Salmon Versus Power: Dam Removal and Power Supply Adequacy

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Abstract—*Dam removal is gaining both support and resistance in different communities and political circles in the Pacific Northwest of the United States, given its sensitive environmental and economic consequences. The Columbia River Basin (CRB) offers a unique opportunity to examine to what extent the replacement of hydroelectric dams affects reliability and adequacy of the power system given long-standing proposals to remove the four Lower Snake River dams to improve the survival of the endangered salmon species. Key results show that replacing the four dams leads to an inadequate energy supply, necessitating the need for more capacity to satisfy requirements. Although the four dams have higher nameplate capacity, they provide a much lower effective capacity. Thus, the debate about removing dams should be an opportunity for CRB managers to consider investment options in new ecosystem services and energy solutions that maintain adequate performance.*

Key words: Adequacy, battery storage, dam removal, regional power planning, renewable energy

INTRODUCTION

THE Columbia River Basin (CRB) offers a unique opportunity to examine the extent a replacement of hydroelectric dams with alternative resources affects reliability and adequacy. Proposals to remove four lower snake river (LSR) dams to improve the survival of endangered salmon species have been debated for decades [1], [2].

The dams in question are the Lower Granite, Little Goose, Lower Monumental, and Ice Harbor dams. These dams jeopardize salmon migration and threaten population stability and flourishing. Considerations of removing dams are not unique to the CRB, but occur internationally. There is growing interest to better understand the risks and trends of dam removal [3], [4].

We report on our study that explores the impact of removing these four LSR dams. We also identify alternative resource portfolios to substitute for the loss of hydropower generation. Resource and energy managers should see this as an opportunity to consider a holistic approach for maintaining an adequate electricity supply while enabling endangered salmon populations to flourish again.

BACKGROUND

A broad range of variables represent power system reliability. The most pertinent variable is having an adequate supply of generation [5]. Multiple energy resources—hydroelectric, wind, and solar—present modeling challenges to energy planning. Unlike conventional fossil fuel resources, generation from hydro resources and from variable energy resources have greater uncertainties and are highly dependent on river flows, wind velocity, and sun availability [6]–[8].

To more accurately determine the effective energy capacity provided by these resources, it is necessary to evaluate how they perform when added to an existing power system. To be able to do this, we utilize simulation models. Power system simulation models are used to calculate the *associated system capacity contribution* (ASCC). The ASCC is the percentage of a resource's nameplate—ideal—capacity that can be reliably produced for adequacy—meeting necessary requirements. It is a function of resource type, location, period of use, installed capacity, and overall resource mix [9]. The ASCC is used to determine resources included in alternative replacement portfolios that are necessary to maintain the region's power supply adequacy.

Reliability and adequacy are two interrelated concepts. Reliability captures the ability of the power system to deliver electricity. Adequacy is a component of reliability and measures whether the power supply has sufficient generating capability to serve all demands [10], [11].

By evaluating the performance of current and future power system configurations, planners can compare the risk associated with alternative energy and climate change policies to produce an optimal resource expansion plan. Each adequacy metric is assigned a threshold that represents acceptable tolerance for risk of shortfall for consumers.

While reliability and adequacy are related, satisfying one metric does not guarantee that remaining metrics will also be satisfied [12]. Commonly used adequacy metrics include loss of load probability (LOLP), loss of load hours (LOLH), loss of load events (LOLEV), and expected unserved energy (EUE).

LOLP is defined as the probability that load will surpass available generation over a specified time period—hour, day, month, or year. Annual LOLP, the probability of facing a shortfall year, is defined as a year with at least one shortfall event. In the Pacific Northwest, the accepted annual LOLP threshold for adequacy is 5%.

LOLH is the expected number of shortfall hours per year. LOLEV—also referred to as the loss of load frequency—is the expected number of shortfall events per year. EUE is the expected amount of load not served per year, usually measured in Megawatt-hours (MWh). Unlike LOLP, there is no accepted standard threshold risk for LOLH, LOLEV, and EUE for the Pacific Northwest.

