

Lower Snake River Dams Power Supply Replacement Analysis

Prepared for

Northwest RiverPartners

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1. Executive Summary

This study evaluates the power supply-related financial and CO₂ emissions impacts of breaching the four Federal dams on the lower Snake River. This analysis assesses the loss of the U.S. Army Corps of Engineers owned dams (Ice Harbor Dam, Lower Monumental Dam, Little Goose Dam, and Lower Granite Dam) on the lower Snake River (LSRD) within the context of the most recent electric sector clean energy laws.¹

Key Findings:

- Multiple prior studies have modeled LSRD replacement costs and impacts without considering existing grid decarbonization laws. The material impacts of losing the LSRD can only be properly understood by modeling the requirements of reaching a zero-carbon grid, both with and without the LSRD in place and then measuring the change in operating requirements to maintain grid reliability.
- Existing electric sector decarbonization laws require an unprecedented buildout of 160,000 MW of new resources by 2045, with a cost of \$142 billion within the Western Power Pool (WPP - formerly the Northwest Power Pool).²
- **The replacement of LSRD power generation capacity would require an *additional 14,900 MW of new resources* (i.e., wind, solar, storage, and demand response) and *at an additional \$15 billion in cost*.** The high costs of LSRD replacement are driven by the following key factors:
 - Initial resource additions are required to address existing laws.
 - The more on-demand generation the region loses (i.e., coal, natural gas, hydro, nuclear), the more variable generation (solar/wind) plus storage (batteries/pumped storage) must be built to ensure sufficient generation is always available.
 - The overbuild of renewables is not useful in many parts of the year and, by 2045, 35% of the annual energy from renewable resources is unusable and is curtailed.
 - To fulfill clean energy mandates, renewables and storage are built to replace the loss of the LSRD peak capacity, but due to curtailments, only 9 to 12% of the new resources can be utilized to meet demand.
- Even if the WPP region *doubles* its historic pace of renewable buildout, **it is unlikely that state requirements are met until 2076, causing emissions in the Pacific Northwest to increase by 132 million metric tons (MMT) of CO₂ to maintain grid reliability.**
- Requiring an additional 14,900 MW of resources to be built to replace the carbon-free LSRD capacity puts further stress on the ability to achieve state policy mandates, likely adding an additional 5 MMT – 8.5 MMT of CO₂ released into the atmosphere.

¹This study assumes the following laws as part of the baseline for the electric system: Washington’s 2019 Clean Energy Transformation Act, Oregon’s Emissions Reduction House Bill 2021, California’s Senate Bill 100, Colorado’s 2019 Clean Energy Legislation, Nevada’s 2019 Clean Energy Legislation

² Western Power Pool states assumed for this study include Washington, Oregon, Montana, Idaho, Wyoming, Nevada, Utah, Colorado, and a small portion of California.

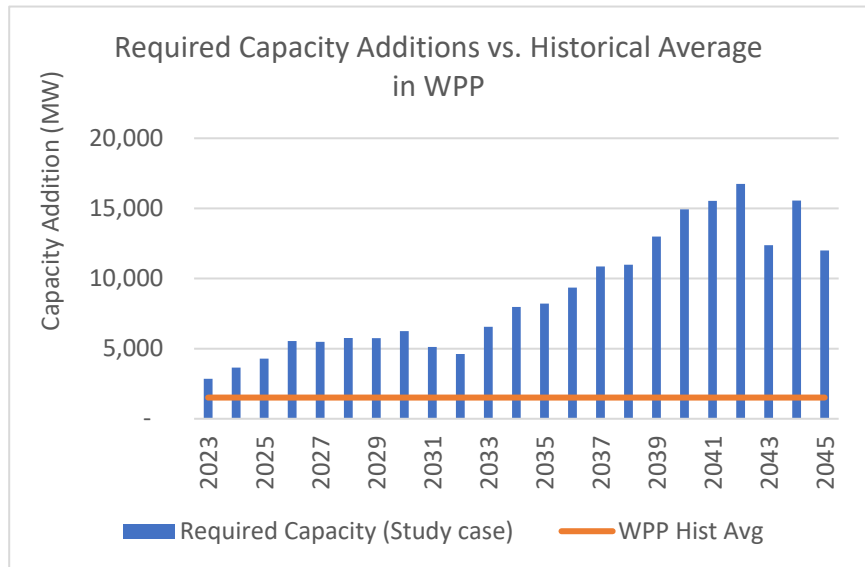
Table 1. Summary of results.

Name	Type	Renewable and Storage Capacity	Total Cost (NPV) †
Base Case (with LSRD)	Base expansion case to meet state clean energy laws and maintain reliability <u>with</u> the lower Snake River dams	160 GW	\$142 B
Study Case (Base Case without LSRD)	Study expansion case to meet state clean energy laws and maintain reliability <u>without</u> the lower Snake River dams	175 GW	\$157 B
Difference	Impact of Breaching	15 GW	\$15 B

†NPV corresponds to 2023 using 2% inflation and discount rate.

Additional Details:

- More than 7,600 MW of renewable and battery storage additions are needed every year from 2023 – 2045 to meet WPP state requirements and replace the capacity of the LSRD.
- This requirement significantly exceeds the average build of 1,500 MW per year from 2007 – 2021 in the WPP, putting achievement of state policy mandates at risk.



The table and graphic below compare the required pace of build needed to meet the Study Case (7,600 MW/year) to historic experience in the WPP, CA and ERCOT.

Figure 1: Projected achievement dates of WPP grid decarbonization mandates based on historic build pace in various markets

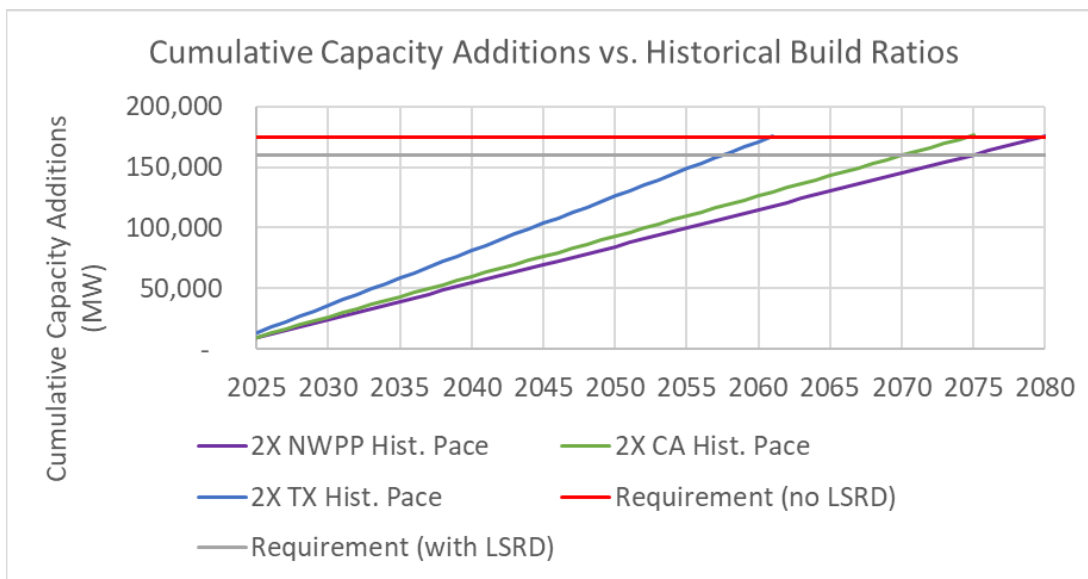


Table 2. Achievement of Study Objective under different build-out scenarios.

Annual Average Renewable Capacity Additions in WPP to meet Study Case			
	Using WPP Historic Buildout Pace	Using CA Historic Buildout Pace	Using ERCOT Historic Buildout Pace
Annual average renewable capacity additions from 2007 – 2021 (MW)	1512	1661	2326
Estimated achievement of clean energy laws if double the historic pace of capacity additions (Year)	2076	2071	2057
Added emissions due to delay (MMT) ‡ ³	136	114	55
Estimated achievement of clean energy laws and replacement of LSRD if double the historic capacity additions (Year)	2081	2076	2060
Added emissions due to delay for replacement of LSRD (MMT) ‡ ⁴	8.5	8.5	5.1

+Western Power Pool (WPP), California, and Electric Reliability Council of Texas (ERCOT)

‡Assumes average emission rate from 2030-2045 applied to each future year.

