BONNEVILLE POWER ADMINISTRATION

2020 Resource Program

CONTENTS

INTRODUCTION

This report begins with a general overview, noting the purpose of the Resource Program, highlighting changes from the previous assumptions and methodology, and summarizing key findings of the analyses. This is followed by a more indepth look at each of the components of the Resource Program, including the assumptions, methodologies and the respective study results, along with a brief section on Bonneville's next steps culminating from the conclusions. Finally, the Transmission Supplement provides a synopses of long-term planning for Bonneville's transmission infrastructure in support of meeting its anticipated future energy obligations in the 10-year study period covering fiscal years 2020–2030.

1.1 Overview

Bonneville launched its Resource Program shortly after passage of the Northwest Power Act in 1980 to assess the agency's need for power and reserves and develop an acquisition strategy to meet those needs. The 2020 Resource Program provides analysis and insight into long-term, least-cost power resource acquisition strategies. To accomplish this, the Resource Program examines uncertainty in loads, water supply, resource availability, natural gas prices, and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations.

Bonneville has refreshed the 2018 Resource Program for 2020. In 2018, Bonneville expanded its Resource Program methodology, time frame and granularity for analyzing its resource needs and potential solutions. The results of this process helped Bonneville decide the shape and amount of conservation, or energy efficiency (EE), budgeted for and targeted in the 2020–2021 fiscal year time period. The 2020 Resource Program utilizes the same process and advancements as 2018, but refreshes inputs and expands the risk analysis to incorporate sensitivities to help Bonneville understand how the results may be impacted by changes in key assumptions. The results yield a refined vision into Bonneville's needs and low-cost resource strategies across a broad spectrum of future market conditions for a base case and alternative sensitivities that include reductions in Federal Columbia River Power System (FCRPS) generation, reduced market depth assumptions, and increased incidences and magnitudes of scarcity pricing in the Western Electricity Coordinating Council (WECC).

Bonneville's 2018–2023 Strategic Plan describes the actions it will take over the next three years to remain a competitive supplier of low cost power to its regional firm power customers. To support these strategic goals, the 2020 Resource Program details a comprehensive planning analysis that seeks to align Bonneville's resource acquisitions, including energy efficiency and demand response initiatives, with its long-term power supply needs.

Despite BPA's commitment to conducting periodic long-term planning exercises, the Resource Program is neither a decision document nor is it a process required by any external entity. Rather, it is a voluntary body of work, undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations and strategic objectives cost-effectively.

1.2 Transmission Supplement

In addition to the typical power analysis, the 2020 Resource Program also seeks to address the integrated power and transmission responsibilities and assets controlled by Bonneville. Planning for power and transmission in an integrated manner is a complicated task, but doing so provides cost-effective planning value to Bonneville. The regional power resource base is undergoing a period of rapid change as some Pacific Northwest states move to decarbonize their sources of power by requiring utilities to use more renewable energy resources to supply retail loads in their respective states. Some of these states have passed laws that have resulted in utility decisions to retire the least efficient carbon-emitting generating plants, i.e., coal plants. The impacts of these changes, while providing benefits in terms of reduced greenhouse gas emissions, will cause new stresses on the power system, necessitating innovative energy solutions. Furthermore, regional transmission systems will also face new challenges as the power generation base changes in both makeup and location.

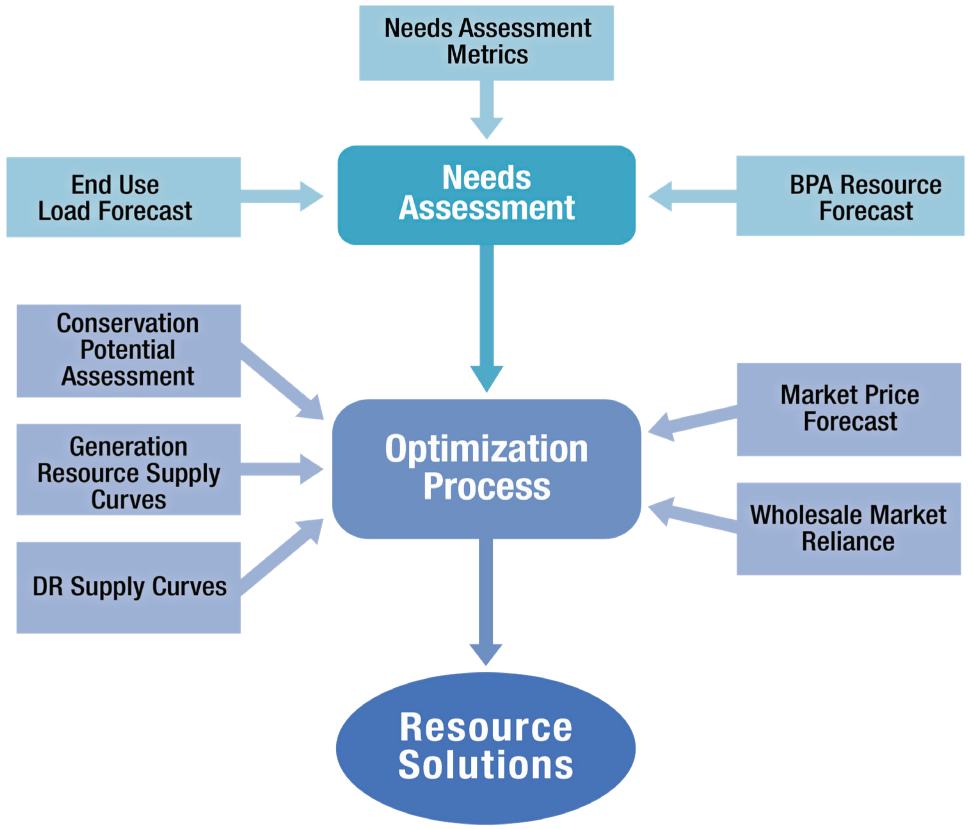
In response to this, the 2020 Resource Program incorporates a Transmission Supplement that addresses how Bonneville Transmission Services is planning for the future of the transmission grid. While the Transmission Supplement has not yet been integrated into the Resource Program's formulation and modeling, we are committed to exploring ways of linking Power and Transmission long-term planning in our future forecasting efforts.

1.3 Methodology

The Resource Program begins with a forecast of Bonneville's obligations to supply firm power and the existing resources available to meet that demand, and then determines any additional need for incremental energy or capacity in the Needs Assessment. It then identifies and evaluates potential solutions to meeting those needs including energy efficiency, demand response, and power purchases.[1] The Resource Program then outlines potential strategies for meeting Bonneville's needs. Figure 1.1 provides a high-level diagram of the Resource Program process.

[1] Currently, these resource solutions are sufficient to meet Bonneville's anticipated obligations. The Resource Program may need to evaluate alternative resource additions in the future if the regional landscape changes and no longer enables this current set of alternatives to meet Bonneville's anticipated obligations.

Figure 1.1 Resource Program Process



To appropriately assess the costs and benefits of resource solutions, Bonneville uses Aurora® to create an electricity price forecast. Aurora® is a computer software tool that can be used to produce energy market price forecasts, value and uncertainty analyses, and automated system optimization. The energy market price forecast incorporates a natural gas price forecast, a renewables build forecast, and assumptions around many other important factors, including regional generating resource retirements, negative price bidding activity, and load forecasts for surrounding regions.

Aurora® was also used to perform portfolio optimization analysis that assessed candidate resources' performances against 400 sets of potential future market conditions. The result of the optimization process is a set of 40 different portfolios that all meet Bonneville's needs.

The 2020 Resource Program is a refresh of the 2018 analyses. The process from 2018 is the same, but only certain inputs, including the load forecast, resource forecast, needs assessment, market prices, and resource costs were updated. Additionally, the timeframe of analysis was shortened from 20 years to 10 years to focus on the period closer to when Bonneville will inform its actions based on the Resource Program results. Bonneville anticipates completing another 20-year analysis and updating all of the inputs in its 2022 Resource Program.

1.4 Conclusions

The following summarizes the main conclusions of the 2020 Resource Program:

- The second half of April is when Bonneville, per the Needs Assessment metrics, sees its largest heavy load hour energy needs where large deficits are observed under low water conditions. These are in addition to the long-standing winter deficits carried over from the 2018 results.[2]
- Bonneville has surplus capacity in the winter and the summer. This is a change from the 2018 Resource Program, which identified a growing deficit in the summer 18-hour capacity metric.
- The expected market price at the Mid-Columbia trading hub declined from an average of $36.50/MWh in the 2018 Resource Program to $23.60/MWh in the 2020 Resource Program.
- Similar to previous Resource Program findings, the least-cost mix of resources that will meet Bonneville's expected energy needs consists of conservation and energy purchased from the market.
- Demand response is not a part of the least-cost portfolio selected to meet Bonneville's needs at this time, which differs from recommendations in the 2018 Resource Program. This new finding reflects the lack of a capacity need and a cost calculation correction.

The following sections provide a more detailed look at the 2020 Resource Program.

2 The 2018 Resource program identified the largest heavy load hour energy needs as existing in the winter.

SECTION 2: NEEDS ASSESSMENT

2.1 Overview

The goal of the Needs Assessment is to measure Bonneville's existing system, in relative isolation, against Bonneville's obligations to supply power to show whether any long-term energy and/or capacity shortfalls exist over a 10-year study horizon. The Needs Assessment forecasts Bonneville's needs for long-term energy and capacity based on resource capabilities and projected obligations to serve power. The Needs Assessment informs later steps of the Resource Program, where resource optimization techniques are used to evaluate and select potential solutions for meeting Bonneville's long-term needs based on cost and risk.

2.2 Methodology

The Needs Assessment incorporates hourly forecasts of Bonneville's power service obligations and resource capabilities. These forecasts are produced by the Agency Load Forecasting system and include projections of customer energy needs that Bonneville is obligated to meet under its power sales contracts. The Needs Assessment includes a frozen efficiency obligation forecast, meaning historical trends of energy efficiency savings achievements were not projected forward into the obligation forecast. In addition to assuming no future energy efficiency is achieved, the studies also assume no access to heavy load hour market purchases, and only 1,000 MW of light load hour purchases are available to facilitate hydropower system shaping.

The Needs Assessment resource capability forecasts also include projections for Bonneville's regulated[3] hydropower resources. These forecasts are produced by the Hourly Operating and Scheduling Simulator (HOSS) model. The HOSS forecasts, along with the forecasted capability of Bonneville's other hydropower and non-hydropower resources, such as Columbia Generating Station, are compared to projected load obligations. This determines if obligations ever exceed resource capabilities, leading to potential energy or capacity shortages within the study period. The hydropower assumptions used in this study are consistent with those in Bonneville's BP-20 Rate Case Final Proposal, with the addition of the 125% total dissolved gas (TDG) flexible spill operation agreed to in the 2019-2021 Flexible Spill Agreement.[4]

The Needs Assessment uses the following four metrics to assess Bonneville's long-term energy and capacity needs. The Needs Assessment used in the 2020 Resource Program provides 10-year continuous forecasts for three energy metrics (Annual Energy, P10 Heavy Load Hour, and P10 Superpeak). Due to the higher workload associated with producing

3 Regulated hydropower refers to the 14 hydro projects located on the Columbia and main tributaries that are modeled in BPA's HYDSIM model. This includes projects such as Grand Coulee, Chief Joseph and Bonneville.

4 The 2019-2021 Spill Operations Agreement and other information can be found at https://www.bpa.gov/efw/fishwildlife/SpillOperationAgreement/Pages/default.aspx.

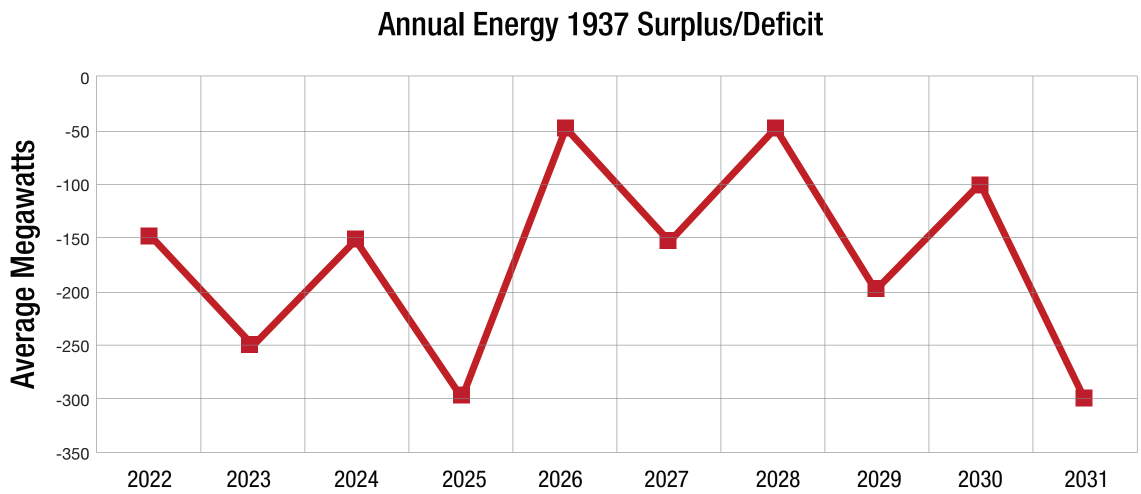
forecasts for the 18-Hour Capacity metric, the Needs Assessment provides a capacity metric forecast only for the summer of 2025.

- **Annual Energy:** Evaluates the annual energy surplus/deficit under 1937 critical water conditions, using forecasted load obligations and expected Columbia Generating Station output (CGS is the Northwest's sole commercial nuclear energy plant).
- **P10 Heavy Load Hour:** Evaluates the 10th percentile (P10) surplus/deficit over heavy load hours, by month, given variability in hydropower generation, load obligations, and Columbia Generating Station output amounts.
- **P10 Superpeak:** Evaluates the P10 surplus/deficit over the six peak load hours per weekday by month, given variability in hydropower generation, load obligations, and Columbia Generating Station output.
- **18-Hour Capacity:** Evaluates the surplus/deficit over the six peak load hours per day during three-day extreme weather events and assuming median water conditions. Winter and summer extreme weather events, such as cold snaps or heat waves, are analyzed, both of which assume maximum delivery of the Canadian Entitlement outside of the region, zero wind generation, and limited energy market purchases. Winter events assume reduced streamflows due to impacts from ice forming in reservoirs. Summer events assume reduced Columbia Generating Station output due to adverse weather conditions, as the plant must downpower during high temperatures for safety reasons.

2.3 Results

Figure 2.1 presents the results for the Annual Energy metric. Bonneville measures its ability to provide firm power by projecting the anticipated hydropower system generation, based on the current system performance level, outages, and operating restrictions, and using historic streamflows from 1937, which are the second lowest streamflows on record. By this measurement, Bonneville's anticipated system output is lower than its obligations for the duration of the study horizon, causing deficits. The generation shape shows a repeating pattern of larger deficits in odd years caused by Columbia Generating Station's biennial refueling and maintenance outages, which results in less generation every other year. The shift in generation between 2025 and 2026 is due to the expiration of certain long-term power sales contracts.

Figure 2.1



The P10 Heavy Load Hour results for the 10-year study horizon are shown in Figure 2.2. The largest energy deficits under this metric occur in the second half of April and across the winter. Over the study range, the P10 Heavy Load Hour metric remains consistently deficit during these periods, with the largest energy deficits occurring in the second half of April.

While Bonneville has sizeable deficits in winter and the second half of April, the P10 energy surpluses or deficits vary widely by month. For example, Bonneville consistently has large surpluses of energy in the May-July timeframe, corresponding with peak streamflows occurring during spring runoff.

