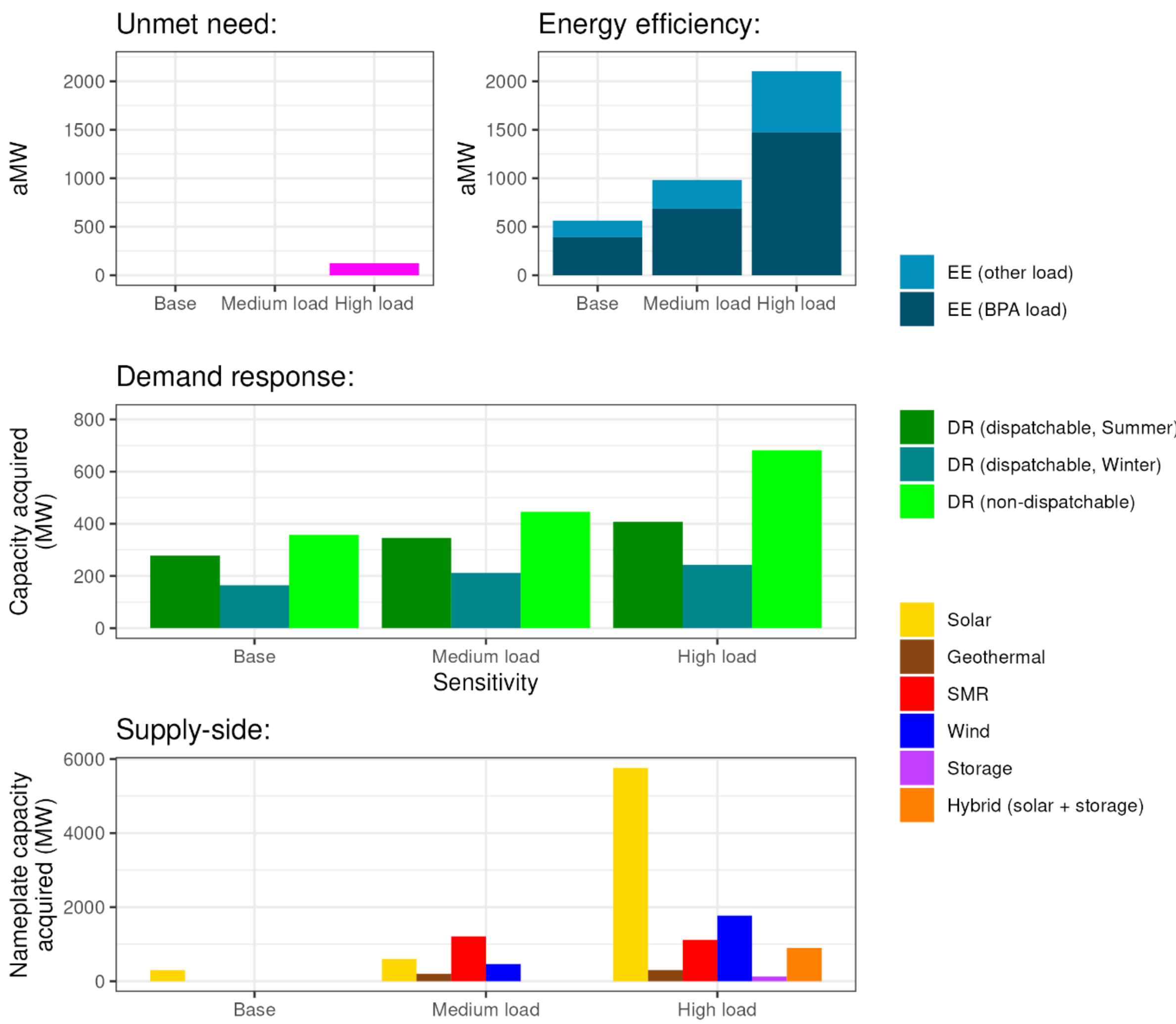
In addition to the resources included in the least-cost portfolio, many supply-side resources available at later start dates (i.e., 2037 and 2043) are also lower-cost than market purchases, including SMR as well as additional solar, wind and geothermal resources. These resources are not included in the least-cost portfolio because all needs have already been met by the time they are available to go online.

For this sensitivity, the effects of doubling market prices are approximated using results from the Base Scenario performance study. Doubled market prices are modeled by doubling the value of energy generated and consumed by resources in those resources' net cost calculations. In addition, resource contributions to meeting p10 flat and HLH energy needs are based on performance studies with P99 to p100 flat monthly market prices. Typically, these prices approximately double the prices in the performance runs used to calculate resource contributions to flat and HLH energy needs in the Base Scenario. This modeling approach is somewhat biased against variable-cost resources that would be expected to run more often when prices are higher. Although this increased energy output is captured in calculation of resources' contributions to meeting p10 energy needs, it is not captured in the resource net cost calculations.