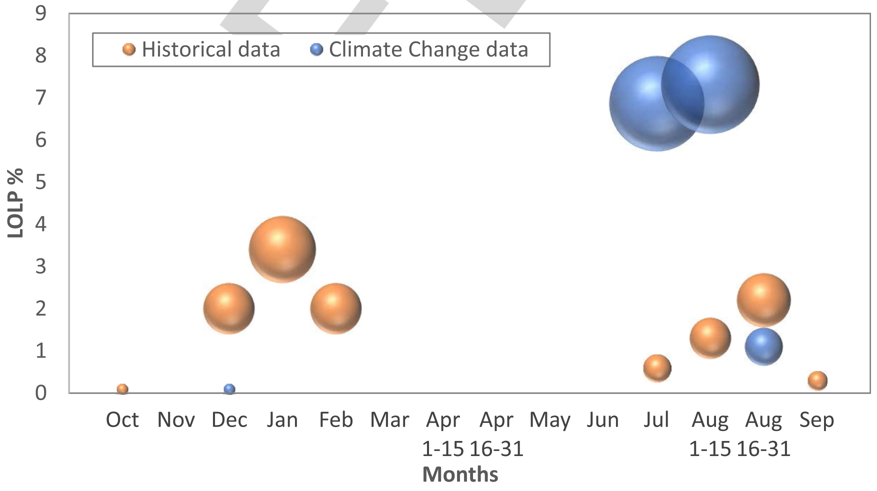

Figure 1. Forecasted Monthly LOLP for the year 2025.

CLIMATE CHANGE IMPACT

The complexity and uncertainty of variable energy resources are further exacerbated by the seasonal changes that are induced by climate change relative to observed historical patterns. Differences between climate change forecasts and traditionally utilized historical data can have significant implications for managerial decisions regarding new resource acquisitions.

Predicted climate changes suggest a need to transition away from historic observations of river flows and temperatures to climate change forecasted data [13], [14]. The hydroelectric and wind power potentials of river basins are especially sensitive to changes in river flow and temperature cycles.

For its analyses, the Northwest Power and Conservation Council (NPCC) uses downscaled general circulation model results prepared by the River Management Joint Operating Committee. In the CRB, the importance of using climate change data can be seen in the seasonal shifts in monthly LOLP presented in Figure 1. The comparison requires changing the data inputs of the NPCC energy adequacy model used in the CRB. One version of the model uses historical observations of river flow and temperatures and another version uses the climate change predicted data [13]. We ran the simulation again for the power system, but for operating year 2025 under both conditions to compare monthly LOLP values.

The differences between historical records and forecasted data appear to be significant. One reason is because we are comparing data from a long historic record to a shorter time period predicted future record for climate change information. Year-to-year effects of climate change are small. As can also be seen by the size of the circles, the larger circles mean a greater likelihood of inadequate supply in some of the future climate change predictions.

The power system for operating year 2025 is simulated under both climate change (blue) and historical conditions (gold) for monthly LOLP values. Using historical data, LOLP challenges appear both in winter and summer—with the worst performance around 4%. Under a climate change scenario nearly all LOLP events are in summer, but have greater LOLP values to a maximum of just over 7%.

This initial evidence is important because it may affect future resource choices. For example, some wind sites provide higher summer generation and would be better choices to offset the high summer LOLPs resulting from using climate change forecasts.

If energy planners and decisionmakers continue using historical data as currently practiced in energy models, instead of projected climate change data, the seasonal pattern of resource need will be misrepresented and could lead to less optimal or wrong resource choices and potentially higher costs.

METHODOLOGY

This study employs NPCC's adequacy model called GENeration Evaluation SYStem (GENESYS) to evaluate various future configurations of power supply from the four LSR dams. GENESYS is a Monte-Carlo hourly chronological simulation model that incorporates hydro, fossil fuel, nuclear, and renewable resources, along with energy conservation and interregional energy market transactions.

Hydroelectric generation is guided by reservoir rule curves that are determined by the Bonneville Power Administration (BPA) and other federal agencies. These rule curves provide a maximum monthly elevation for flood control, a minimum monthly elevation for power generation, and a target monthly elevation to maximize end-of-year refill probability.