Figure 2.2

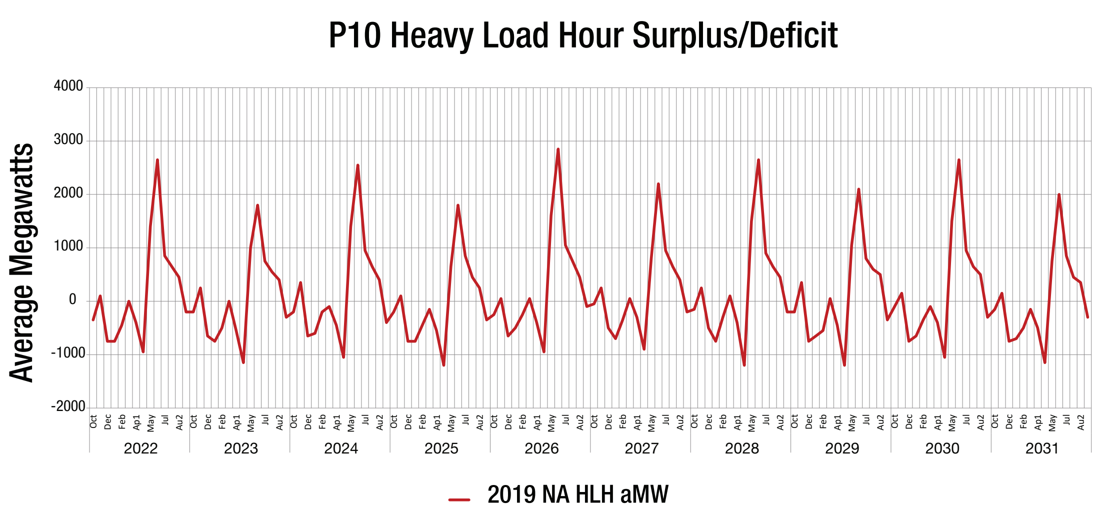
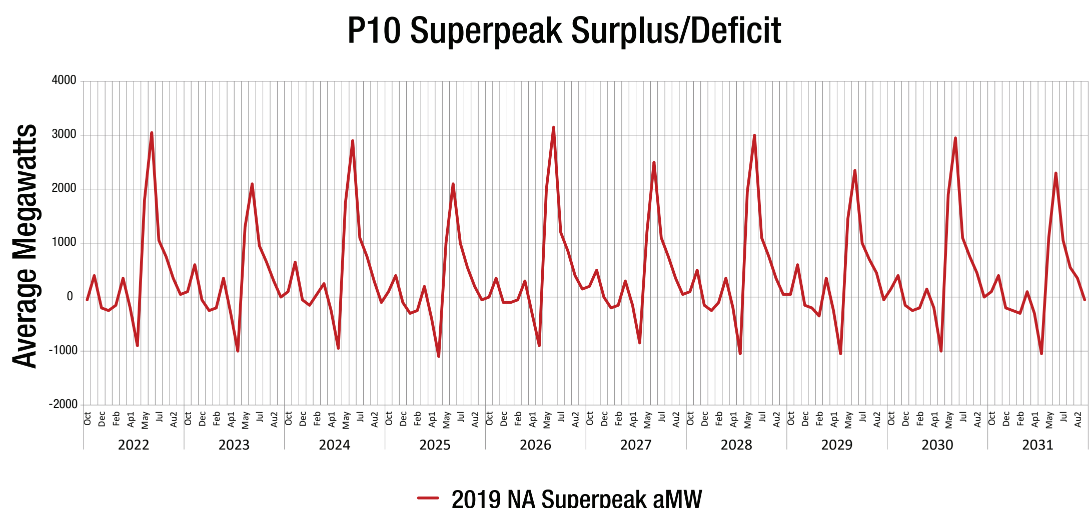


Figure 2.3 presents the P10 Superpeak results for the 10-year study horizon. Similar to the P10 Heavy Load results, the largest deficits under this metric occur in the second half of April and across the winter. The P10 Superpeak metric remains consistently deficit during these periods over the 10-year range, but note that these results also show fairly consistent surpluses from May-November.

Figure 2.3



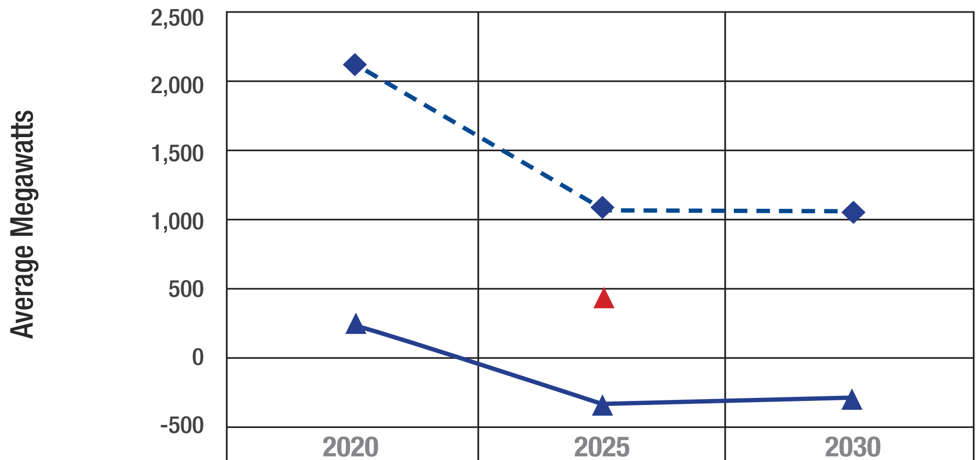
The results for the 18-Hour Capacity metric, showing a surplus in summer 2025, are pictured alongside the corresponding results from the prior 2017 Needs Assessments in Figure 2.4. These results show the scale of Bonneville's increased capacity resulting from operational changes outlined in the Flexible Spill Agreement. The Agreement allows for spill operations to end and power generation to resume in the second half of August, the time period in which Bonneville has historically been the most capacity constrained. Relaxing the spill constraint enables the hydropower system to produce much more energy, completely eliminating Bonneville's summer capacity deficit. As noted above, and described in more detail, below, Bonneville only conducted one 18-hour capacity study for the 2020 Resource Program.

2.4 Conclusions

Overall, the 2019 Needs Assessment results indicate that Bonneville is energy-limited but has surplus capacity. The P10 Heavy Load Hour deficits surpass the P10 Superpeak deficits in most months, while the 18-Hour Capacity metric shows a surplus. Bonneville's largest projected needs for energy now occur under low water conditions in the second half of April, caused by new spill requirements coupled with the possibility for the weather to remain quite cold into April, delaying higher streamflows from spring runoff while simultaneously boosting energy demand. Needs Assessment simulations showed that when these three factors are combined, Bonneville can experience quite large April energy deficits. However, the potential outcomes for April vary widely; while results at the P10 show large deficits, these switch to a surplus at around the 24th percentile, with a monthly average surplus of almost 2000 MW at the 50th percentile.

Figure 2.4

18-Hour Capacity Surplus/Deficit



	2020	2025	2030
2019 NA Summer		450	
2017 NA Summer	250	-350	-300
2017 NA Winter	2,150	1,100	1,050

In line with a well-documented trend in Bonneville's prior Needs Assessments, the 2019 Needs Assessment results also show Bonneville is energy deficit in the winter, with the largest winter deficits occurring in the P10 Heavy Load Hour energy metric. Addressing these deficits requires adding energy to Bonneville's resource portfolio that will both be reliably captured in the lower percentiles of the study's distributions and provide adequate energy to meet monthly average Heavy Load Hour demands. The superpeak deficits are smaller than the P10 Heavy Load Hour deficits; therefore, the P10 Heavy Load Hour deficits were selected as the constraint to be used as input for the Resource Program's optimization model (see Section 4 for information on the optimization model).

Fulfilling the P10 Heavy Load Hour need also provides energy during the superpeak hours of a month — resolving the P10 Heavy Load Hour energy need in this way allows Bonneville to address superpeak and annual energy needs at the same time, while also providing additional increases in Bonneville's capacity.

The 2017 Needs Assessment did not forecast a winter capacity shortfall during its 20-year study period, but it did show a growing summer capacity deficit. However, because of the 2019-2021 Flexible Spill Agreement that allows for spill operations to end in the second half of August, Bonneville's available capacity was expected to increase compared to the 2017 results. This assumption was tested by running an 18-hour capacity study and evaluating results for summer 2025, the period shown as being the most capacity deficit in the 2017 Needs Assessment.

The 2019 study used in the 2020 Resource Program now forecasts a 450 MW surplus for this period. The magnitude of this summer surplus indicated to Resource Program staff that additional capacity studies were not necessary — Bonneville now expects to have surplus capacity in both the summer and winter over the 10-year study horizon. This finding simplified the 2020 Resource Program by eliminating the need to provide a capacity target in the portfolio optimization process.

SECTION 3: RESOURCE ASSESSMENT

3.1 Generating Resources

The 2020 Resource Program includes updated resource cost information to reflect changes in renewables, namely wind and solar technology and associated costs. Declining technology costs and tariffs on imported solar cells introduced after the publication of the 2018 Resource Program could potentially influence the types of resources identified by the portfolio optimization to most efficiently meet regional power needs.

The optimization process determines whether a given generating resource offers an economic advantage relative to another — resources were not pre-screened or selected on the basis of relative levelized costs of energy or capacity. Below is a brief summary of the resource plant types considered for the 2020 Resource Program. A more detailed look at each plant type's characteristics can be found in Appendix H of the Seventh Power Plan.[5]

- **Simple-Cycle Combustion Turbine:** General Electric's LMS100 Single Cycle Combustion Turbine serves as the representative peaking thermal resource considered in the optimization portion of the Resource Program. This resource type was chosen for its flexibility, ability to meet a mix of load conditions, and its widespread use in the Western Electricity Coordination Council as a peaking resource to provide additional energy for meeting peak demands. While the Seventh Power Plan does not include the LMS100 as a reference plant for its aeroderivative class, MicroFin, a tool used for calculating resource costs as part of the Resource Program analyses, contains cost and performance characteristics for the LMS100 and provides the foundation for the assumptions used.
- **Wind:** Bonneville modeled one type of wind resource using updated costs based on the U.S. Energy Information Administration (USEIA) Annual Energy Outlook[6] and wind cost forecasts provided by IHS Markit. The updated wind costs were benchmarked against reference plants from the draft 2021 Power Plan[7] to ensure that they were within a reasonable range. Bonneville estimated wind output for the forecast period using its risk model designed for rate-setting evaluations in conjunction with Aurora®.
- **Solar:** Single-axis and fixed-axis utility-scale solar resource costs were updated to reflect a blend of USEIA and IHS Markit cost forecasts and to include the latest information on tax credits and tariffs. The updated costs were benchmarked against solar reference plant costs from the draft 2021 Power Plan. However, the outlook for solar costs has declined since the USEIA solar cost forecast was published and Bonneville expects lower capital costs assumptions in the next Resource Program.

5 https://www.nwcouncil.org/sites/default/files/7thplanfinal_appdixh_gresources_3.pdf

6 https://www.eia.gov/outlooks/aeo/

7 https://www.nwcouncil.org/2021-northwest-power-plan

3.2 Conservation Supply Curves

3.2.1 Overview

Prior to the 2018 Resource Program, Bonneville had included conservation as a fixed input. In the past, a share of the Council's Power Plan conservation target was assumed to be achieved by its public power customers, and that amount of conservation was included as a predetermined resource that would be applied to meet Bonneville's needs. The remaining needs would then be met with other potential resources after accounting for expected savings from conservation.

Since the 2018 Resource Program enhancements, Bonneville now assesses conservation in line with other available supply and demand-side resources. An available amount of conservation is input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of conservation to be used in the optimization model, Bonneville relies on a Conservation Potential Assessment (CPA) prepared by Cadmus Group. The CPA identifies the amount and costs of energy efficiency measures available from the forecasted customer loads supplied by Bonneville over the planning horizon. This ensures all potential conservation is included and evaluated against competing alternatives in the optimized selection process.[8]

3.2.2 Adjusting for 2020 and 2021 Energy Efficiency Accomplishments

Although the original CPA produced results beginning in 2020, the 2020 Resource Program's evaluation period begins in 2022. To ensure the available conservation potential in 2022 was calculated correctly, Bonneville adjusted the 2020 and 2021 potential based on the expected energy efficiency achievements by making three adjustments.

First, Bonneville's anticipated energy efficiency achievements for 2020 and 2021 were removed from the CPA's potential. Forecasts developed for Bonneville's 2019 Energy Efficiency Implementation Plan[9] showed 45 average megawatts (aMW) per year of EE. The forecast was developed at the sector level (Residential, Commercial, Industrial, Agriculture, and Utility Distribution) but the CPA potential was assessed further according to the specific type and relative cost of EE measures. Resource Program staff allocated expected programmatic savings by sector across these more granular measure categories in the CPA in proportion to the potential calculated by the CPA.

Second, Bonneville removed expected Momentum Savings and Market Transformation savings[10] for 2020 and 2021 from the CPA potential and followed a similar allocation process as described above for programmatic savings. The total net savings was forecast as 22 aMW of Momentum Savings and 35 aMW for Market Transformation, derived from Bonneville's Momentum Savings models and Northwest Energy Efficiency Alliance's annual funder report, which is provided directly to BPA and includes information on NEEA's annual savings.

8 Further details on Bonneville's CPA can be found in the 2018 Resource Program Report, located at https://www.bpa.gov/p/Power-Contracts/Resource-Program/Documents/2018%20Resource%20Program.pdf.

9 https://www.bpa.gov/EE/Policy/EEPlan/Pages/BPA-Energy-Efficiency-Plan.aspx

10 Momentum Savings are the savings that occur outside of energy-efficiency programs and are above the Power Plan baseline that are tracked and reported by BPA. Market Transformation savings are associated with NEEA's programs and intiatives that focus on long term market change and push the region toward more efficient technologies.

Finally, after these three savings streams were subtracted, all remaining lost opportunity savings were also removed from the potential in 2020 and 2021. Lost opportunity savings include when a piece of equipment reaches the end of its life and must be replaced, creating an opportunity to replace it with a more efficient model. Because the equipment must be replaced, the opportunity for increased efficiency only exists at that time, and any lost opportunity potential that was not acquired in a given year needs to be removed from the overall potential without being carried over into the next year.

Incorporating these three adjustments developed a more accurate forecast for the potential conservation savings starting in 2022, the beginning of the 2020 Resource Program's evaluation period.

3.3 Demand Response Supply Curves

In preparation for the 2018 Resource Program, Bonneville contracted with Cadmus Group to conduct a demand response potential assessment. The assessment identified 14 demand response products with distinct cost and seasonal profiles. The full potential assessment, including methodological discussion, is available on Bonneville's website.[11]

In Bonneville's Resource Program, demand response is considered as a potential solution to meeting capacity needs, if capacity deficits are identified in the Needs Assessment. Because the 2020 Needs Assessment did not show capacity deficits during the planning horizon, demand response was removed from the pool of resources available for selection in the portfolio optimization.[12] This decision was further confirmed by tests during the resource optimization process, which indicated that demand response would not be selected in least cost portfolios.[13]

The removal of demand response in the 2020 Resource Program does not have implications for Bonneville's long-term stance on this potential solution to capacity deficits — it is a reflection of the current state of the agency's needs. Bonneville will continue to assess the use of demand response in future Resource Programs.

3.4 Wholesale Energy Market

3.4.1 Wholesale Market Price Forecast

Bonneville used Aurora® with West Interconnect, a zonal topology, to generate a 10-year forecast of Mid-Columbia prices. This forecast consists of a distribution of 400 risk-informed hourly forecasts sampled two weeks per month.[14] Each of the 400 forecasts is based on a unique water year sequence, natural gas price forecast, WECC-wide load forecast, hourly wind generation pattern, schedule of Columbia Generating Station outages, and hourly transmission path rating (as applied to the Alternating Current, Direct Current and British

11 https://www.bpa.gov/EE/Technology/demand-response/Pages/Resources.aspx

12 The primary value of demand response is derived by a load decreasing its electricity consumption for a limited duration of time. It is therefore considered primarily a capacity resource.

13 Moreover, it was found that inclusion of demand response distorted the overall performance of the resource optimization process and would encumber the identification of an efficient frontier. Once it was determined that Demand response would not be selected in the least-cost portfolio, it was removed from successive modeling runs to avoid this distortion.

14 For more information about Aurora® and the risk models employed to produce this forecast, see the Power Market Price Study and Documentation, BP-20-FS-Bonneville-04.

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.

The WECC load forecast is consistent with Bonneville's 2018 forecast except for California, which has been updated to be consistent with California Energy Commission's 2017 Integrated Energy Policy Report's Mid Demand-Mid Available and Achievable Load Forecasts.[15]

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 on the dispatch, or production, cost of natural gas-fired generators. Relative to the 2018 Resource Program, there were significant declines in projected natural gas prices over the forecast horizon resulting from the expectation for plentiful production of low-cost associated gas produced by oil-focused extraction activity.

