LOWER SNAKE RIVER DAMS POWER REPLACEMENT STUDY

Assessing the technical feasibility and costs of clean energy replacement portfolios

March 2018

An independent study commissioned by the
NW Energy Coalition

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Acknowledgements

This project would not have been possible if it were not for the valuable contributions of the Northwest Power and Conservation Council and ColumbiaGrid (and its members). These entities kindly provided data, modeling tools, and/or feedback during the analysis. They have not, however, participated in the project and their role in providing information or review is not an endorsement or support of the project or its findings.

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EXECUTIVE SUMMARY

Study Overview

This study was commissioned to investigate the technical feasibility of replacing the Lower Snake River (LSR) Dams with an energy portfolio that meets the power needs of the region while minimizing costs and increases in greenhouse gas (GHG) emissions. The main driver for the study traces back to concern by certain parties surrounding the impact the LSR Dams may have on endangered salmon and steelhead species in the Columbia River Basin. One proposed option to reduce the impact that the LSR Dams have on fish and their habitat is to breach the dams. Since the LSR Dams generate emission-free power and provide grid services, their removal—absent adequate replacement—has the potential to create new power needs for the Northwest region.

The study investigates this issue at the system level by analyzing a range of thematic and representative replacement power portfolios using a suite of modeling tools. The portfolios consider new wind, solar, energy efficiency, demand response, energy storage, and gas-fired generation. These modeling tools, and their data, are well known to the Northwest region and are commonly used to plan the region's transmission, generation, and energy policy.

Through this portfolio-based analysis, the study seeks to answer the following core questions:

1. Can an energy portfolio replace the LSR Dams without compromising the region's reliability and resource adequacy while minimizing or eliminating increases to GHG emissions?
2. If replacement using clean resources is not possible, what incremental infrastructure might be required?
3. At what approximate cost might the replacement portfolios be achieved?
4. What additional value might the replacement portfolios offer?

In answering these questions, the study hopes to advance the Northwest region's understanding of the technical and economic power planning issues surrounding the topic. Additionally, the modeling approach used to perform the assessment attempts to bridge gaps between power planning and transmission planning, analyzing the regional system from the most critical perspectives using a coordinated modeling platform. In doing so, the study seeks to introduce a modeling framework that can be advanced by regional planners tackling complex planning challenges that impact the reliability, resource adequacy, economics, and operational performance of the power system.

Analytical Method and Key Assumptions

Fundamental to the analytical method is a Reference Case and three thematic replacement portfolios used as representative replacement strategies for the LSR Dams:

- In the **Reference Case** the LSR Dams continue to generate power and the rest of the system reflects enacted policy, anticipated generation and transmission, planned levels of demand response, and mid-level forecasts for energy efficiency.
- The **Non-Generating Alternative (NGA) Portfolios** assume that the LSR Dams are replaced primarily with demand-side technologies such as demand response and energy efficiency. They also include small amounts of battery storage and market purchases.
- The **Balanced Portfolios** assume that the LSR Dams are replaced with a broad and balanced spectrum of resources, adding significant levels of wind and solar generation along with lower but still substantial levels of energy efficiency and demand response.
- The **All Gas Portfolio** assumes a mix of gas-fired generators replace the LSR Dams.

Although the portfolios were not optimized on a cost or emission basis, several versions of each portfolio theme were studied, including a "Plus" version of the Balanced and NGA Portfolios that included the highest levels of clean energy resources considered in the study.

The study evaluated the portfolios for a single year in the 10-year timeframe with modeling tools that assess reliability, resource adequacy, costs, and operational impacts. This timeframe is a reasonable approximation given (1) the fairly long lead time required for major generation retirements and transmission additions; (2) the need to coordinate data across models that usually do not interact; and (3) the fact that that transmission planning and associated models are generally not focused on timeframes further out than 10 years.

The analyses used to evaluate the portfolios were:

- **Resource Adequacy** – The GENESYS model, an hourly simulation stochastic model used by Northwest planning entities, was used to identify the frequency and magnitude of conditions in which the region does not have sufficient power supply to serve demand. It captures statistical variations in load, wind, solar, thermal generation, and captures unique characteristics of the Northwest hydro system. The goal of these studies was to determine if the replacement portfolios could serve loads as robustly and dependably as the LSR Dams—i.e., to ensure that "resource adequacy" was met. Data and the model itself were provided by the Northwest Power and Conservation Council (NWPCC).
- **Transmission Reliability** – An analysis of transmission reliability was performed using the PowerWorld™ modeling software, which was populated with study case data from the ColumbiaGrid regional planning organization. The study evaluated the transmission system under winter and summer peak conditions and tested its ability to remain within required operating ranges prior to, during, and after "events" such as transmission line outages. The purpose of these studies was to ensure that the regional grid remained stable and reliable during stressed system conditions after implementing the replacement portfolios.
- **Production Cost Modeling** – The ABB GridView™ model was used to analyze the hour-to-hour operation of the system. The production cost model tool simulates system operation subject to real-world constraints such as transmission limits, generation operating characteristics, and load levels. A highly detailed transmission system is represented in the model, including substations, transformers, and transmission lines. For this study, the tool was used primarily to assess the operational cost and emission impact of the portfolios.

Given the wide range of modeling tools used in the study, comparable customized data inputs were required for each model. Care was taken to ensure that there was cross-model consistency for the Reference Case and replacement portfolios represented in each model, especially as it pertained to anticipated levels of load, generation, generation retirements, and planned transmission. If there was not alignment between core assumptions, the study defaulted to assumptions from the Seventh Northwest Conservation and Electric Power Plan ("7th Power Plan"), which was developed by the NWPCC and is the most complete and accurate forecast for generation, load, and energy conservation in the region. The study also aligned its geographical focus with the planning scope of the NWPCC, which includes Oregon, Washington, Idaho, and Montana. The replacement portfolios are summarized below in **Table A.**

Table A: Summary of Replacement Portfolios

	Portfolios				
Resources	NGA	NGA *Plus*	Balanced	Balanced *Plus*	All Gas
Demand Response (summer) (winter)	971 MW 1,039 MW	971 MW 1,039 MW	485.5 MW 519.5 MW	485.5 MW 519.5 MW	-
Energy Efficiency	320 aMW	880 aMW	160 aMW	160 aMW	-
Battery Storage	100 MW	100 MW	-	-	-
Wind[1]	-	-	500 MW	1,250 MW	-
Solar[2]	-	-	250 MW	750 MW	-
Gas: Combined Cycle	-	-	-	-	500 MW
Gas: Reciprocating Engine	-	-	-	-	450 MW

Reliability and Resource Adequacy Performance

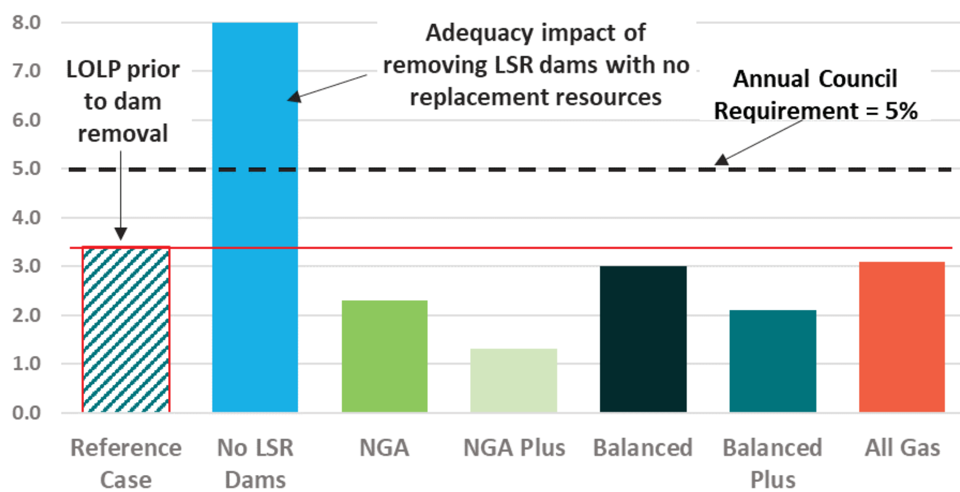
To address the impact to resource adequacy from removing the LSR Dams, GENESYS studies were conducted for the Reference Case (including the LSR Dams) and for each of the replacement portfolios with the dams removed and new resources added. The criteria for

[1] Wind resources were located in Montana.
[2] Solar resources were located in Idaho.

system adequacy were based on annual and monthly metrics—a conservative approach that ensured a "like-for-like" replacement of the LSR Dams.

The loss-of-load probability, or LOLP, indicates the likelihood that resources will not be adequate to serve load in the region. All replacement portfolios resulted in annual LOLP values *lower* than Reference Case value, indicating that the likelihood of load curtailments was *lower* in the replacement portfolio scenarios than in the Reference Case. Notably, all replacement portfolios and the Reference Case are below the NWPCC annual LOLP planning requirement of 5%. Results for annual LOLP are shown in **Figure A.**

Figure A: Resource Adequacy Performance of Replacement Portfolios (Annual LOLP, %))



The study results indicate that by reducing the probability and magnitude of load curtailments, all of the studied replacement portfolios achieved better resource adequacy than the LSR Dams and it is feasible for a portfolio of clean energy resources to provide equal (or better) capacity value compared to what is provided by the LSR Dams. Demand response was very effective at mitigating against potential load curtailments and played a large role in replacing the lost capacity of the LSR Dams. Wind and solar resources were also effective components of the portfolio.

The replacement portfolios were also studied using power flow simulation models to identify any impact to the reliability of the regional transmission system. The assessment featured two analyses: steady-state reliability and transient stability. The assessments used 2027 heavy summer and heavy winter power flow models developed by ColumbiaGrid.[3] Reliability standards and criteria adopted by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) require that the system be able to continue to function within a specific range of voltages, and with transmission loading below facility ratings, under a variety of operating conditions. These operating conditions include contingency or disturbance events such as a loss of a transmission line and/or substation facility. These criteria were used to evaluate the performance of the transmission system for the Reference Case and the replacement portfolios.

Steady-state contingency analysis simulates the system's 20-minute post-disturbance response and ensures the transmission system is within acceptable criteria. The simulation was performed for the Reference Case and the portfolios, and the results were reviewed for reliability issues including thermal line or transformer overloads, bus voltage changes, and bus voltages outside of stability limits. The steady-state contingency analysis did not reveal any new voltage criteria violations caused by implementing any of the replacement portfolios. The study did identify one unaddressed potentially overloaded transmission element, a 7-mile 115 kV line, in all of the replacement portfolios.[4] To ensure the reliability of the replacement portfolios, this transmission overload was assumed to be mitigated through the addition of a second 115 kV line, at a total estimated cost of $10 million. This cost was added to all of the replacement portfolios.

The transient stability analysis looks at the dynamic response of the system, where disturbances are simulated and the system's response is monitored for the first 30 seconds post-disturbance. This analysis included 38 simulations in which line outages[5] were simulated on each side of 19 major 500 kV lines in eastern Washington, Oregon, and between Washington and Montana. The transient stability results were reviewed for reliability issues, including delayed voltage recovery and undamped oscillations in voltage or frequency. The transient stability analysis did not show

[3] The models were used in ColumbiaGrid's 2017 System Assessment.
[4] Three other issues were identified, but ultimately it was determined that they will be addressed by planned projects or remedial action schemes.
[5] Three-phase faults.

incremental voltage or frequency stability issues caused by implementing any of the replacement portfolios.

In sum, since the adequacy of the system was maintained (or improved) and no major regional transmission reliability issues were identified, the study concludes that it is possible to replace the LSR Dams with a mix of clean energy resources without compromising regional resource system adequacy and reliability.

Cost and Emission Impacts

In addition to investigating the technical performance of the replacement portfolios, the study sought to assess the potential impacts of their implementation on regional costs and GHG emissions. The total annualized cost of each replacement portfolio consisted of three components: [6]

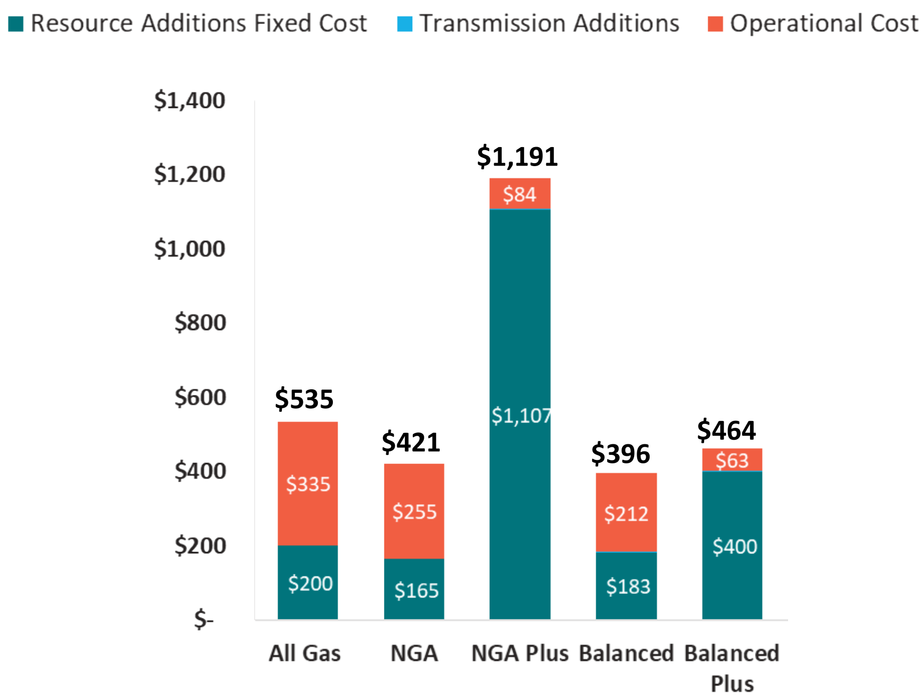
1. **Levelized fixed cost of resources additions** – captured the installation cost of new resources or programs. The study relied on assumptions from the 7th Power Plan for energy efficiency and demand response, and used estimates derived from industry assumptions for wind, solar, and battery storage costs.
2. **Levelized fixed cost of new transmission** – captured the relatively small cost of incremental transmission added to address reliability issues, as mentioned earlier. All other transmission is included in the Reference Case and was considered a sunk cost.
3. **Single-year change in system operating costs** – estimated by the adjusted production cost calculated from production cost simulations. The production cost for the region was offset by the approximated revenue from net exports sold to neighboring regions based on the neighboring/buying regions' marginal power price and simulated power exports to that region. Since the study case used to derive this value represents a median

[6] As detailed later in this report, the study did not account for the following costs: (1) future operational costs or capital expenditures required for continued operation of the LSR Dams and (2) the cost to breach the dams.

condition (hydro, loads, etc.), we consider this value to be an indication of "average" operational cost impacts.

This cost framework was used to calculate the annualized cost of each LSR Dam replacement portfolio option, as presented in **Figure B** as cost increases relative to the Reference Case**.** From an annualized cost perspective, the Balanced portfolio was the most cost effective and three of the four clean portfolios were less costly than the All Gas alternative.[7]

Figure B: Total Annualized Cost of Replacement Portfolios ($M/year)[8]



When evaluating the implications of potential resource strategies for the Northwest region, the NWPCC calculates the total revenue requirement for the region's system. For comparative purposes, the revenue requirement of the replacement portfolios, as represented by their annualized cost, are benchmarked against the 7th Power Plan revenue requirement.[9] The results

[7] The relatively high cost in the NGA Plus portfolio assumes that the portfolio completely exhausts the remaining technically achievable energy efficiency in the region, which is expensive compared to more moderate penetrations of energy efficiency or new wind, solar, or gas-fired resources considered in the other portfolios.

[8] Transmission addition costs are $0.75 million/year and are not visible on the chart.

[9] Comparison used the "Existing Policy Scenario" from the 7th Power Plan.

from the analysis are summarized in **Table B**. Most of the replacement portfolios impact the revenue requirement on the order of 2–3%.

To help understand how revenue requirement values translate to actual customers costs, the NWPCC also calculates representative residential average monthly bills.[10] The metric allows for comparative review of how the incremental costs of a given portfolio could impact residential ratepayer average bills over the approaching 20-year timeframe (on a levelized basis) and how these costs compare to the total ongoing costs of the system. Most of the portfolios in the analysis cause the typical household monthly bill metric to increase $1–$2/month on a 20-year levelized basis.

Table B: Summary of Replacement Portfolio Costs and Emissions

	Replacement Portfolios				
	NGA	NGA *Plus*	Balanced	Balanced *Plus*	All Gas
Δ GHG Regional Emissions (%)	+5%	+2%	+5%	+1%	+8%
Δ Total Annual Cost ($M/year)	**$421**	**$1,191**	**$396**	**$464**	**$535**
Δ Region Revenue Requirement in 2026 (%)	**+2.7%**	**+7.6%**	**+2.5%**	**+3.0%**	**+3.4%**
Δ Levelized Monthly Bill Metric ($/Month)	**$1.16**	**$3.28**	**$1.09**	**$1.28**	**$1.47**

The table also summarizes GHG emissions changes from the Reference Case for each replacement portfolio. One of the goals of the study was to determine if it is possible for replacement resources to result in minimal or no increases to regional GHG emissions. The total regional GHG emissions for each portfolio was based on an accounting framework where emissions from the region were calculated as emissions from generation within the region (or contracted by utilities within the region) plus emissions assumed to be associated with

[10] This calculation is based on the total revenue requirement for the region and relies on estimates regarding the residential sector's share of the system, the forecasted annual revenue requirement, and forecasts for the number of households in the region. The study used the NWPCC assumptions to derive the estimate.

simulated economic power imports into the region.[11] Both components of the GHG emission accounting were based on results from the production cost modeling analysis.

These results show that the best performing portfolio, considering both costs and emissions, is the Balanced Plus portfolio. GHG emissions increase by 1%, there is a 3% increase in the regional revenue requirement (starting in 2026), and the typical household bill metric increases $1.28 per month, on average over the approaching 20-year period. The All Gas portfolio is significantly more expensive and causes emissions to increase by 8%. The NGA portfolio is less effective at mitigating GHG emissions because it includes fewer energy resources and more capacity resources, like demand response. The NGA Plus portfolio is costly because it includes all remaining technically feasible energy efficiency, which becomes very expensive at the far end of the resource supply curve.

Key Sensitivities

The study focused on two sensitivities: (1) the impact of a GHG policy, and (2) reductions in the cost to install wind, solar, battery storage, and energy efficiency.

Given that Northwestern states are currently considering GHG reduction policies, the goal of the sensitivity was to evaluate what, if any, impacts GHG policy might have on the effectiveness of the replacement portfolios from a cost and emissions standpoint. Only the two most aggressive clean replacement portfolios, NGA Plus and Balanced Plus, along with the All Gas portfolio, were included in the sensitivity.[12] Key observations resulting from the GHG policy sensitivity were:

[11] Based on a per MWh emission rate of 944 lb/MWh (0.428 metric ton/MWh) and simulated total annual gross power imports into the region.
[12] The production cost model was adjusted to include a per ton cost associated with GHG emissions from generators in Washington and Oregon ($33.90/metric ton) and an import price for any energy imports into control areas within Washington or Oregon ($14.509/MWh, California and British Columbia excluded).

- If the replacement portfolios are added to the system during a period in which states in the region implemented GHG policy, it is possible to achieve net reductions in regional emissions without the LSR Dams.
- The degree of net emission reductions caused by the dual implementation of GHG policy and the replacement portfolio is heavily driven by the details of the GHG reduction policy itself. For example, this study considered several modeling approaches to represent GHG policy and single-year reductions in emissions between 2–24% were observed across all clean energy replacement portfolios studied. By comparison, the emission increase of removing the LSR Dams (and replacing them with a clean energy portfolio) is 1% (for the Balanced Plus portfolio), which is small by comparison to the emission reductions achieved by the GHG policy. This indicates that GHG policy will be critical in future GHG reductions in the region and that emission issues associated with LSR Dam replacement could be addressed in concert with GHG policy.
- If the LSR Dams are replaced only natural-gas fired resources, even in the face of GHG policy, significant reductions in emissions are less likely to occur.

The clean energy cost sensitivity looked at the effect of reducing the installed cost of wind, solar, and battery storage by 20%, 30%, and 40%, respectively. It also assumed that the remaining amount of technically achievable energy efficiency cost 20% less. Since only a portion of the total replacement portfolio costs are made up of fixed resource costs, the low installation cost sensitivity had a minor but by no means insignificant effect on the total cost of portfolios. For example, the Balanced Plus and the NGA Plus portfolios cost 18% and 14% less, respectively, assuming the lower clean energy resource costs.

Summary of Findings

In seeking answers to the core study questions, the assessment led to a number of findings regarding the feasibility and impacts of replacing the LSR Dams with clean energy portfolios. The key findings from the study are summarized below.

1. **It is possible for a set of clean energy resources to replace the most important power attributes that the four LSR Dams are forecasted to contribute to the Northwest region.** The level of wind, solar, energy efficiency, demand response, and battery storage required to achieve sufficient replacement, as defined by this study, is readily available in the region. Study results indicate that a balanced and coordinated implementation of these resources does not result in any major reliability issues and the region's resource adequacy can be improved relative to the business-as-usual future with the LSR Dams retained.

2. **The cost to achieve a balanced clean energy replacement portfolio that includes both generation and demand-side measures is relatively small in comparison to the total cost of the Northwest power system.** The regionally adequate and reliable portfolios considered in the study increase the region's costs by 2–3% after accounting for portfolio-driven changes in regional operational costs, new transmission costs, and the cost of new resources and programs associated with the portfolio.

3. **Despite losing the emission-free power from the LSR Dams, net reductions in regional GHG emissions are possible if the clean energy replacement portfolios are implemented in combination with GHG reduction policies.** Even if GHG reduction policy is not considered, a balanced portfolio of replacement resources results in a minor impact on greenhouse gas emissions for the region (about 1% increase), and more environmentally-efficient outcomes driven by replacement portfolios not considered in this analysis may be possible.

4. **After incorporating a minor transmission upgrade to address the only incremental replacement portfolio-driven reliability issue, the clean replacement portfolios met reliability criteria under peak summer and winter conditions.** The required upgrade added a relatively small cost to the total portfolio cost ($750,000 per year). After incorporating the upgrade, all replacement portfolios met NERC/WECC reliability criteria for both steady-state and transient stability system performance for the stressed winter and summer conditions studied.

5. **The replacement portfolios provide greater capacity value (compared to the LSR Dams) and reduce the likelihood of the region not having sufficient power to meet peak demands.** Since the replacement portfolios achieved this result without any new conventional resources, the assessment demonstrates that new gas-fired generation is not required to address regional capacity needs that arise when the LSR Dams are removed.