³ We applied the average emission rate in Washington and Oregon to each future year, to calculate the added GHG emissions (past 2045) if clean energy laws are not met. These data were filtered to only Washington and Oregon to focus on Pacific Northwest impacts.

⁴ To calculate the incremental emissions from breaching the LSRD, we re-ran the base case expansion plan without the LSRD, again assuming clean energy laws are not met by 2045. Emissions from the base case (with LSRD) were subtracted from the emissions from this new dispatch to estimate the incremental emissions associated from breaching the LSRD.

Parameters:

- This study did not evaluate the cost of building long-distance, high voltage transmission lines.
- This study did not evaluate risks that could further increase costs and/or delay decarbonization timing, including increased electric sector load growth due to electrification, grid reliability, land use, and permitting for new transmission and new resource builds.
- This study did not evaluate non-power related impacts of lower Snake River dam removal, such as the elimination of barging and the resultant higher CO₂ levels from a shift to trucking and rail. It also did not include financial and other considerations related to the loss of irrigation and recreational opportunities afforded by the dams.

Study Approach:

This study uses an electric industry standard Production Cost Model, best available load and resource cost estimates, and a 60-dam hourly production database to evaluate required resources additions in the Western Power Pool footprint. This study quantifies and evaluates the difference in capital costs, operating costs, and total production costs between two scenarios:

- Base Case: Meet reliability and WPP state electric grid decarbonization laws with existing lower Snake River dams,
- Study Case (Base Case without LSRD): Meet reliability and WPP state electric grid decarbonization laws without existing lower Snake River dams

The model's forecast of generation additions required to replace the LSRD may be low due to the following assumptions:

- The study assumed average electric sector load growth and did not account for expected increased electric sector load due to electrification of transportation and buildings.
- The study assumed a lower capacity contribution for the LSRD relative to other regional studies.
- The study includes a limited transmission cost adder for short-distance transmission projects only. Many experts and studies recognize significant new long-distance, high voltage transmission and associated costs will be required to support the new resources needed.
- The study did not put any constraints on wind and solar development and assumed sufficient land was available for new development. Other studies have indicated high land use is required and that state and local laws may limit development.
- The study assumed that adequacy and reliability were maintained under all scenarios by ensuring an industry standard planning reserve margin could be maintained. Other studies have indicated challenges in maintaining system adequacy and reliability to current standards under low or zero carbon scenarios.

Study Conclusions:

- Existing WPP state laws to decarbonize the electric system require 160,000 MW of new generation and batteries.
- An additional 14,900 MW of new generation and batteries will be required to make up for the loss of the LSRD in a zero-carbon future.
- More than 7,600 MW of renewable and battery storage additions is needed every year from 2023 – 2045 to meet the state laws and replace the capacity of the LSRD. This significantly

exceeds the average build of 1,500 MW per year from 2007 – 2021 in the Western Power Pool, putting achievement of state policy goals at risk.

- Even if the WPP region doubles its historic pace of renewable build, it is unlikely that state goals are met until 2076 and emissions in the region increase by 132 million metric tons.
- The additional 14,900 MW of resources needed to replace the existing carbon-free LSRD capacity puts further stress on the ability to achieve state policy goals, potentially adding an additional 5 MMT – 8.5 MMT of CO₂ released into the atmosphere.

2. Background

The objective of this study is to evaluate the power supply-related financial and CO₂ impacts of breaching four dams on the lower Snake River – Lower Granite, Lower Monumental, Ice Harbor and Little Goose. The study quantifies: 1) changes in generating capacity⁵, type, location, and amount required to maintain reliability standards and meet state clean energy laws⁶, 2) financial costs associated with the new generating capacity mix, and 3) the CO₂ emissions implications associated with the new generating capacity mix.

To meet the study objective, the study includes the following major tasks:

1. Base Case: Quantify capacity expansion plan (new resource additions) required to meet reliability standards and state clean energy laws if the lower Snake River dams (LSRD) are in place,
2. Study Case (Base Case without LSRD): Quantify capacity expansion plan required to meet reliability standards and state clean energy laws if the LSRD are removed, and
3. Quantify difference in capital costs, operating costs, total production costs, and CO₂ emissions impacts from removing the LSRD.

3. Approach

To meet task 1, we used a Western Electricity Coordinating Council (WECC)-wide zonal production cost model (PCM) configured for long-term capacity expansion. The model was run from 2023-2045 with the LSRD continuing to operate. Dispatch levels, costs, and CO₂ emissions were outputted from this Base case.

To meet task 2, the PCM was run to produce a capacity expansion plan, meeting reliability and state clean energy laws if the LSRD were removed. Retirement dates were set to follow Representative Mike Simpson's (ID – CD2) plan, with two dams removed in 2030 and two in 2031. Dispatch and costs were outputted from this Study Case (Base case without LSRD).

To meet task 3, differences between the two simulations (with and without the LSRD) were calculated, quantifying the additional capacity (amount, type, location, and timing) required to meet state clean

⁵ When this paper refers to capacity, it means nameplate capacity, unless otherwise stated. Nameplate capacity is the fully rated maximum generation a power plant can typically provide if sufficient fuel is available.

⁶ This study does not directly consider the impact of current state clean energy laws on electrification of the transportation and heating resulting in additional load growth. Rather business as usual load growth is used, additional electrification of transportation or heating would lead to a greater amount of capacity and thus cost required to replace the LSRD.

energy laws and maintain reliability. Annual cost differentials and CO₂ emissions between the two runs were also calculated.

4. Methods

Production cost models are used by utilities and regulators to inform long-term planning and policy decisions. For example, the California Public Utility Commission requires production cost modeling for Integrated Resource Plans (IRP) in California. In the early planning years, utilities used spreadsheets and in-house tools for developing long-term plans. However, as the system became more complex these in-house tools have largely been replaced with commercial software. In the WECC, the key commercial software tools are the SERVIM and RESOLVE tools used by CPUC⁷, the ABB Capacity Expansion (CE) tool and the PLEXOS tool used by PG&E⁸, and the Aurora tool used by the Northwest Power & Conservation Council⁹, Portland General Electric¹⁰, and Puget Sound Energy¹¹.

The production cost models solve for the least cost solution to meet forecasted load (i.e., demand for electricity) with a given set of existing or candidate generating resources subject to constraints. Constraints typically include transmission flow limits, renewable energy targets, energy efficiency and resource retirement targets.

We used the Aurora commercial production cost model for this work. Inputs for the commercial PCM were developed by EGPS and evaluated with historical data. In addition, EGPS has an hourly production database for 60 dams in the Pacific Northwest that represent most of the hydroelectric operating capacity in the region. This dataset was used to derive unit-specific hydro monthly shapes and annual capacity factors for each hydro unit, including the four LSRD studied here, based on normal hydro years and normal hydro months.¹² Unit specific hourly shaping parameters were developed using hourly generation data from 2018 to 2021. A description of the EGPS production cost model and inputs is in Appendix A.

5. Model Inputs

⁷ CPUC RA and IRP Model, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2019>

⁸ SCE IRP, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M346/K291/346291781.PDF#:~:text=In%20this%20IRP%20filing%2C%20SCE%20includes%20a%20proposed,any%20energy%20storage%20used%20to%20meet%20their%20needs>

⁹ https://www.nwcouncil.org/2021powerplan_aurora-model/

¹⁰ PGE IRP, <https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFIlvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf>

¹¹ Puget Sound Energy IRP, https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf

¹² The University of Washington Climate Impact Group predicts, under likely climate change scenarios, the Pacific Northwest will see annual precipitation to remain at about historical normal, but with an earlier run-off pattern caused by warmer weather. The Energy GPS analysis did not attempt to alter historic flow river flow patterns. <https://cig.uw.edu/wp-content/uploads/sites/2/2020/12/snoveretalsok2013sec5.pdf>

The WECC is often broken down into five subregions for purposes of understanding reliability. In fact, the North American Electric Reliability Corporation (NERC) currently breaks WECC into planning regions comprised of the Western Power Pool (WPP), California and Mexico (CA/MX), the Southwest Reserve Sharing Group (SRSR), Alberta (AB), and British Columbia (BC)¹³. NERC utilizes these groupings, because these sub-regions tend to have similar operating practices and demand patterns.



Figure 1. Reliability Regions within WECC

Note, as defined WPP includes former subregion of Rocky Mountain Reserve Group. Source: EGPS.