Several processes inform Bonneville's Aurora® resource portfolio. First, data from the USEIA's database of planned and sited resource additions and retirements over the horizon of the BP-20 rate period were referenced against additional data from sources such as Bonneville's Transmission Interconnection Queue, WECC's 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. Bonneville staff then added sufficient generic resources to this stack to meet state Renewable Portfolio Standards (RPS) using energy constraints in the Aurora® long-term capacity expansion mode. 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 mode was used to add and retire thermal resources. Aurora® adds and retires thermal resources based on economics and an operating reserve margin, which guarantees that sufficient generating resources are available to meet peak load plus about 15%. Resources that are not expected to cover their costs are retired.

This price forecast reflects the effects from applicable state RPS on utilities within the WECC enacted as of July 1, 2019, as well as Washington's Clean Energy Transformation Act. Additional clean energy policies at the municipal or utility level are not included. New state RPS targets in Nevada and New Mexico, additional rooftop solar, and updated utility-scale renewable resource cost estimates resulted in a substantial increase in modeled solar buildout over the forecast horizon.

This forecast also incorporates a simplistic depiction of negative variable costs for renewable resources, driven by such things as federal production tax credits for wind resources, renewable energy credits, and power purchase agreements, in which all WECC renewable resources are given variable costs of about -$23 per megawatt-hour (MWh, in real 2016 dollars). Impacts from including negative prices on expected Mid-C prices are most apparent in the near-term and during spring off-peak hours. Beginning around 2025, high midday solar output is expected to drive lower prices in the spring on-peak hours, resulting in Mid-C heavy-light price inversions, on average. By 2030, the growth in solar coupled with negative bid behavior results in heavy-light price inversions, on average, for the majority of the year.

15 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03, accessed Feb 1, 2018.

The following figures depict the results of the Mid-C price forecasts. Figure 3.1 shows an annual average price for all hours by year. Figure 3.2 presents average monthly prices for all hours by each month for the years 2022, 2025, and 2030. Figure 3.3 depicts the average hourly prices by hour in the month of May for the years 2022, 2025 and 2030. Figure 3.4 is a comparison between the Mid-C price forecasts for the 2018 and 2020 Resource Programs.

Figure 3.1

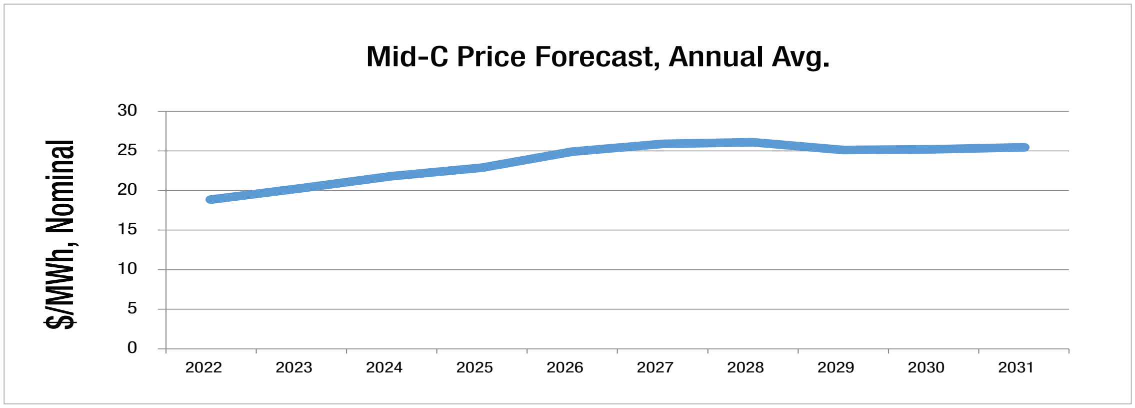


Figure 3.2

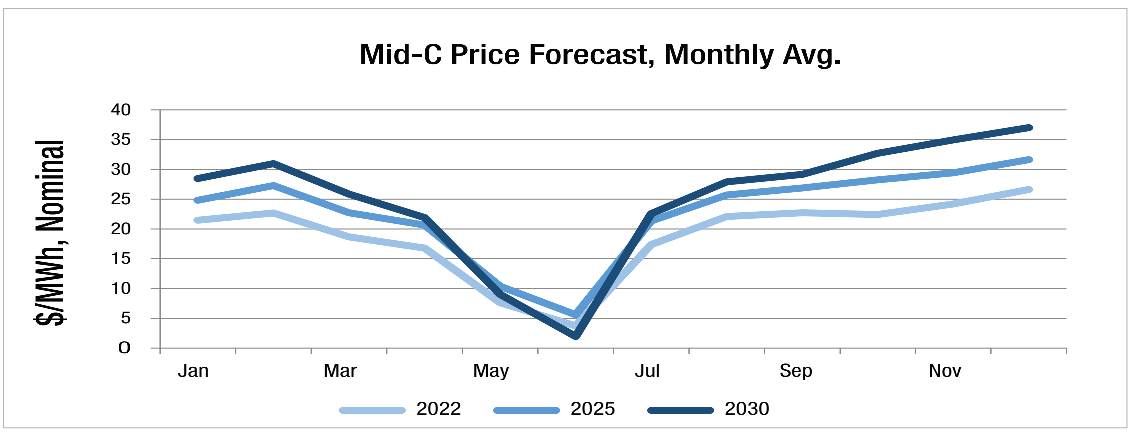


Figure 3.3

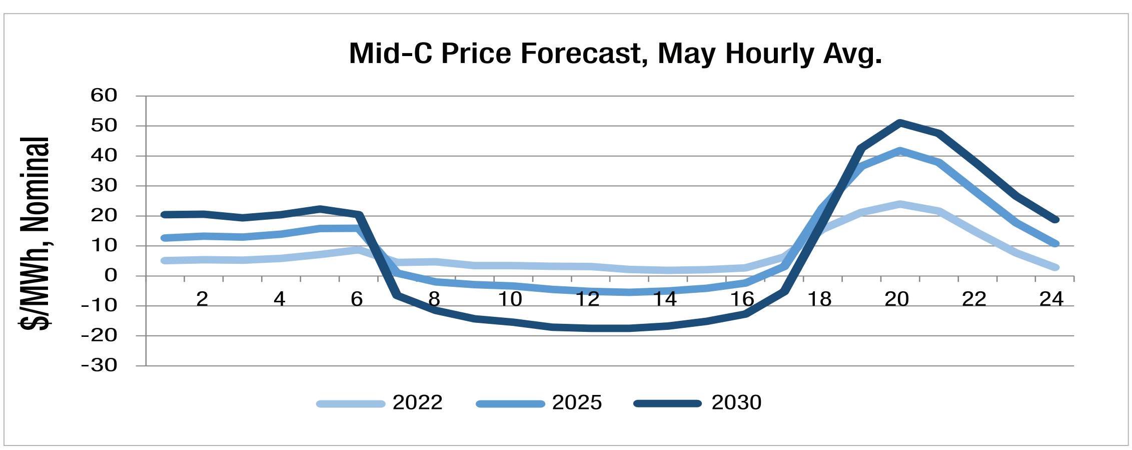
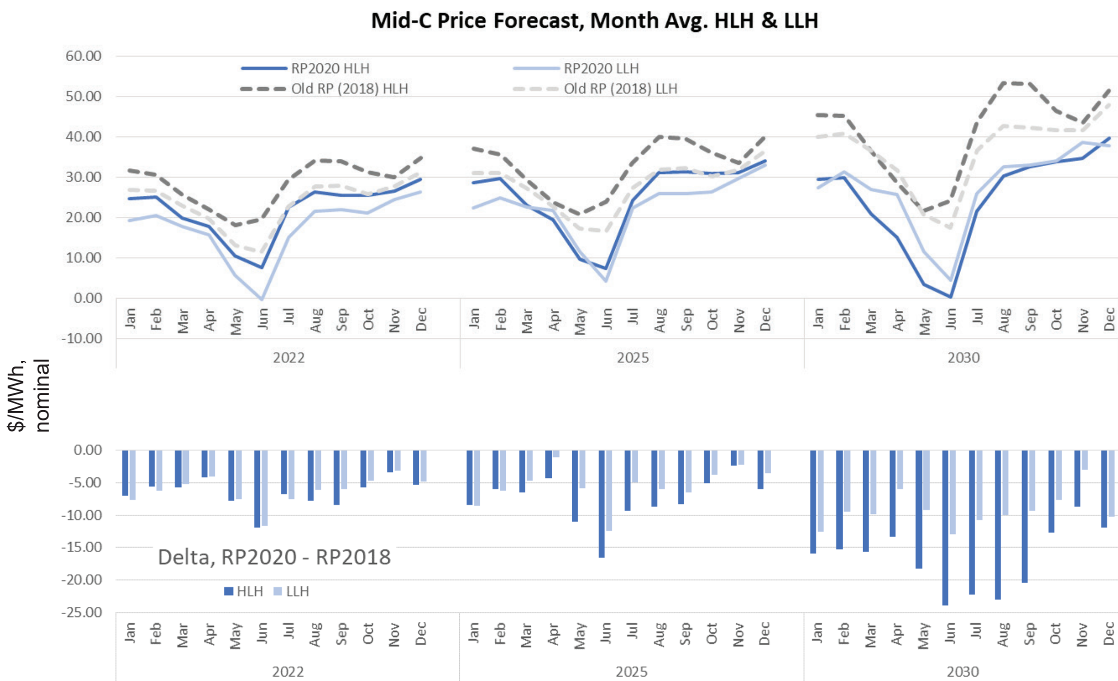


Figure 3.4



3.4.2 Market Reliance Limit

Given expected fundamental changes in energy markets across the WECC driven by growth in renewables and sustained low natural gas prices, Bonneville used AURORA® to assess future energy availability and establish monthly market reliance limits for the 10-year planning horizon.[16] Starting with Bonneville's baseline resource build used to generate the market price forecast (see section 3.4.1), Pacific Northwest regional hydropower generation is set to monthly P10 levels to represent scarcity conditions on the system, then loads are incrementally added until a 5% loss-of-load probability threshold is exceeded. It is assumed that, up until that point, the region can rely on market exchanges to meet energy needs rather than building or maintaining additional resources. Bonneville is then allocated a share of the load increase (market availability) proportional to its share of regional load. This sets Bonneville's market reliance limit. The evaluation is done on a monthly basis with flat load additions, and the market limit is 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 or a WECC-wide Independent System Operator. The estimate simply reflects expected physical energy availability given projections of WECC load-resource balance and transmission capabilities.

16 This is the same study approach used in the 2018 Resource Program.

3.5 Conclusions

When exploring possible solutions to its needs, Bonneville considered a wide range of technologies including thermal generation, demand side management, and renewable generation. Compared to the 20-year timeframe from the 2018 Resource Program, the 10-year average prices from the 2020 Resource Program declined by $12.90/MWh to average $23.60/MWh, driven by the emergence of a large renewable resource buildout and plentiful, low-cost, gas supply. Beginning around 2025, high mid-day solar output is expected to drive lower prices in the spring on peak hours, resulting in Mid-C heavy-light price inversions. These inversions become more prevalent, and persist for the majority of the year by 2030.

SECTION 4: PORTFOLIO OPTIMIZATION

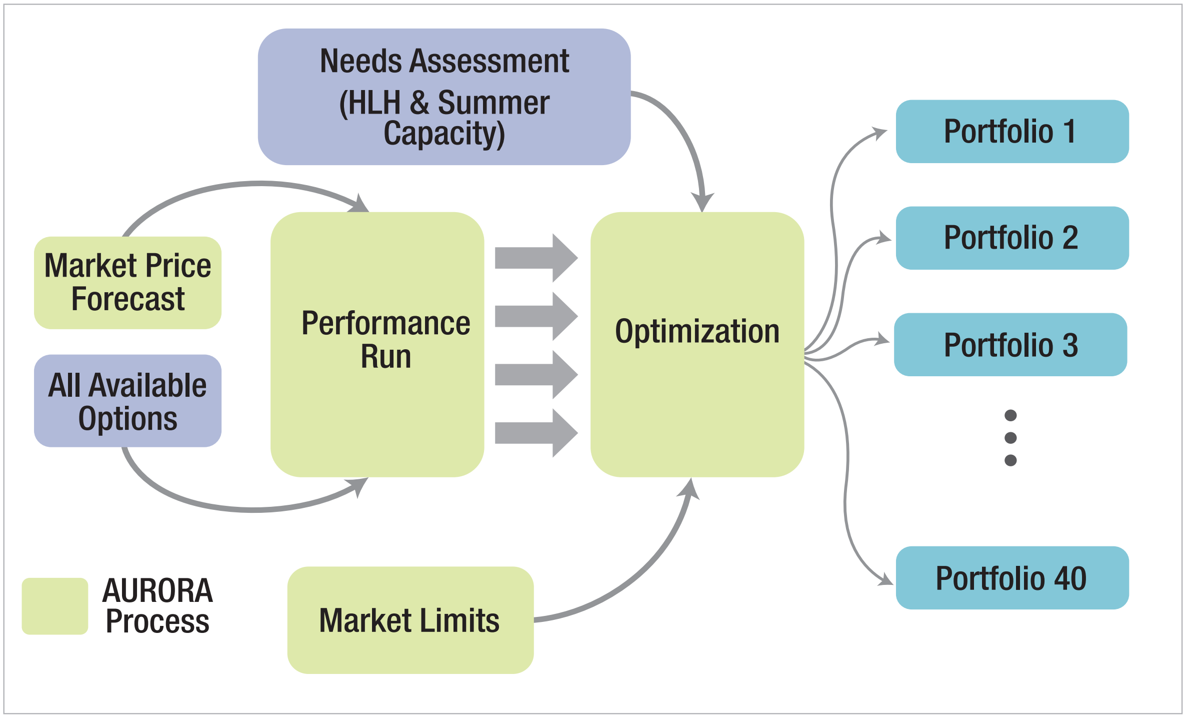
4.1 Overview

For the 2020 Resource Program, Bonneville used Aurora® to calculate combinations of resource options that satisfy its needs throughout the 10-year planning horizon that balance minimizing cost with alternatives that reduce risk exposure.[17] These portfolios are used to further inform Bonneville's resource strategy, by providing information on the amount of Energy Efficiency Incentive funding which might be invested over the upcoming rate period.

4.2 Methodology

Figure 4.1 depicts the overall process and key inputs for Bonneville's portfolio optimization. Resource Program staff begin by evaluating the options discussed in Section 3 against the 400 market price forecasts to assess the individual resource's performance against the market on an hourly basis. This step, called the performance run, informs Bonneville's heavy load hour energy needs, and the market reliance limits serve as inputs for the optimization step. This process is outlined in Figure 4.1.

Figure 4.1



[17] "Risk" is defined here as variation in total portfolio costs across the 400 market price forecasts (see market price forecast, Section 3.4).

Aurora® employs a linear optimization to jointly solve for the least-cost solution of meeting energy needs over the 10-year planning horizon (Portfolio 1), subject to market reliance and resource constraints. Portfolio 1 is selected by lowest average cost, over the 10-year study horizon, across the 400 price sets without considering how total portfolio costs may vary. The model then solves for portfolios that minimize variation in total portfolio costs at progressively higher average total portfolio cost levels.[18] This results in a series of portfolios that create an efficient frontier, as demonstrated in Figure 4.2. The frontier is efficient in the sense that, at any given cost point, there is no combination of available resources that would reduce the variation in total portfolio costs. Therefore, all portfolios above the efficient frontier are suboptimal because their costs can either be reduced without an increase in variance, their variance can be reduced without an increase in cost, or both cost and variance can be reduced to arrive at a better performing portfolio.

4.3 Portfolio Optimization Results

Compared to the 2018 Resource Program, the shorter study timeframe and lower market price forecast combined resulted in reduced portfolio costs, and also reduced the size and occurrence of "negative cost[19]" portfolios. Additionally, fewer energy needs and lower market prices shifted portfolio selections to heavily favor energy efficiency and market purchases so that every portfolio consisted exclusively of differing amounts of these two resources.

As discussed in the previous section, the Aurora® optimization process was used to produce an efficient frontier. The modeling resulted in 40 different portfolios of resources. Resource Program staff then analyzed the individual portfolios to evaluate the composition, magnitude, cost and risk of solutions selected to determine the net present value (NPV) of the portfolios. Figure 4.1 shows the model output of the 40 different portfolios for the 2020 Resource Program.