6. While this study provides a significant contribution to the ongoing analyses around potential removal of the LSR Dams, there are a number of areas which may warrant additional study:

    a. **Identifying the most cost effective, environmentally efficient, and robust/adequate replacement portfolio will require scenario-based optimization studies.** This analysis demonstrates what could be possible, in terms of evaluating portfolios on different modeling platforms, but does not represent a least-cost, optimized portfolio. An effort by the region on this front may lead to more efficient outcomes than what was identified and considered in this analysis.

    b. To fully assess the benefits and costs associated with dam removal and replacement, **future studies should gather and incorporate detailed cost estimates surrounding planned, long-term capital and maintenance costs that could be avoided if the dams were removed and replaced, the cost of fish programs that could potentially be avoided, as well as any incremental costs required to breach the dams.** Benefit-cost analysis was not the purpose of this study and these costs were not considered, but they will be critical to future benefit-cost analyses as the planned costs associated with the continued operation of the LSR Dams represent a benefit when avoided, which would make the replacement portfolios in this study relatively less costly. Similarly, the costs to breach the dams represent an incremental cost, which would make the replacement portfolios more expensive.

c. Future assessments could **consider the LSR Dam replacement issue in combination with other evolving policy, climate, and economic factors**. For example, this study did not look at how low water years might impact costs or emissions or costs in the region. If climate conditions change the magnitude or timing of runoff, the value of the LSR Dams could be significantly impacted given their run-of-river operational status.

d. The impacts of decarbonization policy requires additional investigation. For instance, GHG policy analysis in this study showed that reductions from these policies are much larger than the GHG emission impacts associated with certain replacement portfolios. **An optimal "portfolio" might be partly made up of physical resources and partly made up of energy policy aimed at reducing GHG emissions**.

e. The study used strict assumptions with regard to resource adequacy and capital costs and relaxing these assumptions should be considered to further minimize cost impacts.

f. The study did not consider the impacts of high renewable penetration levels in neighboring states, such as California, nor did it consider the implications of changes to natural gas prices, load forecast, market structure, and other key variables. These additional sensitivities are important to understand going forward.

g. The residential bill metric analysis was conducted at an average, regional level and more granular analysis will be required to better assess how the cost implications of any replacement portfolios could impact customers.

h. The transmission reliability analysis in the study relied on the best and most accurate data available to those conducting the assessment. Importantly, regional reliability is not the only metric critical to system operation and planning. An assessment to evaluate the impact, if any, that the removal and replacement of the LSR Dams might have on path transfer capabilities would be important to identify. With this information in hand, any potential impacts to transfer capability can be weighed against the value of that transfer capability and the broader costs and benefits of the decision.

The study does not provide exacting recommendations about the composition of a replacement portfolio, nor does it recommend or support dam removal or claim to have considered all benefits and costs that would weigh on such a decision. It does, however, **utilize a modeling framework that was effective** at evaluating this complicated issue from the most critical perspectives. More importantly, the study **seeks to add to the regional dialogue on the topic by evaluating the feasibility of a range of potential replacement portfolios based on a consideration of their technical merits, reliability implications, potential costs, and impacts to the region's emissions.**

1.0 INTRODUCTION

Federally managed hydropower generation has been a hallmark of the Northwest power system for decades. The Federal Columbia River Power System (FCRPS) consists of 31 federally owned multi-use dams that provide over 22,000 MW of generation capacity across the Columbia River and its tributaries in Washington, Oregon, Idaho, and Montana. The four Lower Snake River Dams (LSR Dams) of interest in this study—Ice Harbor, Lower Monumental, Little Goose, and Lower Granite—have a combined nameplate capacity of over 3,000 MW, are all located in southwest Washington, and are part of the FCRPS (**Table 1**). The LSR Dams are owned and operated by U.S. Army Corps of Engineers (ACE). Bonneville Power Association (BPA) is responsible for marketing and delivering their output through its transmission system.

Table 1: LSR Dam Summary

	Nameplate Capacity (MW)	20-year Average Capacity Factor (%)	In-service Year
Ice Harbor	603	34%	1962
Lower Monumental	810	34%	1969
Little Goose	810	32%	1970
Lower Granite	810	32%	1975
TOTAL	**3,033**		

1.1 Study Drivers

This analysis investigates the technical feasibility of replacing the LSR Dams with an energy resource portfolio that, given the constraints of this study, minimizes net system cost and increases to Northwest greenhouse gas (GHG) emissions while preserving appropriate levels of regional reliability and resource adequacy. [13] The need for the analysis is tied to a decades-old debate surrounding thirteen salmon and steelhead species in the Columbia River Basin, which are listed under the Endangered Species Act, and federal agency plans to protect the fish and

[13] This report uses the term GHG emissions or simply "emissions" to generally to refer to carbon, carbon dioxide (CO_2) or carbon dioxide equivalent (CO_2e). In this study, GHG emissions are limited to those associated with the combustion of fossil fuels in thermal power generation facilities.

their habitat. The Endangered Species Act requires that the FCRPS "action agencies"—which include the Army Corps of Engineers, Bonneville Power Administration and the Bureau of Reclamation—protect the species from increased risk of extinction. To comply with the Endangered Species Act, the action agencies are required to take mitigation measures established in FCRPS Biological Opinions (BiOps). These measures are called Reasonable and Prudent Alternatives (RPAs) and include how the LSR Dams should be operated to protect endangered species.

A series of BiOps have been issued, updated and re-issued since the early 1990s. Many of them have been challenged in federal court for not adequately addressing the endangered species in the FCRPS waterways. In 2014, in response to a Court Remand Order that required a reexamination of the previous BiOps, the National Oceanic and Atmospheric Administration (NOAA) Fisheries issued a supplemental FCRPS BiOp to identify the specific action plan through 2018. In 2016, a federal judge in Oregon invalidated the subsequent BiOp, and called for a new BiOp and National Environmental Policy Act (NEPA) analysis to be completed by March 2018. The judge concluded that the federal agency RPAs were not adequately improving endangered fish populations. The judge also suggested that removing one or more of the LSR Dams may need to be considered to be compliant with the Endangered Species Act.[a, b] None of the BiOps issued to date by the federal agencies have recommended removing dams.

The decision and analysis to remove dams is complex, especially when, as in the case of the LSR Dams, the facilities serve multiple purposes including transport, irrigation, recreation, and power production. This analysis is limited to only the power production components of the LSR Dam removal issue. It does not consider any environmental benefits of removing the dams, including how endangered or threatened species would be affected. Additionally, this is not a cost-benefit analysis in that the capital expenditures required to remove the dams are not compared with holistic or aggregate benefits. Such an analysis is a broader task that should be conducted at a higher, multi-sector level than this energy-specific analysis.

Finally, this report does not take a policy position on whether the dams should or should not be removed. The study is agnostic on the topic and seeks only to assess the power-related impacts that might occur if the dams were removed and replaced by other resources.

1.2 Purpose and Core Questions

The study was designed to test the technical feasibility of replacing the LSR Dams with a clean energy portfolio while ensuring the reliability, stability, and adequacy of the Northwest power system. To accomplish this, a suite of analytical power system planning tools was used to forecast the value of the LSR Dams in the regional power system and assess the ability of energy replacement portfolios to provide similar technical capabilities—a "like-for-like" replacement. The goal of the study was to facilitate conclusions around the technical feasibility of the replacement portfolios and to provide information surrounding their relative costs and potential impacts to GHG emissions in the region.

If the LSR Dams were to be removed, and their value to the regional power system lost, there is a wide range of solutions that could be considered when attempting to achieve "like-for-like" replacement:

- **Supply-side alternatives**, such as new wind, solar, or gas-fired generation, are an obvious option since they are generating resources that produce electricity just like the LSR Dams.
- **Demand-side alternatives**, such as energy efficiency (or conservation) and demand response, could be equally effective options as they address the "gap" created by dam removal by changing the magnitude and timing of power demand. This option can be just as effective as supply-side alternatives since *avoiding* the need to produce electricity in certain amounts and at certain times can be just as or more efficient than maintaining the same demand for power and producing energy from new resources.
- Certain aspects of the LSR Dams could be replaced through the **purchase of power** from the wholesale market. This means that instead of adding resources or reducing demand,

the region would fill the "gap" by relying on existing generation within the region or from imports from surrounding areas. Since the Northwest is a net exporter of power, reductions in exports would also be an effective replacement of the lost power.

Each of these three categories of options offers different capabilities in terms of the energy, capacity, and reliability services that would be necessary to replace the LSR Dams.

The Northwest region has one of the cleanest energy supplies in the country. Its historical reliance on hydropower and energy conservation, as well as recent and planned retirements of coal-generation and investments in wind and solar, have all played a role in this clean energy profile. Given the historical precedent, and long-term plans for decarbonization in Oregon and Washington, minimizing the increases to GHG emissions caused by energy portfolios used to replace the LSR Dams is a significant driver of the study.[c, d]

In addition to the technical and environmental considerations for a potential replacement portfolio, the costs must also be considered. The Northwest benefits from some of the lowest-cost power in the country—much of that due to the inexpensive and lasting nature of hydropower assets. While this analysis does not seek to perform an all-in benefit-cost assessment of dam removal and replacement, it does consider how much the replacement portfolios might cost, in total, from a power system perspective.

Core Questions

Having established the purpose of the study, below are the four core questions that the analysis set out to answer:

1. **Can an energy portfolio replace the LSR Dams without compromising the region's reliability and resource adequacy while minimizing or eliminating increases to regional GHG emissions?** Also, how might the portfolio change or perform under different futures?

2. If replacement using clean resources is not possible, **what incremental infrastructure (e.g., additional transmission, substation equipment, gas-fired resources) might be required to fill the gap?**

3. **At what approximate cost might the replacement portfolios be achieved?**

4. **What additional value might the replacement portfolios offer?**

The study's analytical framework and portfolio-based assessment methodology are designed to focus on these core questions.

1.3 Report Organization

The report is organized as follows:

- **2.0 Analytical Approach** details the study methodology, simulation models and data used to perform the assessment, and background on the criteria used to evaluate the performance of replacement portfolios.
- **3.0 Reference Case and Replacement Portfolios** documents key assumptions used to develop the Reference Case and presents the replacement portfolios subject to analysis.
- **4.0 Replacement Portfolio Performance** describes how the replacement portfolios performed in terms of resource adequacy, reliability, operational cost, GHG emissions, and details how the portfolio results would be affected by the imposition of GHG policies.
- **5.0 Replacement Portfolio Costs** describes how the cost analysis was completed and how the replacement portfolios' total annualized costs compare with the total revenue requirement of the region.
- **6.0 Findings** attempts to respond to the core study questions and presents the most salient take-aways and next steps to consider for future analyses on the topic.

- **7.0 Appendices** capture technical details not included in the body of the report.
  - **Appendix A: Forecasted Value of the LSR Dams** summarizes the value the region can expect from the dams in the coming years and explains where and how the various value streams were or were not captured in the study.
  - **Appendix B: Levelized Fixed Cost Methodologies by Resource** provides a detailed summary of the cost assumptions and their derivation.
  - **Appendix C: Reliability Study Dispatch Assumptions** is for transmission planners interested in how various resource types were dispatched in the power flow studies.

2.0 ANALYTICAL APPROACH

2.1 Overview

This study seeks to assist Northwestern stakeholders in developing a deeper understanding of the feasibility, cost, and power system impacts of replacing the LSR Dams with a portfolio of new resources and technologies. Recognizing the broad nature of such an analysis, the study adopted a set of core principles to help ensure this outcome was achieved. The study principles were to:

- **Rely on established and authoritative data sources, models, and planning metrics that are familiar to stakeholders in the Northwest.** Do not create new models or study frameworks—thoughtfully combine modeling capabilities that already exist in the region. Capture the unique characteristics of the Northwest hydro system using tools and methods familiar to the region.

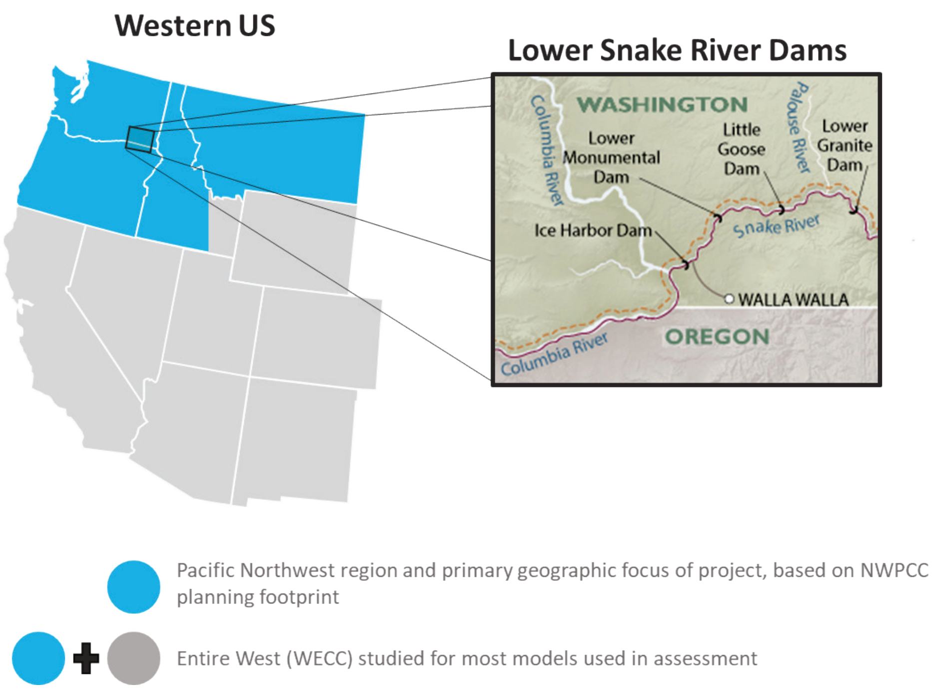
- **Do not seek to fully optimize the replacement portfolios for economic or environmental efficiency.** Allow for iterations of the portfolios, adhering to hard constraints such as system reliability and resource adequacy, while taking a bookend approach to portfolio development and allow the assessment to be customized and exploratory when investigating cost and emission impacts.

- **Focus the geographical scope on the Northwest power system footprint.** This assumption allows comparability (and benchmarking) with established regional planning efforts.

- **Create common databases and assumptions across study phases and modeling platforms.** For example, ensure major announced coal retirements are properly reflected in all models.

The geographic scope of the assessment is summarized in **Figure 1.** The location of the LSR Dams in relation to the Northwest region, as defined by this study, is shown.

Figure 1: Geographic Scope of Study[e]



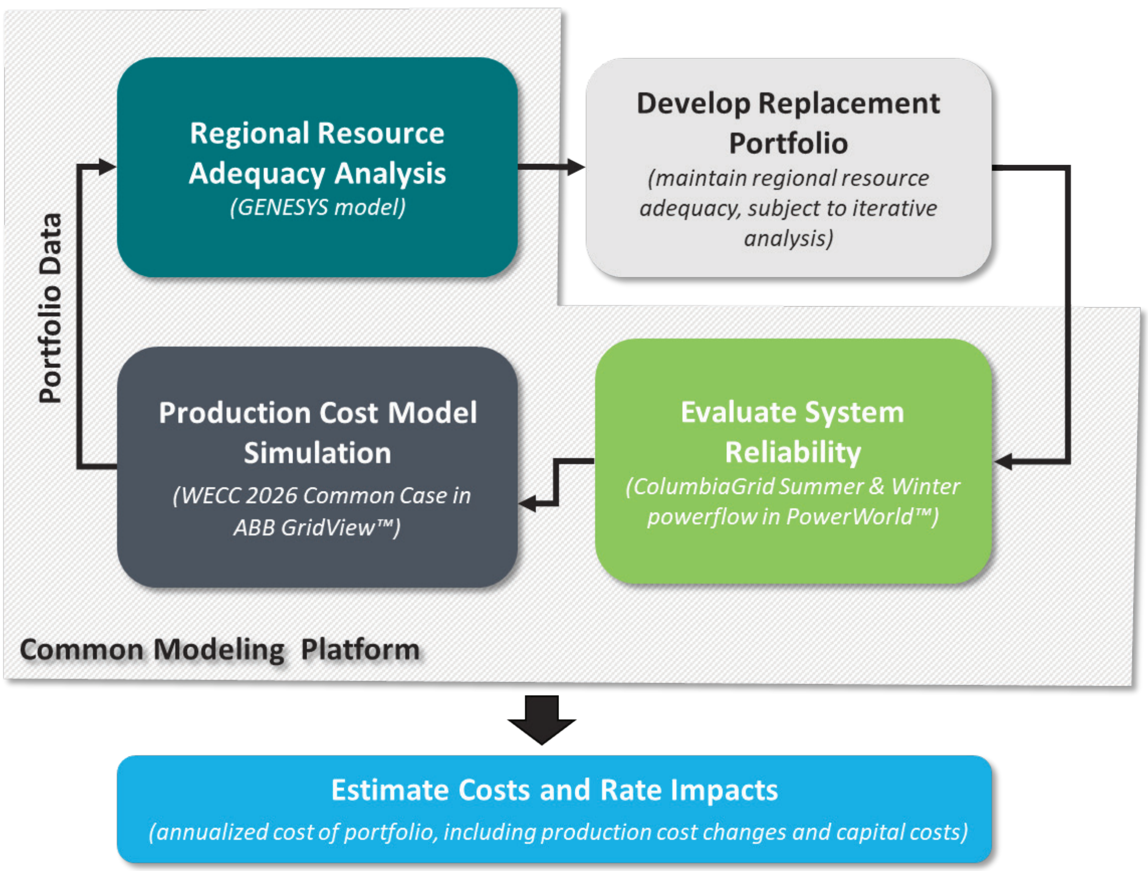
The study defined the "Northwest region" consistent with the planning scope adopted by the Northwest Power and Conservation Council (NWPCC), which generally aligns with the utility footprints in Washington, Oregon, Idaho and Montana. While the Northwest region (or the "Northwest" or "region" for the remainder of this report) was the focus of the modeling and post-model analysis, the entire Western Interconnection system was accounted for either implicitly or explicitly in the modeling, depending on the type of model.[14]

[14] Production simulation and power flow modeling represents the entire Western Interconnection, while the NWPCC resource adequacy model (GENESYS) focuses on the Northwest region but captures interactions with neighboring areas.

2.2 Methodology

The study methodology relies on an integrated analytical framework that investigates the **reliability, resource adequacy, operational, emission, and cost** impacts associated with removing the LSR Dams and replacing them with energy portfolios. We believe this study is one of the first times a suite of power system modeling tools has been leveraged in this fashion in the Northwest. The analytical platform used to perform the study is shown in **Figure 2**.

Figure 2: Analytical Platform



The general approach of the study was to define a Reference Case, or "business-as-usual" future in the 10-year timeframe and study it using the models shown above to derive baseline results. Then, the LSR Dams were removed from the Reference Case and substituted with portfolios of resources—the replacement portfolios. These replacement portfolios were then analyzed using the same modeling methods for future performance, and they were iteratively adjusted as necessary to meet the planning criteria outlined later in this section.

The modeling tools and study process outlined in the figure are summarized below:

- **Regional Resource Adequacy Analysis** – In the electric industry, resource adequacy (adequacy) is a critical component considered by resource planners as it helps ensure that there will be sufficient generation available to service electricity demands in all but the most extreme and unlikely conditions. This study considers (1) the impact to adequacy when the LSR Dams are removed (and not replaced) and (2) the ability of the replacement portfolios to provide equal or enhanced value in this area. The NWPCC evaluates the Northwest region's resource adequacy as a part of its planning process and has established metrics and modeling tools for this purpose. This assessment used those same modeling tools and datasets to evaluate the adequacy of the replacement portfolios. The resource adequacy analysis was performed for the study year 2026.

- **Evaluate System Reliability** – System reliability is similar to resource adequacy but is focused on the transmission system and its ability to reliably facilitate the delivery of generation to loads. Usually, when evaluating the system for reliability performance, transmission planners study it under snapshot "stressed" conditions, which in the Northwest can be when power demands are very high under summer and winter "peak" conditions. To be reliable, the system must be able to deliver power to loads within acceptable performance standards under these worst-case conditions, including when transmission lines or generators unexpectedly go out of service. The North American Electric Reliability Corporation (NERC) requires that utilities plan their systems in accordance to a set of Transmission Planning Standards (TPL) that establish criteria and study methods to analyze system performance. These criteria, along with applicable Western Electricity Coordinating Council (WECC) guidelines, were used to assess the reliability performance of the transmission system when the LSR Dams are replaced by alternate portfolios. The study used 10-year power flow models produced by the ColumbiaGrid regional planning organization, which include data for the BPA system and the rest of the Western Interconnection. Power flow modeling was performed for the study year 2026 (including the winter season 2026-2027).

- **Production Cost Modeling** – The study used production cost modeling to evaluate operational aspects of the replacement portfolios. Nodal security constrained economic dispatch optimization is performed via the model, which captures the technical capabilities of the transmission system, generation operational constraints and costs, and the hour-to-hour load requirements of the region. It also captures the variable nature of wind, solar, and hydro generation. While production cost modeling serves many purposes, in this assessment it was used primarily to study the impacts of the replacement portfolios on operational costs and emissions. The study used the commercially available GridView™ software with a modified version of the WECC 2026 Common Case dataset, which represents the expected loads, resources, and transmission topology 10 years into the future. BPA, WECC, and ColumbiaGrid all use this software and the WECC dataset. The NWPCC uses a similar tool for its assessments. Production cost modeling for this study was performed for the single target year 2026.

- **Common Modeling Platform** – As referenced above, the study focused on the 10-year timeframe with 2026 as a representative year for detailed simulations. This timeframe is as far out as reliability assessments are performed, and since the study's goal was to maintain commonality across datasets and rely on existing models, this single representative-year approach for detailed modeling was employed. Key modeling assumptions were made consistent across the modeling platform, which allowed the study team to confidently analyze the replacement portfolios using this robust set of tools and criteria.

- **Develop Resource Portfolios** – The development of the replacement portfolios was not optimized, although the details of the portfolios were iterated to achieve the goals of the study. The portfolios were developed by first addressing the adequacy needs of the system that were created when the LSR Dams were removed. The study made assumptions on the type, size, location, and technical performance of each resource in the portfolio.[15] The portfolio was tested for reliability performance and evaluated in the production cost model to assess emission and operational cost changes. The portfolios were adjusted further based on findings from these initial analyses.

- **Estimate Cost and Rate Impacts** – Each portfolio was evaluated for its impacts to total system costs. The cost analysis captured the fixed cost of new resource additions, the fixed cost of any required transmission additions, and the change in system operating costs. These costs were annualized to represent the total cost of the replacement portfolio. The rate impact analysis relied on methods employed by the NWPCC in the Seventh Northwest Conservation and Electric Power Plan ("7th Power Plan" or "7th Plan") and compares a typical residential monthly bill metric across different replacement portfolios and the Reference Case.

The criteria used in the modeling tools outlined above to perform the assessment are expanded on in Section 2.3.

2.3 Planning Criteria and Metrics

Core to this study was developing a reasonable answer to the following question: **At what point should a replacement portfolio be deemed "reliable" and sufficient to meet the needs of the region?**

In answering this, the study sought to establish robust and defensible planning criteria that took conservative approaches in meeting "hard constraints" such as system transmission reliability and regional resource adequacy. While there are other technical scopes, methods, and criteria that could have been employed, those summarized below were most appropriate given the datasets available, tools employed, and the study's intent.

[15] The report refers to the term "resource" generally, and it is defined to encompass demand-side (e.g., energy efficiency), supply-side (e.g., new wind/solar), or market-side components (e.g., market purchases of power).

Resource Adequacy

The NWPCC uses GENESYS (Generation Evaluation System) to assess the adequacy of the Northwest power supply. The tool is used not only by the NWPCC but also by numerous other regional entities to perform adequacy assessments, hydro flow studies, and economic analyses of hydro dispatch changes. GENESYS is an hourly simulation stochastic model that can be used to identify conditions in which the region does not have sufficient power supply to serve loads, subject to statistical variations in load (temperature), wind generation, solar generation, streamflow (hydro conditions), and the forced outage of thermal generators. The two metrics used to evaluate resource adequacy in this assessment are:

- **Loss of Load Probability (LOLP)** – Indicates the likelihood that load is curtailed, calculated as the number of simulations performed that have curtailment divided by the total simulations. LOLP is a good indicator of the frequency of loss of load events, but two resource portfolios with the same LOLP can have very different underlying events since the metric does not capture the magnitude or severity of the load curtailment event.