The WPP NERC reliability area covers the Pacific Northwest (PNW¹⁴) as well as Montana, Idaho, Nevada, Utah, Wyoming, and Colorado. Parts of the WPP are located in California (e.g., the Balancing Area of Northern California). The WPP has approximately 64 Gigawatts (GW) of peak load and approximately 115 GW of generating resources, primarily comprised of hydro, natural gas, coal, and wind. As with other regions, significant amounts of coal generation have been, or are planned to be, retired.

¹³ https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

¹⁴ The PNW for this report is defined by the available generation and load data. It encompasses Oregon and Washington hourly load, Oregon and Washington natural gas, coal, and nuclear generation, BPA wind and solar, hydro production from the 60 largest dams in the US portion of the Columbia River Basin, plus transmission flows reported by BPA between the PNW and British Columbia, Montana/Idaho, and California.

Daily operation within the WECC is the responsibility of 38 Balancing Authorities (BA). Part of the daily operation requirements for a BA is to ensure, at a fine temporal scale, load and generation are always balanced. This is accomplished by perfectly balancing load and generation, within the balancing authority footprint, on a second-to-second basis such that system frequency is maintained at 60 hertz.

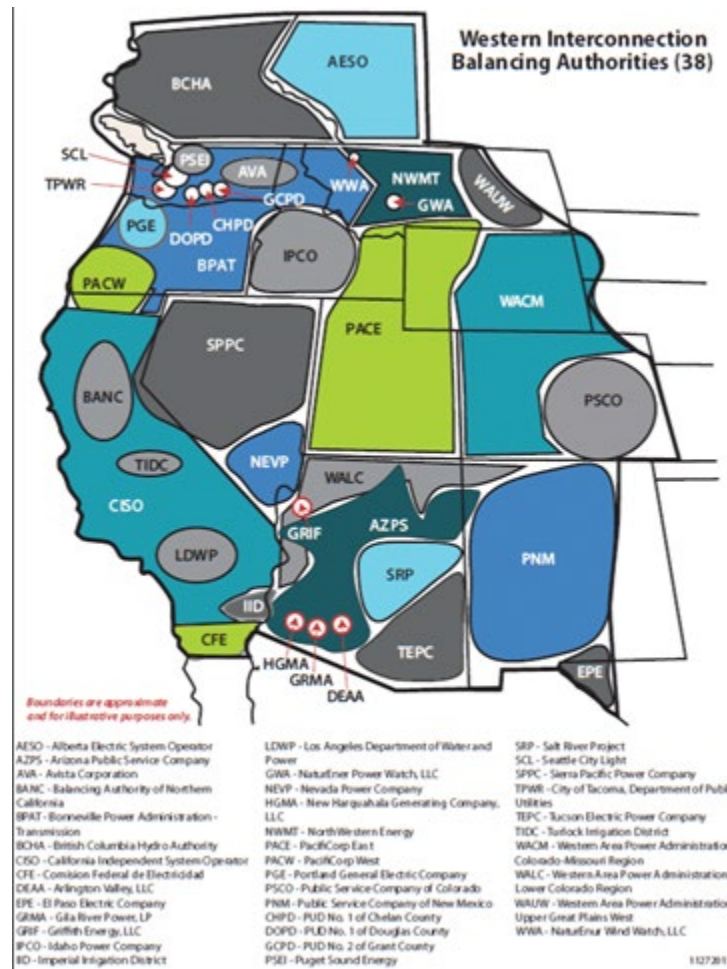


Figure 2. WECC Balancing Authorities

The California Independent System Operator (CAISO) maintains the balancing for much of California. Within the SRSR, the BAs are WAPA Lower Colorado, Arizona Public Service, Salt River Project, Tucson Electric Power, Public Service of New Mexico, and El Paso Electric. Within the WPP Rocky Mountain region (as defined by NERC), the BA's include Public Service of Colorado, WAPA Rocky Mountains, and PacifiCorp East. Within the WPP region outside of the Rocky Mountains, the BAs include WAPA Upper West, NW Montana, Idaho Power, PacifiCorp West, Bonneville Power, Avista, Portland General Electric, Seattle City Light, Tacoma Power, Puget Sound Energy, and various Public Utility Districts (PUD) including Grant County, Douglas County, and Chelan County.

A fundamental input for PCM is the definition of the transmission topology and load zones. These inputs specify where potential transmission constraints may occur as well as the load requirement for generation to serve. If BAs are aggregated and real transmission constraints not considered, the model will never capture actual system conditions. In general, our model captures the WECC BAs as individual load zones. BA loads are directly applied to each zone and disaggregated for finer granularity in some cases such as BPA Northwest, Southwest, and East. Between zones transmission constraints may exist such as the Cross Cascades Transmission Constraint, but do not exist between all BAs (e.g., Avista and BPAT East). A summary of our transmission topology for the PNW is shown in Figure 3.

From the perspective of where the LSRD are located, major constraints include the AC and DC lines to California and limits to BC to the north and ID/MT to the east.

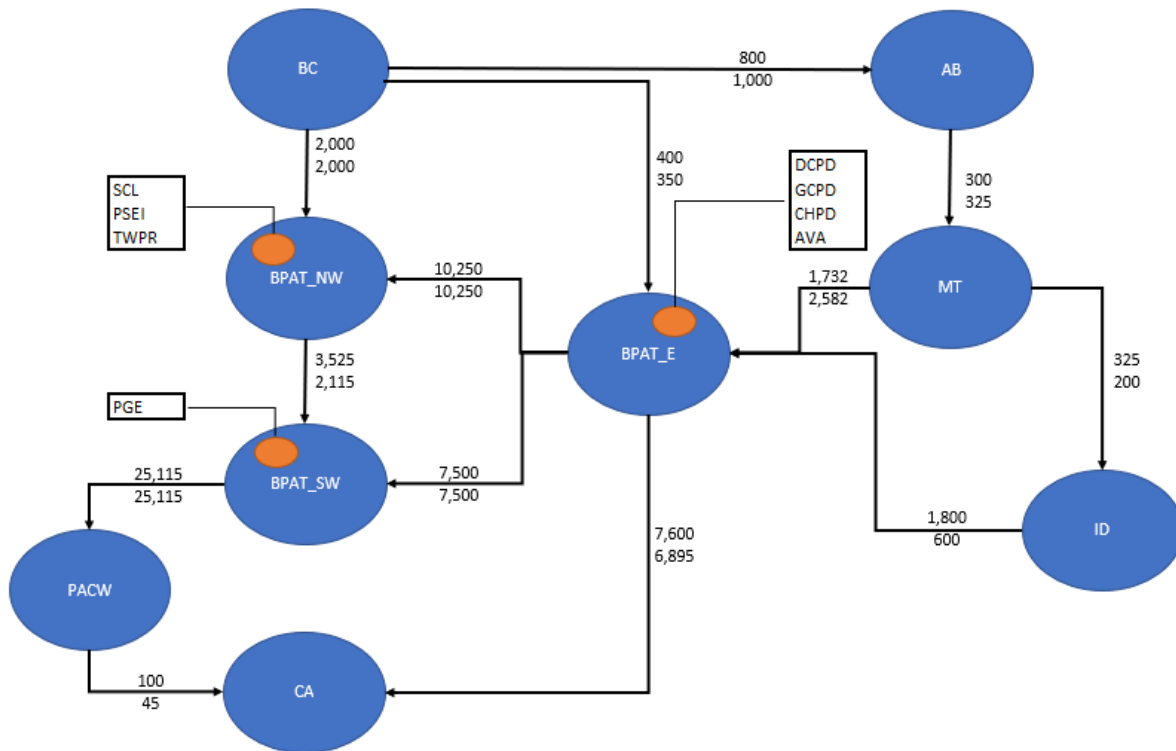


Figure 3 | Wire Bubble Diagram for PNW. Topology for the rest of WECC not shown. Note: Top value is the transfer capability in the direction indicated by the arrow and the bottom value is the transfer capability in the reverse direction. Source: EGPS, WECC.

Load is forecasted at each BA in the WECC using publicly available sources such as the FERC 714 and Utility Integrated Resource Plans (IRP). As such, the forecasted load growth represents a P50 business as usual case and does not assume aggressive electrification scenarios¹⁵. For the WPP, the load growth

¹⁵ Current estimates of electrification in WA show over 1.5 times the growth in electricity demand from transportation and heating fuel switching to electricity. These were not included in the study.

is shown in Figure 4 and represents an 0.9% annual growth rate for both peak and energy. The load growth assumptions for Washington and Oregon are lower, however, at 0.5% energy average annual growth rate.