6.3.4 Load Adder Sensitivities

Least-cost portfolios for the medium load and high load sensitivities include substantial resource acquisitions beyond those in the Base Scenario, and even these large acquisitions are not sufficient to meet all needs in 2026-2028 in the high load sensitivity (Figure 6-12). Acquisitions, which are driven primarily by HLH energy needs, include increased investment in energy efficiency and demand response programs in addition to very large additions of supply-side resources.

Figure 6-12: Resources acquired by 2045 in the Base Scenario and medium and high load sensitivities



Supply-side acquisitions in the medium load sensitivity are identical to those in the Base Scenario until 2037 (Figure 6-13, Figure 6-15). The least-cost portfolio includes all the geothermal resources available in Mid-C in 2037 and 2043 (100 MW each year), 460 MW of wind in 2037 (including 160 MW in SWEDE), 300 MW of solar in 2043, and 1,200 MW of SMR in 2043.

Similar to the 'No market' sensitivity, the least-cost portfolio in the high load sensitivity includes all solar, hybrid solar plus storage and wind capacity available in Mid-C in 2026, as well as 81% of the 84 aMW of energy efficiency available to serve Mid-C BPA load in that year (Figure 6-14, Figure 6-16). In addition, it includes 125 MW of 6-hour storage. However, these resources do not generate enough energy to meet all needs in 2026-2028, with the largest shortfall in early April. Additional large acquisitions of supply-side resources are made in every available year (i.e., 2031, 2037, and 2043) and include 3,400 MW of Mid-C solar in 2031, additional sizeable wind and solar acquisitions in both Mid-C and SWEDE regions, all available Mid-C geothermal capacity (300 MW total), and 1,100 MW of SMR in Mid-C.

Figure 6-13: Medium load sensitivity: Mid-C Annual aMW contributed by energy efficiency, demand response and supply-side resources

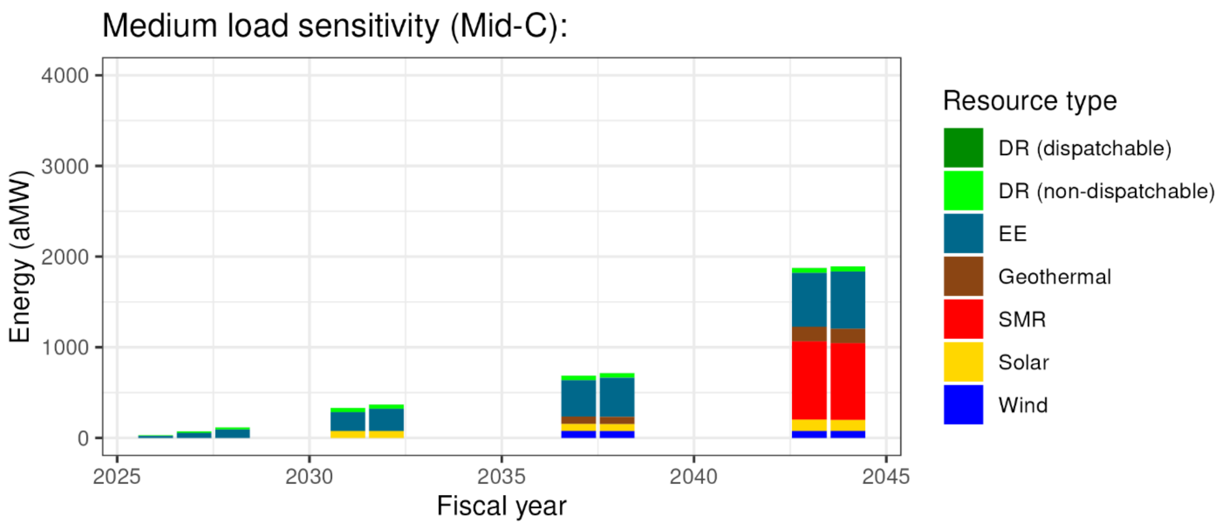


Figure 6-14: High load sensitivity: Mid-C Annual aMW contributed by energy efficiency, demand response and supply-side resources