- **Expected Unserved Energy (EUE)** – Is calculated as the total curtailed energy, in megawatt hours, per month, divided by the total number of simulations. This represents the average monthly curtailed energy. It can also be calculated annually. This metric gives information about the severity or magnitude of the loss-of-load events and is usually used in conjunction with LOLP.

The NWPCC adopted a resource adequacy standard in 2011 that requires that the LOLP for the region be less than 5% for five years into the future. The NWPCC is currently considering revisions to this standard, so this study uses the standard only as a reference point.

Using the metrics defined above, a replacement portfolio was assumed to replace the capacity value of the LSR Dams when all of the following conditions were met:

1. **Annual LOLP** is at or below the level established in the Reference Case;

2. **Annual EUE** is at or below the level established in the Reference Case;
3. **Monthly LOLP** values are at or below the level established in the Reference Case; and
4. **Monthly EUE** values are at or below the level established in the Reference Case.[16]

If all four of these criteria were met by a replacement portfolio, the study considered that portfolio to be equal or better than the LSR Dams in terms of its capacity value.

Reliability

The reliability assessment leveraged 2027 heavy summer and heavy winter power flow models[f] created as part of the ColumbiaGrid 2017 System Assessment to compare the performance of the system to applicable standards and criteria adopted by NERC[g], WECC[h], and individual transmission system owners. The NERC, WECC, and owner-adopted standards require that the system be able to continue to function within a specific range of voltages and with transmission loading below facility ratings under a wide variety of operating conditions. These operating conditions include contingency or disturbance events such as a loss of a transmission line and/or substation facility.

Steady-state contingency analysis was the first phase of the reliability assessment, in which disturbances were simulated and the system's 20-minute post-disturbance response was reviewed and compared against the above-mentioned reliability standards. This evaluation leveraged the ColumbiaGrid member-vetted contingency definitions and monitoring criteria embedded in the ColumbiaGrid power flow cases. The steady-state results were reviewed for reliability issues including thermal line or transformer overloads, severe bus voltage changes, and bus voltages beyond stability limits.

Transient stability analysis was the final phase of the reliability assessment, in which disturbances were simulated and the system's response was monitored for the first 30 seconds post-disturbance. This analysis included 38 simulations on the Reference Case and all

[16] Since the two monthly criteria are very conservative targets, these were applied using some judgement, as described later in the document.

replacement portfolio cases, in which three-phase faults were simulated on each side of 19 major 500 kV lines in eastern Washington, Oregon, and between Washington and the Colstrip generating facility. The transient stability results were reviewed for reliability issues, including delayed voltage recovery and undamped oscillations in voltage or frequency.

During each phase of the reliability assessment, each flagged reliability issue was scrutinized (1) with regard to its relevance to the removal and replacement of the LSR Dams and (2) through collaboration with ColumbiaGrid and the owners of facilities involved in the reliability issue to determine the legitimacy of the issue. **Table 2** illustrates this logic.

Table 2: Logic for Reliability Issues

IF	THEN
Reference Case issue persisted in replacement portfolio cases	Noted as an existing planning issue with mitigation scope that could be affected by the replacement portfolio
New issues were identified in replacement portfolio cases	Mitigation was developed as part of the replacement portfolio

If the reliability issue was found to be legitimate and there was no existing plan which would mitigate the issue, then a mitigation plan was developed and included as part of the assumptions of the replacement portfolio.

GHG Emissions

One of the goals of the study was to determine if it was possible for replacement resources to result in minimal or no increases to regional GHG emissions. To accomplish this, changes in annual emissions from the Reference Case to the replacement portfolios were calculated. The total regional GHG emissions for each portfolio was based on an accounting framework where emissions from the region were assumed to be:

1. Emissions from **generation within or contracted by utilities** in the region based on simulated generation from fossil-fired resources and unit-specific emission rates; plus

2. Emissions calculated from "unspecified" **economic imports into the region**, based on a per MWh emission rate of 944 lb/MWh (0.428 metric ton/MWh) and total annual gross power imports into the region.[17, i]

Both components of the GHG emission accounting were based on results from the production cost modeling analysis. Note that to prevent double counting, the study assumed that clean power exports were **not** credited as emission reductions within the region based on avoided emissions outside of the region. This calculation was applied consistently to the Reference Case and the replacement portfolios to track relative changes in the region's emissions.

Operational Costs

Changes in operating cost for the Northwest region were also calculated based on results from the production cost modeling analyses. The study tracked changes in adjusted production cost as a proxy for changes in regional operational costs borne by Northwest customers. The equation to calculate adjusted production cost for the region was defined as:

Adjusted Production Cost for Region = **Production cost of generators in region** − **Revenue from net exports**

The production cost of generators in the region captures the operating cost (including fuel, start-up costs, and other non-fuel fixed and variable operational costs) for all generators physically within or contracted/owned by utilities in the region. The production cost is offset by revenue from the sale of power to neighboring regions. The revenue from net exports assumes:

- Gross power sales are valued at the purchasing region's load-weighted area-level marginal power price, indicative of the price that load in that area is willing to pay for the next megawatt-hour of generation;
- The cost of gross imports (purchases by the Northwest) are calculated using the same method;

[17] The unspecified emissions rate used in this study mirrored the California Air Resources Board (CARB) GHG Mandatory Reporting Regulation, which is currently 0.428 metric tons of carbon dioxide equivalent/MWh for imported emissions from unspecified sources.

- Sales from and to the region are based on the actual area-to-area power flow observed in the simulation; and
- The cost of gross imports is netted from gross power sales to calculate the total revenue from net exports.

Since the Northwest region is a net exporter, the adjusted production cost for the region is less than the total production cost due to the revenue offset by net exports. As shown later in the study results, certain replacement portfolios cause production cost and revenue from net exports to be higher or lower than the Reference Case based on the makeup of the replacement portfolio. This effect is captured in the operational cost analysis, which is further detailed in Section 5.

3.0 REFERENCE CASE AND REPLACEMENT PORTFOLIOS

To understand how the Northwest power system would be impacted if the LSR Dams were removed, it was necessary to build a "business-as-usual" case, which this study refers to as the Reference Case. Replacement portfolios were designed to fill the gap created once the LSR Dams were removed from the Reference Case. Each of the three models used in the study evaluated a coordinated version of the Reference Case. The NWPCC's 7th Power Plan provided the foundation for building the Reference Case. The 7th Plan also established many of the parameters for incremental resources used to create the replacement portfolios.

This section summarizes how the 7th Power Plan informed certain aspects of the study, how the Reference Case was developed for each of the three simulation tools, and what the replacement portfolios entail.

3.1 NWPCC Seventh Power Plan's Role in this Study

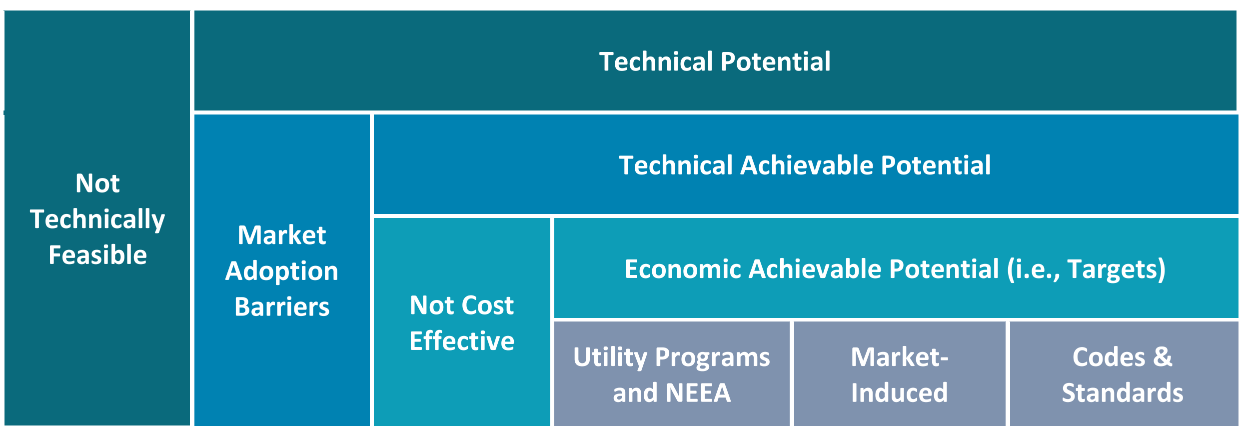
Every five years, the NWPCC develops a comprehensive plan to ensure the Northwest's power supply and to acquire cost-effective energy efficiency over a 20-year time horizon. The most recent version of the plan, the 7th Power Plan, was adopted in 2016 and evaluates 800 possible futures across 20 scenarios. The Regional Portfolio Model (RPM) is used to estimate the system costs of a resource strategy under a given scenario in the 7th Plan. The RPM tests a wide range of resource strategies including the timing and amount of energy efficiency and demand response adopted.[j]

This study utilized the 7th Plan and its RPM data as the primary sources for determining the levels of energy efficiency and demand response to include in the Reference Case, as well as defining the maximum levels of these resources that are technically achievable and available to replace the LSR Dams. Additionally, many of the cost assumptions for resource additions were based on estimates developed in the 7th Plan. The 7th Plan's relationship to resource cost assumptions are described in **Appendix B.**

Energy Efficiency in the 7th Plan

The 7th Plan utilizes the Northwest Power Act's definition of conservation—"using less electricity to provide the same level of services"—to describe energy efficiency resources that reduce the need to build new generation, transmission and distribution resources.[18] In the Northwest, efficiency is the second-largest resource behind hydroelectricity in the region.[k] The 7th Plan identified approximately 3,500 average MW (aMW) of technically achievable energy efficiency potential and 3,000 aMW of cost-effective potential by 2026.[l, m] Technically achievable resources, according to NWPCC, are those that might not be cost-effective or immediately available to develop. Economic achievability describes resources that are cost effective but are not yet adopted. The NWPCC illustrates the relationship between cost-effective and technically achievable resources as shown in **Figure 3**, below.

Figure 3: NWPCC 7th Power Plan Levels of Conservation Potential[n]



To eliminate double-counting the energy efficiency potential, the 7th Plan load forecast model produces a "frozen-efficiency" forecast which assumes that the efficiency level is fixed or frozen at the base year of the plan (in the case of the 7th Plan, the base year is 2015).[19, o] As

[18] This report uses the term "energy efficiency" rather than the NWPCC's preferred term, "conservation." For purposes of this study and report, they have the same meaning.

[19] An exception is made if, for example, a known federal standard will take effect in a specific future year that will lower consumption of a specific appliance. In that case, the efficiency measure will lower the future year frozen-efficiency load forecast.

discussed later in Section 3.2, RPM data is used to form the basis for the load forecast and efficiency levels in the Reference Case.

Demand Response in the 7th Plan

Demand response typically refers to voluntary load reductions during peak demand events that defer (or avoid) new generation, transmission or distribution resources. In the Northwest, demand response programs are characterized by their ability to contribute to either winter or summer peak demand events, since the region's power demands can peak in both seasons. The 7th Plan identified demand response achievable potential for 2026 of approximately 3,200 MW in the winter and 3,000 MW in summer.[p] The RPM identified approximately 2,050 MW of cost-effective summer potential and 1,700 MW of winter potential by 2026.[20]

The 7th Plan only modeled demand response's ability to provide peak shaving, and did not consider its potential to provide ancillary grid services. Likewise, demand response resources were only assumed to reduce peak demand in this study. Additionally, the power flow modeling approach in this study accounted for the 7th Plan's demand response allocation between customer classes throughout the Northwest region when applying demand response to the replacement portfolios.

3.2 Reference Case

The Reference Case provides the baseline for comparison to the replacement portfolios in the study. In the Reference Case, the LSR Dams remain intact and the case reflects: (1) achievement of existing state policy for renewable portfolio standards; (2) ten-year plans for generation and transmission; (3) planned levels of demand response consistent with 5-Year Action Plan assumptions from the 7th Plan; and (4) the ten-year levels of conservation identified from the 7th Plan's Regional Portfolio Model. These Reference Case assumptions were made consistent

[20] Cost-effective demand response levels were determined from the 7th Plan's Regional Portfolio Model's "2026 Frozen Efficiency Medium Load" game 137, which was randomly selected from the group of "2026 Frozen Efficiency Medium Load" games.

across the three modeling tools used in the study. **Figure 4** summarizes the major regional retirements and new transmission expected to be added to the region.

Figure 4: Major Generation Retirements and Transmission Additions in Reference Case

Major Regional Retirements

Boardman	585 MW	2020
Colstrip 1 & 2	614 MW	2022
Centralia 1 & 2	1,340 MW	2020 & 2024
North Valmy 2	268 MW	2019

Significant New Transmission in Region

Boardman to Hemingway (B2H)
Gateway West and South
Wallula – McNary
West of McNary Reinforcement (Big Eddy – Knight)

I-5 Corridor upgrade not included in Reference Case

GENESYS Reference Case

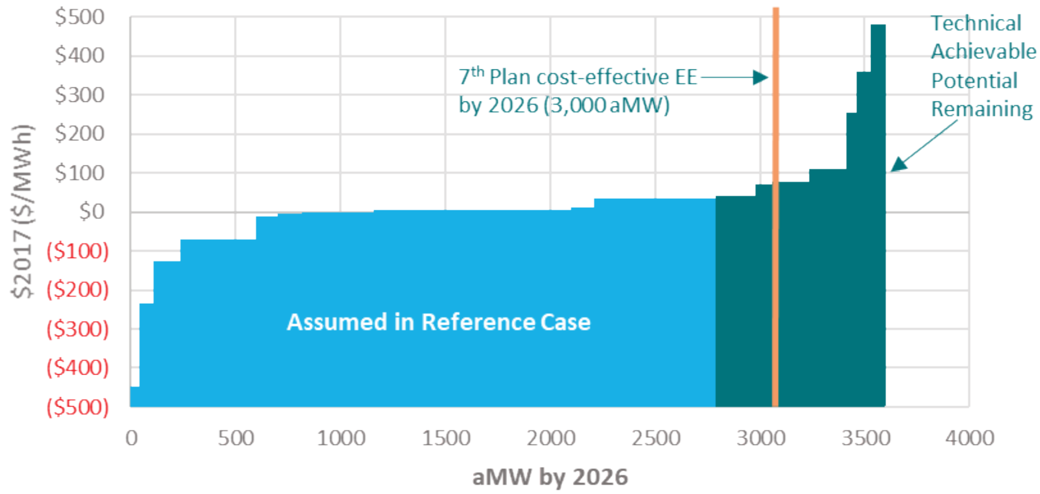
The GENESYS modeling of the Reference Cases assumed the 2026 load forecast and associated level of energy efficiency from a "Medium Load" game in the 7th Plan Regional Portfolio Model,[21] which selected an average of 2,680 aMW of energy efficiency by 2026. Therefore, the Reference Case in this study also assumes 2,680 aMW of energy efficiency by 2026.

Figure 5 depicts the 7th Plan supply curve for the technical achievable energy efficiency potential by 2026. After accounting for the energy efficiency already included in the Reference Case, the replacement portfolios in the study were built using the energy efficiency remaining in the supply curve. This ensured an accurate accounting of the availability and cost of new energy efficiency.[22]

[21] The energy efficiency assumptions were part of the RPM results for game 137, which was randomly selected from the group of "2026 Frozen Efficiency Medium Load" games.

[22] The supply curve was developed using 7th Plan data. The NWPCC calculates the total resource net levelized cost of energy efficiency to compare conservation resources with supply-side resources. When the total benefits of the resource exceed its costs, the total resource net levelized cost of the resource can be negative.

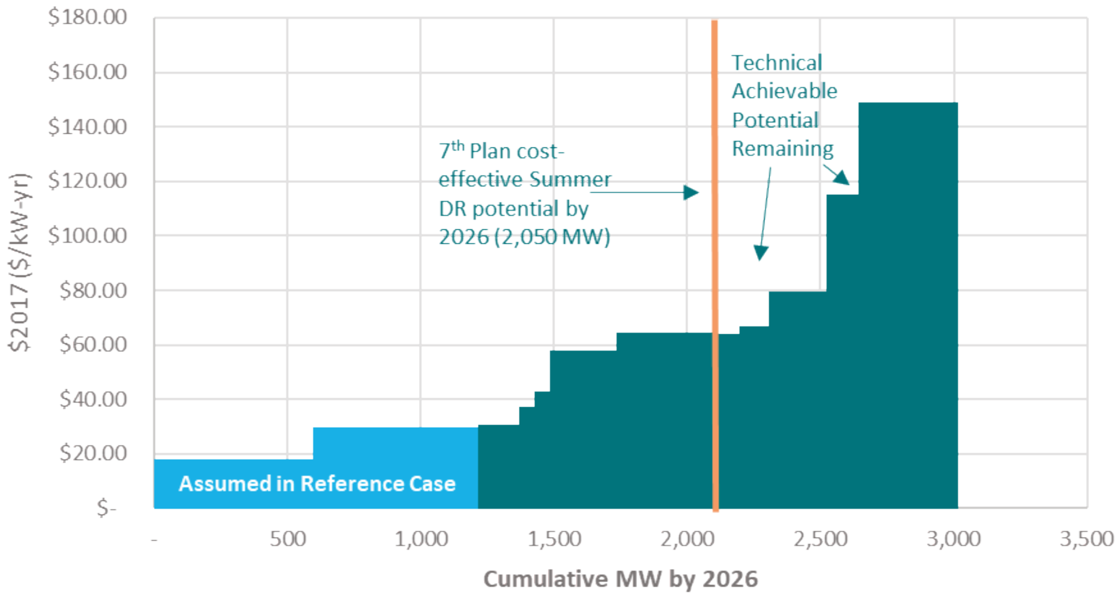
Figure 5: 7th Plan Energy Efficiency Supply Curve (aMW)[q]



The NWPCC's 7th Plan 5-Year Action Plan identified at least 600 MWs of demand response (by 2022) as cost effective across all scenarios.[r] This study assumes that the region achieves this target. To reflect this, the study relies on assumptions from the NWPCC 2022 System Adequacy Assessment, which assumes 661 MW and 1,079 MW of *new* demand response in winter and summer, respectively, by 2022. Because the Action Plan identifies resources that are expected to be adopted, and the System Assessment assumptions reflect achievement of this goal, these demand response levels were included in the Reference Case.

Figure 6 depicts the 7th Plan supply curve for the technical achievable demand response potential by 2026. It also shows the total amount of demand response included in the Reference Case. The replacement portfolios in this study draw from demand response resources "further up" the supply curve at a higher cost than those already "sunk" in the Reference Case.

Figure 6: 7th Plan Demand Response Supply Curve (MW, Summer)[5]



Power Flow Reference Case

Several modifications were made to the ColumbiaGrid power flow cases to produce Reference Cases to serve as reasonable starting points for the reliability assessment.[23] Outlined below are the modifications made to the 10-year transmission planning cases and the rationale behind them:

- **Updates to contingency definitions and monitoring criteria to better mimic ColumbiaGrid's final 2017 System Assessment**: These were implemented after the March 21, 2017 posting consistent with conversations with ColumbiaGrid staff and BPA.
- **Implemented recent transmission and resource updates**:
  - Retired Colstrip Units 1 and 2
  - Retired North Valmy Unit 2
  - Removed I-5 upgrade transmission project
- **Reduced LSR Dams' dispatch**: The ColumbiaGrid power flow cases represented highly stressed load and generation dispatch conditions typical of models focused on assessing

[23] Since the Reference Case assumptions are represented in multiple models in the power flow assessment, we refer to them collectively as Reference Cases here.

system reliability in the most extreme conditions. However, these conditions represented higher total dispatch from the LSR Dams than had ever been observed under those conditions. To address this, 10 years of historical LSR Dam generation data was compared against BPA load data to determine LSR Dam dispatch levels that occurred coincident with BPA peak load. For winter, the LSR Dam average coincident dispatch was 1,040 MW, and the study assumed the second highest historic dispatch (1,590 MW). In summer, the average coincident dispatch was 855 MW and the study assumed LSR dispatch at 1,497 MW (also the second highest historic dispatch level coincident with peak load). While these dispatch levels are not the highest recorded LSR Dam dispatches during winter and summer peak conditions, they are much higher than what usually occurs, but not so high as to capture any potential tail conditions (e.g., 80th percentile).

  - The Northwest thermal and non-LSR hydro dispatch (and Northwest exports to California in the heavy winter case) were updated to achieve load-resource balance after reducing the LSR Dams' dispatch.

Appendix C includes detailed tables that summarize the changes made to generation dispatch and interchange levels in the summer and winter Reference Cases.

Production Simulation Reference Case

The study made modifications to the WECC 2026 Common Case (Version 2.0) dataset, which represents the expected loads, resources and transmission topology ten years in the future. The modifications include:

- Removed Northwest Resource Adequacy ("NW RA") placeholders for synergy with NWPCC GENESYS assumptions
- Updated Rock Island, McNary, John Day, The Dalles, Bonneville, Wanapum, and Grand Coulee hydro modeling
- Implemented general wind and solar curtailment prices based on renewable energy credit and production tax credit values (-$15/MWh & -$25/MWh, respectively)

- Implemented historically based hourly shapes for the DC interties between the Western and Eastern Interconnections
- Activated GridView™ 7-day Look Ahead logic to improve dispatch
- Implemented recent planned retirements and replacements in the Southwest region

3.3 Description of Replacement Portfolios

To develop the replacement portfolios, the study used an iterative approach across the three modeling tools to develop replacement portfolios that could preserve the region's resource adequacy and reliability requirements, while also limiting increases to the region's GHG emissions. The LSR Dam replacement portfolios are meant to demonstrate what could be possible, but do not represent a least-cost, optimized portfolio.

Three thematic replacement portfolios were developed for the study, with two of the themes having a "Plus" version for a total of five portfolios. The themes for the replacement portfolios were their primary resource: non-generating alternative (NGA) resources, a balance of renewable and non-generating resources, and gas-fired resources. The composition of each replacement portfolio analyzed in the study is summarized in **Table 3**. An explanation of each portfolio and rationale for each incremental resource amount is described in more detail below.

Table 3: Power Replacement Portfolios – Summary

	Portfolios				
Resources	NGA	NGA *Plus*	Balanced	Balanced *Plus*	All Gas
Demand Response (summer) (winter)	971 MW 1,039 MW	971 MW 1,039 MW	485.5 MW 519.5 MW	485.5 MW 519.5 MW	-
Energy Efficiency	320 aMW	880 aMW	160 aMW	160 aMW	-
Battery Storage	100 MW	100 MW	-	-	-
Wind[24]	-	-	500 MW	1,250 MW	-
Solar[25]	-	-	250 MW	750 MW	-

[24] Wind resources were located in Montana.
[25] Solar resources were located in Idaho.

Gas: Combined Cycle	-	-	-	-	500 MW
Gas: Reciprocating Engine	-	-	-	-	450 MW

Non-Generating Alternative Portfolios

- **Non-Generating Alternative (NGA) Portfolio** is comprised primarily of non-generating resources including *all* of the remaining cost-effective demand response and energy efficiency potential outlined in the 7th Plan through 2026, 100 MW of winter capacity market purchases from California, and a 100 MW, 4-hour lithium-ion battery to serve load in stressed conditions.
- **NGA Plus Portfolio** is made up of the same resources as the NGA Portfolio, with one change to the energy efficiency additions. The NGA Plus Portfolio includes *all* of the remaining efficiency identified as technically achievable.