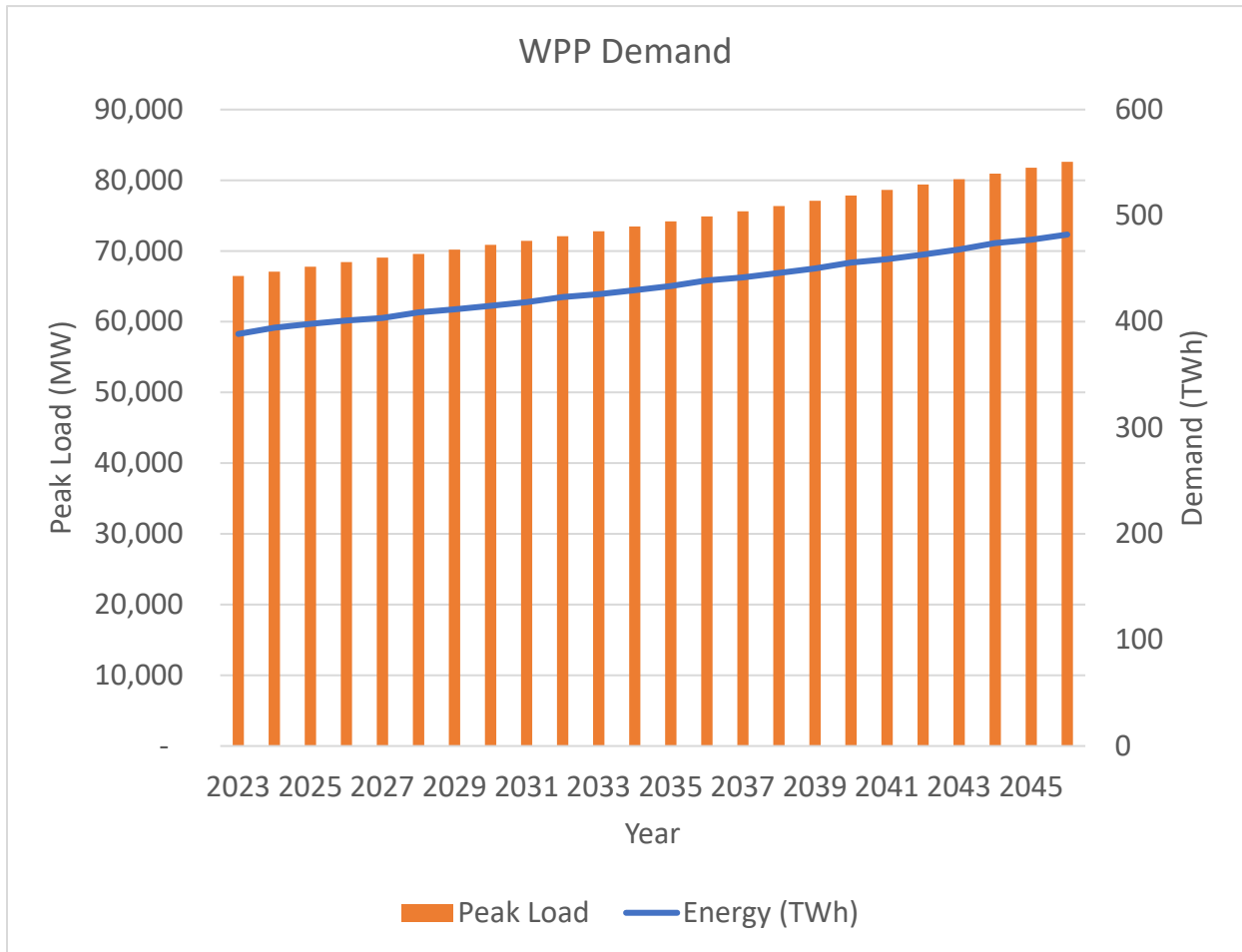


Figure 4. Peak and energy load forecast for the WPP.

Existing and planned capacity addition and retirements are inputs into the model to determine the initial capacity supply balance. We use the EGPS Power Database which relies on public information from a variety of sources such as the US Energy Information Administration (EIA) 860 and 923 reports as well as professional judgement. The WPP installed capacity in 2021 is approximately 115 GW and is comprised mostly of hydro, gas, coal, and wind as shown in Figure 5.

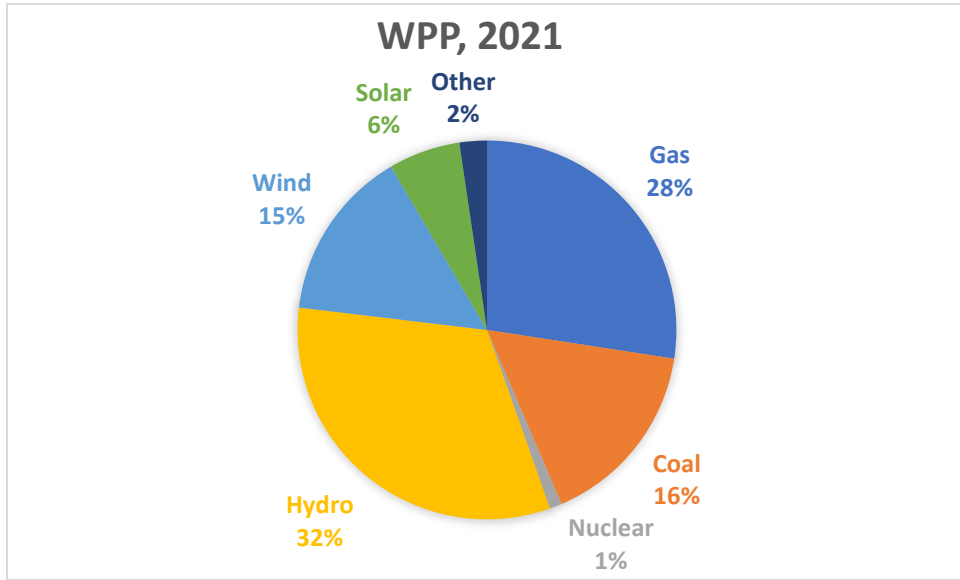


Figure 5. Installed capacity distribution in the WPP. Source: EIA, EGPS.

The largest change expected in the thermal fleet across WECC is the retirement of coal units. Our assumptions for coal retirements for all of WECC are shown in Figure 6 and total nearly 28 GW of firm capacity retirements. Individual coal plant retirement assumptions for the WPP are listed in Appendix B.

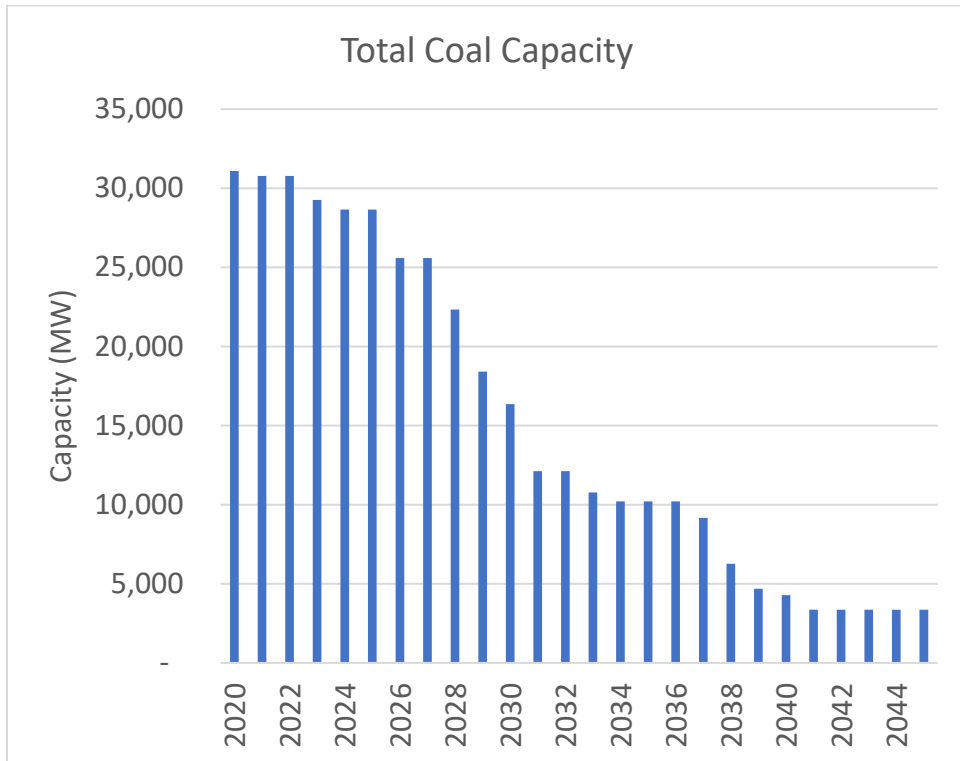


Figure 6. Total expected coal retirements in the WECC. Source: EIA, WPP, EGPS.