Among other outputs, GENESYS calculates various adequacy metric values along with an estimated amount of required new effective capacity if the portfolio being analyzed is found to be inadequate. The chronological hourly power system simulation in GENESYS is performed thousands of times for a single operating year—the operating year runs from October to September.

To test the impact of dam removal, the 2025 power system is first evaluated to determine needed capacity expansion to get the LOLP to the 5% standard. Given that the NPCC's power plan is still under development, combustion turbine (CT) resources are used as a surrogate for the plan's resource strategy to provide the needed capacity. Once the 2025 power system is made adequate with the addition of the natural gas-fired CT, the four lower LSR dams are removed from the analysis.

Finally, alternative resource portfolios that include different mixes of renewable and conventional energy sources are added to restore the LOLP back to the 5% standard. Each alternative portfolio is then evaluated based on performance metrics generated from the model and costs obtained from the National Renewable Energy Laboratory (NREL) annual technology baseline data.

IMPACT OF REMOVING THE FOUR LSR DAMS

The analysis of the 2025 baseline case that includes the planned decommissioning of 2276 MW of coal plant nameplate capacity results in an LOLP of 12.2% and requires an estimated 1551 MW of effective new capacity for adequacy—to reduce the LOLP to 5%. The baseline is modified with the addition of 870 MW of CT nameplate capacity to reach adequacy.

The four LSR dams are removed from the preceding baseline resulting in an LOLP of 9.7% and requiring an estimated 1088 MW of effective new capacity to maintain adequacy. Managers should take notice of this effective capacity as it is much smaller than the total nameplate capacity of the LSR dams—3033 MW. In other words, removing the LSR dams does not require replacing their entire nameplate capacity, but only 1088 MW in effective capacity.

The performance impact is evaluated with the metrics EUE, LOLH, and LOLEV as shown in Figure 2.

Each of the three performance metrics increased, implying that the system will perform worse with dam removal. The conventional interpretation is that dam removal would increase the expected frequency of curtailment events from 1 in 5.5 years to 1 in 3.2 years (calculated as 1/LOLEV). The difference in the expected event duration (LOLH times the number of years between events) is 3.18 hours per event in the baseline and 3.58 hours per event after dam removal. The expected event magnitude (EUE times the number of years between events) is 3492 MWh in the baseline and 4445 MWh in the case of dam removal—this represents an extra 950 MWh curtailed.

HYDROELECTRIC SUBSTITUTION PORTFOLIOS

Seven alternative resource portfolios are created to achieve an adequate power supply for the dam removal case—a mix of wind, solar, battery storage, and natural gas. Four portfolios rely on renewable sources only, and three include minimal natural gas in the mix alongside wind, solar, and battery storage.

The portfolios consist of: (A) wind-only; (B) solar-only; (C) 50% wind and 50% solar; (D) CT, 250 MW battery, wind, and solar; (E) CT, 500 MW battery, wind, and solar; (F) CT, 750 MW battery, wind, and solar; and (G) 1000 MW battery, wind, and solar.

The required adequacy nameplate capacity for each resource in each portfolio is calculated using its ASCC and the estimated needed effective capacity from the dam removal case. The resultant nameplate capacity of each portfolio is shown in Figure 3 ranked by highest to lowest capacity.

The wind-only portfolio (A) requires the most additional nameplate capacity—2.5 times greater than the runner up and 4.6 times the portfolio with the least nameplate capacity required. The three portfolios with the lowest amounts of needed nameplate capacity to satisfy the effective capacity requirement for adequacy are C (2044 MW), G (1690 MW), and F (1551 MW).

