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Erin E. Apperson
Assistant General Counsel

October 28, 2019

<u>Via Email</u>

Public Utility Commission of Oregon
ATTN: Filing Center
201 High Street, SE, Suite 100
Salem, OR 97301

Re: UE 358 – PGE's Replacement of E3 Report in Exhibit 403

Dear Filing Center:

Please find enclosed the replacement of the Energy and Environmental Economics, Inc. Report filed in PGE's Cross-Examination Exhibit 403, as Attachment 026-B on September 26, 2019. The report is being replaced due to a pagination error in the previously filed report.

Sincerely,

Erin E. Apperson
Assistant General Counsel

EEA:al

Enclosure

Resource Adequacy in the Pacific Northwest

March 2019

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

March 2019

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Study Sponsors

This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy, and the Public Generating Pool (PGP). PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington: Chelan County PUD, Clark Public Utilities, Cowlitz County PUD, Eugene Water and Electric Board, Klickitat PUD, Grant County PUD, Lewis County PUD, Tacoma Power, Snohomish County PUD, and Benton PUD.

Acknowledgements

E3 thanks the staff of the Northwest Power and Conservation Council (NWPCC) for providing data and technical review.

Conventions

The following conventions are used throughout this report:

+ All costs are reported in **2016 dollars.**
+ All levelized costs are assumed to be **levelized in real terms** (i.e., a stream of payments over the lifetime of the contract that is constant in real dollars).

Acronyms

CONE	Cost of New Entry
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GENESYS	NWPCC's Generation Evaluation System Model
GHG	Greenhouse Gas
ISO	Independent System Operator
LOLE	Loss-of-Load Expectation
LOLF	Loss-of-Load Frequency
LOLP	Loss-of-Load Probability
MISO	Midwest Independent System Operator
MMT	Million Metric Ton
MTTR	Mean Time to Repair
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
PNUCC	Pacific Northwest Utilities Conference Committee
PRM	Planning Reserve Margin
RA	Resource Adequacy
RECAP	E3's Renewable Energy Capacity Planning Model
RPS	Renewables Portfolio Standard
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

Executive Summary

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

Background and Approach

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

- How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
- How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?
- How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
- How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
    - Natural gas generation is the most economic source of firm capacity today;

- o Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
- o Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
- o Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.

2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;

- o Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.

3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.

4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

- o Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- o Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;

- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy.

1 Introduction

1.1 Study Background & Context

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

1.2 Prior Studies

In 2017-2018, E3 completed a series of studies[1] for PGP and Climate Solutions to evaluate the costs of alternative electricity decarbonization strategies in Washington and Oregon. These studies were conducted using E3's RESOLVE model, which is a dispatch and investment model that identifies optimal long-term generation and transmission investments in the electric system to meet various decarbonization and renewable energy targets. The studies found that the least-cost pathway to reduce greenhouse gases from electricity generation is to replace coal generation with a mix of energy efficiency, renewables, and natural gas generation. While these studies examined in great detail the economics of new resources needed to achieve decarbonization, including the type, quantity, and location of these resources, they did not look in-depth at reliability and Resource Adequacy.

1.3 Purpose of Study

This study builds on the previous Northwest Low-Carbon Scenario Analysis conducted by E3 for PGP in 2017-2018 by focusing on long-run reliability and Resource Adequacy. This study uses E3's Renewable Energy Capacity Planning (RECAP) model, a loss-of-load-probability model designed specifically to test the Resource Adequacy of high-renewable electricity systems under a wide variety of weather conditions, renewable generation, and forced outages of electric generating resources. Specifically, this study examines four key questions:

+ How to maintain Resource Adequacy in the 2020-2030 timeframe under growing loads and increasing coal retirements?
+ How to maintain Resource Adequacy in the 2050 timeframe under different levels of carbon abatement goals, including zero carbon?

[1] https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/

- How much effective capacity can be provided by wind, solar, electric energy storage, and demand response?
- How much firm capacity is needed to maintain reliable electric service at various levels of carbon reductions?

1.4 Report Contents

The remainder of this report is organized as follows:

- Section 2 introduces Resource Adequacy and current practices in the Northwest
- Section 3 describes the study's modeling approach
- Section 4 highlights key inputs and assumptions used in the modeling
- Section 5 presents results across a variety of time horizons and resource portfolios
- Section 6 discusses implications of the results
- Section 7 summarizes the study's conclusions and lessons learned

2 Resource Adequacy in the Northwest

2.1 What is Resource Adequacy?

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run standard on the maximum frequency of reliability events where generation is insufficient to serve all load. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability. Ensuring resource adequacy is an important goal for utilities seeking to provide reliable service to their customers.

While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Council (NERC) and the Western Electric Coordinating Council (WECC) publish information about resource adequacy but have no formal governing role.

While a variety of approaches are used, the industry best practice is to establish a standard for resource adequacy using a two-step process:

+ **Loss-of-load-probability (LOLP) modeling:** LOLP modeling uses statistical techniques and/or Monte Carlo approaches to simulate the capability of a generation portfolio to produce sufficient generation to meet loads across a wide range of different conditions. Utilities plan the system to meet a specific reliability standard that is measured through LOLP modeling such as the expected frequency and/or size of reliability events; a relatively common standard used in LOLP modeling is “one day in ten years,” which is often translated to an expectation of 24 hours of lost load every ten years, or 2.4 hours per year.[2]

+ **Planning reserve margin (PRM) requirements:** Utilities then determine the required PRM necessary to ensure that the system will meet the specific the reliability standard from the LOLP modeling. A PRM establishes a total requirement for capacity based on the peak demand of an electric system plus some reserve margin to account for unexpected outages and extreme conditions; reserve margin requirements typically vary among utilities between 12-19% above peak demand. To meet this need, capacity from resources that can produce their full power on demand (e.g., nuclear, gas, coal) are typically counted at or near 100%, whereas resources that are constrained in their availability or ability to dispatch (e.g., hydro, storage, wind, solar) are typically de-rated below full capacity.

While LOLP modeling is more technically rigorous, most utilities perform LOLP modeling relatively infrequently and use a PRM requirement to heuristically ensure compliance with a specific reliability standard due to its relative simplicity and ease of implementation. The concept and application of a PRM to measure resource adequacy has historically worked well in a paradigm in which most generation capacity is “firm”; that is, the resource will be available to dispatch to full capacity, except in the event of unexpected forced outages. Under this paradigm, as long as the system has sufficient capacity to meet its peak demand (plus some reserve margin for extreme weather and unexpected forced outages), it will be capable of serving load throughout the rest of the year as well.

However, growing penetrations of variable (e.g., wind and solar) and energy-limited (e.g., hydro, electric energy storage, and demand response) resources require the application of increasingly sophisticated modeling tools to determine the appropriate PRM and to measure the contribution of each resource towards resource adequacy. Because wind and solar do not always generate during the system peak and because storage may run out of charge while it is serving the system peak, these resources are often de-

[2] Other common interpretations of the “one day in ten year” standard include 1 “event” (of unspecified duration) in ten years or “one hour in ten years” i.e., 0.1 hrs/yr

rated below the capability of a fully dispatchable thermal generator when counted toward meeting the PRM.

2.2 Planning Practices in the Northwest

A number of entities within the Northwest conduct analysis and planning for resource adequacy within the region. Under its charter to ensure prudent management of the region's federal hydro system while balancing environmental and energy needs, the Northwest Power and Conservation Council (NWPCC) conducts regular assessments of the resource adequacy position for the portion of the Northwest region served by the Bonneville Power Administration. The NWPCC has established an informal reliability target for the region of 5% annual loss of load probability[3]—a metric that ensures that the region will experience reliability events in fewer than one in twenty years—and uses GENESYS, a stochastic LOLP model with a robust treatment of the resource's variable hydroelectric conditions and capabilities, to examine whether regional resources are sufficient to meet this target on a five-year ahead basis.[4] These studies provide valuable information referenced by regulators and utilities throughout the region.