Candidate resources are new build options that the PCM must choose from to meet reliability, policy, and least cost energy constraints. We have included wind, solar, standalone 4-hour lithium-ion batteries and hybrid solar plus storage resources as candidate units. We have used publicly available data sources such as the NREL Advanced Technology Baseline dataset for base financial assumptions for the candidate resources. In addition to these resources, Demand Side Management (DSM) resources can be utilized by the model to reduce load in peak periods. We allowed the model to use up to 1,000 MW of DSM in each load zone.

Our capital cost assumptions (not including major transmission upgrades) decline over time as shown in Figure 7. In addition, location specific cost adders are applied based on EIA data. Candidate wind and solar resources are given locations and corresponding hourly production shapes that result in further locational granularity. Because of the tremendous amount of capacity required to meet clean energy requirements, we have also included additional transmission cost adders to the wind candidate resources to reflect additional costs of building new, short-distance transmission.

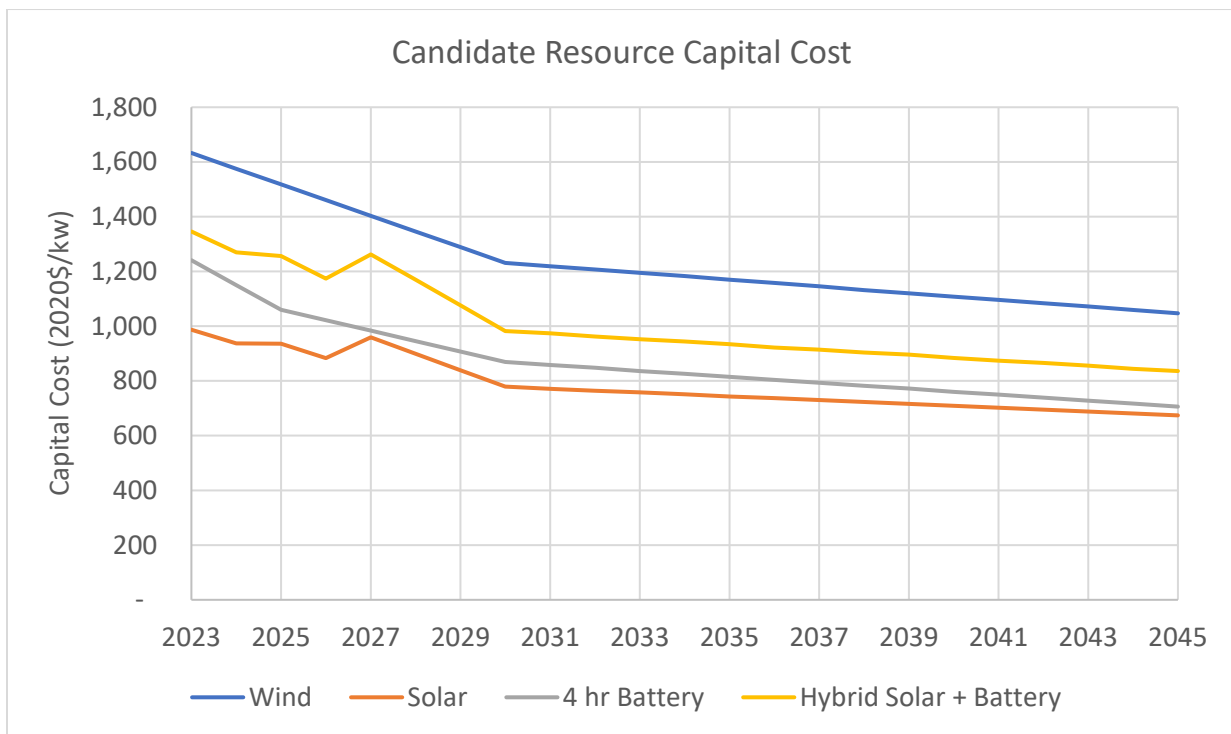


Figure 7. Capital cost assumptions for new candidate resources. Assumes declining Solar investment tax credit through 2026 applied to both standalone solar and hybrid units. Based on NREL ATB¹⁶ and EIA AEO¹⁷.

Existing clean energy laws are specified as a requirement in the PCM. The requirements included in this study are Washington state’s 100% Clean Energy Transformation Act (CETA), Oregon House Bill 2021, as well as requirements outside of the immediate study area such as the California Senate Bill 100, and the 2019 clean energy laws in Colorado and New Mexico. The clean energy laws are inputted in two ways to ensure compliance. First, a minimum renewable generation requirement is specified, and second a maximum carbon emissions constraint is specified. The renewable generation requirement allows for

¹⁶ NREL ATB; <https://atb.nrel.gov/>

¹⁷ EIA AEO; <https://www.eia.gov/outlooks/aeo/>

resources to be built most economically and ensures stable model results. The emission requirement enforces in-state laws. Imports from out of state may contain carbon and thus offset the emission constraint. In this case, we ensured the emission intensity of out-of-state imports is lower than offsets allowed by losses.

Reliability is captured as a constraint to the model in the form of a required Planning Reserve Margin (PRM). The PRM minimum requirement used in the model is 16.1% as defined by the NERC Long-Term Reliability Assessment.¹⁸

The one-hour capacity contribution of all resources other than wind and solar are inputted. In the case of thermal, we input a capacity credit of the full capacity less forced outage rates. In the case of hydro, we applied a 67% capacity credit across each month. This capacity credit was arrived at from analysis done in California and represents a lower value than recent estimates in the WPP’s Western Resource Adequacy Program (WRAP) methodology. Therefore, this assumption is less generous to the amount of peak capacity required to replace the LSRD.¹⁹ In the case of storage, we inputted a capacity credit starting at 80% and declining over time to represent a declining Effective Load Carrying Capability (ELCC; the amount of perfect capacity that can be replaced by a given technology). In the case of wind and solar, the PCM calculates the output during the top 100 net load hours during the simulations and uses that value as the capacity credit. This approach is like an ELCC study by calculated dynamically within Aurora. The resulting capacity credit declines as a function of solar capacity on the system due to solar generation pushing the net peak load (i.e., peak demand after generation is accounted for) further in the evening.

6. Results and Discussion

Table 3. Summary of results.

Name	Type	Renewable and Storage Capacity	Total Cost (NPV) [†]
Base Case (with LSRD)	Base expansion case to meet reliability and state clean energy laws with the LSRD	160 GW	\$142 B
Study Case (Base Case without LSRD)	Study expansion case to meet reliability and state clean energy laws without the LSRD	175 GW	\$157 B
Difference	Impact of Breaching	15 GW	\$15 B

[†]NPV corresponds to 2023 using 2% inflation and discount rate.

In the Base Case 160 GW of capacity is required throughout the WPP to meet state clean energy laws and maintain reliability. This capacity is comprised of wind, solar, and storage units (Figure 8). Most new additions are from wind and solar, with nearly 32 GW from battery storage units. By 2045, the one-hour Net Qualifying Capacity (NQC), or capacity that counts towards meeting the net peak load and thus

¹⁸ https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

¹⁹ The LSRD have a combined nameplate capacity of over 3000 MW, but taking a conservative approach, the study assigns them 1844 MW of one-hour sustained peaking capacity based on the hydropower capacity credit used in the model.

planning reserve margin, drops to 20% for wind and 3% for solar at these capacity levels thus requiring significant amounts of capacity to replace the LSRD.