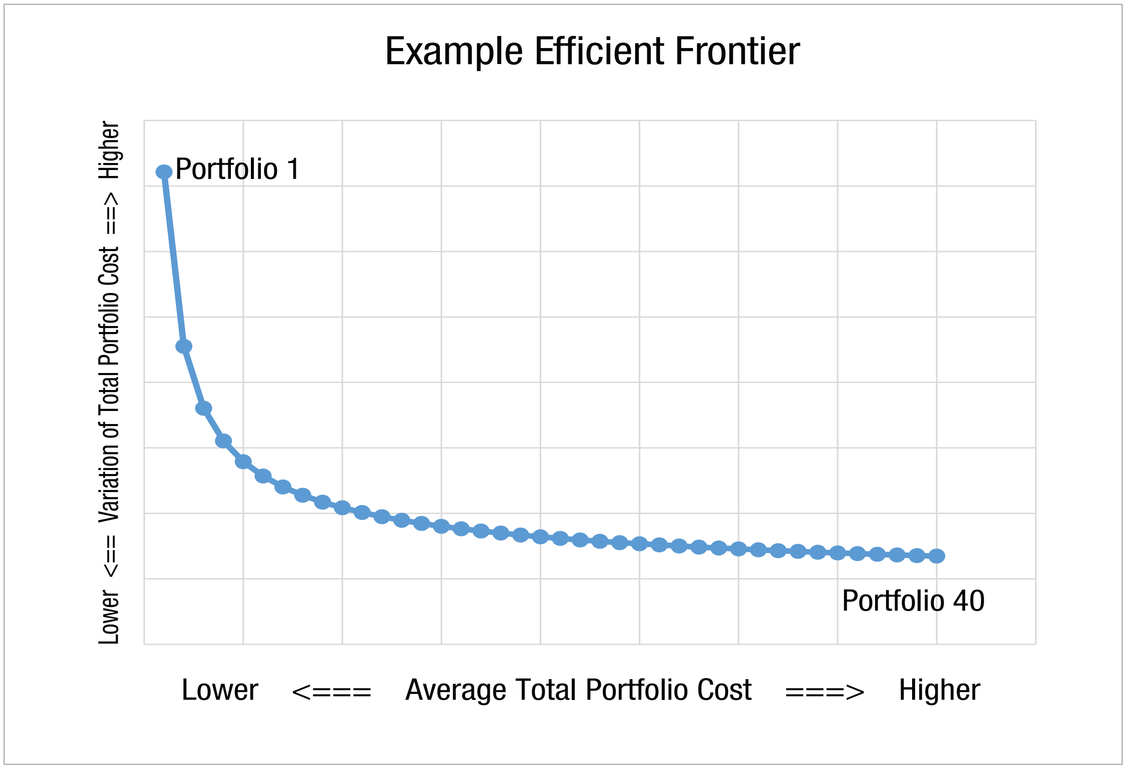
Given the changes in Bonneville's loads, resources, needs, and market price forecast, some results have shifted from the 2018 Resource Program findings. The overall variance in total cost for the portfolios is smaller, and the reduction in variance from one portfolio to the next is also smaller. This results in a reduction of the measure of variance by less than $1 million for even the largest reduction in point-to-point variance (the step between the first and second portfolios).

A driving factor for this is that the magnitude of portfolio costs has gone down. In 2018, the least cost portfolio had a "negative cost" of around $-1.5 billion, while the portfolio with the least variability in total cost (the highest cost portfolio) was over $4.5 billion. Now, these

[18] After finding the least-cost portfolio, the optimization model then solves for a portfolio with the lowest total cost variation (in terms of total portfolio cost standard deviation) without regard for total cost level (Portfolio 40). These two portfolios become end points of an efficiency curve. The range of average total portfolio cost is then split up according to the number of desired portfolios (Bonneville selected 40). For each point along this range, the optimization model solves for a portfolio of resources that minimizes total portfolio cost variation while holding to a particular average cost level.

[19] Some portfolios resulting from the portfolio optimizer show that their cost is a negative value. This results when the combination of resources in the portfolio produce revenue from market sales in excess of the combined cost of acquiring the resources. In addition, some energy efficiency bundles, because they are evaluated using Bonneville's formulation of a Total Resource Cost Test, are represented to the optimization model as having a negative cost.

Figure 4.2



corresponding portfolios have a negative cost of about $-50 million and about $850 million, respectively. These changes are primarily due to three things:

1. **Reducing the timeframe of the analysis from 20 years to 10 years**: This eliminated years with higher market prices (the 2018 Resource Program assumed the market price for electricity increased over time) and reduced energy efficiency's ability to generate value through creating sales of energy or avoiding energy purchases.
2. **Lower needs:** Having lower energy needs reduced the amount of resources or market purchases required to meet this modeling constraint, thereby lowering overall costs.
3. **Lower market prices:** Lower market prices make energy purchases less expensive, lowering overall portfolio total cost while also reducing the opportunity for energy efficiency to be less expensive than market purchases, which limits the generation of "negative cost" resources and portfolios.

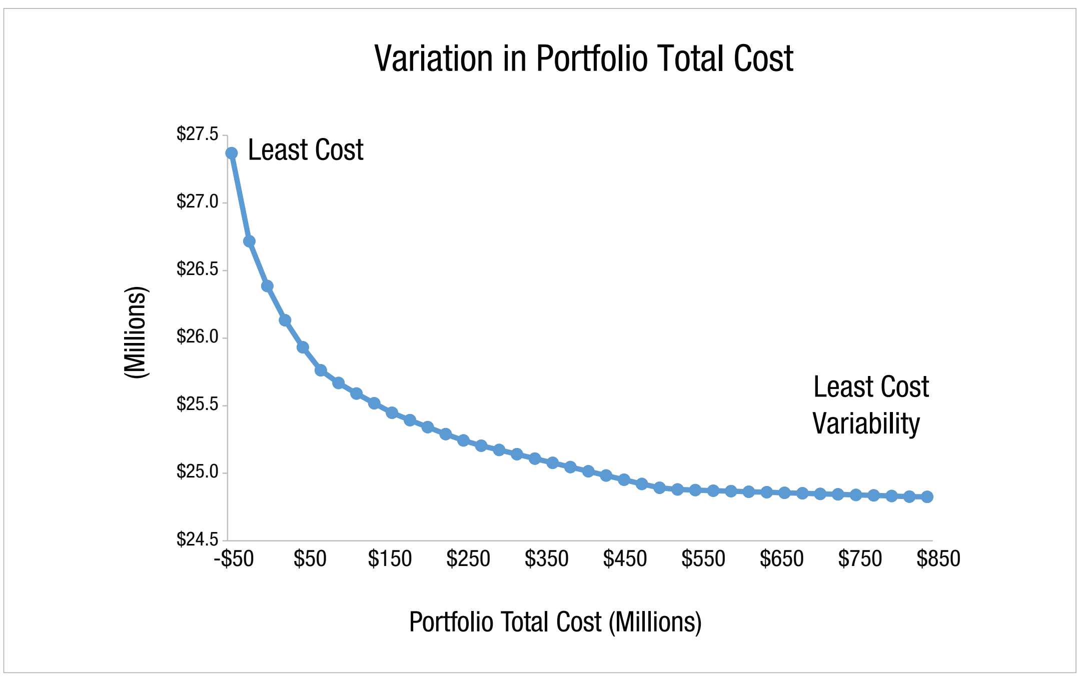
Additionally, while all the portfolios still meet the identified needs from the Needs Assessment, none of the 40 portfolios contained any resources other than energy efficiency and market purchases. In the 2018 Resource Program, the portfolio optimization selected demand response in every portfolio and began selecting other major resources in portfolio 7. The shift away from other resources in the portfolio selection was caused by multiple factors, but the primary drivers were the elimination of a capacity need from the Needs Assessment (see Section 2 on page 7) and the lower overall energy needs compared to the 2018 findings. Given fewer needs, cost-effective energy efficiency and market purchases were found as being always sufficient to satisfy the model's constraints.

Table 4.1 highlights two other important trends in the resources acquired in the three lowest-cost portfolios. First, the size of the portfolio's largest monthly average market acquisition declines over time, as the energy efficiency resource increases in size. Second, compared to the 2018 Resource Program, energy efficiency acquisitions declined. The least-cost portfolio in 2020 chooses about 10 aMW less energy efficiency than in 2018, 34 aMW less for the second portfolio, and 38 aMW less for the third.

Table 4.1

Max Monthly Market Purchase[20] (aMW)				Energy Efficiency Acquired (aMW)		
Portfolio	2022-2023	2024-2025	2026-2031	2023	2025	2031
1	1064	1021	890	111	229	506
2	1056	1007	876	120	245	506
3	1052	1000	867	123	250	503

Figure 4.3



The results reflect that as the model attempted to reduce the variance in costs, it did so with fewer market purchases and more energy efficiency. This finding is not new — because energy efficiency can be acquired at a fixed price, it thereby lowers portfolio cost variation in portfolios two and three. However, the 2020 results exhibit only minimal drops in market purchases, corresponding with the small decreases in portfolio variance.

~~Notably, in the~~ 2020 Resource Program there is no month where Bonneville's P10 Heavy

20 The Max Monthly Market Purchase reflects the maximum purchase the model made in any one month (HLH aMW).

Load Hour need for monthly energy exceeds Bonneville's assumed maximum monthly Market Purchase Limit. The result of this is the portfolio optimizer could meet every need constraint identified by the Needs Assessment with market purchases, if either necessary or economic to do so. Thus, the portfolio optimizer only acquired resources that were cheaper than the average market purchase: low-cost energy efficiency from the conservation potential assessment.[21]

4.4 Conclusions

The portfolio optimization process results demonstrate that the most economical solution for Bonneville to meet its energy obligations continues to be a combination of market purchases and energy efficiency. Energy efficiency was acquired in the least-cost portfolio up until it was as expensive as market purchases, and then the optimization solved for the remaining needs with market purchases. Low-cost energy efficiency remains Bonneville's preferred resource to meet identified energy needs.

The lack of a capacity need from the Needs Assessment results led to no portfolios selecting demand response in the resource optimization process. Additionally, the combined impacts of lower needs, lower market prices, and the shorter timeframe of the study horizon led to a reduced amount of energy efficiency identified in the least cost portfolios.

It is important to note that while the Needs Assessment looks at Bonneville's loads and resources in isolation, other regional studies have identified future capacity shortfalls in meeting the entire Pacific Northwest's load. Bonneville's system does, and is expected to continue to, provide surplus capacity to the region, which is anticipated to become increasingly valuable as thermal generation continues to be retired from the grid in accordance with decarbonizing legislative goals. Additionally, the Needs Assessment does not analyze the use of the federal system to provide balancing services for variable energy resources, instead specifically retaining the federal system's capacity for service to Bonneville's statutory obligations. These and other issues are addressed in separate forums; the 2020 Resource Program results should not be viewed as representing the capacity needs for the entire region, or any other specific entities within it.

21 To further investigate risks to Bonneville's outlook and Resource Program results, scenario analysis examined how higher needs, lower resources, lower market depth limits, or higher market prices, might impact results. Details and conclusions of this analysis are presented in Section 5.

SECTION 5: SENSITIVITY ANALYSIS

While the portfolio optimization balances cost with a measure of cost variance to assess the tradeoff between risk and cost, there are number of other factors that can represent risk and may impact the optimization process results. To assess how outcomes may change if certain input parameters were different than assumed in the base case, Bonneville identified four key sensitivities to test:

1. **Larger needs**: Larger energy needs could occur if Bonneville possesses fewer resources or has higher loads than anticipated. While much of the work required to complete the 2020 Resource Program was finished before there was a proposal for a Preferred Alternative (PA) in the Columbia River System Operations (CRSO) draft Environmental Impact Statement (EIS), Resource Program staff were able to develop a sensitivity test for optimization results when its resources were reduced to approximate the impacts of the Preferred Alternative.
2. **Reduced Market Purchase Limits:** There is much concern in the region around the retirement of thermal generating resources (mainly coal plants), reliance on renewable generation for their replacement, and how that may impact the amount of available energy for purchase on the open market. In light of this, Bonneville tested multiple reductions to the Market Purchase Limit constraint in the optimization model to assess how results would change if there was less energy available on the market than the model's assumption.
3. **Scarcity pricing:** The market price forecast declined substantially from 2018 to 2020. As a production cost model, Aurora® does not always accurately capture actual market behavior in certain instances, particularly during scarcity events. This can result in the under-forecasting of market prices in the precise times when Bonneville may need to make market purchases. To assess the potential for higher prices than assumed in the Bonneville forecast and used as input in this Resource Program, a sensitivity was constructed with the specific aim of simulating scarcity pricing events.
4. **A combined scenario:** A sensitivity was constructed to combine the above three factors to assess the joint impacts of higher needs, reduced Market Purchase Limits and scarcity pricing to determine what levels of adjustment yield major changes to the 2020 Resource Program results.

The results from testing for each of these sensitivities on the 2020 Resource Program results follow.

5.1 Approximate Needs from the Columbia River System Operations Preferred Alternative

For this sensitivity, an adjustment was made to the P10 Heavy Load Hour needs as an input to the optimization model based on a comparison of the Whitebook's Resource Program resource availability and the CRSO PA's resource availability for 1937. This application to P10 energy needs from of the Needs Assessment is imperfect because 1937 impacts do not necessarily correspond to P10 Heavy Load Hour needs. However, Resource Program staff believe this to be an adequate proxy for the change in hydropower operations under the PA, and the analysis was considered necessary to inform both the agency and the region about potential effects on Bonneville's resources. Any impacts will not be known until operational changes from the CRSO EIS are implemented, occurring well after publishing this Resource Program. Table 5.1.1 details the monthly inventory changes made to the Resource Program's monthly energy needs.

Table 5.1.1: Monthly CRSO Adjustment to Resource Program Inventory

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
MW-month	177.3	-89.4	-23.8	358.5	-682.2	18.3	163	345.2	-1021.5	-253.4	148.3	-121.7

As seen above, the imputed impact of the CRSO PA varies by month: in some months, like January, higher generation is expected, while in other months, like February, lower generation is expected. The largest decreases in inventory were in June, yet Bonneville's generation at the P10 Heavy Load Hour level remains sufficient to meet expected June load obligations. As seen in Figure 2.2, the Resource Program results show Bonneville's largest surpluses in June, with P10 inventories in excess of 1500 aMW across all years. The most substantial change was in February, where the -682.2 MW-month adjustment pushes Bonneville's P10 Heavy Load Hour energy need above its Market Purchase Limits in eight of 10 years. After the adjustment, February became Bonneville's most limiting month, with the result that February's P10 Heavy Load Hour deficits drove the model's resource acquisition decisions in the CRSO PA sensitivity.

The flat application of the single year of CRSO PA adjustment values to the entire study period caused some modeling complications because it generated a resource acquisition need of 107 MW-mo in the first February of the timeframe, 2022. Resource acquisitions are only forced by a need for Heavy Load Hour energy in any month exceeding the assumed Market Purchase Limit. If the need is less than the Market Purchase Limit, the optimization model can choose to meet the entire need with market purchases or a combination of resources and market purchases.

The large resource need in the first study year, created by applying the flat CRSO PA need adjustment, exceeded the combined availability of low-cost energy efficiency, which is limited by ramp rates (only so much is available in the first year) and market purchases. This pushed the model to acquire a number of generating resources even in the least-cost portfolio. These resources were *only* required in February 2022, the second month of the model's analysis. After this month, the ramp up of the energy efficiency bundles cover each ensuing February's need for Heavy Load Hour energy. As energy efficiency bundles ramped up, generating resources were also dispatched less frequently in later years.

Acquiring the long-term output of a physical resource to cover a single month's anticipated shortage in the near-term Heavy Load Hour energy forecast was not representative of the practical actions Bonneville would pursue if faced with this situation. Additionally, impacts of the CRSO PA, if adopted, would be phased in over a number of years, and the full inventory impact shown in Table 5.1.1 may never even be realized (some measures which cause incremental reductions of inventory may not ever be implemented). For this reason, it was appropriate to scale down the first February's need for Heavy Load Hour energy, reflecting the anticipated phased application of CRSO PA measures, to achieve more reasonable model results. After making this adjustment, the new binding time period — driven by high needs and low market depth — was February of 2029 with a 462 MW-month need after accounting for allowable market purchases. The least cost portfolio purchased just enough energy efficiency to produce exactly 462 MW-mo in February 2029.