While the work of the Council is widely regarded as the most complete regional assessment of resource adequacy for the smaller region, the Council itself holds no formal decision-making authority to prescribe new capacity procurement or to enforce its reliability standards. Instead, the ultimate administration of resource adequacy lies in the hands of individual utilities, often subject to the oversight of state commissions. Most resource adequacy planning occurs within the planning and procurement processes

[3] This Council's standard, which focuses only on whether a reliability event occurred within a year, is unique to the Northwest and is not widely used throughout the rest of the North America

[4] The most recent of these reports, the Pacific Northwest Power Supply Adequacy Assessment for 2023, is available at: https://www.nwcouncil.org/sites/default/files/2018-7.pdf (accessed January 18, 2019).

of utilities: individual utilities submit integrated resource plans (IRPs) that consider long-term resource adequacy needs and conduct resource solicitations to satisfy those needs.

Utilities rely on a combination of self-owned generation, bilateral contracts, and front-office transactions (FOTs) to satisfy their resource adequacy requirements. FOTs represent short-term firm market purchases for physical power delivery. FOTs are contracted on both a month-ahead, day-ahead and hour-ahead basis. A survey of the utility IRPs in the Northwest reveals that most of the utilities expect to meet a significant portion of their peak capacity requirements in using FOTs.

FOTs may be available to utilities for several potential reasons including 1) the region as a whole has a capacity surplus and some generators are uncontracted to a specific utility or 2) natural load diversity between utilities such that one utility may have excess generation during another's peak load conditions and vice versa. The use of FOTs in place of designated firm resources can result in lower costs of providing electric service, as the cost of contracting with existing resources is generally lower than the cost of constructing new resources.

However, as loads grow in the region and coal generation retires, the region's capacity surplus is shrinking, and questions are emerging about whether sufficient resources will be available for utilities to contract with for month-ahead and day-ahead capacity products. In a market with tight load-resource balance, extensive reliance on FOTs risks under-investment in the firm capacity resources needed for reliable load service.

Table 1: Contribution of FOTs Toward Peak Capacity Requirements in 2018 in the Northwest

Utility	Capacity Requirement (MW)	Front Office Transactions (MW)	% of Capacity Requirement from FOTs
Puget Sound[5]	6,100	1,800	30%
Avista[6]	2,150	-	0%
Idaho Power[7]	3,078	313	10%
PacifiCorp[8]	11,645	462	4%
BPA[9]	11,506	-	0%
PGE[10]	4,209	106	3%
NorthWestern[11]	1,205	503	42%

[5] Figure 6-7: Available Mid C Tx plus Additional Mid-C Tx w/ renewals in PSE 2017 IRP: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/8a_2017_PSE_IRP_Chapter_book_compressed_110717.pdf?la=en&revision=bb9e004c-9da0-4f75-a594-6c30dd6223f4&hash=75800198E4E8517954C63B3D01E498F2C5AC10C2

[6] Figure 6.1 (for peak load), Chapter 4 Tables for resources in Avista 2017 IRP: https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2017-electric-irp-final.pdf?la=en

[7] Table 9.11 in Idaho Power 2017 IRP: https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf

[8] Table 5.2 in PacifiCorp 2017 IRP (Interruptible Contracts + Purchases): https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

[9] Bottom of the page in BPA fact sheet: https://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf

[10] PGE 2016 IRP Table P-1 Spot Market Purchases (rounded from 106), Capacity Need : https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp

[11] Table 2-2 for peak load and netted out existing resources (Ch. 8) @ 12%PRM from NorthWestern Energy 2015 IRP: https://www.northwesternenergy.com/our-company/regulatory-environment/2015-electricity-supply-resource-procurement-plan

3 Modeling Approach

3.1 Renewable Energy Capacity Planning (RECAP) Model

3.1.1 MODEL OVERVIEW

This study assesses the resource adequacy of electric generating resource portfolios for different decarbonization scenarios in the Northwest region using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a loss-of-load-probability model developed by E3 that has been used extensively to test the resource adequacy of electric systems across the North American continent, including California, Hawaii, Canada, the Pacific Northwest, the Upper Midwest, Texas, and Florida.

RECAP calculates a number of reliability metrics which are used to assess the resource adequacy for an electricity system with a given set of loads and generating resources.

+ **Loss of Load Expectation (hrs/yr) – LOLE**
  - The total number of hours in a year where load + reserves exceeds generation
+ **Expected Unserved Energy (MWh/yr) – EUE**
  - The total quantity of unserved energy in a year when load + reserves exceeds generation
+ **Loss of Load Probability (%/yr) – LOLP**
  - The probability in a year that load + reserves exceeds generation at any time
+ **Effective Load Carrying Capability (%) – ELCC**
  - The additional load met by an incremental generator while maintaining the same level of system reliability (used for dispatch-limited resources such as wind, solar, storage, hydro, and demand response). Equivalently, this is the quantity of perfectly dispatchable

generation that could be removed from the system by an incremental dispatch-limited generator

- **Planning Reserve Margin (%) – PRM**
  - The resource margin above a 1-in-2 peak load, in %, that is required in order to meet a specific reliability standard (such as 2.4 hrs./yr. LOLE)

This study uses 2.4 hrs./yr. LOLE reliability standard which is based on a commonly accepted 1-day-in-10-year standard. All portfolios that are developed by RECAP in this analysis for resource adequacy are designed to meet a 2.4 hrs./yr. LOLE standard.

RECAP calculates reliability statistics by simulating the electric system with a specific set of generating resources and loads under a wide variety of weather years, renewable generation years, and stochastic forced outages of electric generation resources and imports on transmission. By simulating the system thousands of times with different combinations of these factors, RECAP provides robust, stochastic estimation of LOLE and other reliability statistics.

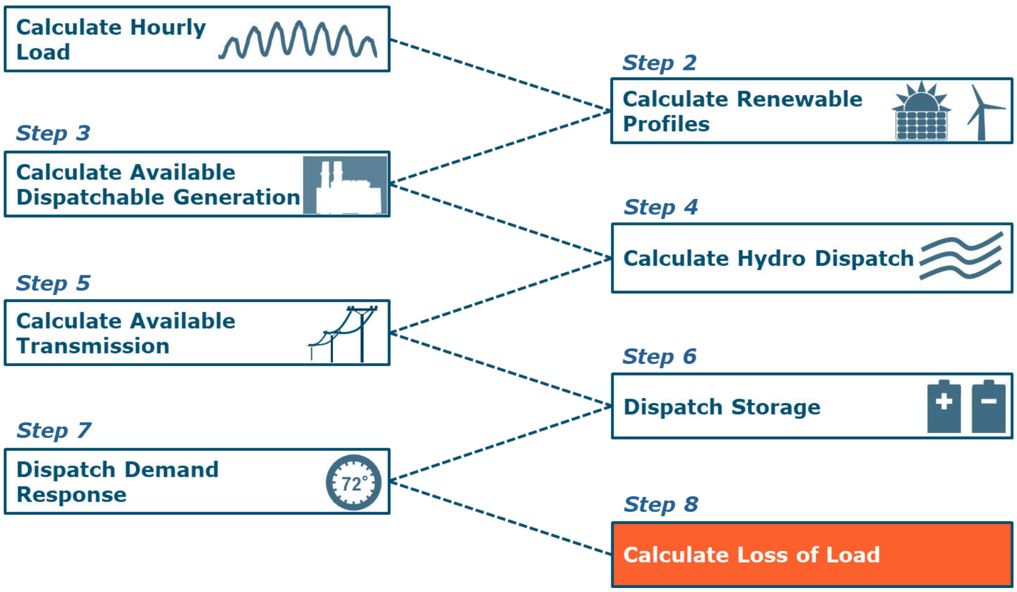
RECAP was specifically designed to calculate the reliability of electric systems operating under high penetrations of renewable energy and storage. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state of charge and energy availability for dispatch-limited resources such as hydro, energy storage, and demand response.