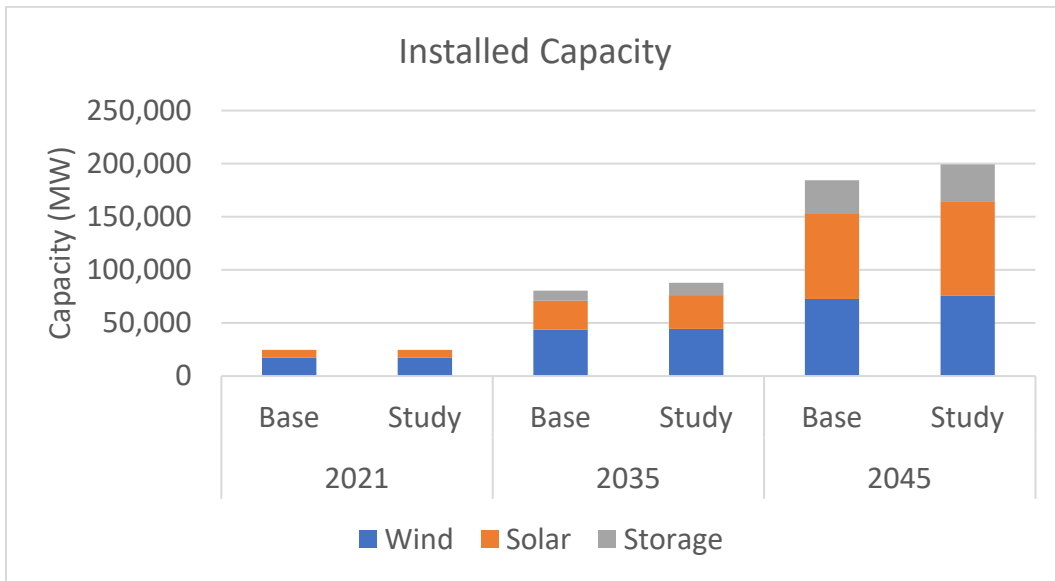


Figure 8. Installed capacity for the base and study case. Note the LSRD are breached in 2030 and 2031 corresponding to the Simpson proposal.

When the LSRD are removed, 175 GW of capacity is required in the WPP (Figure 8 and Figure 9). This is an increase of 14.9 GW comprised predominately of solar (8.7 GW), and nearly equal amounts of wind (3.3 GW) and storage (2.9 GW).

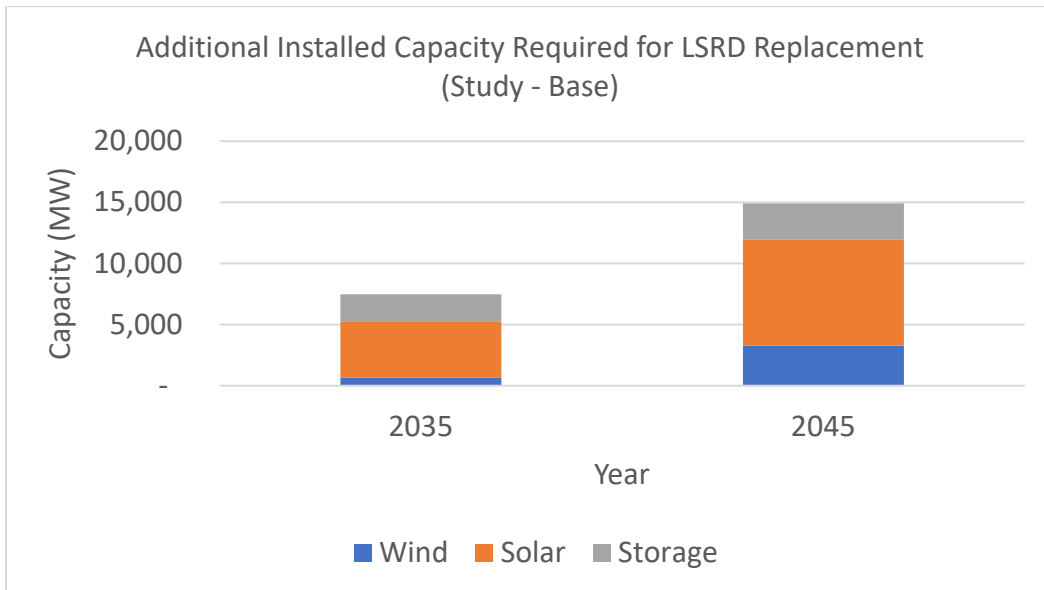


Figure 9. Renewable and storage capacity differences between the study and base case. This represents the additional capacity required to replace the LSRD.

In addition to the peak credit, energy curtailment of renewable resources plays an important role in the required capacity additions without the LRSR. Much of the renewable energy produced by these additions are in excess of load and export capabilities and curtailment rates are 35% for wind and solar resources in 2045. Given that wind and solar already have low-capacity factors due to variable generation (25 to 35%), the high curtailment rates result in overall capacity factors on the order of 9 to 12%.

The cost impacts of this replacement capacity have a Net Present Value (NPV)²⁰ of \$15 billion from 2030-2045 (Figure 10). In 2045 the annual recurring costs are \$2.5 billion. These costs are primarily driven by the new resource capital costs which are annualized. Other costs include the ongoing fixed costs for maintenance, variable operating costs, fuel costs, and emissions costs if applicable. These costs reflect the electricity replacement costs for the LSRD and do not account for major maintenance events (e.g., turbine replacement at the LSRD) or the costs related to the construction of long-distance, high voltage transmission lines to import additional renewable generation into the WPP. The study also does not consider the impacts to other sectors such as transportation or irrigation if the dams are removed.

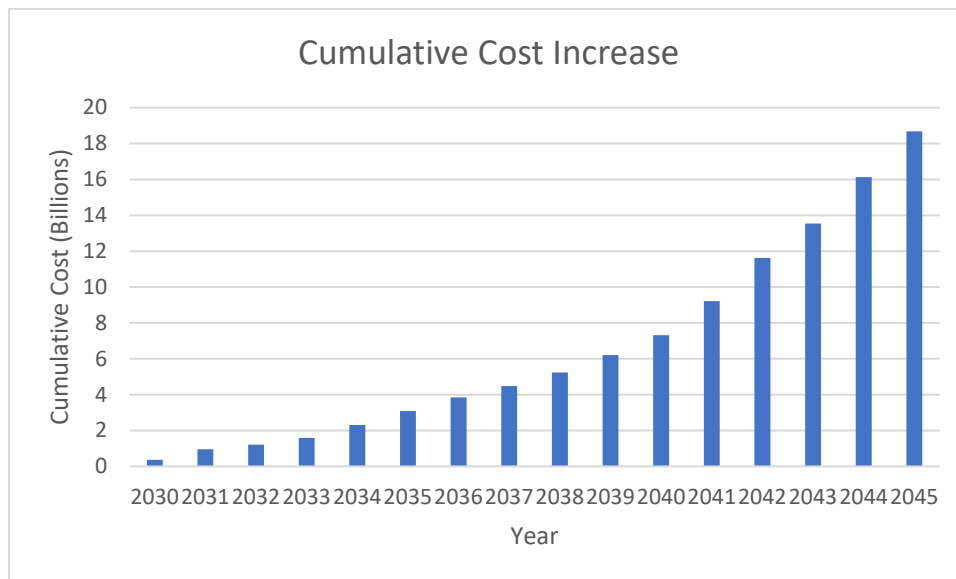


Figure 10. Increased costs from removing the LSRD. Cost represents annualized capacity costs from the added capacity as well as ongoing fixed costs, variable operating costs, and fuel costs.

With the significant capacity requirements already required for the base case and more required for LSRD replacement, it is likely that the additions of new generators will *not* keep up with the expansion plan estimated in this study. More than 7,600 MW of combined renewables, demand response, and battery storage additions are needed every year from 2023 – 2045 to meet WPP state requirements and replace the capacity of the LSRD (Figure 11). This pace of buildout significantly exceeds the average annual amount of wind, solar and storage capacity added by WPP, California or ERCOT in the last 15 years, putting achievement of state policy mandates at risk.

²⁰ 2% annual inflation and discount rate were used in the NPV calculation.