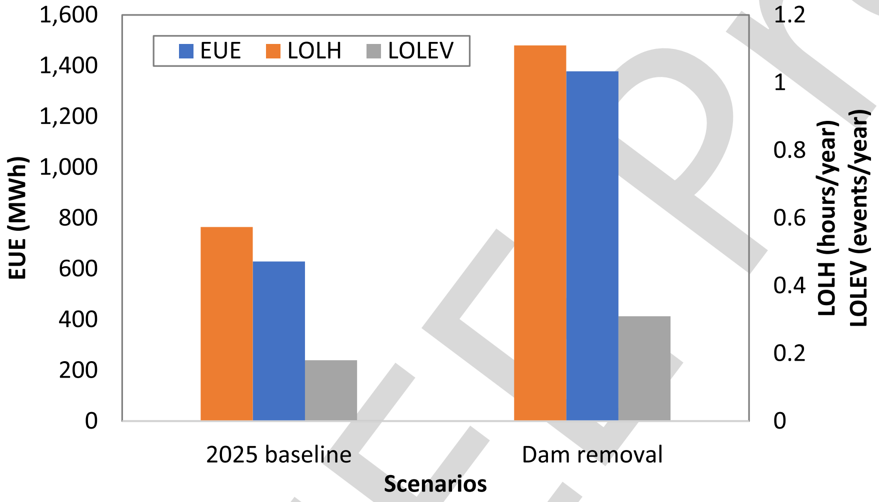

Figure 2. Impact of LSR Dam removal.

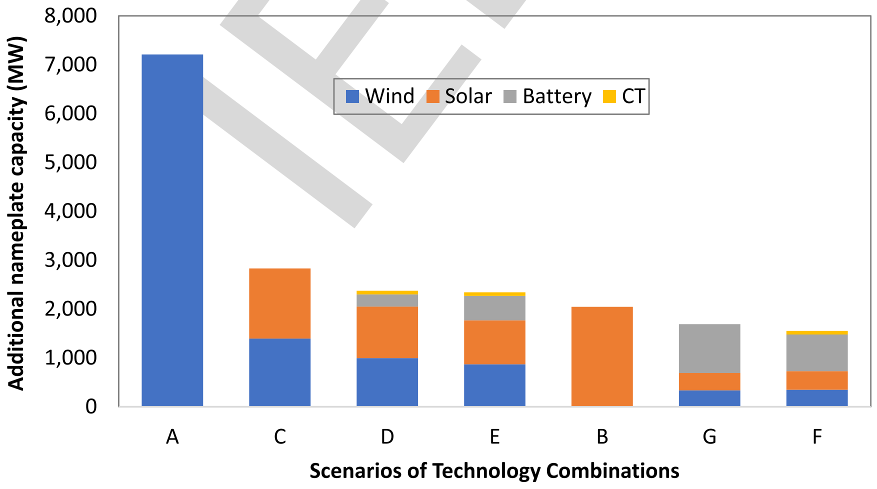

Figure 3. Added MW nameplate capacities.

The performance of each portfolio—using alternative adequacy metrics—is shown in Figure 4. Though all portfolios satisfy the NPCC's 5% annual LOLP adequacy standard, the portfolios differ in the frequency (LOLEV), duration (LOLH), and magnitude (EUE) adequacy metrics.

The *solar-only* portfolio (B) exhibits the best performance. The two portfolios with the least required nameplate capacity—high-capacity battery storage portfolios F and G—perform the worst having the highest EUE and LOLH. The high battery storage portfolios have the same high LOLEV as the wind-only portfolio.

The solar-only option (B) has an event frequency of slightly more than one event every 8 years. The high battery storage portfolios of 750 MW (F) and 1000 MW (G) each have one event per 5.8 and 6 years, respectively.

The event magnitude is also diverse, with 3653 MWh in the solar-only (B) and 4538 MWh and 5478 MWh for the high storage portfolios (F) and (G). The expected event duration across all portfolios shows little variation with a range from 3.28 to 4.03 hours.

The smaller storage portfolios—250 MW and 500 MW storage (D and E)—are relatively comparable to the wind-and-solar portfolios. The solar-only portfolio seems to be the leading contender with the third least new installed nameplate capacity—indicating that it is potentially the cheaper portfolio—with the best performance metrics.

The evaluation of the mixed technology portfolios requires additional consideration. On one hand, the higher storage portfolios require less new installed nameplate capacity and are potentially cheaper than the smaller storage portfolios. Alternatively, they have the worst performance in terms of LOLH and EUE.

A cost evaluation of the portfolios is required to determine an optimal substitution portfolio. These initial costs include the capital expenditure (CAPEX) to operationalize the nameplate capacity of each portfolio, and the recurring annual operations and maintenance (O&M) costs—see Figure 5.