3.1.2 MODEL METHODOLOGY

The steps of the RECAP modeling process are shown below in Figure 1. RECAP calculates long-run resource availability through Monte Carlo simulation of electricity system resource availability using weather conditions from 1948-2017. Each simulation begins on January 1, 1948 and runs hourly through December 31, 2017. Hourly electric loads for 1948-2017 are synthesized using statistical analysis of actual load shapes and weather conditions for 2014-2017 combined with recorded historical weather conditions.

Then, hourly wind and solar generation profiles are drawn from simulations created by the National Renewable Energy Laboratory (NREL) and paired with historical weather days through an E3-created day-matching algorithm. Next, nameplate capacity and forced outage rates (FOR) for thermal generation are drawn from various sources including the GENESYS database and the Western Electric Coordinating Council's Anchor Data Set. Hydro is dispatched based on the load net of renewable and thermal generation. Annual hydro generation values are drawn randomly from 1929-2008 water years and shaped to calendar months and weeks based on the Northwest Power and Conservation Council's GENESYS model. For each hydro year, we identify all the hydro dispatch constraints including maximum and minimum power capacity, 2-hour to 10-hour sustained peaking limits, and hydro budget, specific to the randomly-drawn hydro condition. For each x-hour sustained peaking limit (where x = 2, 4, and 10), RECAP dispatches hydro so that the average capacity over consecutive x hours does not exceed the sustained peaking capability. Overall, hydro is dispatched to minimize the post-hydro net load subject to the above constraints. In other words, hydro is used within assumed constraints to meet peak load needs while minimizing loss-of-load. Finally, RECAP uses storage and demand response to tackle the loss-of-load hours and storage is only discharged during loss-of-load hours. A more detailed description of the RECAP model is in Appendix B.2.

Figure 1: Overview of RECAP Model



3.1.3 PORTFOLIO DEVELOPMENT

RECAP is used in this study to both test the reliability of the existing 2018 Greater Northwest electricity system as well as to determine a total capacity need in 2030 and to develop portfolios in 2050 under various levels of decarbonization that meet a 1-day-in-10-year reliability standard of 2.4 hrs./yr.

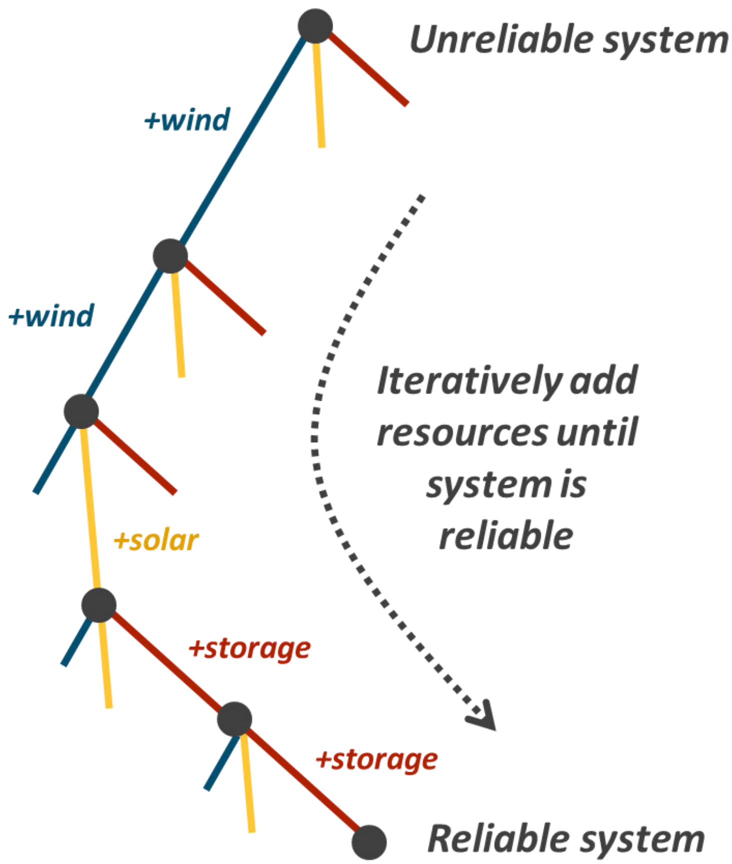
To develop each 2050 decarbonization portfolio, RECAP calculates the reliability of the system in 2050 after forecasted load growth and the removal of all fossil generation but the maintenance of all existing carbon-free resources. Unsurprisingly, these portfolios are significantly less reliable than the required 2.4 hrs./yr. nor do they deliver enough carbon-free generation to meet the various decarbonization targets. To improve the reliability and increase GHG-free generation of these portfolios, RECAP tests the contribution of small, equal-cost increments of candidate GHG-free resources. The seven candidate resources in this study are:

+ Northwest Wind (WA/OR)
+ Montana Wind
+ Wyoming Wind
+ Solar (based on an assumed diverse mix of resources from each state)
+ 4-Hour Storage
+ 8-Hour Storage
+ 16-Hour Storage

The resource that improves reliability the most (as measured in loss-of-load-expectation) is then added to the system. This process is repeated until the delivered GHG-free generation is sufficient to meet the GHG target (e.g., 80% reduction) for each particular scenario. Once a portfolio has achieved the objective GHG target, RECAP calculates the residual quantity of perfect firm capacity that is needed to bring the portfolio in compliance with a reliability standard of 2.4 hrs./yr. This perfect firm MW capacity is converted to MW of natural gas capacity by grossing up by 5% to account for forced outages. Natural gas capacity is used because it is the most economic source of firm capacity. To the extent that other carbon-free resources can substitute for natural gas capacity, this is reflected in deeper decarbonization portfolios that have higher quantities of wind, solar, and storage along with a smaller residual requirement for firm natural gas capacity.

Figure 2 illustrates a simple example of this portfolio development process where RECAP has 3 candidate resources: wind, solar, and storage. The model evaluates the contribution to reliability of equal-cost increments of the three candidate resources and selects the resource that improves reliability the most. From that new portfolio, the process is repeated until either the system reaches a reliability standard of 2.4 or a particular GHG target is achieved.