Balanced Portfolios

- **Balanced Portfolio** includes *half* of the 7th Plan's 10-year forecast for cost-effective demand response and energy efficiency, as well as 500 MW of new wind resources located in Montana and 250 MW of solar resources located in Idaho. The study assumed that Montana wind resources use transmission capacity made available by planned coal retirements. Solar resources are assumed to be delivered using capacity on the planned Boardman to Hemingway (B2H) transmission project (which is included in the Reference Case).
- **Balanced Portfolio Plus** is made up of the same resources as the Balanced Portfolio, but with significantly more wind and solar resources coming from Montana and Idaho, respectively. In this portfolio, the study assumes an additional 1,250 MW of wind and 750 MW of solar relative to the Reference Case.

All Gas Portfolio

- **All Gas Portfolio** contains only new gas-fired generation including a 500 MW combined cycle generator and 450 MW of reciprocating engines spread among 24 units. These resources were modeled near the McNary 500 kV and 230 kV substations and are assumed to have access to a gas pipeline used by existing gas-fired generation in the area. The modeling assumptions for the combined cycle plant and reciprocating engines are consistent with the existing Hermiston Power Project and Port Westward units, respectively.

GHG Reduction Policy Sensitivity Assumptions

Given that states in the Northwest are currently considering GHG reduction policies, the study included a sensitivity to capture the effects of GHG policy in the region being implemented prior to an effort to replace the LSR Dams. The sensitivity addresses the fact it is unlikely that states in the Northwest region will remain static on GHG policy and that if the LSR Dams are removed and replaced, such an effort will not unfold in a GHG policy vacuum. Thus, the goal of the sensitivity was to evaluate what, if any, effects a GHG policy might have on the effectiveness of the replacement portfolios from a cost and emission standpoint. Only the two most aggressive clean replacement portfolios, NGA Plus and Balanced Plus, along with the All Gas portfolio, were included in this sensitivity.

The study assumes that such a policy would not practically impact operations during reliability events (assuming there were no changes to the resource mix) since system operators will seek to maintain system reliability under such stressed peak-load events largely in the same way they do now. As a result, GENESYS and power flow studies were not performed for the sensitivity and only production cost modeling was performed.

To assess the impacts of a GHG policy, the production cost model was adjusted to include a per ton cost associated with GHG emissions as outlined in **Table 4.**[26]

[26] This sensitivity utilized emissions factor equivalent and a carbon planning price (GHG price) based on the California Air Resources Board Mandatory Reporting Regulation used in the implementation of AB-32, the California Global Warming Solutions Act. The sensitivity leans heavily on California policy for simplicity and a cleaner modeling approach, broadly assigning a proxy cost to GHG emissions to reflect the potential impacts of Oregon and Washington GHG policy and does not model any proposed Oregon or Washington policies explicitly. Additionally, the study assumes revenue recycling, meaning that revenues accrued from the additional cost generators pay for carbon emissions/allowances are returned to customers.

Table 4: GHG Policy Sensitivity Assumptions

Element	Assumption	Application	Source
Carbon Price	$33.90/metric ton	Incremental cost applied to all GHG emissions from generators in Washington or Oregon	Planning price used by the California Independent System Operator (CAISO) to reflect AB-32
Import Adder Price	$14.509/MWh	Cost of importing "unspecified" emissions (0.428 metric ton CO_2e/MWh) into control areas within Washington or Oregon, **except** for imports from California and British Columbia	Consistent with rules established by California Air Resources Board for importing "unspecified" emissions

4.0 REPLACEMENT PORTFOLIO PERFORMANCE

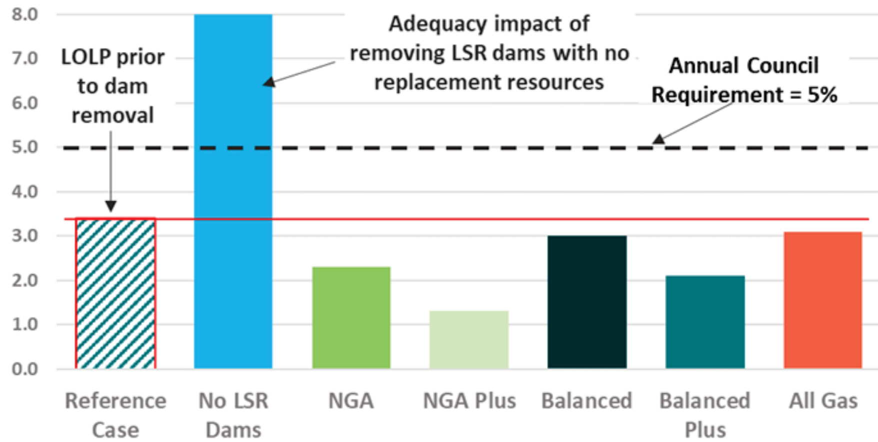
The results and findings from the portfolio studies are organized by the type of analysis. The review of the performance of the replacement portfolios begins with resource adequacy (Section 4.1), and then reliability is evaluated (Section 4.2). Section 4.3 discusses the operational costs of the portfolios, along with changes in GHG emissions associated with the different portfolios. Section 5.0 focuses on the total replacement portfolio costs.

4.1 Resource Adequacy Performance

GENESYS studies were conducted for the Reference Case (with the LSR Dams) and for each of the replacement portfolios. The target for system adequacy is based on the annual and monthly LOLP and EUE from the Reference Case—a conservative approach that ensures "like-for-like" replacement of the LSR Dams.

Summary metrics for the analysis are shown in **Figure 7** and **Figure 8**. **All replacement portfolios achieved annual LOLP values lower than Reference Case value**, indicating that the likelihood of load curtailments is lower in the replacement portfolio scenarios than in the Reference Case with the LSR Dams. Notably, all replacement portfolios and the Reference Case are well below the NWPCC annual LOLP planning requirement of 5%.

Figure 7: Resource Adequacy Performance of Replacement Portfolios (Annual LOLP, %))



The decrease in the EUE from the Reference Case to the replacement portfolios indicates that the *magnitude* of the events, in terms of curtailed or dropped load, is also lower with the replacement portfolios than with the LSR Dams.

Figure 8: Resource Adequacy Performance of Replacement Portfolios (Annual EUE, MWh)

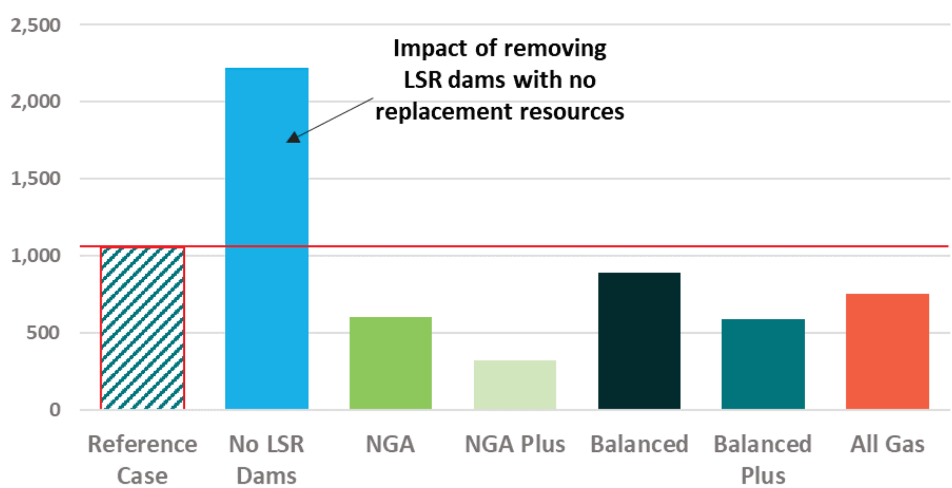
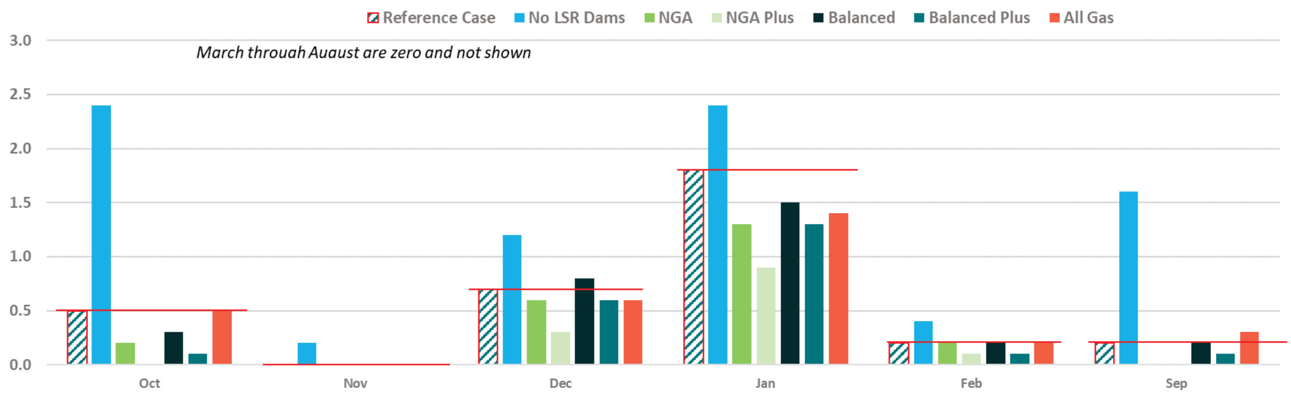


Figure 9 summarizes the performance of the replacement portfolios on a monthly basis. A monthly metric is important because shifting the likelihood of curtailment, as represented by the LOLP, from one month to another is not acceptable from a power planning standpoint. For example, in this study a replacement portfolio would be deficient from a capacity perspective if the portfolio had a December LOLP that was four times that of the Reference Case *even if* that

replacement portfolio was adequate on an annual basis. This monthly criterion is more conservative than what the NWPCC has used historically.[27]

Figure 9: Resource Adequacy Performance (Monthly LOLP, %)



Overall, all of the replacement portfolios provided equal or better capacity value than the LSR Dams. However, due the nature of each portfolio, there were some differences in their performance:

- The **NGA and NGA Plus** portfolios had annual LOLPs close to 2% and 1%, respectively. The NGA Plus portfolio was the best performing portfolio from a capacity perspective. It eliminated load curtailments in October and September (which occurred in the Reference Case) and greatly reduced the frequency of curtailments in December and January, compared to the Reference Case. The most effective attribute of mitigating curtailments for these two portfolios was the roughly 1,000 MW of demand response available to mitigate against load curtailments.

- The **Balanced and Balanced Plus** portfolios were weaker than NGA and NGA Plus from a capacity perspective because they included less demand response and energy efficiency. However, the portfolios still reduced the annual LOLP to levels below the Reference Case and substantially improved system adequacy in October and January. The Balanced portfolio had slightly higher LOLP in December, but if we assess January and December

[27] As of the drafting of this report, the NWPCC was considering revising their criteria to include additional metrics and a quarterly analysis. Also, the monthly ordering is based on water year planning. The study also included a review of monthly EUE results and overall, they were very similar to the monthly LOLP results and all replacement portfolios provided sufficient monthly replacement.

together, the aggregate is a net reduction LOLP for the winter months. For this reason, the portfolio was deemed to be sufficient from an adequacy perspective despite the slight uptick in LOLP for a single month.

- The **All Gas** portfolio also effectively reduced LOLP to levels at or below the annual and monthly targets set by the Reference Case.

In total, this portion of the assessment indicates that it is feasible for a set of clean demand- or generation-side resources to fully replace the capacity value provided by the LSR Dams. It also indicates that depending on how the replacement portfolio is constructed, it is possible to enhance the adequacy of the region's system. This enhancement can be achieved with readily available resources. For instance, the NGA portfolio, which improved system performance, included only the remaining levels of *cost-effective* demand response and energy efficiency.[28]

4.2 Reliability Performance

The replacement portfolios were studied using power flow simulation models to assess their impact to the reliability of the regional power system. This assessment features two analyses: steady-state reliability and transient reliability. The results of both studies are summarized below.

Steady-State Reliability

The purpose of the steady-state reliability assessment is to ensure that the system remains within acceptable performance criteria, as outlined in Section 2.3. The steady-state contingency analysis did not reveal new voltage criteria violations caused by implementing any of the replacement portfolios. However, the study did expose several post-contingency thermal overloads, which were reviewed in more detail. Additional review of ColumbiaGrid 2017 System

[28] The GHG reduction policy sensitivities had no bearing on the results of the system adequacy assessment based on the assumption that during times of system stress, the region's power portfolio will be used to its maximum potential to serve load, avoiding load curtailments at all costs. Because of this assumption, no results for the GHG policy sensitivity are included in this section.

Assessment documentation and feedback from BPA led to the identification of transmission plans already in place that would likely fully mitigate all but one of the issues. The remaining issue was the overloaded, 7-mile long Stevens – Snyder – White Bluffs 115 kV lines, which was assumed to be mitigated through the addition of a second 115 kV line, at a total cost of $10 million. **Table 5** summarizes the results of the assessment.

Table 5. Steady-State Thermal Overload Results[29]

Season	Branch and Mitigation	Post-contingency Change in Loading (%) by Scenario Case (from Reference Case)				
		Balanced	Balanced Plus	NGA	NGA Plus	All-Gas
Heavy Summer	Ahsahka - Orofino 115kV Line # 1 ***Mitigated by RAS per ColumbiaGrid report (p. 41)***[30]	+19%	+34%	+9%	+9%	+7%
Heavy Summer	Ashe - White Bluffs 230kV Line # 1 ***Mitigated by updated rating from BPA***	+14%	+14%	+15%		
Heavy Summer	Horn Rap - Red Mountain 115kV Line # 1 ***Mitigated by BPA planned reconductor***	+6%	+3%	+6%	+2%	+1%
Heavy Summer	Snyder - Stevens 115kV Line # 1	+8%	+7%	+8%	+4%	+7%
Heavy Summer	Snyder - White Bluffs 115kV Line # 1	+8%	+6%	+7%	+2%	+7%
Heavy Winter	Franklin 230/115kV Transformer # 1 ***Mitigated by moving new Gas CC to different McNary bus section***					+46%

Transient Reliability

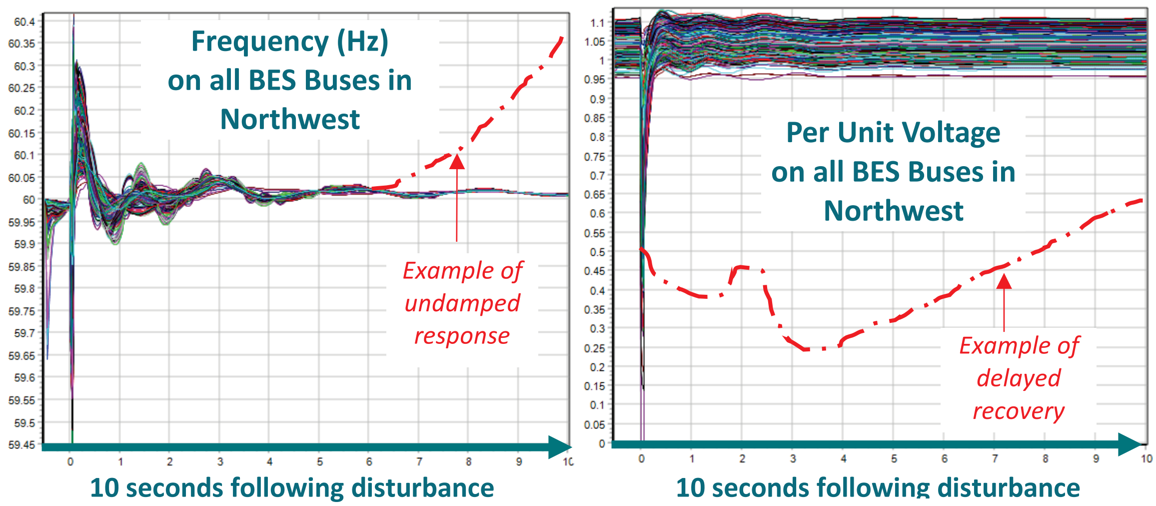
The transient stability analysis did not show incremental voltage or frequency stability issues caused by implementing any of the replacement portfolios. **Figure 10** provides the frequency and voltage responses of the Balanced Portfolio for one of the major contingencies simulated with the power flow cases. The Balanced Portfolio results are provided as a representative sample for all of the transient stability results. Similar profiles of frequency and voltage

[29] To prevent the disclosure of potentially sensitive transmission system information, the most severe contingency and the overload levels are not provided. The decision to provide this information to interested parties will be made on a case-by-case basis and will require that those parties have appropriate permissions in place.

[30] Refers to ColumbiaGrid 2017 System Assessment

responses were observed in all simulations performed for the Reference Case and replacement portfolio cases. The figures include examples of undesirable responses (in red) for context.

Figure 10: Performance of Balanced Portfolio under Major Contingency



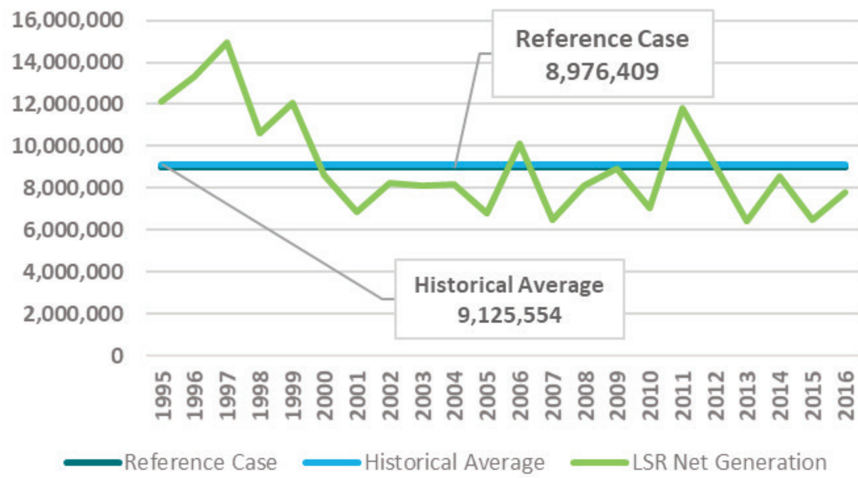
The GHG reduction policy was assumed to not have an impact on the results of the transmission reliability assessment.

4.3 Operational Costs and GHG Emissions

Production cost modeling was used to assess the system operational costs and GHG emission effects of the replacement portfolios.[31] The costs considered in this section are solely the operational costs, and do not include the costs to add the new resources or the costs to add new transmission. (Section 5.0 includes these cost components and is therefore a more comprehensive look at costs). Since the model represents a median hydro future, the LSR Dam generation in the Reference Case is very much in alignment with the historical average, as shown in **Figure 11.**

[31] The model and dataset used for this study represents a "median" system condition in the 2026 timeframe and does not stochastically capture the impacts of variables—it takes a deterministic approach for hydro conditions, gas prices, and other key variables. However, this allows for more detailed representations of the transmission system, generators, system operational characteristics/constraints, and a fully 8760-hour analysis of the system's operation.

Figure 11: LSR Dams Net Generation



The Reference Case includes almost 9,000 GWh of generation from the LSR Dams. The replacement portfolios did not replace all of this energy with *new* incremental resources (when the LSR Dams were removed). The resource additions in the replacement portfolios are shown in **Table 6**.

Table 6: Portfolio Energy Content (MWh)

Portfolio	LSR Dams	New Wind	New Solar	New DR+EE	New Storage	New Gas	TOTAL	% Energy Replaced
Reference	8,976,409	0	0	0	0	0	8,976,409	---
NGA	0	0	0	2,391,174	-72	0	2,391,102	27%
NGA Plus	0	0	0	6,508,404	100	0	6,508,204	73%
NGA Plus + GHG Policy	0	0	0	6,508,364	-100	0	6,508,264	73%
Balanced	0	1,916,947	573,370	1,191,724	0	0	3,688,040	41%
Balanced Plus	0	4,789,169	1,736,860	1,191,772	0	0	7,717,802	86%
Balanced Plus + GHG Policy	0	4,792,359	1,734,863	1,191,943	0	0	7,719,165	86%
All Gas	0	0	0	0	0	2,624,028	2,624,028	29%
All Gas + GHG Policy	0	0	0	0	0	1,321,673	1,321,673	15%

The Balanced Plus and the NGA Plus portfolios replaced the highest percentage of the LSR Dam annual energy at 86% and 73%, respectively. The scenarios could have been revised further to include additional energy in these portfolios, approaching 100% of the annual energy historically generated by the LSR Dams. However, such an approach may not be the most prudent investment strategy for several reasons:

- The replacement portfolios were sufficient to meet the region's capacity needs and thus, any additional MWs of clean generation would have provided no incremental capacity value in terms of replacing the LSR Dams (diminishing the attractiveness of such an investment for that purpose);
- The additional clean energy would be added primarily for environmental purposes, and the implementation of regional policies, such as a carbon tax or cap-and-trade, may be a more efficient means to reducing any emission effects of removing the LSR Dams; and
- In certain years, and in certain seasons, the Northwest region has more energy than it needs due to high hydro conditions, so adding additional energy to replace 100% of the energy provided by the LSR Dams may not be an optimal investment.

The production cost model seeks to serve loads while minimizing operational costs and observing system constraints, like transmission limits and generation operational requirements. The replacement portfolios do not include the LSR Dams and instead include combinations of resources that generate (or reduce load) at different times and in different amounts than the LSR Dams. The modeling indicates the region can still meet its energy needs, but under the median hydro conditions assumed for this study, it adjusts imports and exports from levels in the Reference Case. These changes, and the change in net exports from the Reference Case, are summarized in **Table 7.**

Table 7: Changes in Imports and Exports

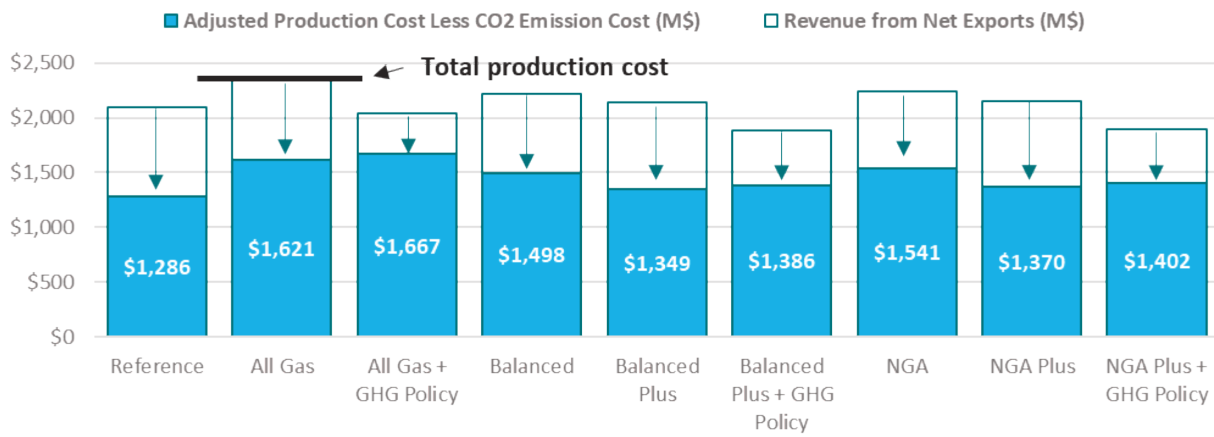
Portfolio	Annual Gross Imports (GWh)	Annual Gross Exports (GWh)	Annual Net Exports (GWh)	Change in Net Exports (GWh)	**Change in Net Exports** (aMW)	**Change in Net Exports** (%)
Reference	13,181	26,510	13,329	0	**0**	**0%**
NGA	13,972	24,799	10,827	-2,502	**-286**	**-19%**
NGA Plus	13,514	26,190	12,676	-653	**-75**	**-5%**
NGA Plus + GHG Policy	18,601	24,521	5,920	-7,409	**-846**	**-56%**
Balanced	14,319	25,781	11,462	-1,867	**-213**	**-14%**
Balanced Plus	13,908	26,888	12,980	-349	**-40**	**-3%**
Balanced Plus + GHG Policy	17,971	24,648	6,677	-6,652	**-759**	**-50%**
All Gas	14,393	25,386	10,993	-2,336	**-267**	**-18%**
All Gas + GHG Policy	19,291	22,427	3,136	-10,193	**-1,164**	**-76%**

Note that the Northwest region today and in the simulated studies is a net exporter of power. Removing the LSR Dams generally increased the amount of gross imports into the region and decreased gross exports, resulting in varying reductions in net exports across the replacement portfolios. The two portfolios that added the most energy, Balanced Plus and NGA Plus, limited the reduction in net exports to 3% and 5% respectively because (1) the portfolios were richer in energy than the other portfolios, limiting the frequency of "net-short" positions when the region had to import power or reduce exports, and (2) the energy in those portfolios was available at times that enabled the portfolios to increase gross exports under certain conditions. These two portfolios indicate the Northwest region can maintain its status as a major exporter of power and still replace the LSR Dams with clean energy portfolios.