As expected, the wind-only portfolio (A) is over three times more expensive—using CAPEX and O&M financial measures—than the next portfolio of split wind and solar (C). The solar-only alternative (B) has the third least costly CAPEX and the smallest O&M. The high storage portfolios have the smallest CAPEX, the only portfolios under $2 billion, and second and third lowest O&M.

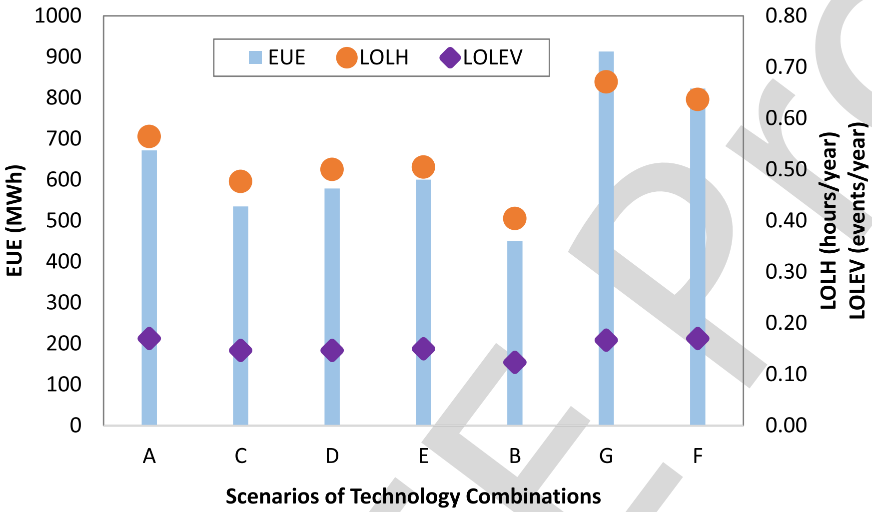

Figure 4. Performance metrics of alternative energy supply portfolios.

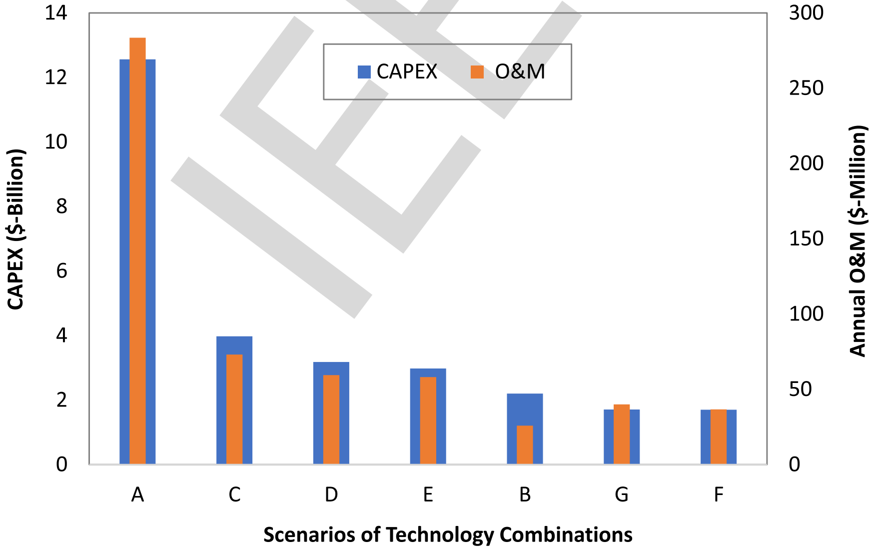

Figure 5. Cost comparison of alternative portfolios based on capital expenditures (CAPEX) and operations and maintenance (O&M) costs.

Taking a closer look at the three least expensive portfolios, the 1000 MW Battery and 750 MW Battery portfolios are about $490 Million and $501 Million, respectively, cheaper in CAPEX than solar-only. In terms of annual O&M, they are $14.1 Million and $10.7 million more expensive. For savings recovery, the difference in O&M would surpass the CAPEX difference after 34.7 and 46.5 years. In other words, the high battery storage portfolios are preferable to the solar-only if technology lifespans are less than 34.7 and 46.5 years.