Energy efficiency acquisitions in the three lowest-cost portfolios are shown in Table 5.1.2 below. The top three portfolios took only energy efficiency, suggesting that Bonneville can accommodate an increase in average annual needs similar to the CRSO PA with additional energy efficiency acquisitions and adequate time. The 2025 target of 306 aMW in this scenario is 77 aMW higher, or an average of approximately 19 incremental aMW per year, than the 2025 target in the 2020 Resource Program analysis.

Table 5.1.2: Energy Efficiency Acquisitions of Lowest-Cost Portfolios

	2023	2025	2031
Portfolio 1	147	306	665
Portfolio 2	139	287	613
Portfolio 3	137	281	585

Overall energy efficiency acquisitions decline as the optimization moves away from the least-cost solution and the model acquires different energy efficiency bundles, and eventually generating resources, that are more expensive but have a more aggressive winter shape. These portfolios reduce market reliance by choosing resources that better meet Bonneville's needs in winter months but also tend to yield fewer market sales in other seasons. In this case, each portfolio still achieves 462 MW-mo in February of 2029, but portfolios two and three achieve up to 80 MW-mo less of Heavy Load Hour energy in spring and summer months.

These details illustrate a tradeoff in the way the optimization calculates risk. The first portfolio contains the least-cost mix of resources that meet Bonneville's needs. Each successive portfolio minimizes risk, or the total cost variance across the 400 price iterations, subject to a larger budget constraint than each previous portfolio. A lower cost variance is achieved by acquiring increasingly more expensive resources that are shaped into the neediest months, reducing market purchases in those months. This also tends to reduce market sales in less needy seasons, such as spring and summer, when excess energy could be sold to other entities at market prices. The reduced market sales also lower the portfolio's overall cost variance because those sales contribute differing amounts of value in each price game to which the portfolio is compared. Eliminating this source of changing value reduces cost variance and thus the portfolio appears less risky by the optimization's risk metric.

5.2 Reduction in Available Market Purchases

The assumed availability of power in the market to purchase when needed is a major driver of the resource selections in the portfolio optimization process. The purpose of this sensitivity is to examine the impact on the Resource Program's least-cost resource selections if energy markets are shallower than assumed in the analysis, such as in a scenario where many of the recently-announced coal retirements are not replaced with new generating resources.

To test the impact of the assumed market depth, a phased-in reduction to the Market Purchase Limit from 2022 to 2026 was modeled. The Market Purchase Limit was reduced 10% per year until only 50% of the 2020 Resource Program market depth was available in 2026 and later years. Figure 5.2.1 shows a comparison of the Market Purchase Limit and needs for the 2020 Resource Program. Figure 5.2.2 shows this same data under the reduced Market Purchase Limit scenario.

Figure 5.2.1: 2020 Resource Program Needs and Market Purchase Limits (MW-mo)

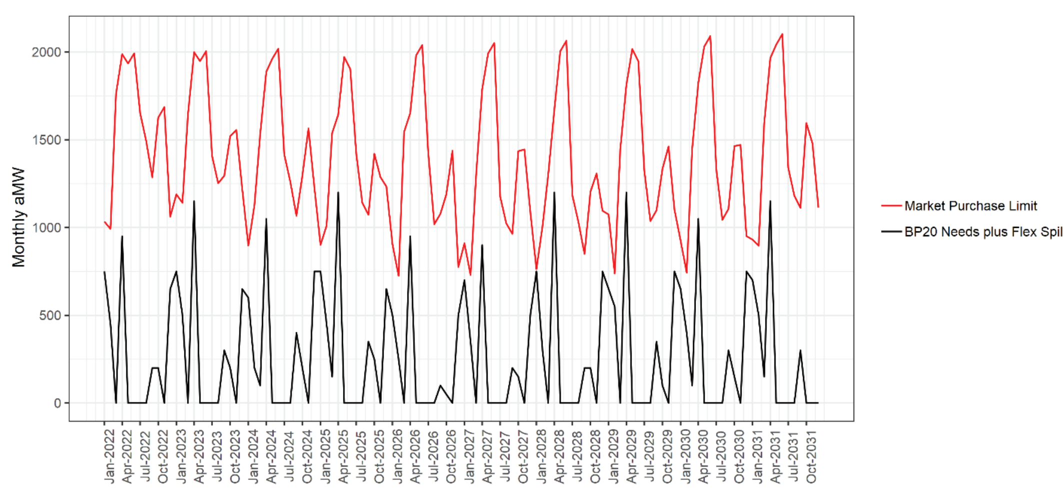
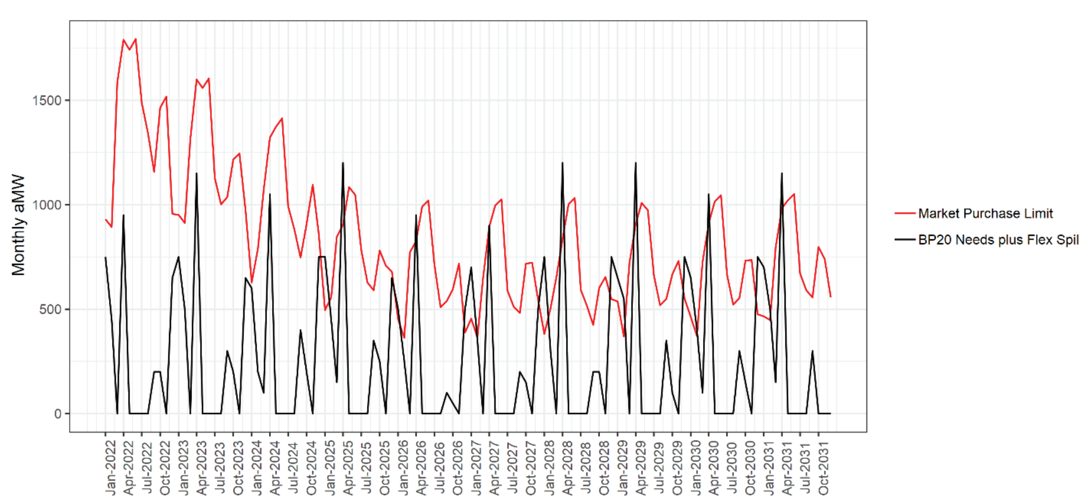


Figure 5.2.2: Scenario-Adjusted Market Purchase Limits (MW-mo)



After the adjustment to the Market Purchase Limit was made, the new binding time period — driven primarily by high P10 Heavy Load Hour needs and the reduction in market depth — was April 2025 with a 296 MW-mo need after market purchases. The least-cost portfolio purchased just enough energy efficiency to produce exactly 296 MW-mo in April 2025.

The three lowest-cost portfolios' resource acquisitions from the final run are shown in Table 5.2.1, below. The top portfolio took only energy efficiency but an additional natural gas generating resource was selected in portfolios two and three. Average annual generation by portfolio for generating resources is shown in Table 5.2.2.

Table 5.2.1: Energy Efficiency Acquisitions of Lowest-Cost Portfolios (aMW)

	2023	2025	2031
Portfolio 1	180	373	811
Portfolio 2	157	322	664
Portfolio 3	153	313	630

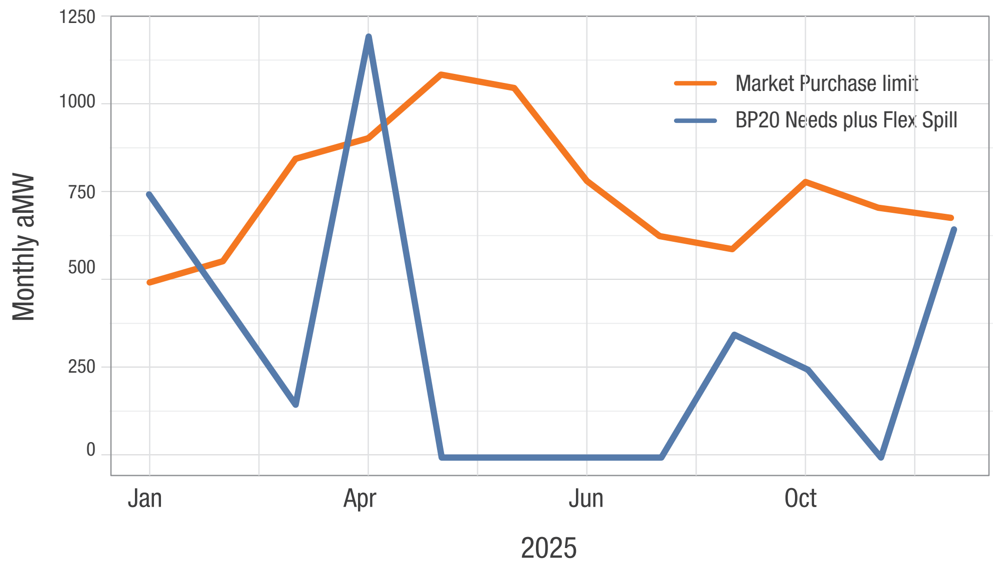
Table 5.2.2: Natural Gas Generation of Lowest-Cost Portfolios (aMW)

	2023	2025	2031
Portfolio 1	0	0	0
Portfolio 2	33	29	23
Portfolio 3	33	29	23

As the model reduces its exposure to market risk, or total cost variance across the 400 price iterations, it acquires more expensive resources that have a more aggressive shape in the constrained month. This is consistent with findings from the 2018 Resource Program and other sensitivities in the 2020 Resource Program. Each portfolio still achieves about 300 MW-mo in the binding month (April 2025), but portfolios two and three acquire less Heavy Load Hour energy in other months with low needs. It is also notable that when generating resources are selected, they are operated less frequently in later years as energy efficiency savings increase.

This study also analyzed how shallow the market could become before forcing the model to acquire a generating resource in the least-cost portfolio. Market availability in 2025 (the binding year for resource acquisition decisions in this sensitivity) was reduced from 60% to 55% to 50% in successive model runs. Generating resources first entered the least-cost portfolio when the 2025 Market Purchase Limit was reduced to half of the size assumed in the base-case analysis. Figure 5.2.3 gives a closer view of the needs vs. Market Purchase Limit picture in 2025, which assumed that 55% of the 2020 Resource Program 2025 Market Purchase Limit was still available.

Figure 5.2.3: Needs and Market Purchase Limit for 2025 (MW-mo)



These results indicate that there is sufficient energy efficiency potential from Bonneville customer loads for Bonneville to cost-effectively meet its needs with energy efficiency even in this extreme scenario, where market depth in 2025 is 45% lower than is expected from AURORA modelling in the 2020 Resource Program analysis. That said, the least-cost portfolio's 373 aMW acquisition for 2025 is 144 aMW higher than base case's 2025 energy efficiency acquisition.

5.3 Scarcity Pricing

The market price forecast used in the 2020 Resource Program analysis is created using a production cost model, which can sometimes struggle to capture extreme scarcity pricing events, like the March 1-3, 2019 Pacific Northwest event where multiple outages, a gas shortage, and cold weather sent Mid-Columbia prices over $1,000/MWh. To address this, Bonneville examined a sensitivity where the top 20% of the price distribution was adjusted higher to assess how the increased likelihood of scarcity pricing events would impact the resource selections in the least-cost portfolio.

This adjusted price forecast consists of market prices from 400 individual runs, and these are used in 400 initial zonal runs which assess the performance of candidate resources under varying market conditions. Market purchases are considered along with supply-side and demand-side resources to meet Bonneville's needs, so market prices can be a major driver of the resource selections in the portfolio optimization process. Resources are acquired either when they are cheaper than market purchases, or if Bonneville's need for Heavy Load Hour energy exceeds the assumed Market Purchase Limit in any given month. Increasing the average market price of electricity tends to increase the amount of resources other than market purchases selected in the least-cost portfolio.

Prices were adjusted for this sensitivity by inflating the top two deciles, or prices representing 1/5 of the total input distribution. The prices in the top decile were increased by a factor of five over the 2020 Resource Program, and those in the next lower decile were doubled. The rest of the pricing distribution was left unaltered. With this adjustment, the market prices in some of the runs used for this sensitivity reach levels similar to the March 1–3, 2019 spike.

The optimization selects all resources with expected revenue greater than expected cost for the least-cost portfolio, then additional resources needed to solve for any residual need. Expected revenue is the product of expected generation and market prices, so the higher average market price in this sensitivity supported a higher level of energy efficiency acquisitions, relative to the 2020 Resource Program. This scenario also uses the same needs and Market Purchase Limit as the 2020 Resource Program, so the additional 117 aMW of energy efficiency acquired in 2025 in this scenario represents the additional amount that has become profitable from an expected revenue standpoint. The three lowest-cost portfolios' resource acquisitions from the final run are shown in Table 5.3.1.

Table 5.3.1: EE Acquisitions of Lowest-Cost Portfolios (aMW)

	2023	2025	2031
Portfolio 1	166	346	759
Portfolio 2	146	302	656
Portfolio 3	140	290	629

5.4 Combined Sensitivity

Needs, market prices, and availability of market purchases are all major drivers of the resource selections in the portfolio optimization process. The other sensitivities have explored the effects of these inputs in isolation, but it is also realistic to expect that they might all occur, to some extent, simultaneously.

This scenario examines the impact on the Resource Program's least-cost resource selections if the adjustments from the other sensitivities are modeled simultaneously, with some modifications made to the Market Purchase Limit. The Market Purchase Limit was reduced less drastically than in the Market Purchase Limit-only scenario, declining to 75% of the 2020 Resource Program Market Purchase Limit by 2026 (see the above sections on scarcity pricing and CRSO PA sensitivities for details about the adjustments made in those scenarios). Figures 5.4.1 and 5.4.2 show the needs and Market Purchase Limits for the 2020 Resource Program and combined scenario, respectively.

Figure 5.4.1: Base-Case Needs and Market Purchase Limits (MW-mo)