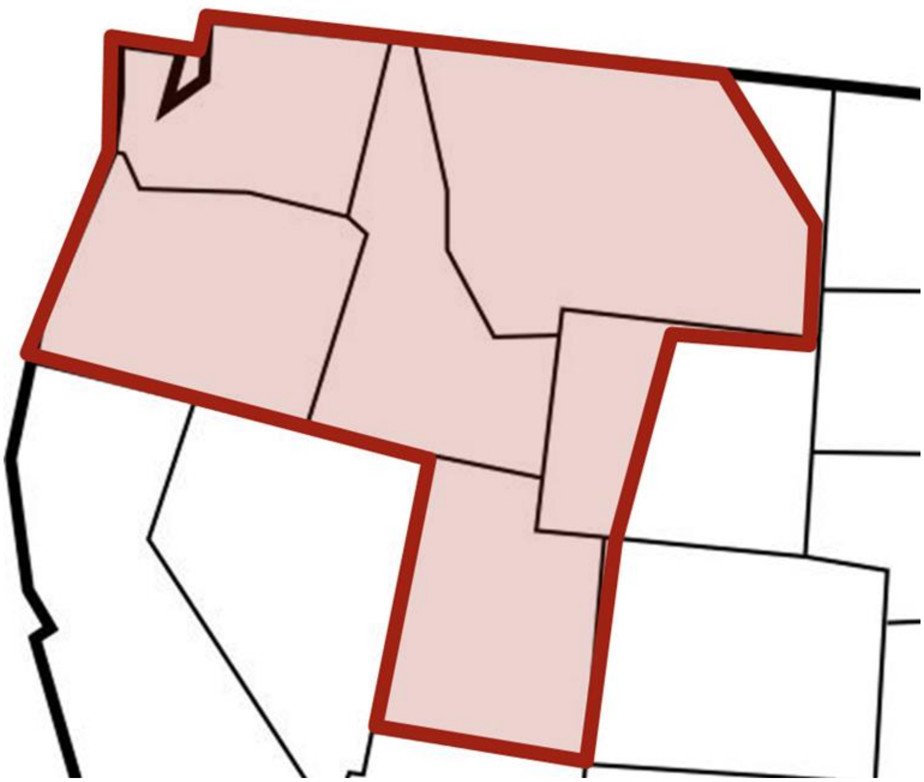
Figure 2: RECAP Portfolio Development Process



3.2 Study Region

The geographic region for this study consists of the U.S. portion of the Northwest Power Pool (NWPP), excluding Nevada, which this study refers to as the "Greater Northwest". This region includes the states of Washington, Oregon, Idaho, Utah, and parts of Montana and Wyoming.

Figure 3: The study region - The Greater Northwest



It is important to note that this is a larger region than was analyzed in the prior E3 decarbonization work in the Northwest which only analyzed a “Core Northwest” region consisting of Oregon, Washington, northern Idaho and Western Montana. The larger footprint encompasses the utilities that have traditionally coordinated operational efficiencies through programs under the Northwest Power Pool and includes utilities that typically transact with each other to maintain resource adequacy and optimize resource portfolios. The larger region also incorporates a footprint that allows for diversity of both load and resources which minimizes the need for firm capacity. The Balancing Authority Areas (BAAs) that were included in this Greater Northwest study region are listed in Table 2.

Table 2: List of Balancing Authorities Included in Study

Balancing Authority Areas Included in Greater Northwest Study Region		
Avista	Bonneville Power Administration	Chelan County PUD
Douglas County PUD	Grant County PUD	Idaho Power
NorthWestern	PacifiCorp East	PacifiCorp West
Portland General Electric	Puget Sound Energy	Seattle City Light
Tacoma Power	Western Area Power Administration Upper Great Plains	

3.3 Scenarios & Sensitivities

This study examines the resource adequacy requirements of the Greater Northwest region across multiple timeframes and decarbonization scenarios.

+ **Near-term (2018)** reliability statistics are calculated for today's system based on 2018 existing loads and resources. These results are presented to give the reader a sense of existing challenges and as a reference for other scenario results.
+ **Medium-term (2030)** reliability statistics are calculated in 2030 for two scenarios: a *Reference* scenario and a *No Coal* scenario. The *Reference* scenario includes the impact of expected load growth and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants. The *No Coal* scenario assumes that all coal is retired.
+ **Long-term (2050)** reliability statistics are calculated in 2050 for multiple scenarios including a *Reference* scenario and for a range of decarbonization targets. The *Reference* scenario includes the impact of load growth, growth in renewable capacity to meet current RPS policy goals, and the retirement of all coal. Decarbonization scenarios assume GHG emissions are reduced to 60%, 80%, 90%, 98% and 100% below 1990 GHG levels through the addition of wind, solar, and electric energy storage.

These scenarios are summarized in Table 3.

Table 3: List of Scenarios and Descriptions

Analysis Period	Scenario	Description
Near-term (2018)	Reference	2018 Existing Loads and Resources
Medium-Term (2030)	Reference	Includes load growth through 2030 and announced generation retirements, notably the Boardman, Centralia, and Colstrip coal plants
	No Coal	Same as 2030 reference but all coal generation in the region is retired (11 GW)
Long-Term (2050)	Reference	Includes load growth through 2050, renewable capacity additions to meet RPS targets, and ***retirement of all coal generation*** (11 GW)
	60% GHG Reduction	Scenarios achieve specified greenhouse gas reduction (relative to 1990 levels) through addition of solar, wind, and energy storage; sufficient gas generating capacity is maintained to ensure reliability (except in 100% GHG Reduction)
	80% GHG Reduction	
	90% GHG Reduction	
	98% GHG Reduction	
	100% GHG Reduction	

This study further explores the potential resource adequacy needs of a 100% carbon free electricity system in 2050 recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. To better understand how those technologies might impact the viability of achieving this ambitious goal, the study includes several sensitivity analyses of the 100% GHG Reduction scenario that assume the wide-scale availability of several such emerging technology options. These sensitivities are described in Table 4.

Table 4: 100% GHG Reduction in 2050 Sensitivities

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

3.4 Key Portfolio Metrics

Each of the scenarios is evaluated using several different metrics which are defined below:

3.4.1 CLEAN ENERGY METRICS

A number of metrics are used to characterize the greenhouse gas content of generation within the region in each of the scenarios. These are:

+ Greenhouse Gas Emissions (MMT CO2): the annual quantity of greenhouse gas emissions attributed to ratepayers of the Greater Northwest region, measured in million metric tons.
+ Greenhouse Gas Reduction (%): the reduction below 1990 emission levels (approximately 60 million metric tons) for the Greater Northwest region.
+ Clean Portfolio Standard (%): the total quantity of GHG-free generation (including renewable, hydro, and nuclear) divided by retail electricity sales. Because this metric allows the region to retain the clean attribute for exported electricity and offset in-region or imported natural gas

generation, this metric can achieve or exceed 100% without reducing GHGs to zero. This metric is presented because it is a common policy target metric across many jurisdictions to measure clean energy progress and is the near-universal metric used for state-level Renewables Portfolio Standards. This metric is consistent with California's SB 100 which mandates 100% clean energy by 2045.

+ **GHG-Free Generation (%):** the total quantity of GHG-free generation, minus exported GHG-free generation, divided by total wholesale load. For this metric, exported clean energy cannot be netted against in-region or imported natural gas generation. When this metric reaches 100%, GHG emissions have been reduced to zero.

3.4.2 COST METRICS

+ **Renewable Curtailment (%):** the total quantity of wind and solar generation that cannot be delivered to loads in the region or exported, expressed as a share of total available potential generation from wind and solar resources.

+ **Annual Cost Delta ($B)** is the annual cost in 2050 of decarbonization scenarios relative to the 2050 Reference scenario. While the 2050 Reference scenario will require significant costs to meet load growth, this metric only evaluates the *change* in costs for each decarbonization scenario relative to the Reference scenario. By definition, the 2050 Reference scenario has an annual cost delta of zero. The annual cost delta is calculated by comparing the incremental cost of new wind, solar, and storage resources to the avoided cost of natural gas capital and operational costs.

+ **Additional Cost ($/MWh)** is the total annual cost delta ($B) divided by total wholesale load, which provides an average measure of the incremental rate impact borne by ratepayers within the region. While this metric helps to contextualize the annual cost delta, it is important to note that the incremental cost will not be borne equally by all load within the Greater Northwest region and some utilities may experience higher additional costs.