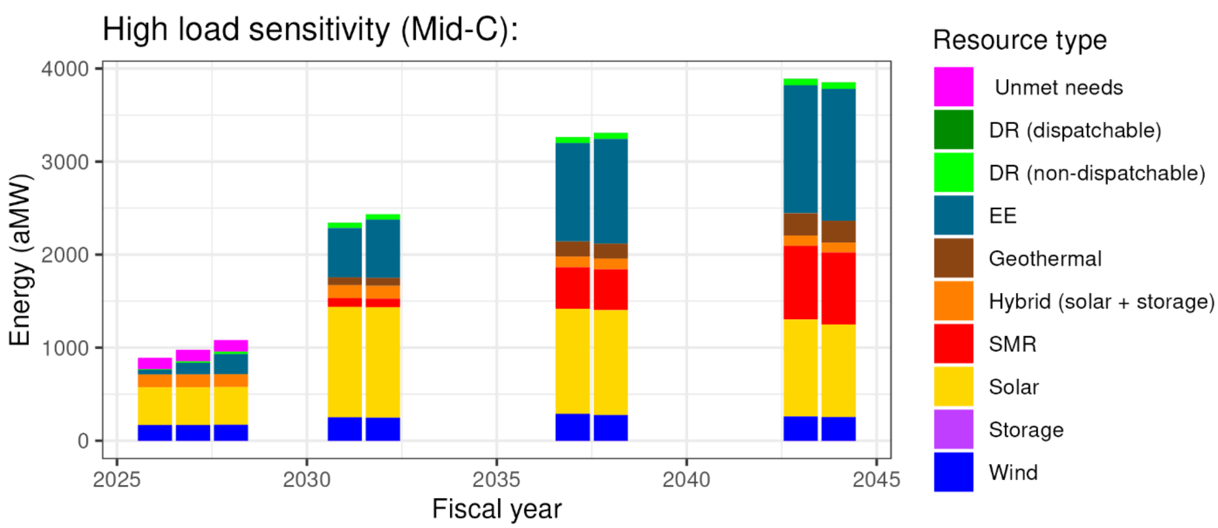


Figure 6-15: Medium load sensitivity: SWEDE Annual aMW contributed by energy efficiency, demand response and supply-side resources

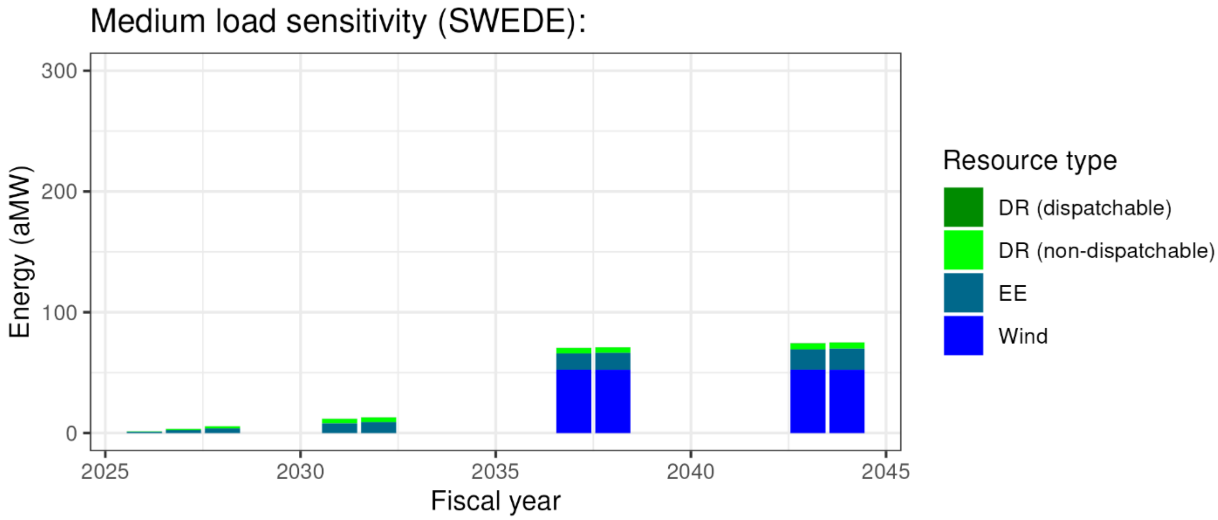
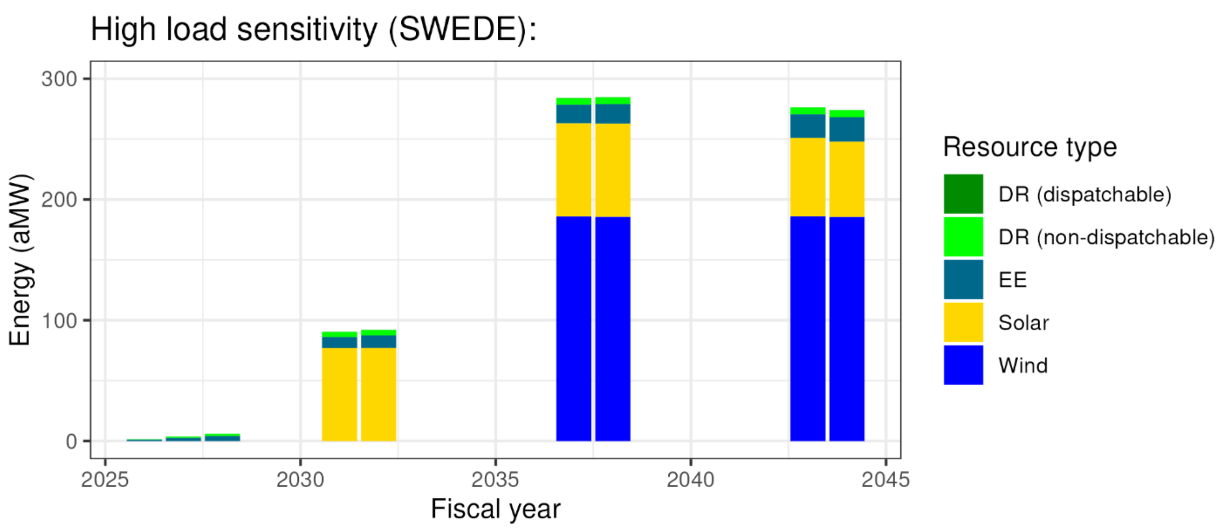