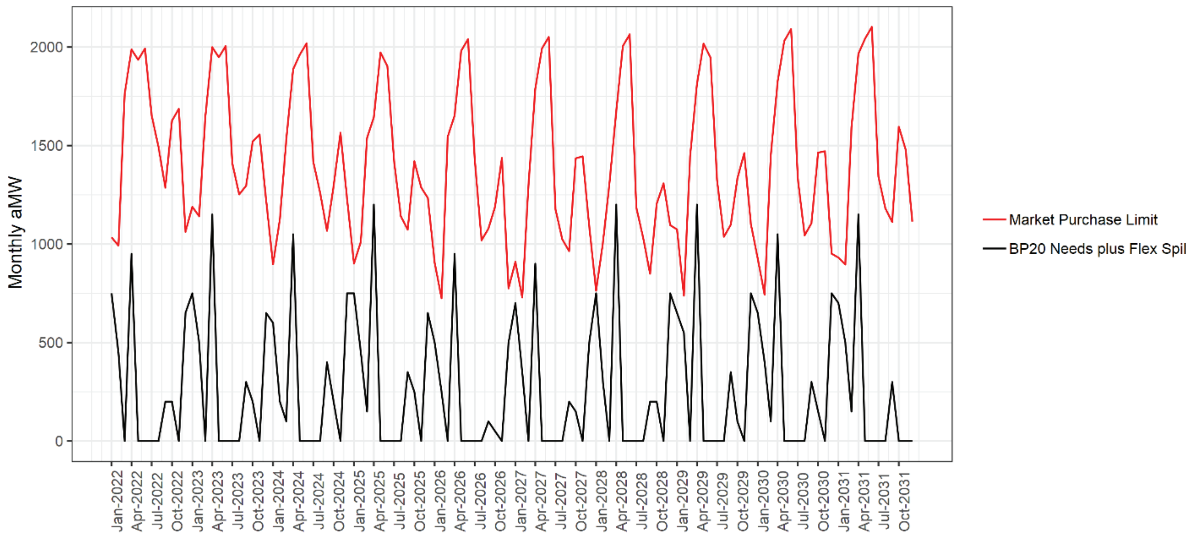
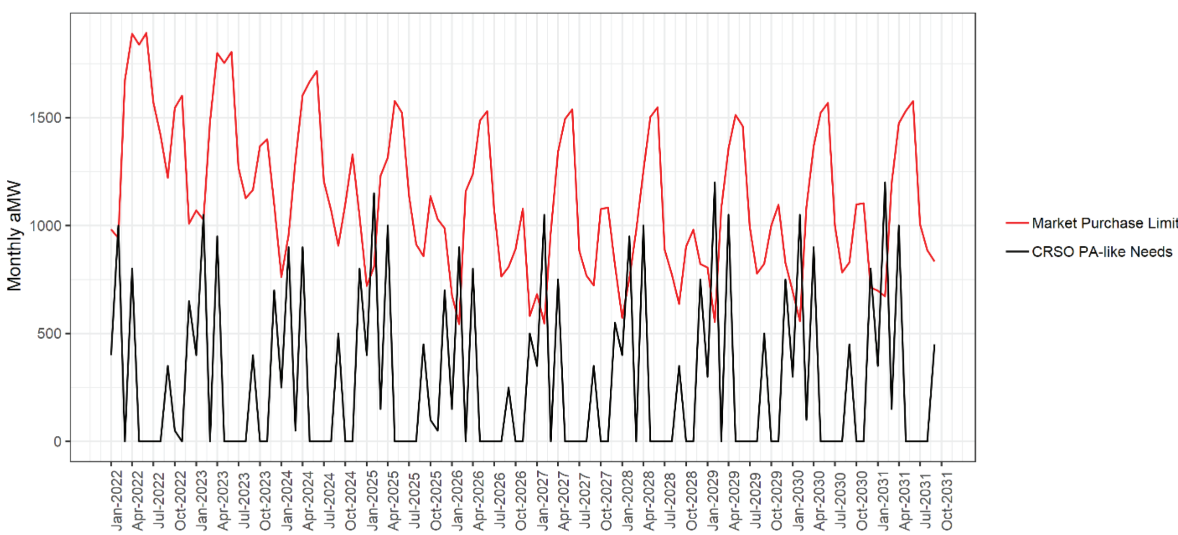
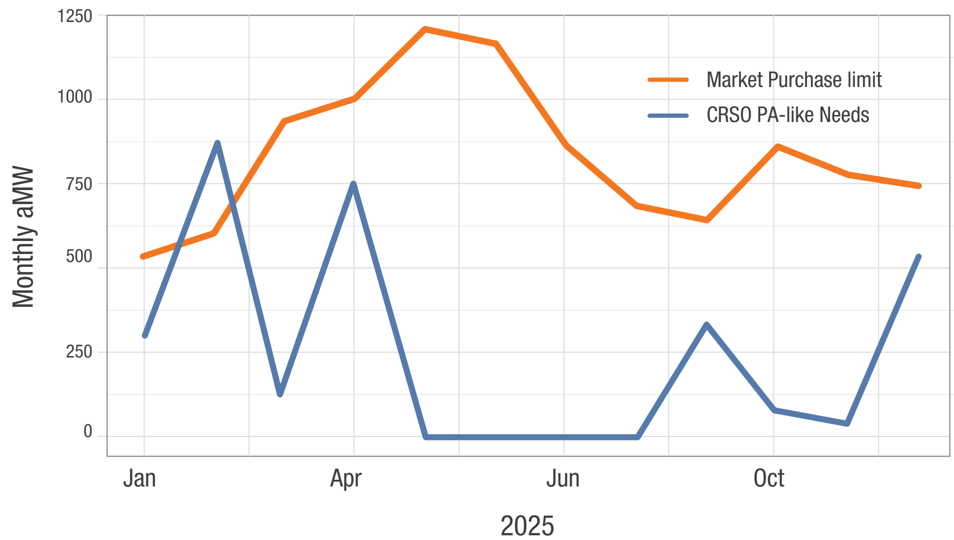


Figure 5.4.2: Scenario-Adjusted Market Purchase Limits (MW-mo)



After the adjustment to the Market Purchase Limit was made, the new binding time period — driven by increased needs and the reduction in market depth — was February 2025 with a 341 MW-month need after market purchases. The least-cost portfolio purchased just enough energy efficiency to produce exactly 341 MW-mo in February 2025. Figure 5.4.3 gives a closer view of the needs vs. Market Purchase Limit picture in 2025, which assumed that 80% of the 2020 Resource Program Market Purchase Limit was still available.

Figure 5.4.3: Needs and Market Purchase Limit for 2025 (MW-mo)



The changes to market prices, market availability, and Bonneville's needs in this scenario all tend to increase the amount of energy acquired in the least-cost portfolio, relative to the 2020 Resource Program. The reduction in the Market Purchase Limit and the increased needs result in a larger gap that must be filled with new resources. Increasing the average market prices (which happens as a byproduct of stretching the top 20% of the market prices) also tends to increase energy efficiency acquisitions relative to the 2020 Resource Program findings, because more energy efficiency bundles fall below the average price of purchased electricity. The three lowest-cost portfolios' resource acquisitions are shown in Table 5.4.1, below.

Table 5.4.1: Energy Efficiency Acquisitions of Lowest-Cost Portfolios (aMW)

	2023	2025	2031
Portfolio 1	191	399	902
Portfolio 2	188	393	882
Portfolio 3	186	389	876

The combination of high market prices with the reduction in available market purchases results in a least-cost portfolio with a substantial amount of revenue generated from market sales in non-winter months. As the model reduces its exposure to market "risk" (total cost variance across the 400 price iterations) in portfolios two and three, it acquires more expensive resources that have a more aggressive shape in winter, but that produce less energy in the other seasons, leading to slight reductions in overall generation and market sales in the risk-reducing portfolios.

Similar to the reduced Market Purchase Limit scenario, Bonneville tested how far the Market Purchase Limit could be reduced before the optimization selected a gas plant in the least-cost portfolio. This occurred when the Market Purchase Limit in 2025 was reduced to 79%

of its 2020 Resource Program level. At this Market Purchase Limit level, economic energy efficiency acquisitions could not ramp up quickly enough to meet Bonneville's needs in February 2025. Energy efficiency was able to ramp up enough to meet needs in later years, so utilization of the gas plant declined in these years, particularly in months with no needs or relatively inexpensive market purchases.

These results suggest that Bonneville can still economically meet needs similar to those from the CRSO PA with energy efficiency, even if actual market depth in 2025 is 20% lower and market prices are higher than what was assumed in the 2020 Resource Program analysis, provided energy efficiency planners have time to ramp up their acquisition efforts. The additional 170 aMW needed in 2025 is a substantial increase over the 2020 Resource Program 2025 target. The results of the scarcity pricing sensitivity suggest that approximately 117 aMW of this energy efficiency increase consists of bundles now profitable under the higher market prices. The other 53 aMW of additional energy efficiency in 2025 is acquired to fill the remaining need after purchasing all profitable energy efficiency and after market purchases.

SECTION 6: ACTION ITEMS

6.1 Next Steps

The 2018 Resource Program introduced many new concepts, methodologies and data that provided valuable new insights for meeting Bonneville's power obligations. The 2020 Resource Program refreshed some key inputs and introduced sensitivity analysis. Looking toward to the next Resource Program, Bonneville plans to further develop and refine the enhancements it has made for the 2018 and the 2020 Resource Program, including a new Conservation Potential Assessment that incorporates information from the Northwest Power and Conservation Council's 2021 Plan and adding energy storage resources into the portfolio optimization process.

Bonneville will also monitor events that could change the forecasted outcomes of the 2020 Resource Program, such as new clean energy legislation or implementation of revised operations stemming from the Columbia River System Operations Environmental Impact Statement. 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.

SECTION 7: TRANSMISSION SUPPLEMENT

Executive Summary

This chapter was provided by BPA Transmission Services (BPA-TS), and describes the transmission planning process at BPA-TS and how they collaborate with Power Services (BPA-PS). It describes how BPA serves the needs of NT (Network Transmission) and PTP (Point-to-Point) customers and how the Available Transfer Capacity (ATC) is managed to serve the customer requests for service. BPA-TS and BPA-PS work and collaborate closely to manage the hydro resources of the Federal Columbia River Power System (FCRPS) to serve the needs of BPA's network (NT) customers. Besides BPA-PS, BPA-TS has a wide range of customers for Point-to-Point (PTP) transmission services to deliver power from regional resources to hundreds of bulk electric power customers. Some customers are both, NT and PTP.

The chapter starts with an overview of BPA and its strategic objectives. It then reviews the trends BPA-TS believes will most affect its future: Decarbonization, Decentralization, Technology and Regional Cooperation. Each of these brings risks and opportunities to consider in the analytical, modeling and decision making part of the process.

The analytical process starts with Transmission Planning (TP) having a good understanding of NT and PTP customers and their needs and load growth patterns. It also reviews resources; their technology; fuel prices; government policy and much more. Forecasted load and resources are the basis for transmission planning. Also considered are the existing obligations and committed long-term firm transmission service.

Once the system conditions are defined, the analysis turns to completing a system assessment of existing and forecasted load and committed long-term firm transmission service and developing corrective action plans for problem areas not meeting the necessary reliability standards. Finding solutions for these problem areas requires multiple analytical tracks: (a) consideration of non-wires solutions in cooperation with cross-agency organizations at BPA; and (b) coordination with BPA-PS and multiple organizations in TP to collaborate on integrated solutions.

Once BPA-TS completes the system assessment including the proposed transmission corrective action plans and flowgate ATCs, the capacity becomes eligible to meet the needs of BPA customers who submit TSRs (Transmission Service Requests) for transmission capacity for their loads and resources. These TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. With the cluster study, the network can be analyzed for reinforcements and non-wire solutions necessary to serve the TSR needs. Customers are then informed so they can make their project decisions, proceed to contract negotiations and ultimately go to construction.

Throughout the planning process, BPA-TS and BPA-PS work closely in a joint process called the Agency Integrated Planning (AIP). This process ensures a high level of coordination among the different groups in BPA-TS and BPA-PS to achieve an efficient data collection, analytical evaluation and optimal recommendations.

7.1 Introduction

BPA energizes the region through more than 15,000 miles (24,000 km) of transmission lines and 261 substations in the Pacific Northwest, controlling approximately 75 percent of the high-voltage transmission system in the region. BPA also maintains interconnections with other regional power grids: British Columbia to the north; Rocky Mountains, Idaho and Montana to the east and south east; and California to the south. BPA shares two interties with California: (a) California-Oregon Intertie (COI) with northern California utilities; and (b) the Pacific DC Intertie (PDCI) with the Los Angeles Department of Water and Power (LADWP)

Transmission Services' mission as a public service organization is to deliver the best value for BPA customers and constituents as Transmission Services act in concert with others to insure the Pacific Northwest has a transmission system that is prepared to meet the task of integrating and transmitting power from federal and non-federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electric reliability and stability.

BPA-TS is an open access transmission provider that aligns its provision of transmission service with the regulatory framework established by the Federal Energy Regulatory Commission (FERC), designed to prevent undue discrimination in providing access to wholesale transmission capacity. BPA-TS maintains an open access transmission tariff (OATT), and seeks to align its OATT with the FERC *pro forma* OATT to the maximum extent possible. The OATT process is flexible and allows for considerations from other governance structures. BPA-TS provides transmission service to BPA Power customers, Investor Owned Utilities (IOU), Independent Power Producers (IPP) and any other customer. Interested parties request transmission services and follow a well-defined process explained in section 3 of this chapter.

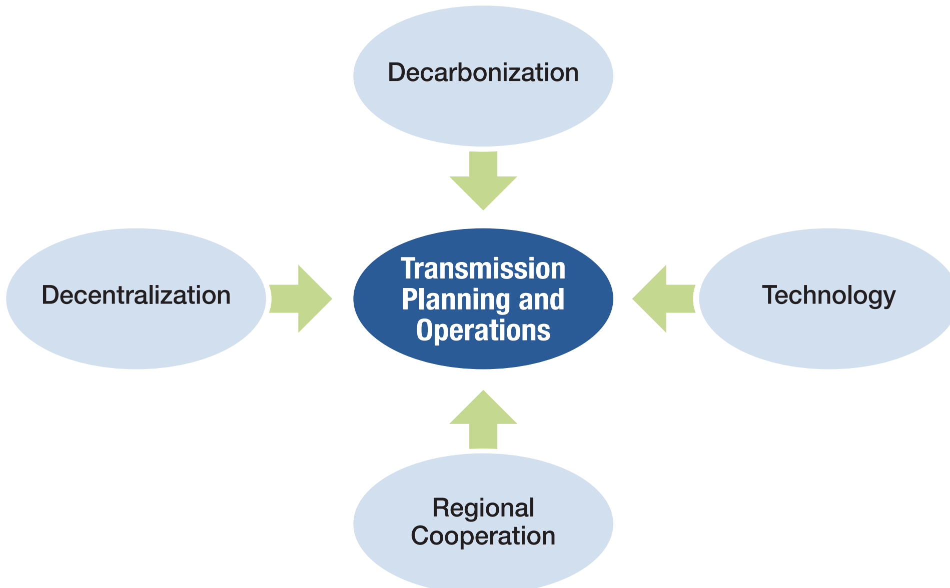
BPA-TS also manages over 2,700 transmission service contracts that enable more than 30,000 transmission reservations and over 200,000 scheduling tags processed each month through Bonneville's commercial systems. Transmission's revenues are about $1.1 billion annually.

The 2018–2023 strategic plan (link: BPA 2018–2023 Strategic Plan), lists four agency objectives.

1. Strengthen financial health
2. Modernize assets and system operations
3. Provide competitive power products and services
4. Meet transmission customer needs efficiently and responsively

BPA's Transmission objectives and strategies are based on its ability to deliver power from generating resources to loads in the region efficiently and responsively.

Figure 7.1: Major Trends Impacting Transmission



For 2020, BPA-TS continues to operate in a landscape of trends that started 10 to 15 years ago, see Figure 7.1. The BPA 2020 Resource Program incorporates the regional trend of new resources, such as wind and solar, and the continuing decline of coal generation while hydro and natural gas continue to hold their share. The major trends for BPA-TS are:

- **Decarbonization —** The prevalent public policy of decarbonization from State regulators in the power and transportation industry has a variety of effects on BPA's future resource mix and load profile. The growth of variable solar and wind resources in the Northwest and California has already changed transmission operations relative to historic patterns, such as shifting the time of peak flows on some paths to be closer to sunset hours to manage the "duck curve" resulting from the ramping of solar resources in California. BPA anticipates these trends to continue and likely become more pronounced as solar penetration continues to increase in California. Decarbonization policies also impact the electrification of the transportation industry. The Northwest has the second largest penetration of EVs in the country. BPA expects load profile changes and increased energy demand with a higher penetration of EVs.
- **Decentralization —** Centralized coal plants, both near major load centers (e.g., Centralia) or remote in Montana (e.g., Colstrip) and Wyoming (e.g. Jim Bridger), are being replaced by more decentralized wind and solar generators. Residential solar is not common in the region, but utility scale wind and solar projects are and they tend to be located in rural areas in the BPA territory. While these individual wind and solar projects are generally smaller increments than single coal units, there are numerous projects proposed or moving forward. The transmission grid of the future will be able to serve a growing number of these smaller generators, in addition to the larger ones in a very diverse set of locations.

- **Technology —** Technology affects every part of the power industry. The faster pace of innovation in a range of areas will affect Transmission in different ways.
    - **Data Centers —** The dramatic growth of digital products have increased the need for data centers and the rural Northwest is one of the preferred locations. BPA expects that trend to continue.
    - **Electrification —** Changing technologies for the end user, such as increased electrification of the transportation sector, will change the load curve. Other examples of the end user electrification is the continuing shift to more digital technologies in lighting and increased use of batteries in consumer electronics.
    - **Smart Grid —** The development of a variety of digital technologies and tools offer Transmission the opportunity to improve its operations, security and customer support.
    - **Solar and wind resources —** Solar and wind technologies will be the prevailing resources developed in the planning horizon. These technologies are far from maturing any time soon and are expected to continue their cost decline making their economics more compelling.
    - **Storage —** The development of utility scale batteries is a relatively new development in the industry. Batteries are being piloted and developed for a range of applications, but there is still a lot to learn. Costs are expected to come down over time because of volume manufacturing and chemistry advances making their use more possible in the latter part of the decade or later. Batteries will also play a central role in the advancement of Distributed Energy Resources (DER), demand response, grid integration and shifting energy usage.
- **Regional Cooperation —** BPA expects to increase its cooperation with regional partners to gain efficiencies in transmission planning and operations. Transmission is an active member of WECC in several workgroups and activities. BPA is also a member of NorthernGrid, Northwest Power Pool (NWPP), and other regional industry organizations. BPA has several initiatives in this area: (a) Studying membership in the EIM market and its plan to decide by 2022; (b) Increased dynamic scheduling; (c) Continued growing participation in the CAISO — PNW power exchange.