3.5 Study Caveats

3.5.1 COST RESULTS

The study reports the incremental costs of achieving various GHG targets relative to the cost of the reference scenario. While the method used to estimate capital and dispatch costs is robust, it does not entail optimization and the results should be regarded as high-level estimates. For this reason, a range of potential incremental costs are reported rather than a point estimate. The range is determined by varying the cost of wind, solar, energy storage and natural gas.

3.5.2 HYDRO DISPATCH

For this study, RECAP utilizes a range of hydro conditions based on NWPCC data covering the time period 1929 – 2008. Within each hydro year, hydroelectric energy "budgets" for each month are allocated to individual weeks and then dispatched to minimize net load, subject to sustained peaking limit constraints that are appropriate for the water conditions. Hydro resources are dispatched optimally within each week with perfect foresight. There are many real-life issues such as biological conditions, flood control, coordination between different project operators, and others that may constrain hydro operations further than what is assumed for this study.

3.5.3 TRANSMISSION CONSTRAINTS

This analysis treats the Greater Northwest region as one zone with no internal transmission constraints or transactional friction. In reality, there are constraints in the region that may prevent a resource in one corner of the region from being able to serve load in another corner. To the extent that constraints exist, the Greater Northwest region may be less resource adequate than is calculated in this study and additional effective capacity would be required to achieve the calculated level of resource adequacy. It is assumed that new transmission can be developed to deliver energy from new renewable resources to wherever it is needed, for a cost that is represented by the generic transmission cost adder applied to resources in different locations.

3.5.4 INDIVIDUAL UTILITY RESULTS

Cost and resource results in this study are presented from the system perspective and represent an aggregation of the entire Greater Northwest region. These societal costs include all capital investment costs (i.e., “steel in the ground”) and operational costs (i.e., fuel and operation and maintenance) that are incurred in the region. The question of how these societal costs are allocated between individual utilities is not addressed in this study, but costs for individual utilities may be higher or lower compared to the region as a whole. Utilities with a relatively higher composition of fossil resources today are likely to bear a higher cost than utilities with a higher composition of fossil-free resources.

Resource adequacy needs will also be different for each utility as individual systems will need a higher planning reserve margin than the Greater Northwest region as a whole due to smaller size and less diversity. The capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production.

3.5.5 RENEWABLE RESOURCE AVALIBILITY AND LAND USE

The renewable resource availability assumed for this study is based on technical potential as assessed by NREL. It is assumed wind and solar generation can be developed in each location modeled in this study up to the technical potential. However, the land consumption is significant for some scenarios and it is not clear whether enough suitable sites can be found to develop the large quantities of resources needed for some scenarios. Land use is also a significant concern for the new transmission corridors that would be required.

4 Key Inputs & Assumptions

4.1 Load Forecast

The Greater Northwest region had an annual load of 247 TWh and peak load of 43 GW in 2017. This data was obtained by aggregating hourly load data from the Western Electric Coordinating Council (WECC) for each of the selected balancing authority areas in the Greater Northwest region.

This study assumes annual load growth of **1.3% pre-energy efficiency** and **0.7% post-energy efficiency**. This assumption is consistent with the previous E3 decarbonization work for Oregon and Washington and is benchmarked to multiple long-term publicly available projections listed in Table 5. The post-energy efficiency growth rate includes the impact of all cost-effective energy efficiency identified by the NWPCC, scaled up to the full Greater Northwest region and assumed to continue beyond the end of the Council's time horizon. Electrification of vehicles and buildings is only included to the extent that it is reflected in these load growth forecasts. For example, the NWPCC forecast includes the impact of 1.1 million electric vehicles by 2030.

In general, E3 believes these load growth forecasts are conservatively low because they exclude the effect of vehicle and building electrification that would be expected in a deeply decarbonized economy. To the extent that electrification is higher than forecasted in this study, resource adequacy requirements would also increase. In this study, total loads increase 25% by 2050, whereas other studies[12] that have comprehensively examined cost-effective strategies for economy-wide decarbonization include

[12] https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

significant quantities of building, vehicle, and industry electrification that cause electricity-sector loads to grow by upwards of 60% by 2050 even with significant investments in energy efficiency.

Table 5. Annual load growth forecasts for the Northwest

Source	Pre EE	Post EE
PNUCC Load Forecast	1.7%	0.9%
BPA White Book	1.1%	-
NWPCC 7th Plan	0.9%	0.0%
WECC TEPPC 2026 Common Case	-	1.3%
E3 Assumption	**1.3%**	**0.7%**

Hourly load profiles are assumed to be constant through the analysis period and do not account for any potential impact due to electrification of loads or climate change. The Greater Northwest system is a winter peaking system with loads that are highest during cold snaps on December and January mornings and evenings. An illustration of the average month/hour load profile for the Greater Northwest is shown in Figure 4.

Figure 4: Month/Hour Average Hourly Load in the Greater Northwest (GW)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	28	27	26	26	26	27	29	32	33	34	33	33	32	32	31	31	31	32	34	34	33	33	31	29
Feb	26	25	25	25	25	26	28	31	32	32	32	31	31	30	29	29	29	30	31	32	32	31	30	28
Mar	24	23	23	23	24	25	28	30	30	30	30	29	29	28	28	27	27	28	28	29	29	28	27	25
Apr	22	22	21	22	22	24	27	28	28	28	28	27	27	27	26	26	26	26	27	27	28	27	25	23
May	22	21	21	21	21	22	24	26	26	27	27	27	27	27	27	27	27	27	27	27	27	27	25	23
Jun	23	22	21	21	22	22	24	26	27	27	28	28	29	29	29	29	29	29	29	29	28	28	26	24
Jul	24	23	22	22	22	23	24	26	27	28	29	30	31	31	32	32	32	32	32	31	30	30	28	26
Aug	23	22	21	21	21	22	24	25	26	27	28	29	29	30	30	31	31	31	30	30	30	28	26	24
Sep	21	20	20	20	20	22	24	25	26	26	26	27	27	27	27	27	27	28	27	28	27	26	24	22
Oct	21	21	20	20	21	23	25	26	27	27	27	27	27	26	26	26	26	27	27	28	27	26	24	22
Nov	24	23	23	23	23	24	26	28	30	30	30	29	29	28	28	28	28	29	31	30	30	29	28	26
Dec	27	26	26	26	26	27	29	31	33	33	33	32	32	31	31	31	31	33	34	34	33	33	31	29

Projecting these hourly loads using the post-energy efficiency load growth forecasts yields the following load projections in 2030 and 2050.

Table 6. Load projections in 2030 and 2050 for the Greater NW Region

Load	2018	2030	2050
Median Peak Load (GW)	43	47	54
Annual Energy Load (TWh)	247	269	309

To evaluate the reliability of the Greater Northwest system under a range of weather conditions, hourly load forecasts for 2030 and 2050 are developed over seventy years of weather conditions (1948-2017). Historical weather data was obtained from the National Oceanic and Atmospheric Administration (NOAA) for the following sites in the Greater Northwest region.