Notably, the GHG policy sensitivity cases, which were studied on the NGA Plus, Balanced Plus, and All Gas portfolios, caused net exports to decrease significantly (more than 50%). A GHG reduction policy puts a cost on GHG emissions so fossil-fired generation units in the region are forced to incorporate this incremental cost to produce power. The GHG reduction policy thus reduced gross exports because it (1) increased the value of in-region low-carbon resources that would have otherwise been exported (but instead were kept in the region because of the high marginal power prices and their value to the region), and (2) increased the costs associated with dispatching thermal generators solely for export, which reduced the region's total energy available for export. In short, when modeling the GHG policy, the region keeps more of its clean power for itself and is not willing to bear the cost of emissions from in-region thermal generation just to export that power. The effect is a large reduction in gross and net exports.

The type of resources in the replacement portfolios and changes in imports/exports across the cases combine to result in changes to the operational cost of the Northwest system. These are represented by the changes in adjusted production cost for each replacement portfolio as presented in **Figure 12**. Section 2.3 details how the adjusted production cost is calculated.

Figure 12: Adjusted Production Cost by Replacement Portfolio (M$)



The Reference Case had the lowest cost at almost $1.3 billion annually and each of the replacement portfolios increased the region's operational costs. Again, the costs considered in this section do not include the costs to add the new resources or the costs to add new transmission. The increased adjusted production costs, focusing on the portfolios without the GHG Policy sensitivity, is discussed below:

- The **All Gas Portfolio was the most costly at just over $1.6 billion, a $335 million per year increase in operational costs above the Reference Case.** Since the portfolio did not include any low/zero-operating-cost power (such as wind, solar, or energy efficiency) the entirety of energy lost by the removal of the LSR Dams had to be made up with either (1) additional generation from new or existing in-region thermal generation or (2) reductions in net exports. These came at a cost to the region in the form of additional fuel, start-up costs, reduction in revenue from exports, and increases in import purchases, which in sum resulted in a 26% increase in operational costs.
- The **Balanced Plus Portfolio, at just under $1.35 billion, had the smallest operational cost impact**, an increase of 5% from the Reference Case ($63 million). Revenue from net exports was the almost the same as the Reference Case (2% decrease), mainly due to the higher amounts of replacement energy included in the Balanced Plus Portfolio.

In addition to operational cost impacts, the production cost modeling tool was used to assess the impacts to the region's GHG emissions. The methodology for this accounting is detailed in

Section 2.3, and the results are in **Table 8.** Note that these values represent the full accounting of GHG emissions adopted by this study, including those associated with imported power. On average, 85% of the regional GHG emissions were due to emissions from generation within the region, and 15% of the total emissions were associated with imports.

Table 8: Total Regional GHG Emissions

Portfolio / Sensitivity	Total CO_2 Emissions Including Annual Gross Imports (Short Ton)	Δ (Short Ton, annual)	Δ (%)	Emission Intensity (ton/MWh)
Reference	43,299,426	0	0%	0.18
Balanced	45,327,168	2,027,741	5%	0.19
Balanced Plus	43,659,702	360,275	1%	0.19
Balanced Plus + GHG Policy	42,491,591	-807,836	-2%	0.18
NGA	45,566,562	2,267,136	5%	0.20
NGA Plus	44,267,489	968,063	2%	0.19
NGA Plus + GHG Policy	43,351,769	52,342	0%	0.19
All-Gas	46,928,920	3,629,493	8%	0.20
All-Gas + GHG Policy	45,357,456	2,058,030	5%	0.20

As shown above, the two "Plus" portfolios were the most effective at mitigating against increases to the region's GHG emissions. The main driver of increased emissions in all of the replacement portfolios was incremental emissions from in-region thermal generation. The Balanced Plus and NGA Plus mitigated this effect the most out of all the portfolios because clean resources (demand-side and generation-side) replaced most of the generation from the LSR Dams, so thermal resources were relied upon less often to make up the difference.

The All Gas portfolio had a significant increase to regional GHG emissions because the clean hydro generation from the LSR Dams was replaced with generation from thermal generation units and power imports.

As mentioned earlier, the dataset used to conduct the study represents a median hydro condition. The study year assumed very little hydro "spill" or overgeneration (when power generation is in excess of what the region can use or sell). This is an important factor to consider when evaluating the impact that the replacement portfolios have on the region's emissions. For a given simulated hour for each of the replacement portfolios, one of four outcomes are possible when the model seeks to fill the remaining energy gap created by removing the LSR Dams and replacing it with wind, solar, energy efficiency, or other clean resources that are not dispatchable:

(1) If the hour was an overgeneration/spill hour in the Reference Case, the previously curtailed energy has a "home" when the LSR Dams are removed because the LSR Dam power is no longer available.
(2) If there is no spill, the region can make up the gap by importing energy.
(3) If there is no spill, the region can make up the gap by exporting less energy.
(4) If there is no spill, the region can make up the gap by generating more power from dispatchable thermal resources.

The production cost model optimizes this decision and makes the most economic choice. In situation (1) there is no incremental cost to the region because the spilled energy was wasted otherwise. As long as the energy gap is less than the spilled power, there is no increase in GHG emissions. In situation (2), the region's emissions go up, and the operational costs go up because of the cost and emissions associated with imports. In (3), there is no change in emissions for the region, but operational costs go up because revenue from net exports decreases if the power is not sold outside the region. Lastly, in (4), operational costs and emissions for the region increase because of fuel costs (and other operational costs) and the incremental emissions from the generation.

It is clear based on these results that it is possible to mitigate the emission effects of removing the LSR Dams by developing a low-carbon replacement portfolio of resources. There is likely an optimal portfolio to do so, but this does not address the annual variations in hydro output, which could have major consequences for identifying how robust the replacement portfolio would need to be, from an energy standpoint, to mitigate 100% of the emissions associated with removing the LSR Dams.

GHG Reduction Policy Sensitivity

The purpose of the GHG reduction policy sensitivity was to evaluate the effects of GHG policy in the region being implemented prior to or along with an effort to replace the LSR Dams. The study used a conservative modeling approach to represent the GHG policy, assigning imports into control areas within Washington or Oregon an assumed “unspecified” import rate (0.428 metric ton CO_2e/MWh which is converted to $14.509/MWh) even if imports were from remote thermal resources owned by those utilities. In-state thermal generators were assigned a $33.90/metric ton carbon price. The modeling is described in detail in Section 3.3, and the results presented prior to this section are based on this approach.

The study also tested applying the full carbon price to these remote but contracted or owned out-of-state resources (versus only charging them the $14.509/MWh unspecified import rate). This modeling approach would be in line with California’s AB-32 (the California Global Warming Solutions Act), in which out-of-state generators that are known to serve in-state load are considered “specified resources” and are assigned the full carbon price.[32]

Results for the two approaches are summarized in **Table 9.**

[32] In the case of plants that are jointly owned, this modeling approach could have the effect of overstating potential GHG reductions beyond what would occur if only the portion of the facility dedicated to serving load in a state with GHG policy was assigned the full carbon price.

Table 9: Summary of GHG Sensitivity Results[33]

Portfolio	Change in GHG Emissions (%) from Reference Case	
	At "Unspecified" Import Rate (Base Assumption)	**At "Specified Source" Carbon Price** (AB-32 Approach)
All Gas + GHG	5%	-17%
Balanced Plus + GHG	-2%	-24%
NGA Plus + GHG	0%	-22%

Representing out-of-state thermal resources as specified resources has a significant impact on total GHG emissions. When all imports are assigned the unspecified rate, emission reductions are small, on the order of -2% and 0% for the Balanced Plus and NGA Plus replacement portfolios, respectively. However, when certain imports are assigned the full emission cost, total emissions for the region would decrease more dramatically, down 24% and 22% (again, respectively). The main driver of the decrease in emissions is a major shift from coal to gas fired-resources that occurs when certain out-of-state coal assets face the full carbon price versus the unspecified import rate.

While GHG policy modeling was not the focus of this assessment, this analysis indicates that the emission impact of the LSR Dam replacement, which is a 1% increase for certain portfolios without any GHG policy, is small in comparison to the potential reductions achievable when the LSR Dams are replaced with clean energy portfolios and GHG policy shifts generation from the remaining coal in the region to gas-fired generation.

[33] Reductions in emissions are relative to Reference Case without any GHG policy, reflecting the impact of implementing the GHG policy *and* the replacement portfolios in concert.

5.0 REPLACEMENT PORTFOLIO COSTS

The cost analysis for the study focused on calculating the incremental cost of each replacement portfolio relative to the Reference Case. The study did not seek to quantify the costs or evaluate the cost-effectiveness of removing the dams, nor did it capture all of the replacement options, or a number of energy and non-energy system benefits. **Table 10** summarizes the total annualized replacement portfolio cost, and the total costs under the two sensitivities.

Table 10: Summary of Total Annualized Replacement Portfolio Cost

Portfolio	$M/yr	GHG Policy Sensitivity?	$M/yr	Low Cost Sensitivity?	$M/yr
Balanced	$396			Yes	$372
Balanced Plus	$464	Yes	$501	Yes	$400
NGA	$421			Yes	$414
NGA Plus	$1,191	Yes	$1,224	Yes	$983
All Gas	$535	Yes	$581		

5.1 Cost Analysis Framework

The total annualized cost of each replacement portfolio is the sum of three components:

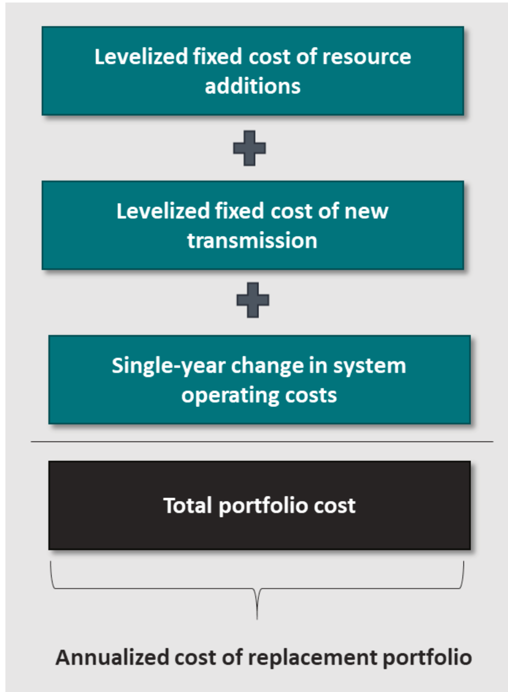
(1) levelized fixed cost of resource additions;

(2) levelized fixed cost of new transmission; and

(3) single-year change in system operating costs as calculated in the production cost model.

This cost framework, as illustrated in **Figure 13** , was used to calculated the annualized cost of each LSR Dam replacement portfolio option. Section 5.2 has a discussion of the total annualized portfolio costs that were summarized in Table 10; subsequent sections discuss the cost components.

Figure 13: Cost Analysis Framework



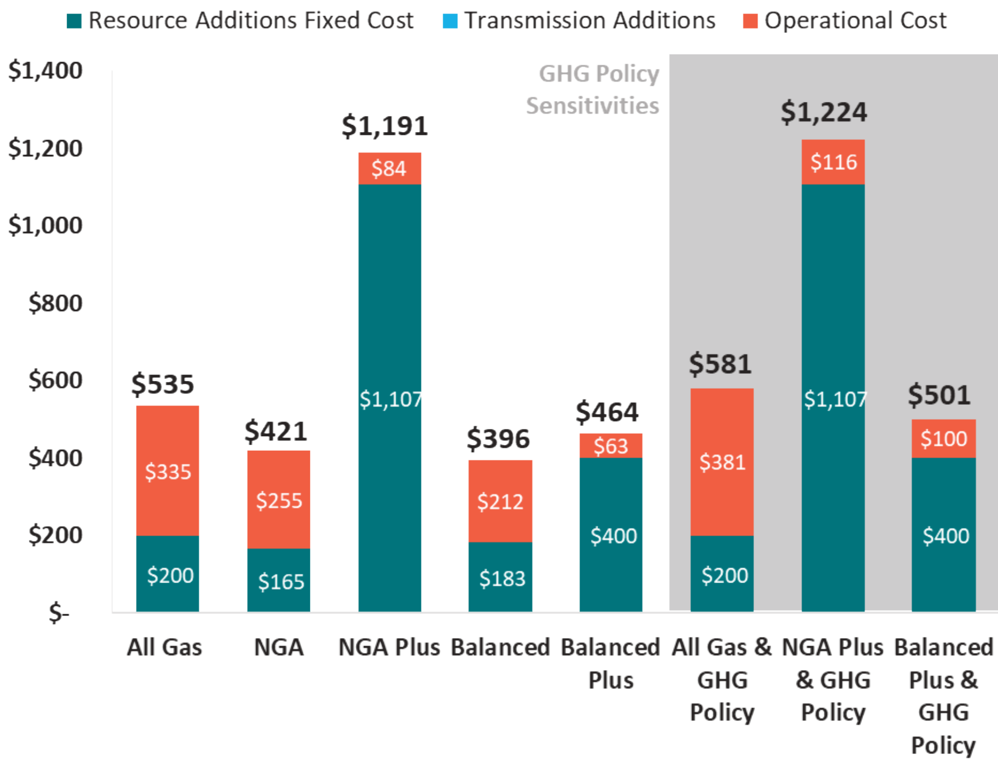
5.2 Total Annualized Replacement Portfolio Cost

The total annualized cost of the replacement portfolios, with detail for each cost component, is summarized in **Figure 14**. The total annualized costs are in a narrow range of $396 million to $581 million, with the exception of the NGA Plus portfolio and NGA Plus with the GHG Sensitivity. These portfolios are more expensive than the others due to the relatively high cost of acquiring all technically feasible energy efficiency.

The NGA and Balanced portfolios are similar in total cost. The Balanced Plus portfolio is about 17% more costly than the Balanced portfolio, but it has the benefit of comparative reductions in GHG emissions. Looking at the cost components, the All Gas portfolios have greater increases in operating costs than the clean replacement portfolios.

Additional transmission costs, at less than $1 million per year, are an insignificant portion of total costs, and are not visible in the figure.

Figure 14: Total Annualized Cost of Replacement Portfolios ($M/year)



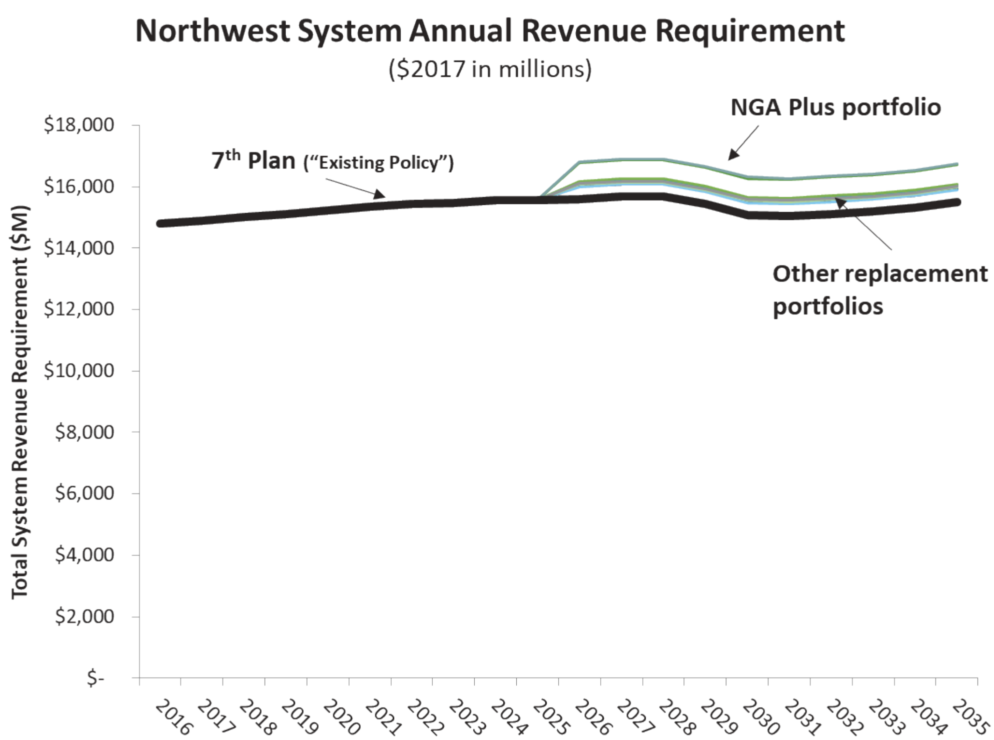
The portfolio annualized cost-analysis results are presented as time-series data in **Figure 15**. In this figure, the costs associated with replacing the LSR Dams with energy portfolios begin to appear in 2026—the year of assumed dam replacement in this study. In reality, the costs would likely phase in over some period as energy infrastructure and programs are deployed. However, for the purposes of this study, this approach allows simple comparisons to the region's total revenue requirement.

In 2026, the region's total revenue requirement under the 7th Plan "Existing Policy" scenario is $15.6 billion.[34] Most of the portfolios analyzed in this study have annualized system costs that are incremental to this regional revenue requirement on the order of $396 million to $581 million. The NGA Plus portfolio is the outlier and sits above the narrow band of the other portfolios in the chart. As mentioned elsewhere, the comparison is not exact as we assume that the 7th Plan forecast includes the cost of continuing to operate and maintain the LSR Dams, so

[34] Value varies slightly depending on the scenario considered in the 7th Plan.

the cost reduction associated with avoiding this cost when the dams are removed is not captured. Likewise, the replacement portfolios do not capture certain costs, like any teardown cost of the dams. The comparison also does not consider avoided costs associated with eliminating fish programs. Regardless, on an order-of-magnitude basis the comparison is informative and addresses the study scope as it puts the estimated cost of the replacement portfolios into context with the rest of the ongoing and planned Northwest system cost.

Figure 15: Northwest System Annual Revenue Requirement ($2017 in millions)



From a cost perspective, the Balanced and Balanced Plus portfolios increase the going-forward average revenue requirement of the region by 2.5% and 3%, respectively, starting in 2026. This incremental cost to the system is comparable in magnitude to the variance across scenarios the NWPCC estimated in the development of the 7th Plan.

This section discussed the total annualized costs for the portfolios. The following three sections provide more detail on the cost components: the new resources, the new transmission, and operating costs.

5.3 Levelized Fixed Cost of Resource Additions

This section presents resource costs as the cost for the additional capacity only. It does not include additional transmission or the operational costs of these portfolios. As noted above, the study relied on the 7th Plan for many of the cost and resource supply assumptions. For wind, solar, and battery storage, the study relied on industry-vetted sources for capital cost estimates rather than utilizing the 7th Plan estimates, which were compiled roughly three to four years before this study commenced and were notably higher than more recent industry estimates.

Table 11 provides a summary of the incremental resource cost of each of the five portfolios, which have annualized costs between $165 million and $1,106 million. The NGA Plus replacement portfolio includes all of the technically feasible energy efficiency, which comes at a very high average cost. As such, it drives up the total NGA Plus portfolio resource cost to over one billion dollars per year. The total costs for the NGA, Balanced, and All Gas portfolios are comparable. The Balanced Plus portfolio is higher because, like the NGA Plus portfolio, it includes additional resources. However, the incremental renewable resources in the Balanced Plus portfolio are much less expensive than the energy efficiency added to the NGA Plus portfolio.

Table 11: Total Annualized Fixed Resource Addition Cost by Portfolio

Resources	Portfolio Fixed Cost (Millions, $2017/year)				
	NGA	NGA *Plus*	Balanced	Balanced *Plus*	All Gas
Demand Response	$68	$68	$15	$15	-
Energy Efficiency	$80	$1,022	$34	$34	-
Battery Storage	$14	$14	-	-	-
Wind	-		$103	$256	-
Solar	-		$32	$95	-
Gas – Combined Cycle	-		-		$107
Gas – Reciprocating Engine	-		-		$93
Capacity Contract (Market)	$3	$3			
Total Annual Fixed Cost	$165	$1,106	$183	$400	$200

The supply curves developed in the 7th Plan for energy efficiency and demand response were utilized in this study to determine the incremental resources and associated costs for the incremental portfolios. **Figure 16** and **Figure 17** illustrate an example of the supply curves and the level of resources selected for one of the portfolios. The supply curve approach was adopted to ensure that the replacement portfolios included technically supported levels of demand-side resources and appropriate costs.