Figure 6-16: High load sensitivity: SWEDE Annual aMW contributed by energy efficiency, demand response and supply-side resources



6.3.5 Costs and Emissions Summary: Market and Load Adder Sensitivities

Total portfolio costs, including the net cost of meeting needs identified by the Needs Assessment along with the net costs of energy efficiency, demand response and supply side resources acquired, range from -$0.2 billion for the high market price sensitivity to more than $37.5 billion for the high load sensitivity (net present value, 2024 dollars; Table 6-6).

Cost comparisons across the base scenario and market limits sensitivities are of value because these sensitivities assume the same loads and market prices, so differences in costs are solely due to different resource portfolios. Furthermore, the market limits sensitivities can be interpreted as strategies to reduce reliance on the market, and comparisons can illuminate costs and benefits of these alternatives.

Reducing market reliance comes at a cost: the total portfolio cost increases from $0.8 billion for the Base Scenario to $2.5 billion for the 'Reduce to 0' sensitivity.

Reduced reliance on the market could also reduce financial risk. Two measures are used to quantify financial risk. The first, portfolio cost variability, estimates variability across conditions. This measure takes the standard deviation of annual costs across performance study model runs and averages these standard deviations across years. The second, tail variable costs, estimates the worst variable costs expected in a month. This measure averages the total monthly variable costs for the worst (i.e., highest-variable-cost) 10 months across performance study runs and months. Portfolio cost variability does not vary substantially across market limits sensitivities. As market reliance decreases, variability in costs from purchasing power decreases, but variability in revenues from selling surplus power increases. However, the tail variable costs do decline with reduced reliance on the market, from $460 million in the base scenario to $360 million in the 'Reduce to 0' sensitivity (2020 dollars).

Table 6-6: Summary of portfolio costs, cost variability and highest variable costs across the base scenario and key sensitivities

	Base scenario	Market limits				High Market Price	Loads	
		Reduce HLH by 25%	Reduce HLH by 50%	Reduce all by 50%	Reduce to 0		Medium Load	High Load
Total portfolio cost (billions of $, NPV, 2024)	$0.8	$0.8	$1.6	$2.2	$2.5	-$0.2	$9.0	> $37.5
Portfolio cost variability (avg. SD*, billions of 2020 $)	$0.24	$0.24	$0.24	$0.24	$0.24	$0.52	$0.27	$0.33
Tail variable costs (Avg. of 10 worst months, billions of 2020 $)	$0.46	$0.46	$0.43	$0.38	$0.36	$0.60	$0.55	$0.78

6.3.6 Tier 1 System Size Sensitivity

The Tier 1 System Size Sensitivity models growing the Tier 1 System Firm Critical Output (T1SFCO) to at least 7,250 annual aMW, distributed across months to match expected loads. Needs are modeled as average monthly energy needs at the whole-system level, with no distinction made between SWEDE and Mid-C zones. Only supply-side resources are allowed to contribute.

The least-cost portfolio for augmenting the Tier 1 system includes large solar and wind acquisitions and modest geothermal acquisitions (Figure 6-17). Solar and geothermal acquisitions are split across the Mid-C and SWEDE regions, and wind is acquired only in the SWEDE region, reflecting higher capacity factors and lower prices in this region (Figure 6-18). This aspect of the results should be viewed with caution because the model does not include transmission costs and constraints associated with delivering energy generated in the SWEDE region to the Mid-C region.

Figure 6-17: Resources acquired by 2045, in the Tier 1 System Size Sensitivity least-cost portfolio