Table 7: List of NOAA Sites for Historical Temperature Data

City	Site ID
Billings, MT	USW00024033
Boise, ID	USW00024131
Portland, OR	USW00024229
Salt Lake City, UT	USW00024127
Seattle, WA	USW00024233
Spokane, WA	USW00024157

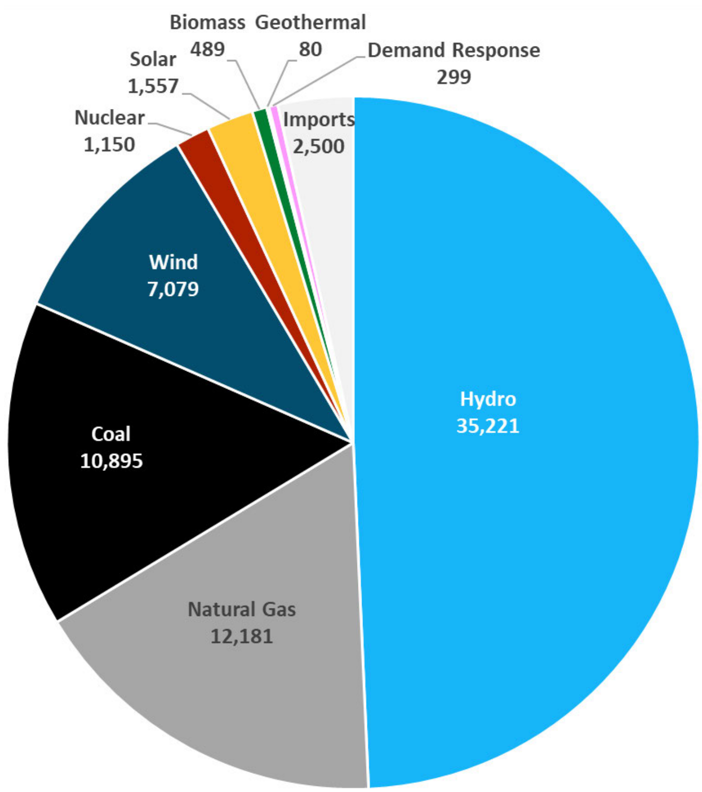
4.2 Existing Resources

A dataset of existing generating resources in the Greater Northwest was derived from two sources: 1) the NWPCC's GENESYS model, used to characterize all plants within the Council's planning footprint; and 2) the WECC's Anchor Data Set, used to gather input data for all existing plants in areas outside of the NWPCC's footprint. For each resource, the dataset contains:

+ Dependable capacity (MW)
+ Location
+ Commission and announced retirement date
+ Forced outage rate (FOR) and mean time to repair (MTTR)

A breakdown of existing resources by type is shown in Figure 5.

Figure 5: Existing 2018 Installed Capacity (MW) by Resource Type



Several power plants have announced plans to retire one or more units. The table below lists the notable coal and natural gas planned retirements through 2030.

Table 8: Planned Coal and Natural Gas Retirements

Power Plant	Resource Type	Capacity (MW)
Boardman	Coal	522
Centralia	Coal	1,340
Colstrip 1 & 2	Coal	614
North Valmy	Coal	261
Naughton	Natural Gas	330

4.2.1 WIND AND SOLAR PROFILES

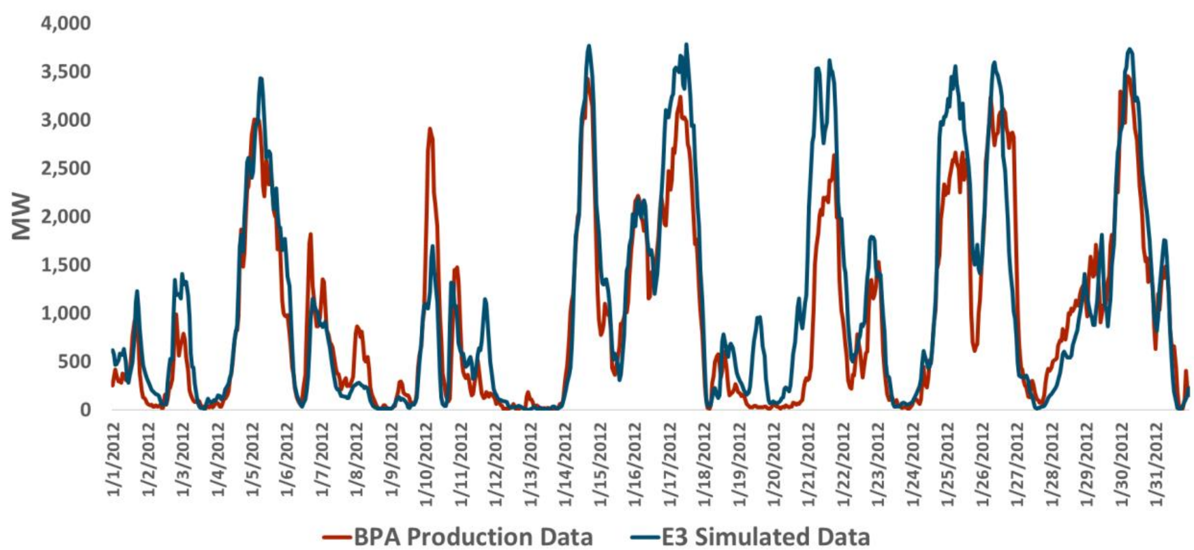
Hourly wind and solar data were collected for each existing resource in the combined dataset at the location of the resource. For wind, NREL's Wind Integration National Dataset Toolkit was used which includes historical hourly wind speed data from 2007-2012. For solar, NREL's Solar Prospector Database was used which includes historical hourly solar insolation data from 1998-2012. These hourly wind speeds and solar insolation values were then converted into power generation values using the NREL System Advisor Model (SAM) under assumptions for wind turbine characteristics (turbine power curve and hub height) and solar panel characteristics (solar inverter ratio). RECAP simulates future electricity generation from existing wind and solar resources using the historical wind speed data and solar insolation data respectively.

Simulated wind generation from existing wind plants within BPA territory was benchmarked to historical wind production data[13]. To simulate wind generation from existing plants accurately, wind turbine

[13] BPA publishes production from wind plants within its Balancing Authority Area in 5-min increments: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx

technology (power curve and hub height) varies for each existing wind farm, based on the year of installation. Figure 6 shows how the simulated wind production compares to historical wind production in BPA territory in January 2012.

Figure 6: Comparison of historical wind generation to simulated wind production for January 2012



A detailed description of the renewable profile simulation process is described in Appendix C.

4.2.2 HYDRO

Hydro availability is based on a random distribution of the historical hydro record using the water years from 1929-2008. This data was obtained from the NWPCC's GENESYS model. Future electricity generation from existing hydro resources is simulated using the historical hydro availability. Available hydro energy is dispatched in RECAP subject to sustained peaking limits (1-hr, 2-hr, 4-hr, 10-hr) and minimum output levels. The sustained peaking limits are based on detailed hydrological models developed by NWPCC. Available hydro budgets, sustained peaking limits, and minimum output levels are shown for three hydro years – 1937 (critical hydro year), 1996 (high hydro year), and 2007 (typical hydro year). The 10-hour sustained peaking limits for each month represent the maximum average generation for any continuous 10-hour period within the month.