Figure 16: Energy Efficiency Supply Curve Example - NGA Portfolios[t]

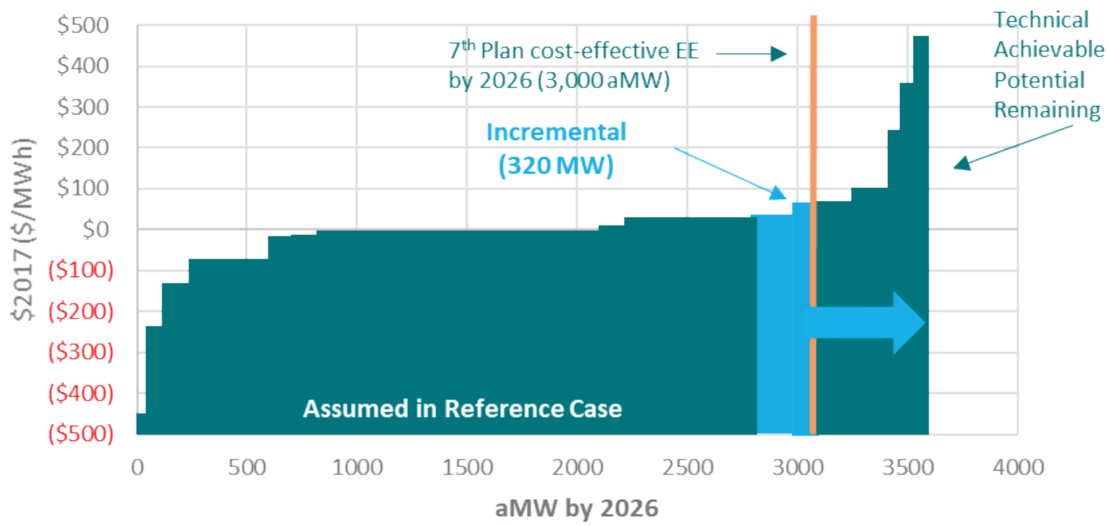
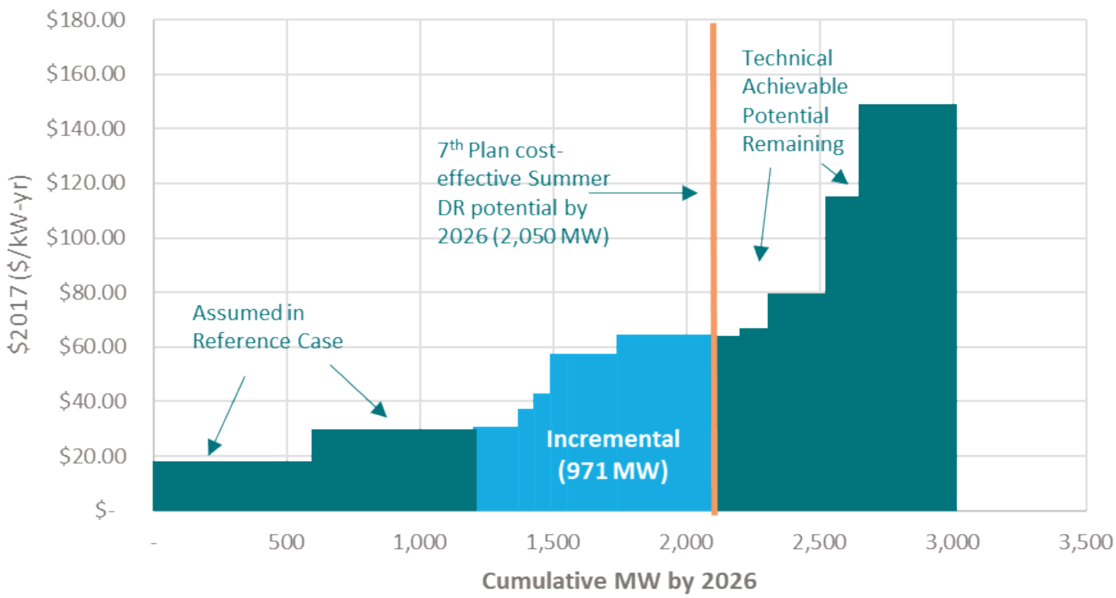


Figure 17: Demand Response Supply Curve - NGA Portfolios (Summer)[u]



A summary of the key resource cost assumptions used to calculate the levelized fixed cost of resource additions is provided in **Table 12**.

Table 12: Summary of Resource Cost Assumptions

Thermal Generation or Capacity Market Cost

Resource Type	Capital Cost ($/kW-ac)	Levelized Fixed Cost ($/kW-year)
Gas Combined Cycle	$1,498	$213
Gas Reciprocating Engine	$1,416	$206
Capacity Contract (Market)	$30/kW-year	---

Renewable/Storage Cost

Resource Type	Capacity Factor (%)	Installed cost ($/kW-ac)	Levelized Fixed Cost ($/kW-year)	Levelized Cost of Energy ($/MWh)
Wind (Montana)	44%	$1,639	$205	$53.24
Solar, Single-axis Tracking (Idaho)	26%	$1,440	$127	$59.10
Li-ion Battery (4-hr)	---	$753	$141	---

Demand-side Cost Assumptions

Resource Type (incremental to Reference Case)	Resource Potential	Average Levelized Fixed Cost ($/kW-year)	Average Levelized Cost of Energy ($/MWh)
“Cost Effective” Energy Efficiency	320 aMW	---	$28
50% of “Cost Effective” Energy Efficiency	160 aMW	---	$24
“Technical Achievable Potential” Energy Efficiency	880 aMW	---	$132
“Cost Effective” Demand Response	~1000 MW	$68	---
50% of “Cost Effective” Demand Response	~ 500 MW	$29	---

Additional detail on the methodology behind each of these assumptions is provided in **Appendix B**.[35]

[35] The capacity contract cost estimate is detailed in the Appendix. It is based on average bilateral system capacity contracts in the CAISO from 2016.

5.4 Levelized Fixed Cost of New Transmission

The results and assumptions associated with this assessment indicate that relatively little new transmission would be required to implement the LSR Dam replacement portfolios. There are a few reasons for this. First, there are several significant transmission projects that are already scheduled to be built in the region and/or generation retirements that will enable renewables to reach the region (i.e., wind generation using Colstrip transmission) for the 2026 study year, as summarized in **Figure 4** in Section 3.2. This study assumes the cost of those transmission facilities are sunk, and the network load in the region will pay for their costs and thus, utilities in the region will have access to their capacity. That capacity could be used, potentially, to help facilitate delivery of some of the resources in the replacement portfolios.

Second, the reliability assessment indicated minimal new transmission assets to facilitate the replacement portfolios. The identified upgrades included less than 10 miles of new 115 kV line and substation work with a total cost of $11 million and an annual revenue requirement of roughly $750,000. Since the upgrade was identified in all of the replacement portfolios, this annualized cost was added to all portfolios. However, the cost of this line is insignificant compared to the annual fixed and operational costs of the replacement portfolios. The cost estimate was derived using the Transmission Expansion Planning Policy Committee (TEPPC) Transmission Capital Cost estimator.[36]

5.5 Single-Year Change in System Operating Costs

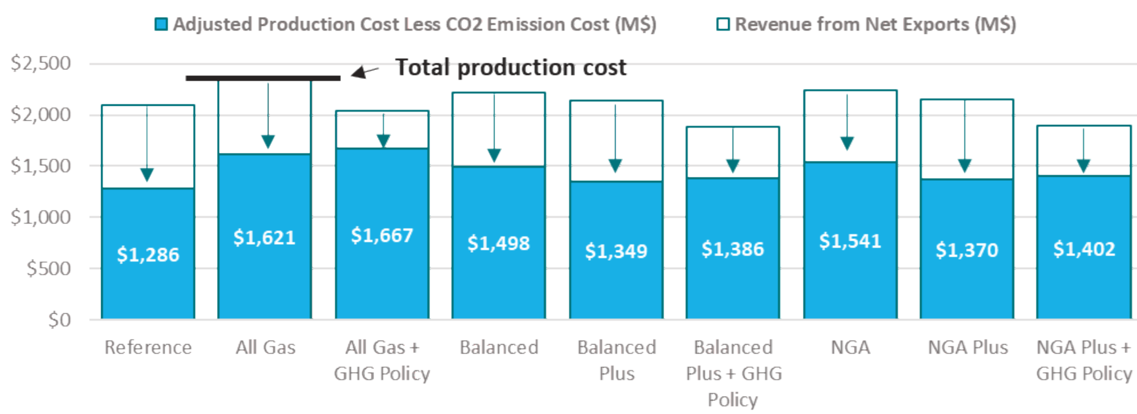
The total operational cost to serve load in the Northwest region was approximated as the adjusted production cost of the region calculated from the Reference Case and replacement portfolios' production cost simulations. The method is outlined in Section 2.3. Generally, the

[36] Key assumptions in calculating the capital cost and revenue requirement of the transmission project: 7 miles of 115 kV transmission line reconductoring, terrain multiplier of 1.5, ACSR conductor, lattice structure, no right-of-way costs included, three new line positions at existing substations, other various substation work, includes AFUDC, 40-year economic life, O&M, property tax, insurance, 21% Federal tax rate, 100% debt financed (assuming a combination of Treasury Notes and Bonds, consistent with public power financing by BPA), 30 year debt period at 5% interest rate.

operational cost of the regional system is characterized as the operational cost of all of the Northwest region generation less revenue from exports sold to neighboring regions.[37]

Figure 18 shows the resulting adjusted production cost for each case and how it compares with the total production cost. As shown, revenue from net exports decreases the total production cost of the Northwest system to arrive at the adjusted production cost. These results were previously discussed in depth in Section 4.3, and this figure is identical to **Figure 12**.

Figure 18: Adjusted Production Cost by Portfolio



The single-year change in system operating costs for each replacement portfolio was the adjusted production cost of that portfolio less that of the Reference Case, as shown in **Table 13.** The NGA and Balanced replacement portfolios cause Northwest operating costs to increase by 16–20% as energy is made up with purchases, new generation, and decreases in exports. The "Plus" portfolios have more energy and thus impact the region's operating costs by a relatively lower 5–7%.

[37] When calculating adjusted production cost for portfolios that included the GHG policy modeling, the study assumes a revenue neutral GHG reduction program, meaning that revenues collected under the carbon price policy are returned to customers and thus, these operational costs exclude the carbon costs associated with emissions but include the cost of shifting the merit order dispatch of thermal generation in response to the explicit carbon price.

Table 13: Change in Adjusted Production Cost from Reference Case to Replacement Portfolios

Portfolio	Adjusted Production Cost (M$)	Δ (M$)	Δ (%)
Reference	$1,286	---	---
All Gas	$1,621	$335	26%
All Gas + GHG	$1,667	$381	30%
Balanced	$1,498	$212	16%
Balanced Plus	$1,349	$63	5%
Balanced Plus + GHG	$1,386	$100	8%
NGA	$1,541	$255	20%
NGA Plus	$1,370	$84	7%
NGA Plus + GHG	$1,402	$116	9%

5.6 Cost Sensitivities

A cost sensitivity was performed to test how the total replacement portfolio costs might change if certain technologies' capital costs are reduced further than what is assumed in this study. A summary of the cost sensitivities is provided in **Table 14**.

The sensitivity assumed energy efficiency costs were reduced 20% relative to Base Costs, applicable only in the NGA Plus portfolio where the full technical achievable potential of energy efficiency was deployed. The intent was to capture any technological advances or new conservation that may bring down the future costs of energy efficiency resources.

The sensitivity also considered wind, solar, and battery storage cost reductions of 20%, 30%, and 40%, respectively, with the intent of capturing the relative maturity of the technologies and any deeper cost reductions that might be realized in the future.

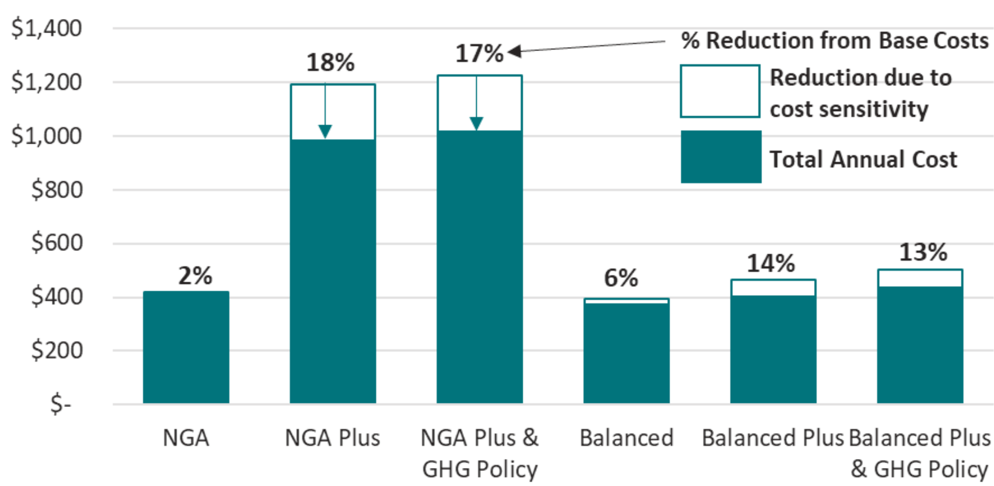
Table 14: Summary of Resource Installed Cost Changes

Summary of Resource Installed Cost Changes (2026 installation, 2016$)			
Resource Type	**Base Cost**	**Reduction (%)**	**Low Cost Sensitivity**
Wind (Montana)	$1,639/kW	**20%**	$1,311/kW
Solar, Single-axis Tracking (Idaho)	$1,400/kW	**30%**	$980/kW
Li-ion Battery (4-hr)	$753/kW	**40%**	$452/kW
Technical Achievable Potential Energy Efficiency	$132/MWh	**20%**	$106/MWh

Based on these assumptions, the low-cost sensitivity has a small effect on total costs, with the exception of the NGA Plus alternative. The NGA Plus portfolio included all technically achievable energy efficiency and when the cost for that conservation was decreased, the savings were pronounced: a 17–18% reduction in total costs.

For the Balanced Portfolio, since fixed capital costs make up only a portion of the total portfolio costs the 20-30% reductions in capital costs translated to 6–14% in total cost reduction. A summary of the total annual cost of replacement portfolios under the low-cost sensitivity is provided in **Figure 19**.

Figure 19: Total Annual Cost of Replacement Portfolios for Cost Sensitivities ($M/year), and Cost Reduction (%) from Sensitivity



5.7 Estimated Bill Metric

When evaluating the implications of potential resource strategies for the Northwest region, the NWPCC calculates representative residential average monthly bills. This calculation of a typical monthly residential bill is based on the total revenue requirement for the region and relies on estimates regarding the residential sector's share of the system annual revenue requirement and forecasts for the number of households in the region.[v,38] It considers the ongoing costs of the existing system, as well as incremental costs added in any given scenario. The purpose of this calculation is not to anticipate, in any precise fashion, what monthly bills might be. Rather, the purpose is to assess how changes to the regional revenue requirement look when those costs are spread across the households in the region. For this reason, this study refers to the impacts to monthly bills as a *metric*—one of many used in this analysis to help understand the relative impact of the replacement portfolios.

The revenue requirement and residential bill impacts of the replacement portfolios in this study are benchmarked against the 7th Plan, since the Reference Case and the study footprint were aligned with the 7th Plan developed by the NWPCC. Since utility customer rate analysis is more complex than the analysis performed by the NWPCC or this study, the metric is most useful on a comparative basis, focusing on how the incremental costs of a given portfolio (compared to the Reference Case) directionally impact residential ratepayers and how these costs compare to the total ongoing costs of the system.

The results from the analysis are summarized in **Table 15**.

[38] The NWPCC assumes that 47% of the region's annual revenue requirement is assigned to the residential customers. The NWPCC workpapers from the 7th Power Plan also include assumptions regarding the number of households in the region. These data were used to perform the rate impact analysis for this study. The analysis also assumes that the portfolio costs to replace the LSR Dams are incurred in 2026 and begin to impact residential bills that same year (and years beyond that based on the annualized cost of the portfolios). The 20-year levelization period was selected based on NWPCC assumptions. For this portion of the analysis, the study assumes a 4% discount rate, consistent with the 7th Plan. For the sensitivities investigating the GHG Policy impacts, the revenues from the modeled carbon tax are not included.

Table 15: Estimated Impacts to the Typical Residential Monthly Bill Metric

Replacement Portfolio	Change in Levelized Residential Electric Bill ($) ($/month/household)	Change in Residential Electric Bill (%)
Reference Case	---	---
All Gas	$1.47	1.4%
All Gas + GHG Policy	$1.60	1.6%
NGA	$1.16	1.1%
NGA Plus	$3.28	3.2%
NGA Plus + GHG Policy	$3.37	3.3%
Balanced	$1.09	1.1%
Balanced Plus	$1.28	1.2%
Balanced Plus + GHG Policy	$1.38	1.3%

The results show that, on a levelized basis spanning the approaching 20 years, the average residential monthly bill *metric* increases between $1.09 to $3.37 per month as a result of the costs associated with implementing the replacement portfolios considered in this study. This reflects a 1–3% increase in monthly bills for the typical residential customer over the approaching 20-year period studied and for which NWPCC was available (2016-2036).

Consistent with the revenue requirement analysis results, the Balanced portfolio causes the lowest cost impact, at $1.09 per month increase to the residential bill metric. The Balanced Plus portfolio costs 19 cents per month per household more than the Balanced portfolio and has the added benefit of mitigating almost all of the GHG emission impacts of removing the LSR Dams. The GHG policy sensitivity, when applied to the Balanced Plus portfolio, causes an additional increase of 10 cents per month per household, which results in a 1.3% increase from the typical monthly bill metric calculated for the Reference Case.[39]

[39] Since this analysis captures 20 years of forecasted power system costs and the LSR Dam replacement costs do not start until the 10th year of that period (and would continue for some time thereafter), a sensitivity looking at the impact of levelizing the monthly bill metric on a 30-year basis was performed. This analysis assumed that Reference Case revenue requirements would continue at the 20-year compound annual growth rate for an additional 10 years, and that the annualized cost of the replacement portfolios would continue to represent additive costs to the region out past the 20-year mark. On average across the portfolios (excluding the NGA portfolios), this approach increased the change in levelized average residential bill metric by about 0.5%, or roughly 43 cents per month. The most economic portfolios would still be in the $1–$2/month range even if the levelization period for the metric was extended to 30 years.

These costs, as represented by these metrics, may appear low. The main driver for this is the fact that the region's 2026 revenue requirement is almost $16 billion and the incremental cost of the portfolios conceptualized in this study are relatively small as a percentage of that ongoing cost. The cost of today's system and the cost for the system in the future including the assumptions contained in the Reference Case is much larger than the cost of the replacement portfolios themselves. This magnitude issue impacts the typical bill metric analysis. Importantly, this study recognizes the importance of developing a more complete understanding of the rate impacts associated with LSR Dam removal and replacement. This will require a comprehensive accounting of all costs and benefits associated with the investment and detailed ratepayer impact analysis—an analysis that is outside the scope of this study but one the Northwest region should consider taking on in the future.

6.0 FINDINGS

The study was designed to answer four core questions related to the power system impacts of removing the LSR Dams:

1. Can an energy portfolio replace the LSR Dams without compromising the region's reliability and resource adequacy while minimizing or eliminating increases to regional GHG emissions?
2. If replacement using clean resources is not possible, what incremental infrastructure (e.g., additional transmission, substation equipment, gas-fired resources) might be required to fill the gap?
3. At what approximate cost might the replacement portfolios be achieved?
4. What additional value might the replacement portfolios offer?

The decision about whether or not to retire generation resources is highly complex and involves factors beyond the scope of this study. Because of this, this study does not seek to provide conclusions surrounding: (1) if the LSR Dams should be removed; (2) the identification of an optimal plan for their replacement; and (3) a comprehensive assessment of the benefits, costs, and ratepayer impacts of taking these actions. Instead, the study seeks to investigate the technical feasibility and regional impacts of replacing the LSR Dams with a clean energy portfolio, and in doing so demonstrates that integrated evaluations of replacement options can be conducted with technical rigor by relying on existing regional planning tools and data. So, while this assessment doesn't purport to have found *the optimal answer* on this complicated issue, by answering the core questions that drove the analysis, it seeks to provide the region with new and useful information about possible solutions that may not have been considered previously.

Table 16 presents a summary of key metrics used in the analysis, all of which help to form the basis to the responses to the core study questions.

Table 16: Summary of Key Findings

	Replacement Portfolios					GHG Reduction Policy Sensitivity		
	NGA	NGA *Plus*	Balanced	Balanced *Plus*	All Gas	NGA *Plus*	Balanced *Plus*	All Gas
Resource Adequacy (Δ LOLP%)	-1.1%	-2.1%	-0.4%	-1.3%	-0.3%	-2.1%	-1.3%	-0.3%
Δ Reliability	One reliability issue identified in all replacement portfolios. The violation was mitigated by transmission upgrade (and cost captured).							
Δ GHG Regional Emissions (%)	+5%	+2%	+5%	+1%	+8%	0%	-2%	+5%
Δ Total Annual Cost ($M/year)	$421	$1,191	$396	$464	$535	$1,224	$501	$581
Δ Region Revenue Requirement in 2026 (%)	+2.7%	+7.6%	+2.5%	+3.0%	+3.4%	+7.6%	3.21%	+3.7%
Δ Levelized Monthly Bill Metric ($/Month)	$1.16	$3.28	$1.09	$1.28	$1.47	$3.37	$1.38	$1.60

Below are key findings and answers the core questions this study was designed to address.

1. **A portfolio of clean energy resources, including solar, wind, energy efficiency, demand response, and energy storage, can effectively replace the most critical power attributes the four LSR Dams contribute to the Northwest region.** This finding is based on study results showing that none of the replacement portfolios revealed major regional reliability issues and regional resource adequacy was improved compared with the Reference Case. Based on the assumptions used to develop the portfolios, the approximate magnitude of clean resources required for this replacement, such as energy efficiency and renewable power, are or will be reasonably available within the region.

Thus, **dam replacement using clean resources is achievable from both a technical planning regional reliability/adequacy standpoint, and from a resources availability standpoint.**

2. **The total costs of the clean energy replacement portfolios, particularly the balanced portfolios that include both new wind/solar and demand-side measures, are relatively small compared to the total projected costs of the Northwest power system.** The cost of these clean energy portfolios represents a 2–3% increase in the regional revenue requirement starting in 2026. This accounts for the cost of the incremental resource additions, the change in cost of system operation (including increased market purchases) under median conditions, and the cost of new transmission to address minor reliability issues.

3. Study results indicate that **if clean replacement portfolios are implemented in conjunction with GHG reduction policies, substantive net reductions in emissions are possible.** The magnitude of the emission reductions is heavily dependent on the details of the GHG reduction policy. Absent such a policy, a balanced portfolio of resources has a minor impact on greenhouse gas emissions (about 1% increase) compared to expected emissions with the LSR Dams in service. An optimal replacement portfolio could mitigate these emissions further, but such a portfolio was not considered in this analysis and could be the subject of future work.

4. In terms of transmission reliability, with one minor exception, **the clean replacement portfolios met reliability criteria under peak summer and winter conditions and did not create any new reliability issues.** The minor exception, an overloaded 115 kV line identified in *all portfolios* under the peak summer loading condition, was mitigated through an assumed transmission upgrade that had minor cost impacts on the total cost of the portfolios ($10 million total, with a $750,000 per year revenue requirement). After incorporating the upgrade, all replacement portfolios met NERC/WECC reliability criteria for both steady-state and transient stability system performance.

5. The **replacement portfolios provided the region with enhanced resource adequacy compared to the LSR Dams.** That means that in total, the portfolios (compared to the Reference Case) provide greater capacity value and reduce the likelihood of the region not having sufficient power to meet peak demands. Since the replacement portfolios achieved this result without any new conventional resources, the assessment demonstrates that **new gas-fired generation is not required to address regional capacity needs** that arise when the LSR Dams are removed.

   There are potentially other benefits provided by some of the replacement portfolios that are not quantified in this study. For example, while the replacement portfolios are largely weather dependent, the Balanced portfolios would help to diversify the Northwest's power system by relying less on hydropower and more on wind and solar, which could be more valuable in low and very high hydro conditions (which were not considered in cost analysis). Additionally, the NGA portfolios modeled a 100 MW battery storage facility in the Portland area, which could provide support to the South of Allston transmission constraint—the benefits of this were not considered.

6. While this study provides a significant contribution to the ongoing analyses around potential removal of the LSR Dams, there are a number of areas which may warrant additional study:

   a. If the LSR Dams are to be replaced, the portfolio should be identified through robust optimization and scenario analysis – an integrated resource planning-like approach. **The LSR Dam replacement portfolios in this analysis are meant to demonstrate what could be possible, but do not represent a least-cost, optimized portfolio.** An effort by the region on this front may lead to more cost-effective and environmentally efficient outcomes than what was identified and considered in this analysis. For example, the study did not consider the cost and performance tradeoffs of energy efficiency and demand response supply curves with new wind or solar. It also did not consider the incremental cost associated with eliminating the final 1% of emission reductions identified in the Balanced

Plus portfolio. Given the low GHG abatement cost identified in the iterations of the portfolios (about $30/ton), an optimization effort could eliminate this small increase in emissions for a relatively low cost.

b. To fully assess the benefits and costs associated with dam removal and replacement, **future studies should gather and incorporate detailed cost estimates surrounding planned, long-term capital and maintenance costs that could be avoided if the dams were removed and replaced, the cost of fish programs that could potentially be avoided, as well as any incremental costs required to breach the dams.** Benefit-cost analysis was not the purpose of this study and these costs were not considered, but they will be critical to future benefit-cost analyses as the planned costs associated with the continued operation of the LSR Dams represent a benefit when avoided, which would make the replacement portfolios in this study relatively less costly. Similarly, the costs to breach the dams represent an incremental cost, which would make the replacement portfolios more expensive.

c. Future assessments could **consider the LSR Dam replacement issue in combination with other evolving policy, climate, and economic factors.** For example, this study did not look at how low water years might impact costs or emissions in the region.