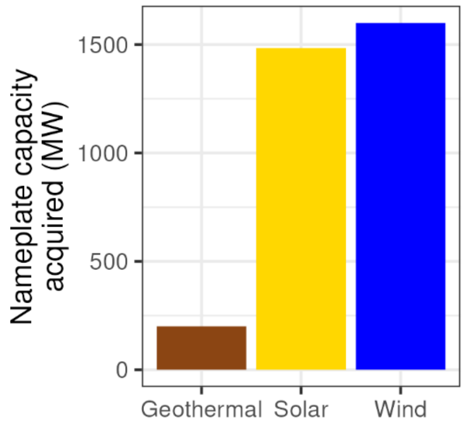
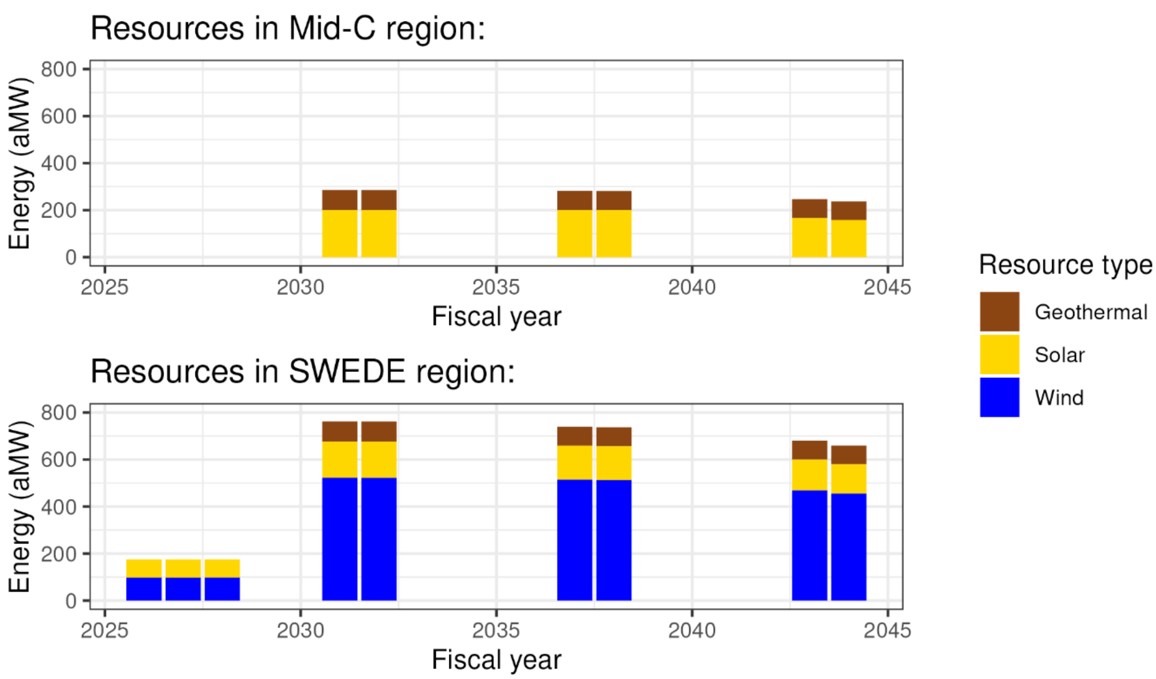


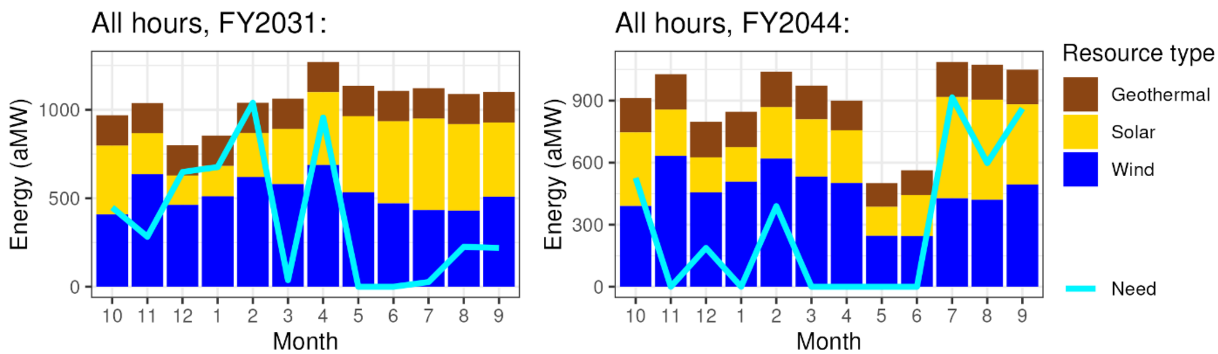
Figure 6-18: Tier 1 System Size Sensitivity: Annual aMW contributed by energy efficiency, demand response and supply-side resources



An outcome of requiring monthly needs to be met by supply-side resources, rather than allowing market purchases, is that generators are built to meet needs in the most constraining month and then produce large surpluses in most other months, even in p10 water conditions (Figure 6-17). February 2031 is the most constraining month in this sensitivity, so all resources had to be acquired by 2031 (Figure 6-16, Figure 6-19).

The first 2 years of the desired T1SFCO augmentation, 2029 and 2030, are not explicitly modeled in the Solver but have similar needs to 2031. Therefore, most resource acquisitions would need to happen two years earlier than shown here. Some of the resource options included in the least-cost portfolio for this sensitivity may not be available in time, and costs may be higher than assumed in the model.