Long Term Transmission Planning conducts Production Cost Modeling and studies system optimization models to gauge market availability of resources, predicting future trends in resource types and location including assumed transmission needs. Transmission Planning conducts powerflow analysis to define system expansion over the Planning Horizon to ensure BPA's transmission system can reliably deliver resources to load and meet its transmission obligations. These will inform the Resource program in the future on market availability, transmission deliverability for future resource scenarios conducted, and show transmission needs for reliable delivery of resources to loads.

7.2 Loads and Resources

Located on the mainstream Columbia River and in several of its major tributaries (Figure 7.2), including the Snake and Willamette rivers, the Federal Columbia River Power System (FCRPS) comprises 33 hydroelectric projects in the Columbia River Basin and provides carbon free energy that accounts for about one third of the electricity used in the Pacific

Northwest. The Bureau of Reclamation (Reclamation) and the U.S. Army Corps of Engineers (Corps) planned, designed, constructed; and own and operate the federal water projects in the Pacific Northwest.

Through its transmission system, BPA markets the power generated from the federal projects and distributes power from federal and non-federal projects. The revenues collected cover the cost of operating and maintaining the projects.

Figure 7.2: FCRPS Resources

BPA delivers power throughout the region to a wide range of customers in accordance with the OATT. Transmission service divided into two broad categories, Network (NT) and Point-to-Point (PTP). The traditional municipalities, Public Utility Districts (PUDs) and cooperatives are mostly Network customers with load serving priorities. Some of these entities are also PTP customers, which require transmission services for their own generation or power purchases outside of the FCRPS. For PTP customers, BPA offers transmission services to a wide variety of customers, such as Investor Owned Utilities (IOUs), Independent Power Producers (IPP) and others. BPA-TS also offers PTP services to some NT customers in addition to their NT services. Figure 7.3 is the load map for 2020. The map includes Network and the larger PTP customers with loads of 25 aMW or more; it does not include PacifiCorp who receives transmission service across the Northwest; and it does not include the smaller than 25 aMW loads, which aggregated to 695 aMW in 2020.

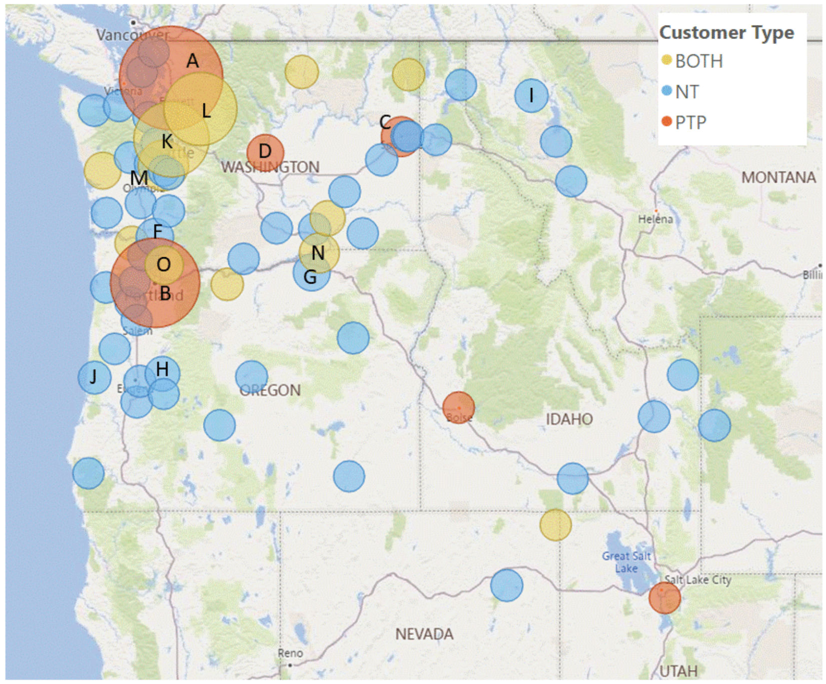
Figure 7.3: 2020 Transmission Loads

Legend – Top 5 NT only	
F	Cowlitz County PUD
G	Umatilla Electric Coop
H	Eugene Water & Electric
I	Flathead Electric
J	Central Lincoln

Legend – Top 5 PTP only	
A	Puget Sound Energy
B	PGE
*	PacifiCorp
C	Avista
D	Alcoa

Legend – Top 5 Both PTP & NT	
K	Seattle City Light
L	Snohomish PUD
M	Tacoma Power
N	Benton PUD
O	Clark Public Utilities

* Not shown



Network Customers

BPA will serve 147 Network customers in the planning horizon (2020-2030) for a total forecast of 8,634 aMW in 2020 and 9,811 aMW in 2030, +13.6% in ten years. In 2020, 39 of these customers have demand of 5 aMW or less. Figure 7.3 shows the loads 25 MW or greater. The load circle area is proportionally sized according to the customer load. The top 5 Network customers only are ranked by demand (aMW) on the legend.

A few of the Network customers will experience significant growth, while others will be mostly flat and in some cases negative. Among the top ten, Umatilla Electric Coop, Cowlitz PUD and Northern Wasco PUD will experience significant growth, while municipalities like Seattle, Tacoma and Eugene will remain mostly flat or even negative. The growth in the rural areas and small towns has been in large part due to server farms and industrial customers attracted to the Northwest for its low cost of power.

Through the planning horizon, the forecasted NT customer peak demand will be winter peaking at 14,457 MW in 2020 and 15,935 MW in 2030.

Point-to-Point Customers

PTP customers enter into Transmission services agreements with BPA to deliver power from one point to another, hence the name Point-To-Point. The PTP customers are shown in Figure 7.3 with the top five on the legend. In 2020, Transmission had 57 PTP customers in six categories as shown in Table 7.1.

Table 7.1: PTP Demand 2020 and 2030

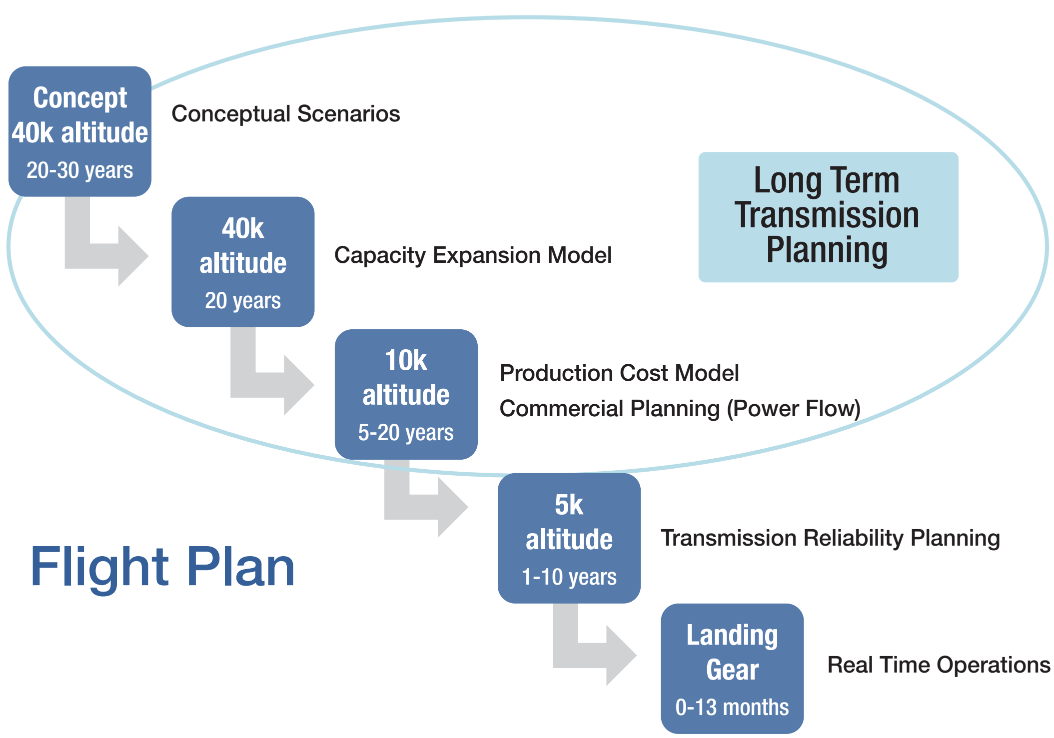
PTP Customer Categories	2020 Demand (aMW)	2030 Demand (aMW)
NT customers	6,149	6,218
Industrial	585	585
Regional Investor Owned Utilities (IOU's)	12,666	13,084
Independent Power Producers (IPP)	1,746	1,889
Interregional	3,424	3,584
BPA Power	2,272	2,272
Total	**26,842**	**27,632**

The combined forecast between the NT and PTP is 35,478 aMW in 2020 and 37,445 aMW in 2030, a growth of 5.5% in the ten year planning horizon. The five largest PTP customers are Puget Sound Energy, Portland General Electric, PacifiCorp, BPA Power Services and Snohomish County PUD.

7.3 BPA Transmission Planning

Transmission planning is done at different levels for multiple purposes. To better understand this process, Figure 7.4: Transmission Planning Flight Plan — is a graphical representation or overview of the various transmission planning processes within Transmission Planning & Asset Management (TP). These processes include, Transmission Planning from a reliability viewpoint and Long Term Transmission Planning from a commercial planning viewpoint.

Figure 7.4: Transmission Planning Flight Plan



A. Transmission Reliability Planning

Every year BPA Transmission Planning conducts a comprehensive assessment of the Federal Columbia River Transmission System (FCRTS) to determine its ability to provide reliable service over a 10-year planning horizon. Transmission Planning studies 27 load service areas and 18 paths under defined limiting system conditions in order to identify any potential performance deficiencies. The analysis is used to identify system reinforcements needed to continue to provide reliable Transmission Service over the planning horizon.

The system assessment allows BPA to demonstrate that existing and forecasted load and projected firm transmission service can be reliably served through, at least, the 10-year planning horizon. It also allows BPA to show that identified corrective action plans, such as system reinforcement, are adequate for reliable performance.

The main objectives of the system assessment are to demonstrate that BPA meets the mandatory North America Electric Reliability Corporation (NERC) TPL Standard “Transmission System Planning Performance Requirements”, reliably serve loads and meet obligations to reliably deliver resources to load. The NERC standard requires that BPA conduct an annual assessment to ensure that the BPA network is adequately planned to supply projected customer demand and projected firm transmission service over the expected range of forecast system demands following a wide range of probable contingency outages.

BPA Transmission Planning evaluates the transmission system for the near-term (one- to five-year) and long-term (six- to ten-year) planning horizons to determine whether system performance meets performance requirements of the NERC TPL Standard, WECC System Performance Regional Criterion, and BPA Reliability Criteria for Transmission Planning. If the system assessment identifies any potential system performance deficiencies, corrective actions, including transmission reinforcements, are developed to address the potential system deficiencies.

Load Forecast

The transmission planning organizations work closely with the load forecasting group to use common processes to identify more efficient ways of collecting and evaluating customer provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning (AIP) process between BPA-TS and BPA-PS.

The overall system assessment starts with developing technical Basecases. A Basecase is a database used by the powerflow software program to model the loads, topology, and generation. Then, contingency outages as required by the NERC TPL Standard are studied using the Basecases to assess required system performance. Assumptions are made in the system assessment Basecases for load forecasts, resource forecasts, and transmission service. The Basecases start from WECC approved Basecases. These include initial load forecasts from BPA’s Load Forecasting and Analysis group, the same initial load forecast used by BPA Power Services for the power Needs Assessment and Resource Program and load forecasts for other utilities represented in the Basecases. If necessary, the load forecasts are then updated with the most up-to-date load forecast data available from the other utilities.

The transmission planning organizations work closely with the load forecasting group to use common processes to identify more efficient ways of collecting and evaluating customer provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning (AIP).

Resource Forecast

Resource forecasts for the system assessment include existing and committed future resources that are expected or forecasted to operate as determined in coordination with Power Services. Specific generation patterns are assessed that are expected to create higher transmission system stress consistent with historical usage to determine the limits of the transmission system.

Existing Obligations and Committed Long-Term Firm Transmission Service

In addition to load and resource forecasts, the system assessment includes existing transmission service obligations and committed long-term firm transmission services. These transmission service obligations and commitments are identified during transmission expansion planning by BPA Long Term Transmission Planning. System assessments conducted by BPA Transmission Planning capture these transmission service obligations and commitments through path flows resulting from the load forecast and the generation patterns that are assessed.

Non-Wires

BPA Transmission Planning in collaboration with the cross-agency Non-Wires team considers the feasibility of non-wires solutions as alternatives to or as deferrals of transmission reinforcement projects. The range of non-wires solutions that are considered include demand-side management (energy efficiency, demand response), distributed energy resources (energy storage, distributed generation), and generation re-dispatch. BPA Transmission Planning conducts a non-wires assessment for each of the load service areas as part of its annual system assessment.

During the system assessment, planning engineers include a qualitative analysis of potential non-wires alternatives. Non-wires alternatives to reliability projects are considered where feasible. For areas that have performance deficiencies and corrective action plans identified within the Planning Horizon, the potential for non-wires alternatives is identified to either correct the deficiency or defer the date when a project is required to comply with the NERC Standards. Alternatively, for those areas with no recommended projects, the potential for non-wires measures to slow or flatten the rate of load growth in the area is identified.

Following the system assessment, BPA Transmission Planning summarizes the areas with the potential for non-wires projects. In collaboration with the BPA Cross Agency Non-Wires team, areas are prioritized and a recommendation is made which area to pursue further analysis by the team.

Coordination between Power Services and Transmission Services

Throughout the planning process, BPA-TS and BPA-PS work closely in a joint process called the Agency Integrated Planning (AIP). This process ensures a high level of coordination among the different groups to achieve an efficient data collection, analytical evaluation and optimal recommendations. Specifically, BPA coordinates between Transmission Planning, Long Term Transmission Planning, and Long Term Power Planning in their planning activities, processes and decision-making in a way that enables BPA to meet and deliver on its statutory load-serving obligations to its regional firm power and transmission customers.

- Transmission Planning coordinates input resource assumptions for system assessment Basecases with Long Term Power Planning and Long Term Transmission Planning including generator capacities under peak load and to ensure they are reasonable both for each plant and allocation among plants. Transmission Planning also collaborates on information regarding generation retirements.
- Transmission Planning coordinates long duration generator outage assumptions for Basecases with Federal Hydro Projects to include in the system assessment studies.
- System assessments and the Resource Plan start from common agency load forecasting information for BPA customers. Transmission Planning and Long Term Power Planning coordinate with Load Forecasting and Analysis to gain a common understanding of the load forecast process, methodology, and outputs.
- When the system assessment is completed, results and corrective action plans are coordinated with Power Services and Transmission Long Term Transmission Planning to collaborate on possible integrated solutions between Transmission and Power.
- Non-wires potential, prioritization, and analysis are done in collaboration between transmission Services and Power Services.

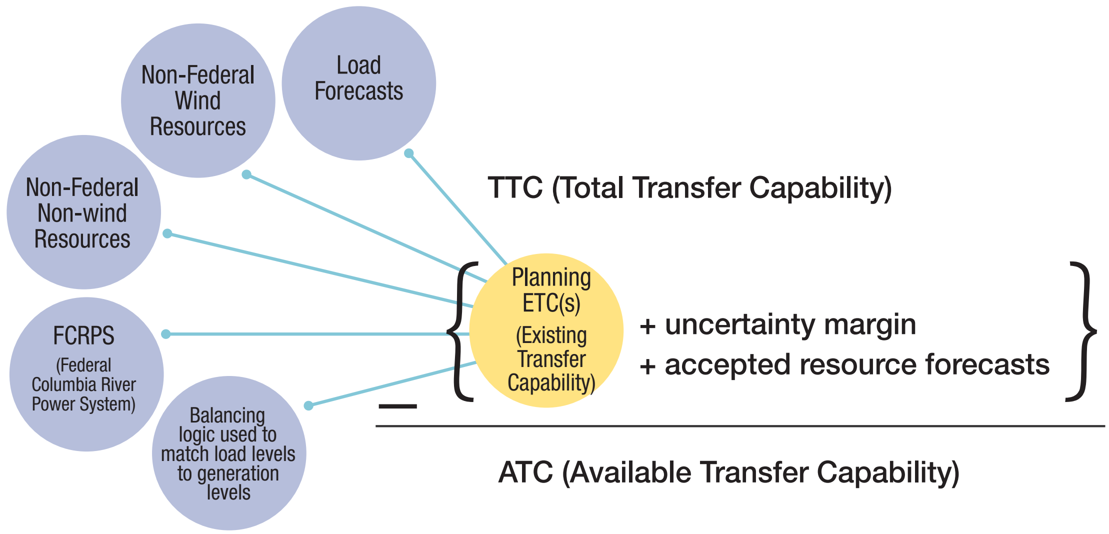
B. Transmission Expansion Planning

Long Term Transmission Planning is responsible for the Transmission Expansion Planning a process which starts by calculating the ATC (Available Transfer Capacity) for each transmission flow gate. The capacity then becomes eligible to meet the needs of BPA customers who submit TSR's (Transmission Service Requests) requesting capacity for their loads and resources. These TSR's are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. With the cluster study, the network can be analyzed for reinforcements necessary to serve the TSR needs. Customers are informed so they can make their project decisions, proceed to contract negotiations and ultimately go to construction. More on how this process works follows.