While high and low water conditions were considered in the resource adequacy portion of the assessment, they were not considered in the operational cost or emissions analysis. If climate conditions change the magnitude or timing of runoff, the value of the LSR Dams could be reduced given their run-of-river operational status. As such, a comprehensive optimization analysis could capture these potential effects and better assign, probabilistically, value to the LSR Dams under a wider range of operational futures. The NWPCC is well equipped for this type of detailed assessment, and this is just one example of why it is important to consider the value of the LSR Dams and their replacement options under a wide range of future conditions.

d. The impacts of a GHG reduction policy needs additional investigation. For instance, the GHG policy analysis in this study showed that reductions from these policies could be much larger than any impact associated with certain replacement portfolios. This is primarily due to the replacement of existing coal resources with new gas resources when a cost is assigned to emissions. The impact of a GHG policy in this study suggests that **an optimal "portfolio" might be one partly made up of physical resources and partly made up of energy policy.**

e. The study used conservative assumptions with regard to resource adequacy and capital costs. Relaxing these assumptions should be considered. For example, is it necessary to replace all of the LSR Dams with firm resources, or can the region rely more on market purchases from neighbors under certain conditions?

f. The study did not consider the impacts of high renewable penetration levels in neighboring states, such as California, nor did it consider the implications of changes to natural gas prices, load forecast, and other key variables.

g. The residential bill metric analysis was conducted at a regional level and more granular impacts should be considered to better assess how the cost implications of the replacement portfolios could impact customers.

h. The transmission reliability analysis was robust and revealed that clean energy portfolios do not compromise the reliability of the regional system during peak winter and summer conditions. However, reliability is not the only metric critical to system operation and planning. For instance, an assessment to evaluate the impact, if any, that the removal and replacement of the LSR Dams might have on path transfer capabilities would be important to identify. With this information in hand, any impacts to transfer capability can be weighed against the value of that transfer capability and the broader costs and benefits of the decision.

The study does not provide any specific recommendations about the exact nature of any potential replacement portfolio, nor does it support or recommend dam removal or claim to have considered the necessary benefits and costs that would weigh on such a decision. It does, however, **make use of a modeling framework that was effective** at evaluating this complicated issue from critical perspectives while also **providing findings designed to advance regional dialog on the technical feasibility and impacts of replacing the LSR Dams with clean energy portfolios**.

7.0 APPENDICES

Appendix A: Forecasted Value of LSR Dams

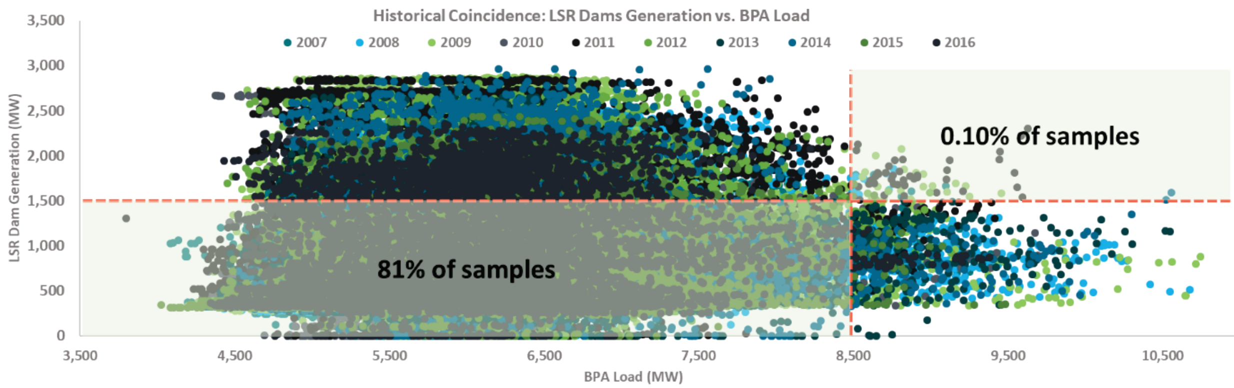
One of the goals of the study was to build a more robust understanding of exactly where and how the LSR Dams provide value to the power system. This value, on a going-forward basis, is what the replacement portfolios sought to replace. Several capacity, energy, flexibility, and stability value streams were considered in varying degrees and are discussed in this section.

Capacity Value

Due to the abundance of hydropower in the Northwest, the region is often considered to be energy-long and capacity deficient—at least from a planning perspective. This does not mean the region does not have energy needs. Rather, it means that capacity issues are usually the first to arise and are often the binding constraint in planning exercises. The NWPCC came to this conclusion in its 7th Plan and, as a result, this study first focused on how removing the LSR Dams could impact the region from a resource adequacy perspective.

Before valuing the LSR Dams based on their impact to adequacy metrics, it is helpful to understand, historically, how the LSR Dams operate and when their power production occurs relative to system peak. Compared to many dams in the Northwest, the LSR Dams all have relatively little storage. The LSR Dams generally operate as "run of river" hydro resources, meaning they have some storage capability but generate roughly based on the flow of their tributary—the Lower Snake River. Consequently, the LSR Dams' power output is seasonal and weather dependent. This seasonal output sometimes does not align with the periods when the power is needed the most. To demonstrate this effect, the total generation from the LSR Dams is plotted against total BPA load over a recent 10-year period in **Figure A-1**. Each point in the chart is a single hour of operation during that 10-year period.

Figure A-1: Historic LSR Dams' Generation and BPA Loads



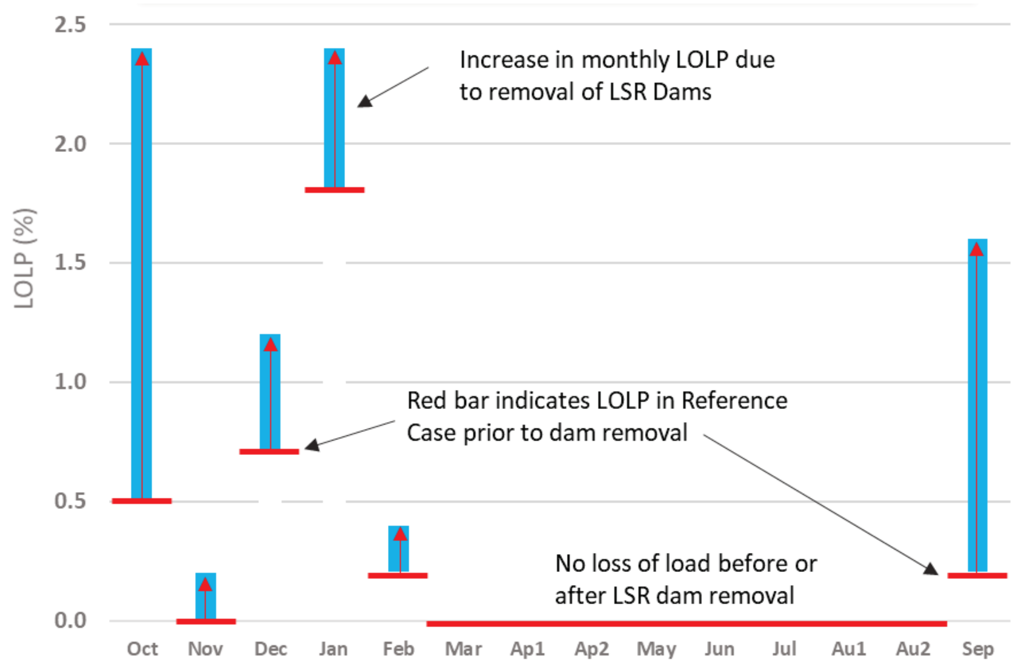
As shown, the LSR Dams provide most of their power when BPA load is at or below about 8,500 MW, which is about 80% of BPA's peak load. 81% of the hours in the 10-year period were situations where the dams generate less than 1,500 MW and BPA load is less than 8,500 MW. It is much less likely that the LSR Dams generate more than 1,500 MW when BPA is at higher load levels. As shown, only 0.10% of hours were hours in which BPA's load was above 8,500 MW and LSR Dam generation was above 1,500 MW. This data is based on U.S. Army Corps of Engineers Northwestern Division Columbia River Basin Water Management historical data.[w]

While the summary above is not technically robust compared to detailed planning simulations, it does help to explain some of the findings from the more technical GENESYS modeling, which looked at the impact of removing the LSR Dams to system adequacy. The Reference Case annual LOLP increases from 3.4% to 8% when the LSR Dams are removed (for the 10-year 2026 timeframe). This increase causes the region to be capacity deficient based on the NWPCC adequacy standard of 5% LOLP.

This finding is also true from a monthly perspective, as shown in **Figure A-2**.[40] Consistent with the generation versus load analysis above, the LSR Dams do provide some capacity value during peak conditions in the winter, but that value is significantly less than what they provide in September and October.[41]

[40] Note that consistent with the NWPCC planning methods, all monthly charts break up April and August into two months for enhanced granularity in hydro transition periods.
[41] The Reference Case was not resource deficient in the summer months and there were no loss-of-load events.

Figure A-2: Monthly LOLP (%) Change from Removing LSR Dams



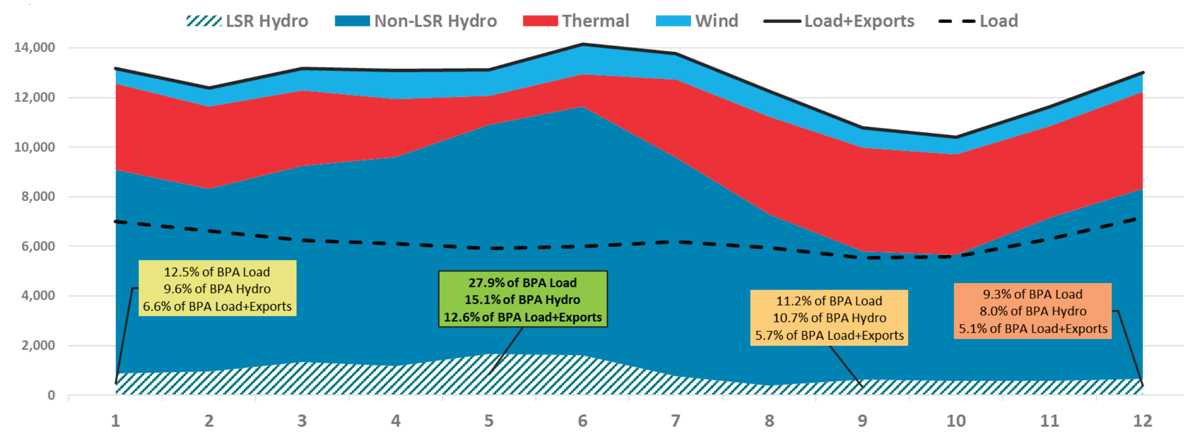
These findings suggest that in order for a replacement portfolio to provide "like-for-like" value, it must offer seasonally targeted adequacy value (in the fall and winter), while still maintaining an annual LOLP of 3.4%.

Energy Value

The energy value of the LSR Dams is also seasonal. Most of their energy output is in the spring. During March, April, May, and June the LSR Dams provide roughly 1,441 aMW of power output. By contrast, from July through February the LSR Dams generate roughly 676 aMW—more than 50% less than during the spring period.

Figure A-3 shows how these generation levels match up with BPA's other resources and total power needs, including BPA loads as well as exports to other power areas.

Figure A-3: BPA Average Monthly Generation (aMW) from 2007-2015



Other Areas of Value

The LSR Dams' value in contributing to system flexibility and stability was not quantified directly since satisfying the various system flexibility and stability requirements was part of the GENESYS, power flow, and production cost simulations.

Operating Reserves: Contingency Reserves

Contingency reserves refer to actions which can be taken to maintain system balance during the unplanned loss of a large generator or transmission line. For example, in the Northwest they are set by the Northwest Power Pool (NWPP), and the NWPP requires utilities to carry contingency reserves equal to 3% of load plus 3% of generation or equal to the magnitude of the single largest system component failure, whichever is larger. At least half of these reserves must be supplied as spinning resources (which are synchronized with the grid and able to respond quickly).

The GENESYS model retained the assumptions from the 7th Plan. The simulation keeps track of any hour in which contingency reserves cannot be maintained. Failure to maintain contingency reserves is treated as a curtailment.

The GridView™ model retained the assumptions from the WECC Common Case. The "spinning" portion was assumed to be 50% of the total contingency reserve requirement (1.5% of load plus 1.5% of generation) and was explicitly modeled.

Operating Reserves: Regulation and Balancing (Load Following) Reserves

Regulation and load following reserves refer to actions taken in the minute-to-minute and 10-minute-to-hours timeframes (respectively) to respond to requests for up and down movements of electric supply and demand.

The GENESYS model retained the assumptions from the 7th Plan:[x]

- The Council does not include any regulation or scheduling operations in its planning process because they are not relevant to developing long-term resource acquisition strategies.
- Balancing reserves are assumed to be provided by both the hydroelectric system and thermal resources.
- Balancing reserves carried by the hydroelectric system are incorporated as constraints in the NWPCC TRAPEZOIDAL ("TRAP") model, which assesses hydroelectric peaking capability. The GENESYS simulation then uses each hydro's sustained peaking capability as determined by TRAP.

The GridView™ model retained the assumptions from the WECC Common Case, which included hourly regulation and load following reserve shapes created by ABB utilizing the "PNNL Methodology." [y]

System Reliability and Stability

System reliability and stability values include a generator's contribution to reactive support, voltage control or regulation, and frequency or governor response. The LSR Dams' individual contribution(s) to meeting the various transmission system planning performance requirements were not directly quantified. Instead, the Reference Case and replacement portfolios were all tested against the same reliability requirements such that whatever gap in system stability or reliability created by removing the LSR Dams was sufficiently replaced by the replacement portfolios.

Appendix B: Levelized Fixed Cost Methodologies

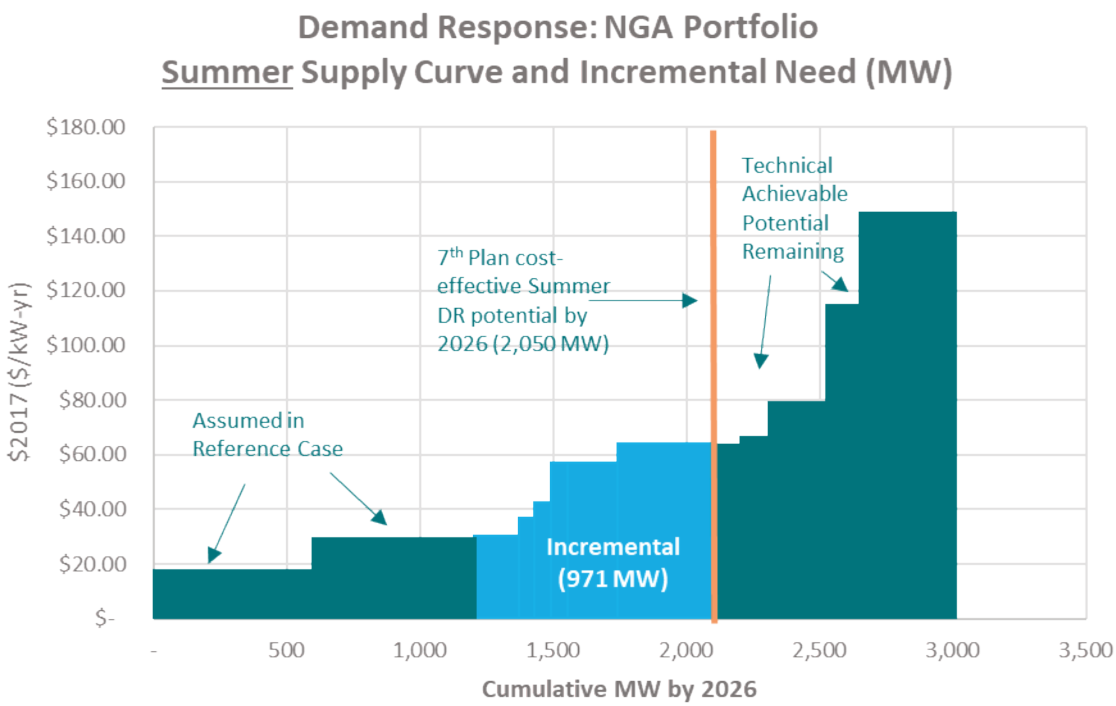
Additional details regarding the methodologies for determining levelized fixed costs of resources used to build the replacement portfolios are provided below. Methodologies for levelized fixed costs are provided for demand response, energy efficiency, renewables and storage, combined cycle and reciprocating engine gas-fired plant, and the capacity contract.

Demand Response

The NWPCC's 7th Plan's supply curve and associated prices for demand response programs with technical potential formed the basis for determining both the amount of additional MWs of demand response and the levelized fixed cost. The NGA and Balanced portfolios' summer demand response resource additions are shown in **Figure B-1** and **Figure B-2**, respectively. [42], [z]

[42] The NGA Plus and Balanced Plus portfolios assumed the same level of demand response resources and uses the same levelized fixed cost assumptions as the NGA and Balanced portfolios, respectively.

Figure B-1: Supply Curve and Price for Demand Response in the NGA Portfolio – Summer and Winter



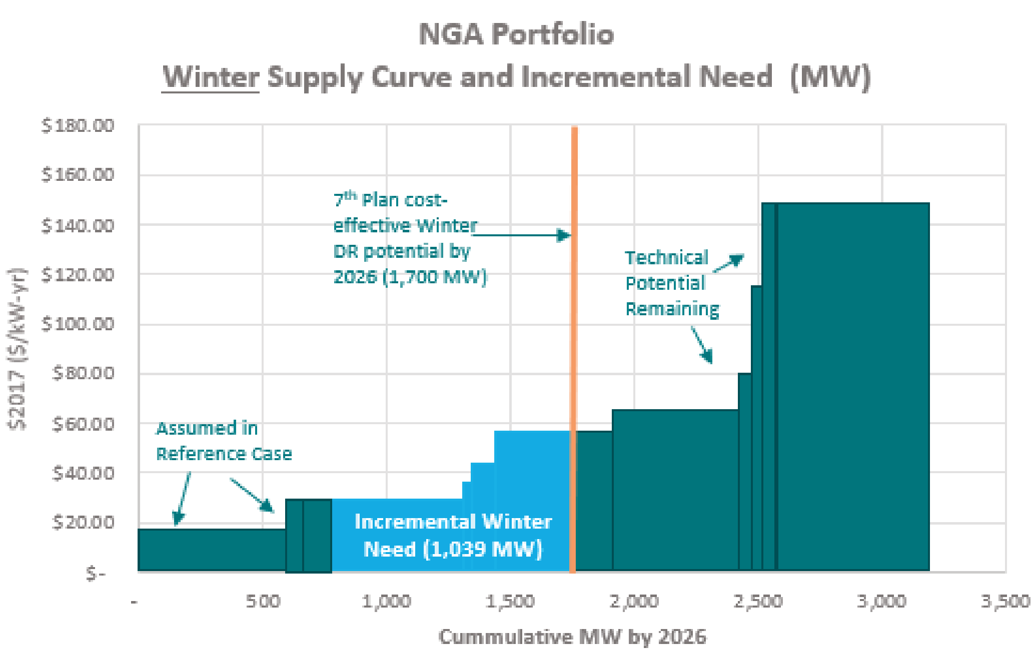
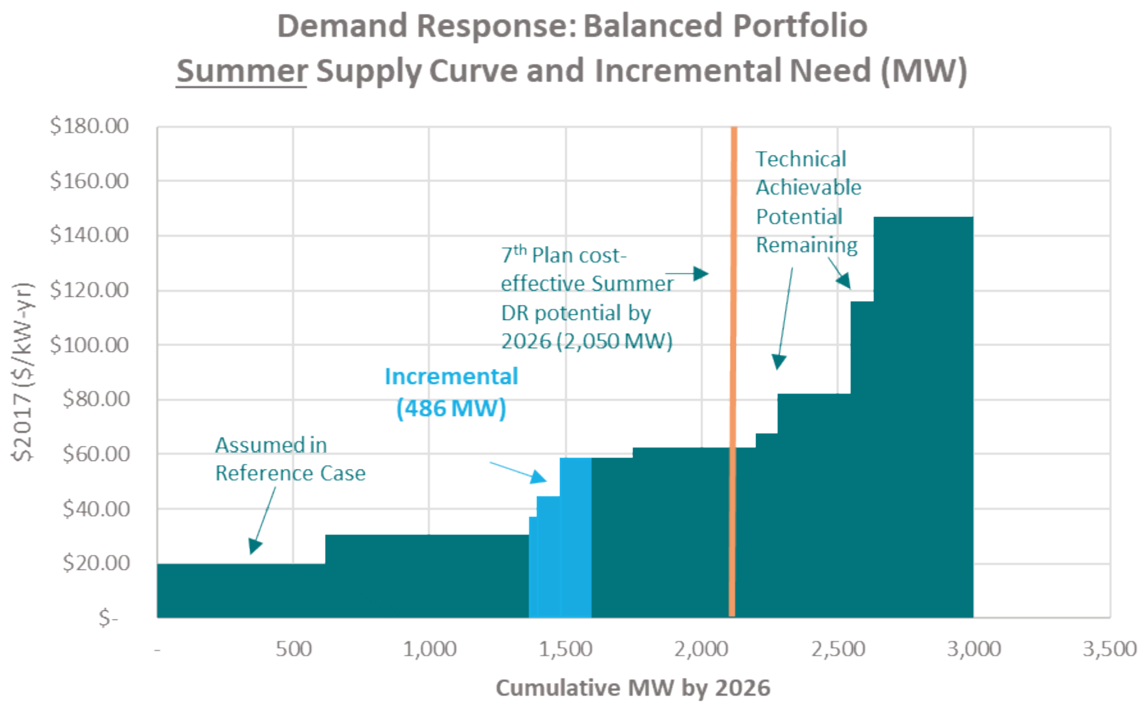
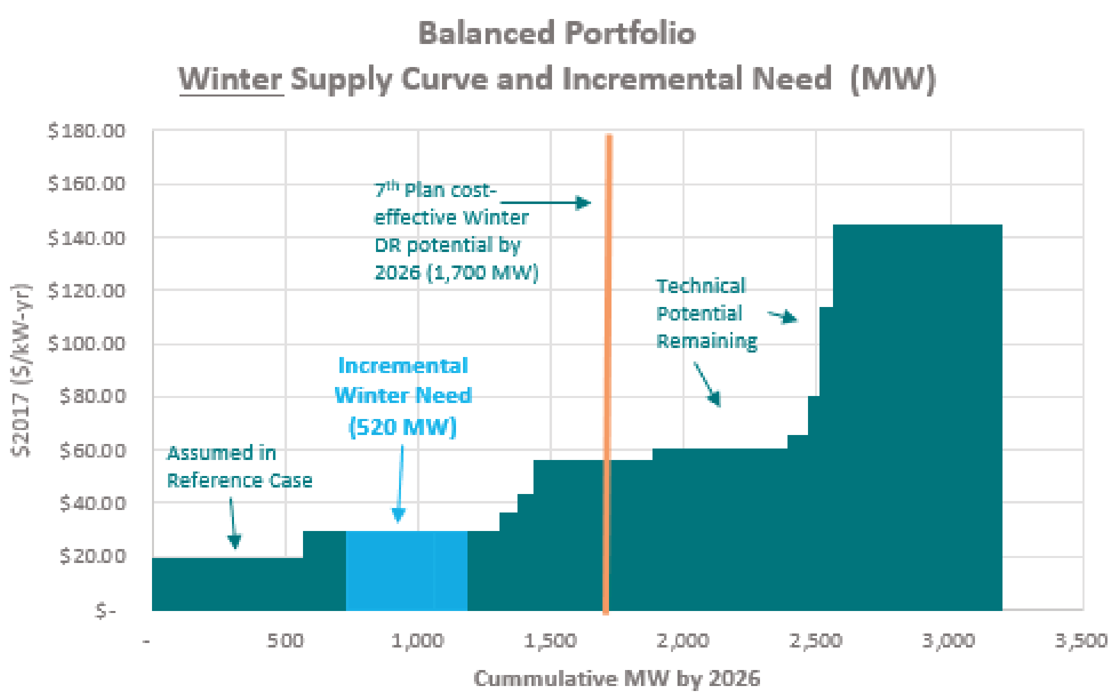


Figure B-2: Supply Curve and Price for Demand Response in the Balanced Portfolio – Summer and Winter





The cost analysis utilized the levelized cost of the programs provided as a Technical Appendix to the 7th Plan, scaled to 2017 dollars.[aa] The analysis distinguished between resources that provided both winter and summer capacity to ensure that there was no double-counting from a cost perspective. Any demand response program that was assumed in the Reference Case was considered "sunk" and did not contribute to the fixed cost of the incremental resources needed to build the portfolio. The weighted-average cost for the incremental demand response additions was calculated based on the specific programs that were assumed in that portfolio.