Figure 7: Monthly budgets, sustained peaking limits and minimum outputs levels for 1937 (critical hydro)

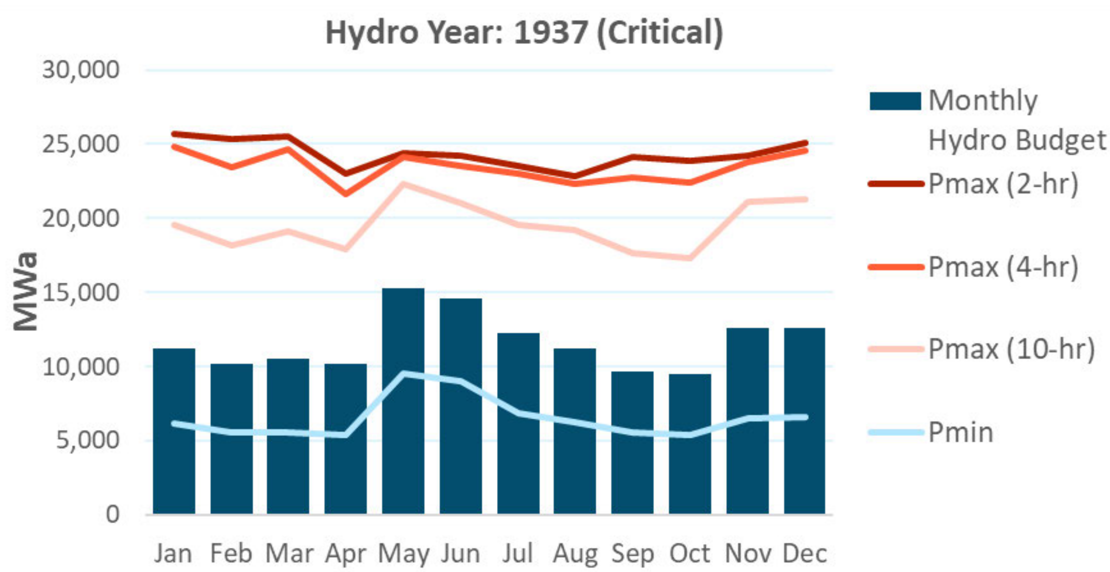


Figure 8: Monthly budgets, sustained peaking limits and minimum outputs levels for 1996 (high hydro)

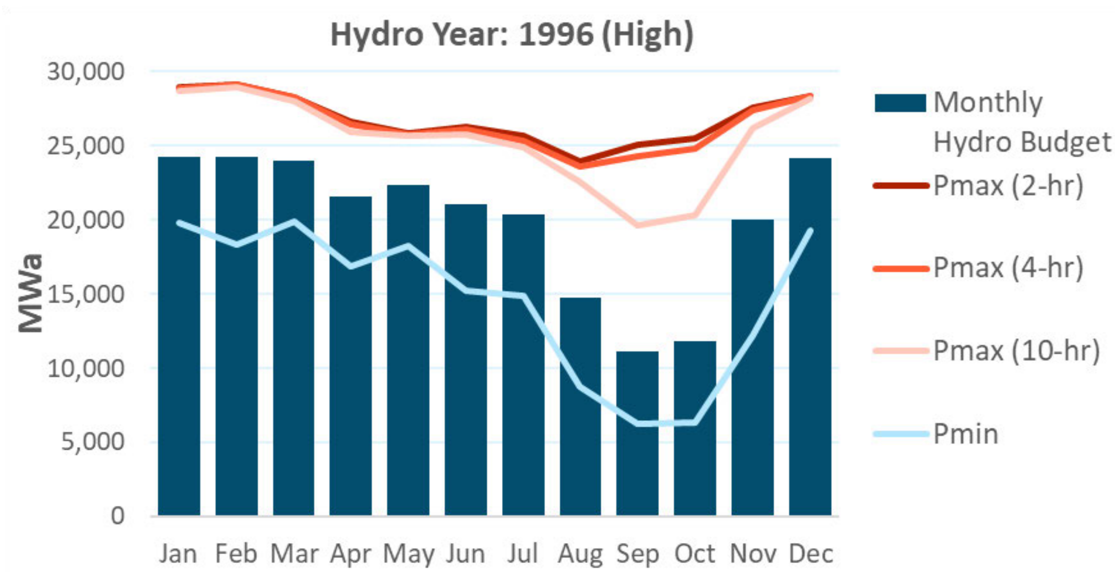
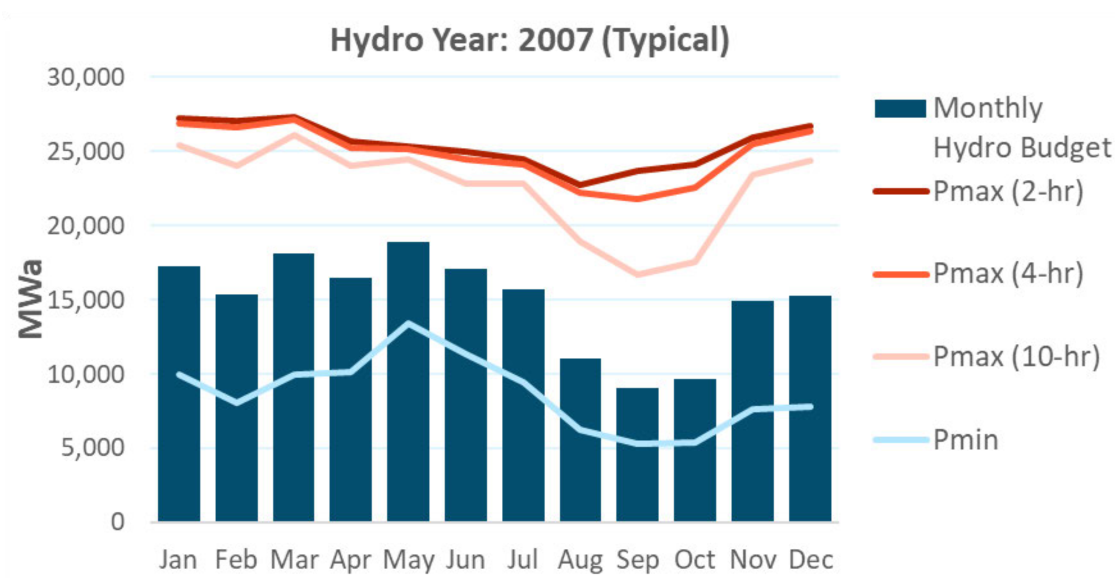


Figure 9: Monthly budgets, sustained peaking limits and minimum outputs levels for 2007 (typical hydro)



4.2.3 IMPORTS/EXPORTS

The Greater Northwest region is treated as one zone within the model, but it does have the ability to import and export energy with neighboring regions, notably California, Canada, Rocky Mountains, and the Southwest. Import and export assumptions used in this model are consistent with the NWPCC's GENESYS model and are listed in Table 9. Monthly and hourly import availabilities are additive but in no hour can exceed the simultaneous import limit of 3,400 MW. In the 100% GHG Reduction scenarios, import availability is set to zero to prevent the region from relying on fossil fuel imports.

Table 9: Import Limits

Import Type	Availability	MW
Monthly Imports	Nov – Mar	2,500
	Oct	1,250
	Apr – Sep	-
Hourly Imports	HE 22 – HE 5	3,000
	HE 5 – HE 22	-
Simultaneous Import Limit	**All Hours**	**3,400**

For the purposes of calculating the CPS % metric i.e., "clean portfolio standard", the model assumes an instantaneous exports limit of 7,200 MW in all hours.