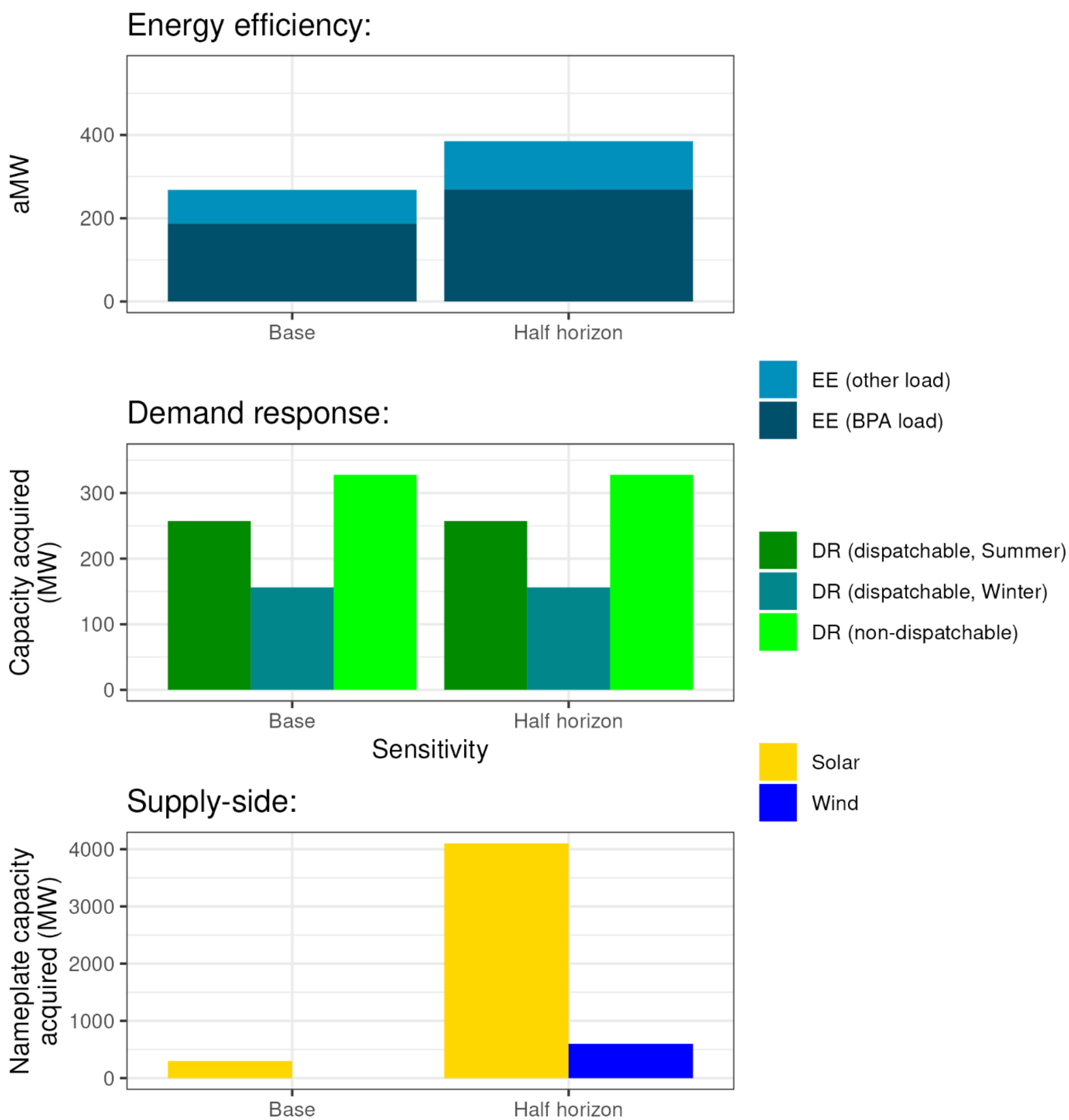
Figure 6-19: Resource contributions to meeting monthly needs in the Tier 1 System Size Sensitivity



6.3.7 Half Horizon Sensitivity

The Half Horizon Sensitivity models the period from 2026 to 2034 instead of the full study horizon of 2026 to 2045. When only the first half of the study horizon is considered, most resources have lower net costs, for two reasons. First, forecast prices are substantially higher in the first half of the study horizon than in the second half. Second, the IRA production tax credits modeled for wind and solar resources pay out in the first decade of the plant's lifespan, leading to much lower costs during that first decade than in subsequent years. Reflecting these lower resource costs, the half horizon model acquires more energy efficiency programs and more solar power than the Base Scenario and acquires wind power (Figure 6-20).