SIGNIFICANCE FOR DECISION MAKERS

This study demonstrates three important points. First, utilizing climate change data is essential for capturing seasonal changes and stress to the power grid more accurately than from using historical observations. This point is especially pertinent in regions were hydroelectric and renewables are large portions of the energy portfolio. A broader perspective is that climate change will influence a broad variety of industries; that investment decisions can be greatly altered in some industries due to these changes—especially agriculture and forestry products for example.

Second, removing the generation capacity of the four LSR dams does not represent the equivalent loss of nameplate capacity. These dams are rated at a total of 3033 MW nameplate capacity yet their contribution to the power system can be replaced by adding only 1088 MW of effective capacity. At 9.7% LOLP, the options to substitute the removed hydropower with a renewable energy mix are more manageable than perceived. Broadly, unexpected results represented by ideal versus actual performance issues occur in all types of systems and capital equipment. Care should be taken to determine the operating environments and assumptions in any investment decision.

Third, a holistic approach is required when considering energy mix alternatives. A single adequacy metric should not be the only variable considered for comparison and decision making. This is particularly true given that multiple alternatives can have the same LOLP yet have widely different performance metrics and costs. With these multiple considerations, it is evident that fossil-free substitution for the dams is feasible.

Without cost considerations, the solar-only portfolio provides the best performance metrics, almost comparable to the system before dam removal in terms of LOLH and EUE, with even better LOLEV. However, with cost considerations, the high storage capacity portfolios are preferable, with slightly higher LOLEV than before removal, but with higher EUE. Based on these findings, the prominent substitution portfolio G is one that uses 74 MW of CT, 750 MW battery storage, 348 MW of wind, and 379.5 MW of solar, totaling $1.698 billion with $36.6 million annual O&M. The main drawback is the higher EUE, but it is offset with the cost savings of $501 million over the solar-only alternative.

Should decision makers prefer an alternative without any fossil fuels, then the option with 1000 MW battery storage, 335 MW wind, and 355 MW solar is the preferable one, costing $10.5 million more at $1.709 billion and $40 million annual O&M. Other priority considerations, such as emission performance could further influence portfolio decisions [15] but based on CAPEX and O&M and performance, the suggested portfolios provide the solution space for further consideration. Overall, the lesson is clear—on various performance and cost measures, alternatives will likely have tradeoffs.

CONCLUSION

Energy production decisions are strongly associated with climate change, and climate change will influence energy production decisions. In this case, the decision to find alternatives to hydro energy production through dams was motivated by another important environmental issue, that of species decimation and biodiversity. In this case, it was Salmon motivating the initial important decision.

Given these motivations, this study evaluated the adequacy impact of removing hydroelectric dams and their substitution portfolios. The GENESYS tool offered a valuable insight into the CRB power system planning, but this tool cannot be used for other river basins. However, the methodology utilized in this research is valuable for managers as a meaningful platform for other regions to follow; determine an adequate baseline case, remove desired hydroelectric dams, and create alternative portfolios by adding diverse generation sources and battery storage until reaching the accepted adequacy risk performance.

This process enables the creation of multiple portfolios to evaluate multiple performance metrics and costs. It is important to evaluate the adequacy and performance of each alternative to evaluate the pre-and postremoval performance and to assess which substitution alternative is preferable.

Managers should transition their perspective to incorporate potential long-term scenarios such as climate change, from *business-as-usual* on input data and regional planning. Climate change data should be used instead of historical observations to account for changes in seasonal behavior to improve investment decision making. This perspective is necessary for a broad variety of large and smaller investment decisions by organizations across a variety of industries influenced by and influencing climate change and can range from construction to transportation decisions across industries.

Regional planning must balance performance and cost metrics. The debate about removing dams should be an opportunity for the managers in the CRB to consider investment options or alternatives in ecosystem services, i.e., fish populations, and energy solutions that maintain adequate performance. To achieve these goals, it is essential that managers take a holistic approach in consideration of models that evaluate technological performance benchmarked against cost in their comparative analysis to select between alternatives. Public policy and decision making should be influenced by the characteristics of large public projects.

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