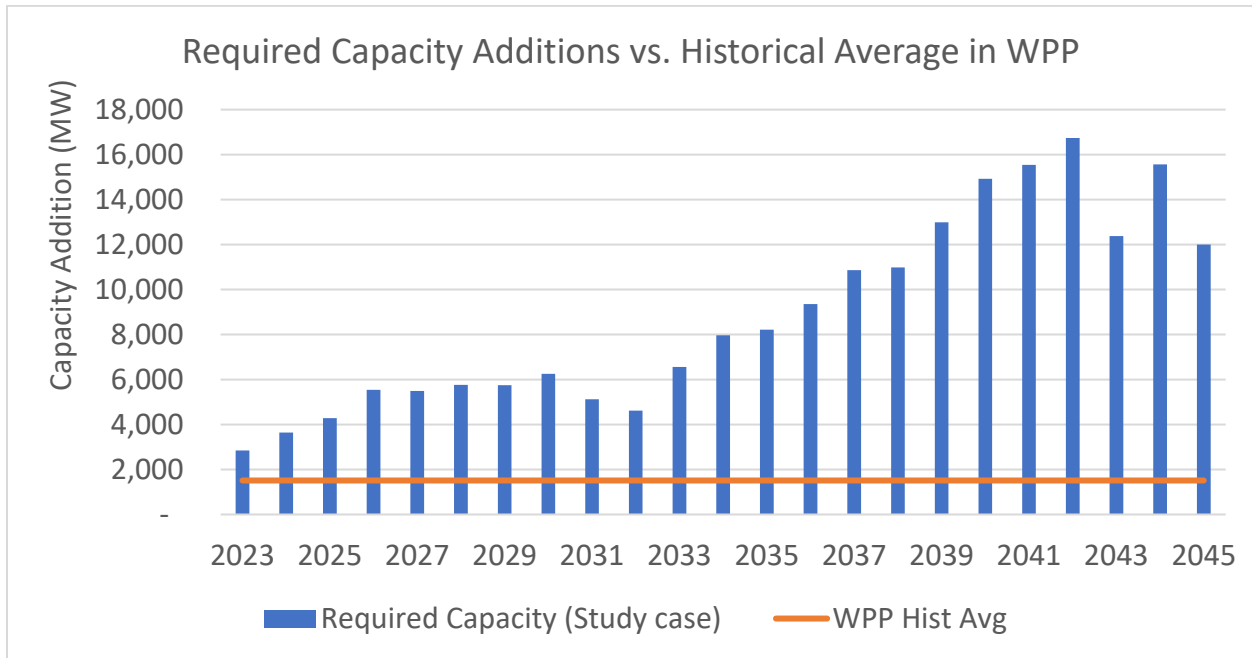


Figure 11. Required capacity additions under the Study Case to replace LSRD, meet state clean energy laws and maintain reliability compared to historical capacity additions in the WPP.

Meeting the capacity requirements laid out in this study is, therefore, unlikely. We can estimate when clean energy laws would be met using historical capacity additions and the capacity requirements from this study with and without the LSRD. If we assume the future additions in WPP, CA, and ERCOT are double that of the historical average, the amount of required capacity to achieve the Base case requirements would not be achieved until 2057 (best case assuming double ERCOT’s historical pace of additions²¹) to 2076 (worst case assuming double WPP’s historical pace of additions²²) (Figure 12).

²¹ Based on renewable and storage additions from 2007 to 2021 using ERCOT Capacity Trends, 2022. https://www.ercot.com/files/docs/2022/06/08/Capacity_Changes_by_Fuel_Type_Charts_May_2022_PlannedMonthly.xlsx

²² Based on renewable and storage additions from 2007 to 2021 using EIA 860 and 923 databases, 2021.

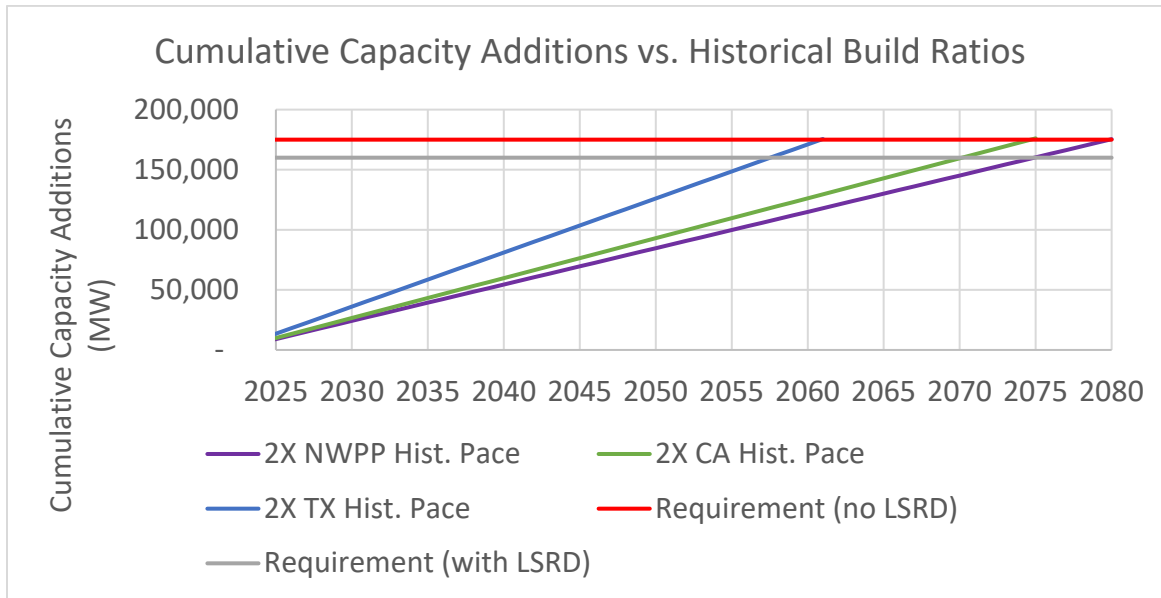


Figure 12. Range of years when the Base case (160 GW) and Study case (175 GW) WPP capacity addition requirements are met assuming double the historical pace of renewable and storage additions in various markets from 2007 to 2021.

Adding the additional 15 GW of capacity to replace the LSRD would further increase these dates by three to five years, based on double ERCOT’s pace and double WPP pace, respectively.

There are also significant implications for emissions. We applied the average emission rate in Washington and Oregon to each future year, to calculate the added GHG emissions (past 2045) if clean energy laws are not met according to various dates. These data were filtered to only include Washington and Oregon to focus on Pacific Northwest impacts. The results show an incremental 136 MMT using twice the historic buildout rate for NWPP, 114 MMT using twice the historic buildout rate for California, and 55 MMT using the historic buildout rate for Texas.

Table 4. Achievement of Study Objective under different build-out scenarios.

Annual Average Renewable Capacity Additions in WPP to meet Study Case			
	Using WPP Historic Buildout Pace	Using CA Historic Buildout Pace	Using ERCOT Historic Buildout Pace
Annual average renewable capacity additions from 2007 – 2021 (MW)	1512	1661	2326
Estimated achievement of clean energy laws if double the historic pace of capacity additions (Year)	2076	2071	2057
Added emissions due to delay (MMT)‡	136	114	55
Estimated achievement of clean energy laws and replacement of LSRD if double the historic capacity additions (Year)	2081	2076	2060
Added emissions due to delay for replacement of LSRD (MMT) ‡	8.5	8.5	5.1

‡Western Power Pool (WPP), California, and Electric Reliability Council of Texas (ERCOT)

‡Assumes average emission rate from 2030-2045 applied to each future year.

To calculate the incremental emissions from breaching the LSRD, we re-ran the base case expansion plan without the LSRD, again assuming clean energy laws are not met by 2045. Emissions from the base case (with LSRD) were subtracted from the emissions from this new dispatch to estimate the incremental emissions associated from breaching the LSRD.

The added emissions resulting from breaching the LSRD results in an additional three to five years delay in achieving a zero-carbon grid, assuming twice the historic buildout pace of WWP, CA, and ERCOT. This delay equates to 5.1 to 8.5 Million Metric Tons (MMT) of CO₂ (Table 2).

7. Conclusions and Recommended Next Steps

This study shows that to replace the LSRD and meet state clean energy laws and maintain reliability will require an additional 14.9 GW of additional capacity and cost an additional \$15 billion to implement.

Clean energy laws in WPP states are aggressive and require 160 GW of renewable capacity to be added in the WPP region. At this level of capacity addition, the net qualifying capacity of renewable generators is greatly diminished thus requiring much more capacity to replace the LSRD. In addition, the renewable generation is curtailed at rates of 35% resulting in overall capacity factors on the order of 9 to 12%, requiring more than one for one capacity additions.

Even if the WPP doubled the historic average new resource builds from the WPP, CAISO, and ERCOT, the amount of required capacity to achieve the Study Case requirements could not be achieved until 2061 to 2080. A delay in meeting clean energy laws until these dates would increase emissions by 62 to 141 million metric tons.