Figure 6-20: Resources acquired by 2032, compared between least-cost portfolios of the Base Scenario and a half horizon version of the Base Scenario



6.4 Natural Gas Assessment

Natural gas resources are assessed through comparisons with modeled resources rather than being explicitly included within the model. BPA chose that approach because of substantial modeling challenges presented by natural gas resources. The diversity of carbon policies across BPA's service territory would require multiple modeling approaches within each scenario and sensitivity, greatly expanding the scope of the resource program modeling. Incorporating natural gas price risk modeling has caused significant delays and errors in other applications. Uncertainty around costs and availability of firm fuel, as well as uncertainty about the costs and key characteristics of transitioning natural gas resources to clean fuels such as hydrogen or biofuels, also make it more difficult to accurately model natural gas resources. However, the exclusion of natural gas resources (or any other type of resource) from the model does not preclude BPA from acquiring any resource necessary to meet needs in a cost-effective manner, as outlined in the Northwest Power Act and consistent with sound utility practice.

To assess whether a natural gas resource would have been selected by the Solver had it been included in the model, resources with similar generation profiles are modeled and their costs are compared. Specifically, the model compares two baseload resources – a combined-cycle natural gas plant and an SMR – because the primary needs driving resource acquisitions in the 2024 Resource Program are monthly average and HLH energy needs. If the natural gas plant has a higher net cost than the SMR, it would not have been selected by the model in any cases in which at least some SMR capacity was available but not selected. Similarly, if it has a lower net cost than the SMR, it would have been selected in any case in which the SMR was selected.

Cost calculations use the assumptions described in section 5.1.3. For natural gas plants, the variable costs include carbon emission costs of about $50/metric ton CO2e (real 2020$). The emissions rate was estimated at 0.428 metric tons CO2e per megawatt-hour which would translate into about $24/megawatt-hour (real 2020$). The carbon emissions rate is based on rough approximations that are generally representative of NW CC plants and a blend of emission rates that came from modeling the Western Interconnection for the market price forecast. The carbon emission cost is based on BPA's forecast of Washington and California's carbon allowance market clearing prices which impact BPA and its customers. If state policies or pricing changes in the future, the carbon emission cost could change.

BPA assumed for this study that the earliest date a new natural gas plant could come online for BPA would be 2035, considering the time required for construction and interconnection processes.[33] This is consistent with the assumptions for all other generating resources that are not already in the interconnection queue (no natural gas was found in the interconnection queue at the time of review and no specific project offer was available at the time). A natural gas resource might be available to BPA sooner than 2035 if it is 1) small, i.e., <50 MW and therefore subject to the small generator interconnection process; 2) already in BPA's interconnection queue or cluster study; or 3) an existing resource. BPA did not include an analysis of resources with these characteristics in the Resource Program because at the time of analysis no natural gas projects were in the interconnection queue or available as active project offers.

[33] Interconnection is a significant driver of these timing assumptions. BPA recently adopted a cluster study approach to interconnection. BPA will begin its Transition Cluster Study this year and will use "Reasonable Efforts" to try and run the cluster studies on a 3-year cycle. If a request for a natural gas plant enters BPA's queue in the next 3 years while the Transition Cluster Study is running, it would be studied during the first durable Cluster Study, which would also run 3 years. After getting through the cluster study (in 6 years from now, assuming everything goes well), the request would go through a Facilities Study, then environmental compliance, then be offered an LGIA, then construction would begin. The Facilities Study usually takes about 6 months, but the environmental compliance and construction is needed is highly dependent on the project location and scope.

The natural gas resource was viewed as bridge resource to accommodate state policy requirements on customers in Washington and Oregon.[34] Thus the contract is assumed to only last through 2045, giving the natural gas resource a 10 year useful life.

Natural gas resources were assessed outside of the Solver by comparing the cost of a natural gas resource to the most comparable generating resource included as an option in the Solver, which was determined to be the small modular reactor (SMR). The intent of this assessment was to determine whether a natural gas resource would likely have been selected in place of the SMR if it were included in the Solver.

A combined-cycle natural gas plant had higher net costs than an SMR built in the same year. Even though the overnight capital cost is considerably greater for the SMR, its longer life span (60 years for SMR), lower fuel costs, and eligibility for Inflation Reduction Act tax credits, along with no carbon emissions costs, make the SMR less expensive overall. The 2024 NPV for the 2035 SMR net costs is $437M. In comparison, the 2024 NPV for the 2035 natural gas combined cycle net costs is approximately $850M. These values are intended to give an indication of whether one resource is likely higher than the other and whether it would be selected. The natural gas resource used did not define specific characteristics and was not intended to represent a precise forecasted cost.

Least-cost portfolios for every sensitivity left at least some SMR capacity unused in every year except 2026 (when SMR was not available), meaning that, assuming a natural gas plant would not be available before 2035, a combined-cycle natural gas resource would not have been selected in any sensitivity (Figure 6-21). However, the ‘no market’ market limits sensitivity and the high load sensitivity both had needs in 2026 through 2028 that could not be met by resources in the model; indicating that if a natural gas plant were available then, it would likely be selected.