Long Term Available Transfer Capability

On an annual cycle, BPA Long Term Transmission Planning uses a power flow based model to calculate Existing Transmission Commitments (ETC) on BPA's monitored Network Flowgates under various system conditions and seasons. Using the calculated ETCs and the Total Transfer Capability (TTC), the algorithm ATCFirm = TTC – ETCFirm informs the available transfer capability inventory across Network Flowgates for the Long Term Market. The annual LT ATC update allows BPA Transmission Services to manage Long Term Firm transmission sales as well as inform the Cluster Study. Please refer to Figure 7.5 below for a graphical representation.

Figure 7.5: Inputs to Long Term ATC Calculations for Network Flowgates



To calculate Long Term ETC, BPA Long Term Transmission Planning engineers utilize five and 10 year out Basecases for winter and summer which originates from WECC approved Basecases. These winter and Summer Basecases represent a normal 1-in-2 non-coincidental peak load forecast. The Basecases include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecast used by BPA Power Services for their Needs Assessment and Resource Program, and load forecasts for other utilities represented in the Basecases. The load forecasts are then updated with the most up-to-date load forecast data available from the other utilities. A Light Spring Basecase is derived from a summer peak Basecase by reducing loads and adjusting generation patterns appropriately to reflect historical spring hydro conditions.

Resource forecasts for FCRPS are provided by BPA-PS and take into account of forecasted FCRPS generator outages for the season. The FCRPS is modeled with three dispatches that separately stress the hydro system at the Upper Columbia, Lower Columbia, and Lower Snake projects.

Non-Federal wind resources identified in PTP and NT contracts are modeled in "off" and "on" scenarios. In the "on" scenarios, PTP wind is modeled at the contract demand and capped by its nameplate and NT wind is modeled at the designated MW level for the generator. In the "off" scenarios, PTP wind is replaced with FCRPS generation using a balancing logic method. Non-federal non-wind resources are modeled at contract demand, capped at the lower of the nameplate or historical peaks/seasonal capability.

Transmission Service Request Study and Expansion Process (TSEP)

Every year, BPA TP conducts a Transmission Service and Expansion Process (TSEP) to analyze requests for new long-term firm transmission service. This includes a Needs

Assessment to identify capacity deficiencies across the transmission system for future requests, and a Cluster Study to identify system reinforcements to provide the requested capacity. A benefit of using the TSEP is that BPA-TS can study transmission requests in aggregate, to identify 'right-sized' transmission solutions to meet the demand. In addition, multiple customers then have the opportunity to participate in cost sharing of any needed transmission infrastructure, resulting in lower cost to individual customers and higher project subscription levels.

As part of the TSEP, BPA Long Term Transmission Planning conducts a Needs Assessment to identify capacity needs across the transmission system in response to Long Term Firm Transmission Service Requests, which feeds into the Cluster Study Process. The Needs Assessment starts with developing a robust range of plausible scenarios that would adequately capture anticipated utilization of BPA's Network Flowgates. These scenarios consider similarly situated resources, expected resource type, and market and weather conditions in the scenario development. The Needs Assessment also utilizes data from Production Cost Modeling to inform an estimated economic merit order dispatch in the scenarios, as well as new plausible scenarios of predicted congestion.

The scenario Basecases used for the Needs Assessment are power flow models that are derived from five year out Long Term Available Transfer Capability (LT-ATC) Basecases for the winter, spring, and summer seasons. Since the starting LT ATC Basecases already include load forecast, resource forecast, and existing transmission service commitments, the derivative scenario cases includes modeling of the long-term firm transmission service requests in BPA's Long Term Pending Queue as well as accepted NT Load growth forecasts from the NT Dialogue. Analyses of the set of scenario Basecases determine which flowgates are deficient in capacity and the amount of capacity needed to accommodate requested future transmission service.

For those transmission paths where capacity deficiencies are identified, BPA Transmission Planning conducts Cluster Studies to identify the system reinforcements needed to provide the required capacity both across the transmission paths and within local areas where associated resources are located.

Once BPA-TP completes the Cluster Study and provides the results and defined transmission reinforcements, study participants decide whether to continue pursuing the requested transmission service. After the study participants have made decisions whether to support the identified transmission reinforcements, BPA-TS then initiates the next year's Cluster Study cycle to respond to new transmission requests submitted since the last beginning of the previous study. This cyclical study process enables BPA-TS to efficiently and timely meet customer needs and satisfy its tariff obligations.

An area of recent interest for BPA-TS is the assessment of battery storage to potentially meet commercial planning needs. The exploration addresses technology improvements, increasing cost reductions in energy storage and the role of energy storage in the commercial planning space. Long Term Transmission Planning is developing a framework to evaluate potential use cases, ownership models, impacts to BPA policies and overall cost structure.

C. Long Term Capacity Expansion

BPA Long Term Transmission Planning utilizes the Long Term Capacity Expansion (LTCE) tool which co-optimizes resource and transmission capacity expansions over a long-term (20 to 30 year) horizon. It identifies future resource capacity and energy deficits in the various sub-regions of the Northwest and computes an optimal mix of both transmission and resource capacity additions.

The initial model is populated with at least 20 years of load, resource and transmission data for the Western Interconnection. Inputs in refining this base data are extracted from a variety of sources such as BPA Transmission Planning, BPA Load Forecasting & Analysis, BPA Long Term Power Planning, Northwest Power and Conservation Council, WECC, and Northwest Power Pool.

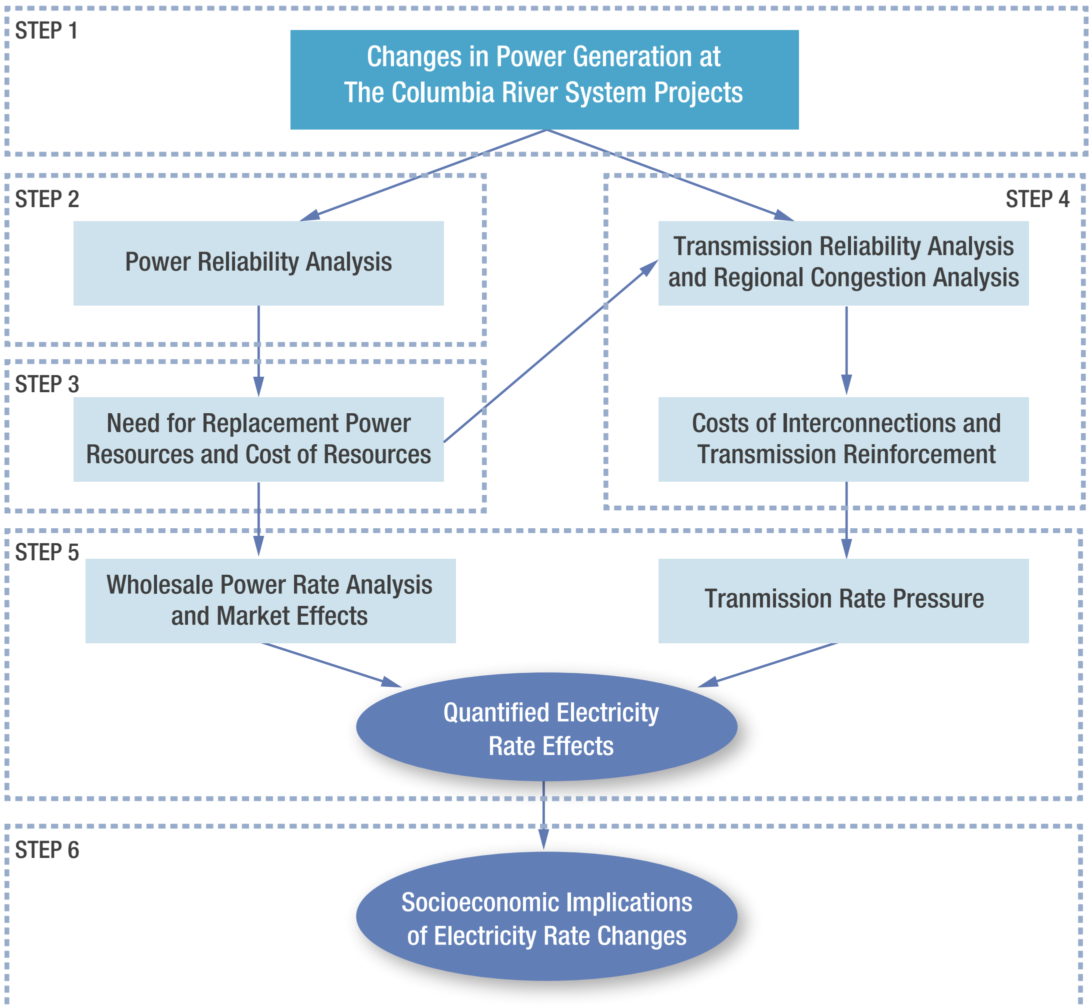
BPA Long Term Transmission Planning is utilizing LTCE with the intent to evaluate several major trends in the external market landscape that impacts transmission. The model has the capability to address how state carbon policies can impact timing of transmission needs and performance in the Pacific Northwest. It can assess how a combination of energy storage, variable energy resources, and hydro perform with respect to adequacy.

D. Intraagency Coordination

There are many examples of coordination between BPA-TS and BPS-PS for large and small projects. One of the most significant efforts in the recent past is the Columbia River System Operations (CRSO) Environmental Impact Statement (EIS). The analytical process between the two organizations followed six steps over the course of two years. Please refer to Figure 7.6: CRSO Work Flow Chart. The process includes linkage of changes in how and where power is generated to effects on the transmission system reliability and congestion.

For example, power planning model outputs related to the capabilities of Columbia River System hydro projects were used as inputs in transmission production cost modeling to forecast changes in transmission path congestion and utilization for each alternative and replacement portfolio. Replacement portfolios developed using power reliability analysis were also tested for impacts on transmission congestion and reliability.

Figure 7.6: CRSO Work Flow Chart



A second example is the cross-agency Southeast Idaho Load Service initiative focused on how to best serve six preference customers in SE Idaho that have long term power and transmission contracts with BPA. This includes commercial negotiations related to the Boardman — Hemingway transmission project (B2H) as well as resource acquisition and transmission service options.

SECTION 8. INTEGRATION IN THE FUTURE

The 2020 Resource Program represents a first step toward bringing Bonneville's Power and Transmission business lines closer together in its bi-annual long-term planning process. Looking ahead to the next Resource Program, anticipated to be published in the 2022 fiscal year, Bonneville plans to continue these integration efforts. While there is much work to be done to establish the precise avenues this progress will take, there are some general commitments and principles Bonneville will pursue.

On the path to the next Resource Program, Bonneville will:

- Continue to collaborate in the Agency Integrated Planning forum, helping to provide internal transparency into long-term planning inputs.
- Work from a set of common assumptions regarding hydrology, FCRPS output forecasts, and load forecasts.
- Pursue a common regional resource build outlook across Power and Transmission planning.
- Advance modeling capabilities to better analyze the impacts of storage resources.
- Explore ways to leverage the collaborative framework pioneered in the CRSO process to improve and integrate periodic long-term planning processes across Power and Transmission.
- Jointly develop, between Power and Transmission, scenarios to study alternative assumptions and examine key findings.

Bonneville acknowledges that the world is ever-changing. The challenges faced in one year may differ from the challenges faced in another year. Risk and uncertainty always complicate forecasting future needs. Despite this flux, a coordinated and robust planning effort will help position Bonneville with the ability to anticipate and respond to the myriad of conditions it may encounter in the future.

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 — Synonym for Load Control Area agency. The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation 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 is capable of responding 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, on the consumer side of the meter facility, such as residential solar.

Canadian Entitlement — The Canadian Entitlement is one-half of a Treaty formula that measures the increase in usable energy and dependable capacity for an imaginary 1960 level hydro-thermal power system with procedures designed to provide acceptable cost/benefits during the life of the Treaty.

Capacity — Capacity is defined and measured in various ways. BPA measures the capacity of its system by determine 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.

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 — The second-lowest historical streamflows on record used to model the amount of power the regional hydropower system could produce, given today's generating facilities and constraints.

Cut plane — Group of transmission lines.

Decarbonization — Reducing the carbon content of all transformed energies such as electricity, heat, liquids, and gases. In the power sector, this means replacing coal, as well as gas and oil, with renewable energy.

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 national 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.

Distributed Energy Resources — systems such as small-scale power generation or storage technologies (typically in the range of 1 kW to 10,000 kW) used to provide an alternative to or an enhancement of the traditional electric power system.

Energy efficiency — Using less energy to perform the same function or service.

Efficient frontier — Result from Resource Program analysis that gives the least-cost combination of available resources that meets the given constrains and also identifies various other combinations of resources that minimize portfolio variance for a given cost point.

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).

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.

Flowgate — Also “flow gate;” 1) Individual or group of transmission facilities (transmission lines, transformers) known or anticipated to be limiting elements in providing transmission service; or 2) designated point(s) on the transmission system through which the Interchange Distribution Calculator calculates the power flow from interchange transactions.

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 cogenerators who produce power for their own use and sell the extra power to their local utilities.

Integrated Resource Plan — A long-term resource planning exercise 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, California, and eastern Montana.

Investor-Owned Utility — A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders; a private utility.

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 — Market Transformation savings are associated with NEEA'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 Council's Plan baseline that are not directly reported by utilities and not part of the NEEA's Net Market Effects.

Network transmission — Transmission contract or service described in a transmission provider's Open Access Transmission Tariff (OATT).

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 (NEAA) — A group of 140 Northwest utilities and energy efficiency organizations that fund activities and programs dedicated to accelerating energy efficiency in the region.

Open Access Transmission Tariff — Tariff for use of high-voltage transmission lines required by FERC under its Order 888. Designed to facilitate open, nondiscriminatory access to all transmission facilities by all power providers; terms and conditions by which BPA provides nondiscriminatory transmission service that is similar to the Federal Energy Regulatory Commission's pro forma tariff mandated for FERC jurisdictional utilities.

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 10th percentile of a distribution.

P10 Heavy load hour — Criteria that evaluates the 10^{th} percentile (P10) surplus/deficit over heavy load hours, by month, given variability in hydropower generation, load obligations, and Columbia Generating Station output amounts.

P10 Superpeak — Criteria that evaluates the 10^{th} percentile (P10) surplus/deficit over the six peak load hours per weekday by month, given variability in hydropower generation, load obligations, and Columbia Generating Station output.

Peak load — The highest amount of one-hour 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.

Point-to-Point transmission — Reservation and/or transmission of energy on either a firm basis and/or a nonfirm basis from point(s) of receipt to point(s) of delivery, including any ancillary services provided by the transmission provider in conjunction with such service.

Ramp rates — 1) The amount of conservation that a program can acquire annually; 2) The rate at which the power output of a generator or generating project can be increased or decreased.

Redispatch — Management of generation patterns to overcome cut plane or outage problems.

Resource portfolio/stack — A set of resources, such as nuclear, natural gas, wind, solar and/or hydropower, used to provide power products.

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

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, and Mexico, and Alberta and British Columbia, Canada.

Western Electricity Coordinating Council (WECC) — An independent, non-profit organization delegated by NERC and FERC to promote the reliability of the power system in the geographic area known as the Western Interconnection.

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