The capacity additions estimated to replace the LSRD in this study may be low due to the following assumptions:

- **Average Load Growth:** The load growth assumptions used are P50 business as usual assumptions. If aggressive electrification load growth occurs, the load may be over 1.5 times higher than captured by this study resulting in higher amounts of capacity and cost to replace the LSRD.
- **Limited Capacity Contribution of Hydro:** The one-hour net qualifying capacity (NQC) credit of hydro used in this study was 67% based on publicly available data for summer periods. The newly formed Western Resource Adequacy Program (WRAP) may result in higher capacity credits for hydro based on max flex production and thus require more capacity and cost to replace the LSRD, all else being equal.
- **High Capacity Contribution of Batteries:** The NQC for batteries used in this study was 80% in 2023 based on the WPP WRAP (assumes net peak load is 5 hours in duration) declining to just over 50% in 2045. Many studies show a much lower NQC credit²³, starting in the 20 to 30%

²³ For example, PSEI's 2021 IRP (<https://www.pse.com/IRP/Past-IRPs/2021-IRP>).

range. A lower battery NQC would lower the value of storage units and thus require more capacity and higher costs to replace the LSRD.

- **Limited Transmission Cost Adder:** The availability of new transmission to support such a massive renewable build out was captured via a cost adder to incremental new wind units only. Major new transmission that is likely needed was not captured in the model and thus costs are likely to be higher when capturing these.

The capacity additions required to replace LSRD in this study may be high if new, not presently available technologies are developed and become commercially available during the study period.

Appendix A. EGPS Production Cost Model

We carefully reviewed several commercial tools and selected the Aurora tool for our production cost modeling. Aurora has been used for over 20 years by large utilities primarily in the U.S. and has well representation in the Western U.S. Aurora uses an optimization algorithm to solve for the least cost solution to meet a load forecast given a set of generating resources subject to constraints. Particularly beneficial features of Aurora for Long-Term Capacity Expansion (LTCE) that are not found in other commercial tools are an iterative approach to capacity expansion, dynamic peak credit calculations, and rigorous battery storage modelling. The iterative approach includes both an expansion plan of new generating resources followed by a commitment and dispatch run of the system. The commitment and dispatch run allows the model to see how existing and new generators operate over the study horizon. Information from this run is then fed back into the LTCE portion to inform a new expansion plan. This iteration process is done until convergence and allows for Aurora to compute expansion plans that meet a wide range of constraints such as reliability and RPS targets.

While we use a commercial tool for our studies, we have built the inputs to the tool from the ground up leveraging the existing EGPS dataset. Inputs are taken from publicly available sources, EGPS in-house tools, and EGPS staff knowledge.

The WECC is represented in our model by 40 zones including many of the 38 balancing authorities shown in Figure 2 with increased granularity for BPAT to separate the NW, SW, and Eastern zones of BPAT. This breakout allows us to capture the Cross Cascades and South of Allston transmission constraints. Transmission limits between zones are derived from historical flow limits, the CPUC RA and IRP Model²⁴, and the WECC Power Supply Assessment²⁵. Load forecasts for each zone are derived from the FERC 714 for zones in the U.S, the NERC ES&D for zones in Canada, and the PRODESEN for Mexico Baja California. Hourly load shapes are derived from the WECC Anchor Data Set (ADS).

²⁴ CPUC RA and IRP Model, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2019>

²⁵ WECC Power Supply Assessment, https://www.wecc.org/Reliability/2016PSA_Final.pdf

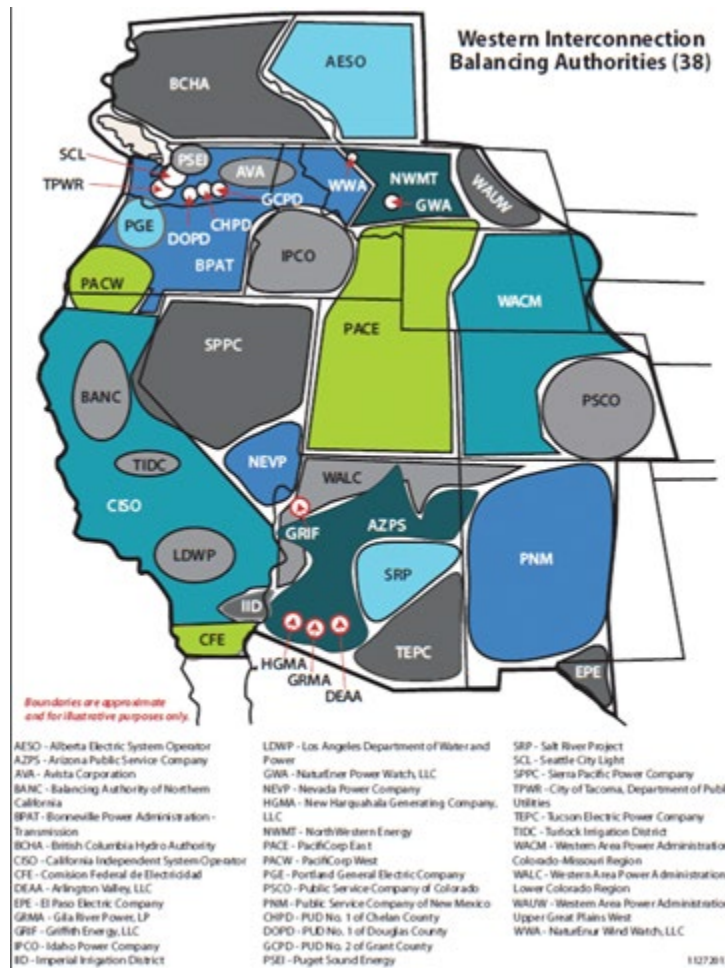


Figure 13. Balancing Authorities in the WECC.

The EGPS Power Database is used to determine the existing supply stack within WECC and is built off a variety of sources including the EIA 860 and 923. Future generator candidates are derived from the EIA and NREL. Generator operational and financial properties are derived from the WECC ADS, the CPUC RA and IRP model, and general rules of thumb from the EPA and NREL. Fuel forecasts for thermal generators are derived from the EIA and forward trading curves. The model contains seven natural gas hubs in the west and unit-level gas transportation cost adders.

Our production cost model has been carefully benchmarked to the last three full years of energy data in terms of installed capacity, generation by fuel type, unit-level hourly hydro generation, transmission flows on major paths, and power prices. Our long-term capacity expansion has been evaluated against publicly available expansion plans including the 2021 NW Power Plan²⁶.

Our model has several differentiators including

- Separate zones for BPAT into NW, SW, and E with current transmission limits between,

²⁶ 2021 NW Power Plan, https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf

- Hydro model in PNW integrated in PCM,
- Tethered to reality with benchmarking three years, and
- Iterate approach to capacity expansion.

Appendix B. Coal Retirement Assumptions

Table 5. Coal retirement assumptions for the WPP. Source: EIA, WPP, EGPS.

Name	Nameplate Capacity	Retirement Date	Generator	State
Comanche (CO)	383	12/1/2022	1	CO
Martin Drake	75	12/1/2022	6	CO
Martin Drake	132	12/1/2022	7	CO
Jim Bridger	608	12/31/2023	1	WY
North Valmy	290	12/1/2025	2	NV
North Valmy	277	12/1/2025	1	NV
Centralia	730	12/1/2025	2	WA
Comanche (CO)	396	12/1/2025	2	CO
Craig (CO)	446	12/1/2025	1	CO
Naughton	256	12/31/2025	2	WY
Naughton	384	12/31/2025	3	WY
Naughton	192	12/31/2025	1	WY
Neil Simpson II	90	12/31/2025	2	WY
Dave Johnston	255	1/1/2027	3	WY
Hayden	275	12/1/2027	2	CO
Dave Johnston	134	12/31/2027	2	WY
Dave Johnston	400	12/31/2027	4	WY
Dave Johnston	134	12/31/2027	1	WY
Craig (CO)	446	9/1/2028	2	CO
Hayden	190	12/1/2028	1	CO
Jim Bridger	617	12/31/2028	2	WY
Pawnee	552	12/31/2028	1	CO
Rawhide	294	12/1/2029	1	CO
Craig (CO)	535	12/1/2029	3	CO
Ray D Nixon	207	12/1/2029	1	CO
Bonanza	500	12/1/2030	1	UT
Wygen 1	90	12/31/2032	1	WY
Laramie River Station	570	12/31/2033	3	WY
Huntington	496	12/31/2036	2	UT
Huntington	541	12/31/2036	1	UT
Jim Bridger	608	12/31/2037	3	WY
Jim Bridger	608	12/31/2037	4	WY
Colstrip	824	12/31/2037	4	MT
Colstrip	824	12/31/2037	3	MT
Colstrip Energy LP	46	12/31/2037	GEN1	MT

Hunter	525	12/31/2038	1	UT
Hunter	525	12/31/2038	2	UT
Hunter	527	12/31/2038	3	UT
Wyodak	402	12/31/2039	1	WY