Figure 6-21: Results of the natural gas assessment

Figure 6-19: Results of the natural gas assessment	Base scenario	Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0	High Mkt Price	Med Load	High Load
2029-2034								
*2035-2040								
2041-2045								

[34] Washington law requires the electricity industry to be greenhouse gas emission free by 2045, and Oregon law includes a staged approach to emissions reductions. BPA is not subject to state law, but its customers are. As a result, if BPA executes a PPA with a greenhouse gas emitting resource that continues in effect beyond 2045, its customers may be required to terminate service with BPA to comply with state law, exposing BPA and its remaining customers to the risk of stranded costs.

	Not Selected
	Likely Selected if Available
	Likely Selected

6.5 Conclusions

As in previous resource programs, the least-cost portfolio for the Base Scenario relies heavily on energy efficiency, demand response and market purchases to meet BPA needs. As loads grow or market access is further limited, resource acquisitions grow quickly. These acquisitions are driven mainly by HLH and flat energy needs, rarely by superpeak or 18-hour capacity needs. Supply-side acquisitions tend to focus on solar and wind resources because of their low costs and their contributions to meeting energy needs. Meeting needs in winter months and early April during the first few years of the study horizon is particularly challenging, and in two sensitivities (the high load sensitivity and the no market purchases sensitivity), resources in the model are not sufficient to meet these needs. Needs in the SWEDE region can be met with energy efficiency and demand response programs along with power imported from the rest of the system unless loads are greater than forecast in the Base Scenario. However, the SWEDE region does offer low-cost supply-side resource options, particularly wind, that may be worth further investigation.

Section 7: Conclusion

7.1 Next Steps

BPA will develop a resource acquisition process. This process will take into consideration the Northwest Power and Conservation Council's power planning work, BPA's Resource Program and BPA's Integrated Program Review. BPA will also take into account customer needs, and other factors such as capacity and resiliency in anticipation of its contracted needs.

Looking toward the next Resource Program, BPA plans to further develop and refine the enhancements it has made for the 2024 Resource Program, including updates to modeling, and refinements to the optimization process and risk analysis.

BPA will also monitor events that could change the forecast outcomes of the 2024 Resource Program, such as changes to clean energy legislation, changes to resource costs or loads, or unforeseen changes to the operations of the Federal Columbia River Power System. The impacts of these and other events, as well as anticipated modeling enhancements and improved information and data that become available, will be incorporated into future planning activities.

7.2 Environmental Analysis

Consistent with the National Environmental Policy Act of 1969 (NEPA), as amended, BPA would conduct appropriate environmental analyses of any future proposed power resource acquisitions informed by the Resource Program prior to any decision to complete an acquisition. All BPA environmental reviews would follow the procedures and requirements applicable to BPA and set forth in U.S. Department of Energy (DOE) NEPA Implementing Procedures (10 C.F.R. § 1021), Council on Environmental Quality Regulations for Implementing the Procedural Provisions of NEPA (40 C.F.R. § 1500–1508), and other laws, regulations and guidance.[35]

Environmental reviews for proposed power resource acquisitions would depend on the nature of the acquisition under consideration. Environmental review, including NEPA analysis, and supporting documentation would be completed prior to any final decision by BPA to pursue a power resource acquisition.

7.3 Transmission Supplement Summary

The Bonneville Power Administration's Transmission Services organization is instrumental to ensuring BPA Power Services' existing generating resources and market purchases are delivered to load in the BPA balancing authority area. Therefore, including a Transmission Supplement is intended to show the deliverability aspect, not just the generation aspect, of how BPA approaches resource adequacy for its

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[35] BPA is aware of the November 12, 2024, decision in *Marin Audubon Society v. Federal Aviation Administration*, No. 23-1067 (D.C. Cir. Nov. 12, 2024). To the extent that a court may conclude that the Council on Environmental Quality regulations implementing NEPA are not judicially enforceable or binding on an agency action, BPA has nonetheless elected to follow those regulations at 40 Code Federal Regulations (C.F.R.) §§ 1500– 1508, in addition to the US Department of Energy's NEPA implementing procedures at 10 C.F.R. § 1021, to meet the agency's obligations under NEPA, 42 U.S.C. §§ 4321 *et seq*.

obligations. BPA also relies heavily on other regional utility transmission providers to ensure that Power Services' load is served in balancing authority areas outside of BPA's. That portion of deliverability is not described in this Transmission Supplement.

If and when Power Services identifies and pursues the acquisition of resources other than energy efficiency and potentially demand response, Power Services would actively coordinate with Transmission Services. Power Services and Transmission Services will coordinate and collaborate on near-term and long-term system planning activities, including model inputs, load forecasts, resource retirement estimates, and several other planning topics of mutual interest. Expanded active coordination would occur if Power Services were to pursue resource acquisitions beyond demand-side resources. For a detailed description of Transmission's planning processes, read the 2024 Resource Program Transmission Supplement.