Energy Efficiency

The NWPCC's 7th Plan's supply curve and associated prices for energy efficiency resources with technical potential formed the basis for determining both the amount of additional aMWs of energy efficiency and the levelized fixed cost. The NGA and Balanced portfolios' energy resource additions are shown in **Figure B-3** and **Figure B-4**, respectively. The NGA Plus portfolio assumed that all of the efficiency with technical potential was adopted, as indicated by the right-pointing, blue arrow in **Figure B-3**.

Figure B-3: Supply Curve and Price for Energy Efficiency in the NGA Portfolio

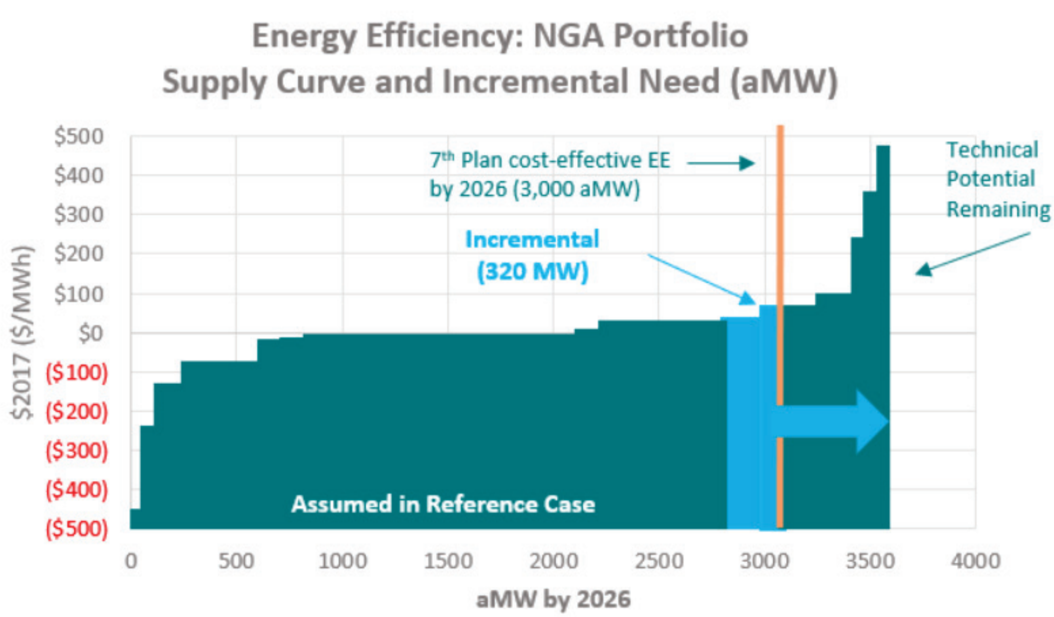
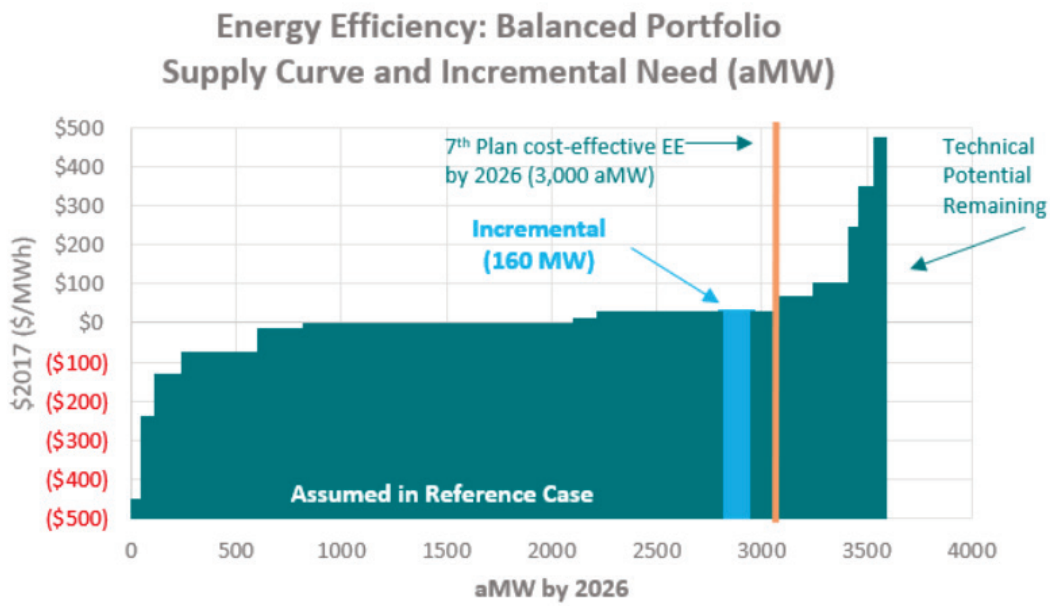


Figure B-4: Supply Curve and Price for Energy Efficiency in the Balanced Portfolio



The cost analysis utilized the levelized cost of the efficiency measures provided in the 7th Plan, scaled to 2017 dollars.[bb] Any efficiency measures that were assumed in the Reference Case were considered "sunk" and did not contribute to the fixed cost of the incremental resources needed to build the portfolio. The weighted-average cost for the incremental energy efficiency additions was calculated based on the specific measures that were needed in each portfolio.

Renewables and Storage

The NWPCC's 7th Plan included capital cost estimates for wind, solar, and battery storage that no longer reflect today's rapidly changing market. Therefore, the study relied on existing industry-vetted cost estimates to determine a levelized fixed cost for wind, solar, and battery storage costs with learning curves to account for future cost declines. **Figure B-5, Figure B-6,** and **Figure B-7** illustrate the range of capital cost estimates reviewed for wind, solar, and battery storage, and the final cost in $/kW that was selected for the study.[43]

[43] Cost estimate figures were all adjusted for 2016 dollars to match the parameters of the WECC pro forma model.

Figure B-5: Industry Estimates for Wind Capital Cost[44]

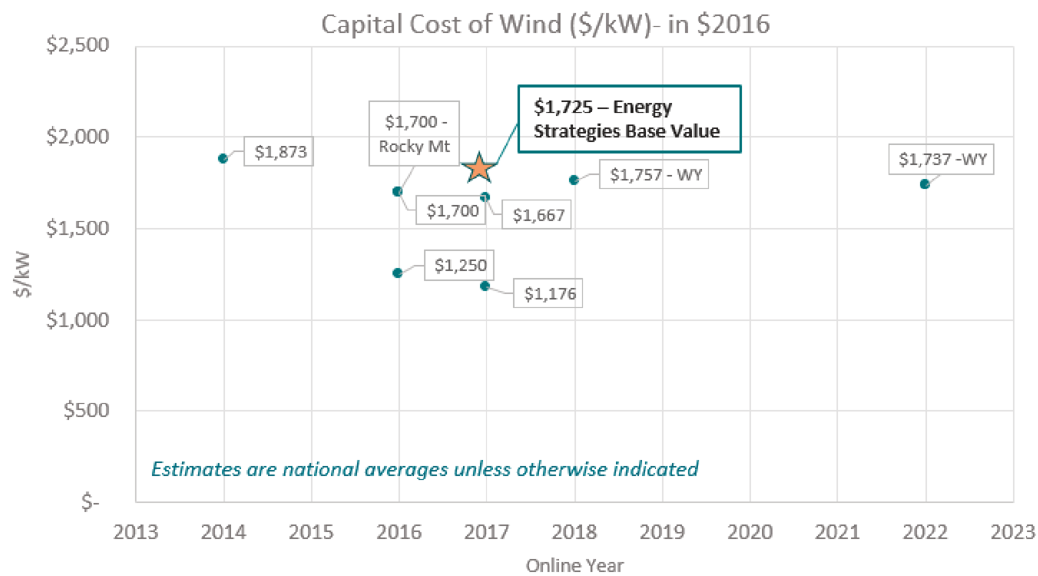
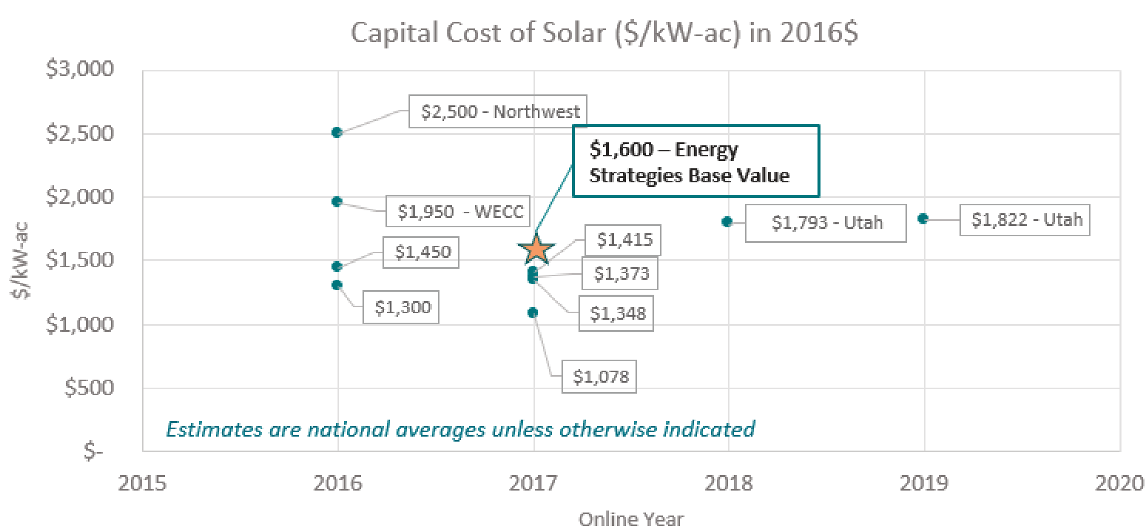


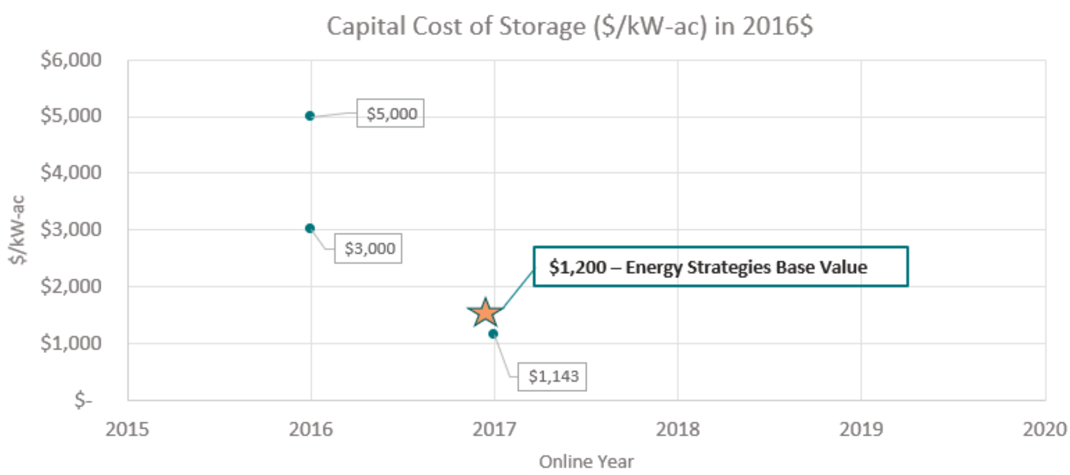
Figure B-6: Industry Estimates for Solar Capital Cost[45]



[44] Sources used to derive the industry estimates for wind include: Lazard v10.0 (high-end and low-end), Lazard v11.0 (high-end and low-end), NREL/LBNL in "Forecasting Wind Energy Costs & Drivers", RESOLVE IRP Input Assumptions from May 2017 (from Black & Veatch), E3 estimates prepared for WECC in January 2017, PacifiCorp IRP.

[45] Sources used to derive the industry estimates for solar include: Lazard v10.0 (high-end and low-end), Lazard v11.0 (high-end and low-end), NREL Solar PV System Cost Benchmark (August, 2017), RESOLVE IRP Input Assumptions (from Black & Veatch), LBNL Utility Scale Solar 2016 Report, E3 estimates prepared for WECC in January 2017, Idaho Power IRP, PacifiCorp IRP.

Figure B-7: Industry Estimates for Battery Storage Capital Cost[46]



The cost analysis utilized the most recent WECC capital cost pro forma model which calculated the levelized fixed cost of each resource based on a user-defined capital cost as well as other input assumptions.[cc] Key assumptions for the cost analysis used in this study are highlighted in **Table B-1**, below, including a 21% federal corporate tax rate to reflect recent tax law changes.[47] The learning curve reduction from the 2017 installation to the assumed 2026 installation date was assumed to be 12.5% for solar and 5% for wind.

Table B-1: Key Assumptions for Solar, Wind and Battery Fixed Cost Calculations

Key Assumptions - Wind	
Economic life	20 yrs
PTC Value in 2026	0%
Corporate Tax Rate	21%

Key Assumptions - Storage	
Technology	4-hour Li-Ion Battery
Economic life	15 yrs
Corporate Tax Rate	21%

Key Assumptions - Solar	
Technology	Single-axis tracking PV
Inverter Load Ratio	1.3
Economic life	25 yrs
ITC Value in 2026	10%
Corporate Tax Rate	21%

[46] Source used to derive the industry estimates for battery storage include: RESOLVE IRP Input Assumptions, E3 estimates prepared for WECC in January 2017 (high-end and low-end), Lazard Levelized Cost of Storage V3 (November, 2017)

[47] The federal corporate tax rate was lowered from 35% to 21% effective in 2018, as part of the Tax Cuts and Jobs Act, which was signed into law in December 2017.

Gas: Combined Cycle and Reciprocating Engine

To calculate the cost of gas-fired generation resource additions, this study leveraged the NWPCC 7th Plan's 2025 levelized fixed costs for dry cooled combined cycle combustion turbine (CCCT) and reciprocating engines on the eastern side of the planning region.[dd,ee] The levelized costs were adjusted for 2017 dollars to maintain consistency with other estimated resource addition fixed costs.

Capacity Contract

The NGA and NGA Plus portfolios included a 100 MW capacity contract for winter market purchases necessary to maintain resource adequacy levels in these replacement portfolios. The assumed cost for a capacity contract is $30/kW-year, and this is based on the California Independent System Operator (CAISO) NP-15 System Resource Adequacy contracted prices for 2017 of $2.50/kW-month, which were based on data from the California Public Utilities Commission 2016 Resource Adequacy Report.[ff]

Appendix C: Reliability Study Dispatch Assumptions

Tables C-1 and C-2 below summarize the notable generation dispatch and transmission flows represented in the power flow cases used and developed for this study.

Table C-1: Generation Dispatch and Transmission Flows – Heavy Summer (MW)

Heavy Summer

Assumption	ColumbiaGrid Case	Reference Case	NGA	NGA Plus	Balanced	Balanced Plus	All Gas
LSR Hydro	2,291	1,497	-	-	-	-	-
Non-LSR Hydro	21,424	21,793	21,693	21,788	21,737	21,683	21,873
Thermal	5,892	6,212	6,212	5,672	7,022	5,334	6,682
Canada->NW	2,296	2,296	2,296	2,296	2,296	2,296	2,296
PDCI N->S Flow	1,240	1,240	1,240	1,240	1,240	1,240	1,240
COI N->S Flow	2,678	2,711	2,648	2,634	2,653	2,568	2,715
New Thermal	-	-	-	-	-	-	958
New DR	-	-	971	1,715	486	486	-
New EE	-	-	425	425	212	212	-
New Battery	-	-	100	100	-	-	-
New Wind	-	-	-	-	500	1,250	-
New Solar	-	-	-	-	250	750	-

Figure C-2: Generation Dispatch and Transmission Flows – Heavy Winter

Heavy Winter

Assumption	ColumbiaGrid Case	Reference Case	NGA	NGA Plus	Balanced	Balanced Plus	All Gas
LSR Hydro	3,080	1,590	-	-	-	-	-
Non-LSR Hydro	23,330	24,056	23,906	24,056	24,004	23,961	23,999
Thermal	8,580	7,920	7,920	7,027	7,920	6,949	8,090
Canada->NW	-1,506	-1,506	-1,506	-1,506	-1,506	-1,506	-1,506
PDCI N->S Flow	384	-	-	-	-	-	-
COI N->S Flow	1,043	313	210	197	98	40	-119
New Thermal	-	-	-	-	-	-	958
New DR	-	-	1,040	1,784	520	520	-
New EE	-	-	425	425	212	212	-
New Battery	-	-	100	100	-	-	-
New Wind	-	-	-	-	500	1,250	-
New Solar	-	-	-	-	250	750	-

ENDNOTES

[a] NOAA Fisheries: http://www.westcoast.fisheries.noaa.gov/fish_passage/fcrps_opinion/federal_columbia_river_power_system.html
[b] National Wildlife Federation, et al., v National Marine Fisheries Service, et al., Case No. 3:01-cv-00640-SI; available here: https://www.documentcloud.org/documents/2823619-1404-2065-Opinion-and-Order.html (courtesy of The Seattle Times, accessed on November 20, 2017)
[c] Washington Greenhouse Gas Emission Reduction Limits, Washington Department of Ecology: https://fortress.wa.gov/ecy/publications/documents/1601010.pdf
[d] Oregon House Bill 3543: https://olis.leg.state.or.us/liz/2007R1/Downloads/MeasureDocument/HB3543/Enrolled
[e] http://www.nww.usace.army.mil/Missions/Lower-Snake-River-Dams/
[f] 27HS Transient Stability System Assessment 2017 Case and 27HW Transient Stability System Assessment 2017 Case posted on March 21, 2017: https://www.columbiagrid.org/basecases-results-documents.cfm
[g] NERC Transmission System Planning Performance Requirements, TPL-001-4: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission%20System%20Planning%20Performance%20Requirements&jurisdiction=United%20States
[h] WECC Transmission System Planning Performance Criterion TPL-001-WECC-CRT-3.1: https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.1.pdf
[i] https://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-2016-unofficial-2017-10-10.pdf?_ga=2.162118974.341105494.1518126429-1689377253.1518126429
[j] NWPCC Seventh Power Plan, Chapter 15, page 12
[k] NWPCC Seventh Power Plan, Chapter 3, page 15
[l] NWPCC Seventh Power Plan, Chapter 12, Tables 12-2, 12-3, 12-4, 12-5, and 12-6
[m] NWPCC Seventh Plan, Chapter 4, page 3
[n] NWPCC Seventh Power Plan, Chapter 12, Figure 12-6
[o] NWPCC Seventh Power Plan, Chapter 7, page 13
[p] NWPCC Seventh Plan technical information webpage, "Demand Response Supply Curve Derivation" spreadsheet, available here: https://www.nwcouncil.org/energy/powerplan/7/technical
[q] Energy Efficiency supply curve graphs in this report were adopted from the NWPCC Seventh Power Plan "*ConsBundle w BC-postfinal.xlsx*" spreadsheet available on the technical information webpage for the Plan: https://nwcouncil.app.box.com/v/7thplanconservationdatafiles
[r] NWPCC Seventh Plan, Chapter 4, page 5
[s] Demand Response supply curve graphs in this report were adopted from the NWPCC Seventh Power Plan *"Demand Response Supply Curve Derivation workbook (xlsx)*" available on the technical information webpage for the Plan: https://www.nwcouncil.org/energy/powerplan/7/technical
[t] Energy Efficiency supply curve graphs in this report were adopted from the NWPCC Seventh Power Plan "*ConsBundle w BC-postfinal.xlsx*" spreadsheet available on the technical information webpage for the Plan: https://nwcouncil.app.box.com/v/7thplanconservationdatafiles
[u] Demand Response supply curve graphs in this report were adopted from the NWPCC Seventh Power Plan *"Demand Response Supply Curve Derivation workbook (xlsx)*" available on the technical information webpage for the Plan: https://www.nwcouncil.org/energy/powerplan/7/technical
[v] NWPCC Seventh Plan, Appendix B: Wholesale and Retail Price Forecast
[w] U.S. Army Corps of Engineers, Northwestern Division, Columbia River Basin Water Management: http://www.nwd.usace.army.mil/Missions/Water/Columbia/
[x] NWPCC Seventh Plan, Chapter 10: https://www.nwcouncil.org/media/7149928/7thplanfinal_chap10_opplanningreserves.pdf

[y] 2026 Common Case Version 2.0 Public Release Package, page 79 of the Release Notes: https://www.wecc.biz/Reliability/WECC%202026%20Common%20Case%20Version%202.0%20Release%20PackagePublic.zip

[z] Demand Response supply curve graphs adopted from the NWPCC Seventh Power Plan *"Demand Response Supply Curve Derivation workbook (xlsx)*" available on the technical information webpage for the Plan: https://www.nwcouncil.org/energy/powerplan/7/technical

[aa] NWPCC Seventh Plan technical information webpage, "Demand Response Supply Curve Derivation" spreadsheet, available here: https://www.nwcouncil.org/energy/powerplan/7/technical

[bb] NWPCC Seventh Power Plan, Chapter 12, Tables 12-2, 12-3, 12-4, 12-5, and 12-6 and Chapter 4, page 3

[cc] Proforma Tool can be downloaded from WECC's website: "*E3 WECC Capital Costs ProForma Tool Final2017-01-31.xls*" available at https://www.wecc.biz/SystemAdequacyPlanning/Pages/Datasets.aspx#LongTermPlanningTool

[dd] Combined cycle combustion turbine resource cost source: NWPCC 7th Plan Appendix H; Page H-12; Levelized Fixed Cost ($/kW-year) for Dry-cooled CCCT installed in 2025: $193.27 in 2012 dollars

[ee] Reciprocating Engine resource cost source: NWPCC 7th Plan Appendix H; Page H-15; Levelized Fixed Cost ($/kW-year) for Recip. Engine on East Side installed in 2025: $187.33 in 2012 dollars

[ff]2016 Resource Adequacy Report, page 21, Bilateral Transactions – RA Price Analysis: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

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