Table 10: Export Limit

Export Type	Availability	MW
Simultaneous Export Limit	**All Hours**	**7,200**

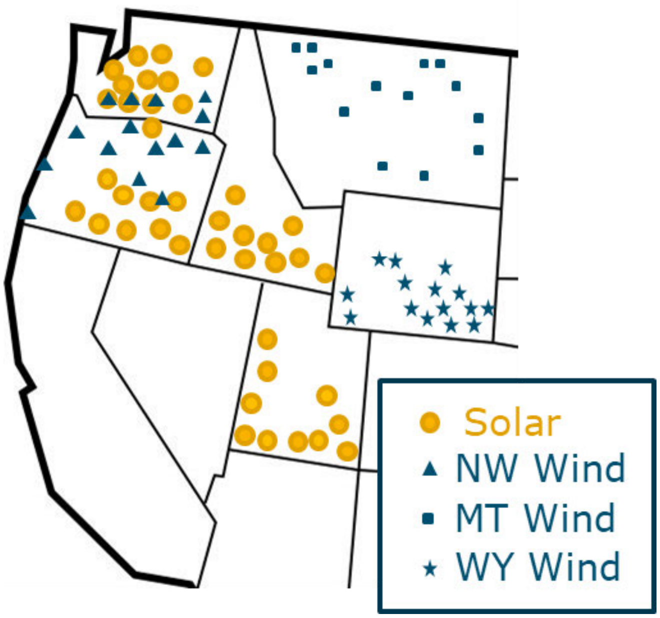
4.3 Candidate Resources

Candidate resources are used to develop portfolios of resources in 2050 to both achieve GHG reduction targets or ensure acceptable reliability of 2.4 hrs./yr. LOLE. For a more detailed description of the portfolio development process, see Section 3.1.3. The 7 candidate resources are:

+ Solar (geographically diverse across Greater Northwest)
+ Northwest Wind (WA/OR)
+ Montana Wind
+ Wyoming Wind
+ 4-Hour Storage
+ 8-Hour Storage
+ 16-Hour Storage

Natural gas generation is also added as needed to meet any remaining reliability gaps after the GHG reduction target is met. The new renewable candidate resources (solar, NW wind, MT wind, WY wind) are assumed to be added proportionally across a geographically diverse footprint which has a strong impact on the ability of variable renewable resources to provide reliable power that can substitute for firm generation. Figure 10 illustrates the location of new candidate renewable resources. When a resource is added, it is added proportionally at each of the locations shown in the figure below.

Figure 10: New Renewable Candidate Resources



The generation output profile for each location was simulated by gathering hourly wind speed and solar insolation data from NREL's Wind Integration National Dataset Toolkit and Solar Prospector Database and converting to power output using NREL's System Advisor Model. The wind profiles used in this study are based on 135 GW of underlying wind production data from hundreds of sites. The solar profiles used in this study are based on 80 GW of underlying solar production data across four states. This process is described in more detail in Appendix C.

New storage resources are available to the model in different increments of duration at different costs which provide different value in terms of both reliability and renewable integration for GHG reduction. Note that the model can choose different quantities of each storage duration which results in a fleet-wide storage duration that is different than any individual storage candidate resource. Because storage is modeled in terms of capacity charge/discharge and duration, many different storage technologies could provide this capability. The cost forecast trajectory for Li-Ion battery storage was used to estimate costs, but any storage technology that could provide equivalent capacity and duration, such as pumped hydro or flow batteries, could substitute for the storage included in the portfolio results of this study.

New renewable portfolios are within the bounds of current technical potential estimates published in NREL.

Table 11. NREL Technical Potential (GW)

State	Wind Technical Potential (GW)
Washington	18
Oregon	27
Idaho	18
Montana	944
Wyoming	552
Utah	13
Total	**1,588**

4.3.1.1 Resource Costs

All costs in this study are presented in 2016 dollars. The average cost of each resource over the 2018-2050 timeframe is shown in Table 12 while the annual cost trajectories from 2018-2050 are shown in Figure 11.

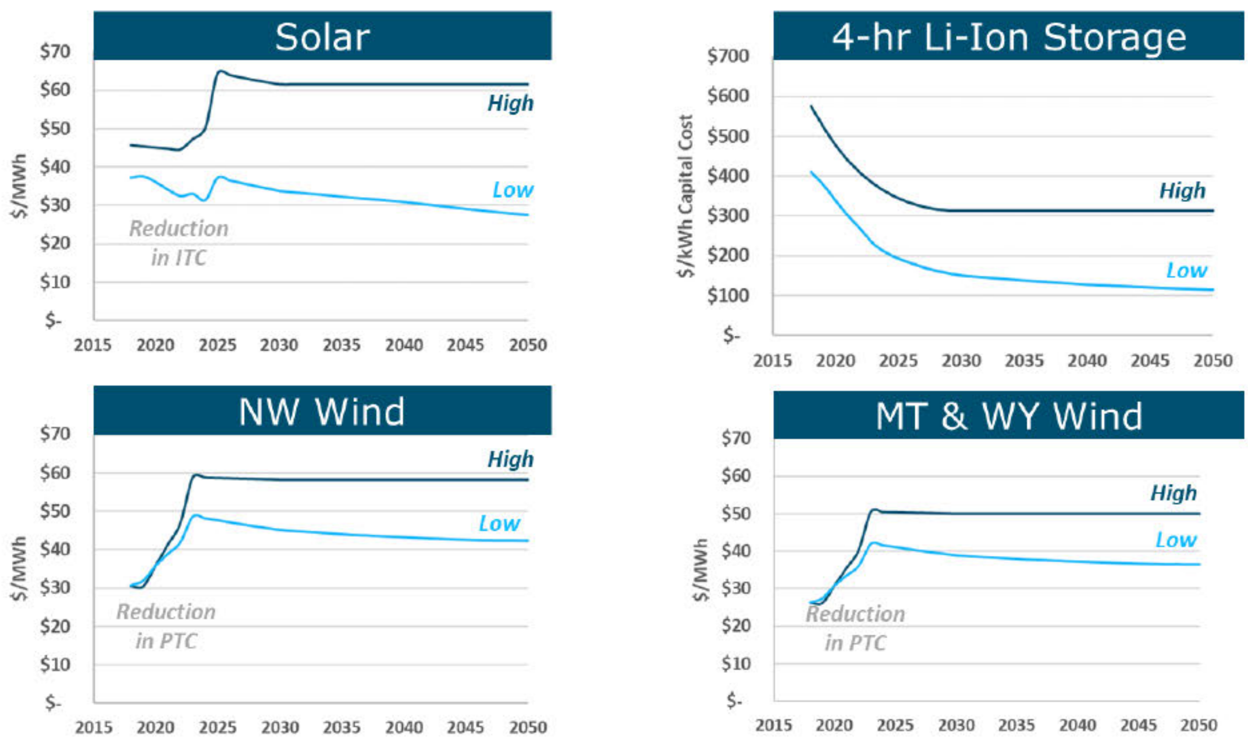
Table 12. Resource Cost Assumptions (2016 $)

Technology	Unit	High[14]	Low[15]	Transmission	Notes
Solar PV	$/MWh	$59	$32	$8	Capacity factor = 27%
NW Wind	$/MWh	$55	$43	$6	Capacity factor = 37%
MT/WY Wind	$/MWh	$48	$37	$19	Capacity factor = 43%
4-hr Battery	$/kW-yr	$194	$97		

[14] Source for high prices: 2017 E3 PGP Decarbonization Study
[15] Source for low prices: NREL 2018 ATB Mid case for wind and solar; Lazard LCOS Mid case 4.0 for batteries

Technology	Unit	High[14]	Low[15]	Transmission	Notes
8-hr Battery	$/kW-yr	$358	$189		
16-hr Battery	$/kW-yr	$686	$373		
Natural Gas Capacity	$/kW-yr	$150	$150		7,000 Btu/kWh heat rate; $5/MWh variable O&M
Gas Price	$/MMBtu	$4	$2		
Biogas Price	$/MMBtu	$39	$39		

Figure 11: Cost trajectories over the 2018-2050 timeframe (2016 $)



4.4 Estimating Cost and GHG Metrics

The cost of the future electricity portfolios consists of (1) fixed capital costs for building new resources, and (2) operating costs for running both existing and new resources. For new wind and new solar resources, the cost of generation is calculated using their respective levelized costs (see Table 12). Cost of electricity generation from natural gas plants includes both the capital cost for new natural gas plants and the operating costs (fuel costs and variable operating costs). All the natural gas plants are assumed to operate at a heat rate of 7,000 Btu/kWh, with the price of natural gas varying from $2 to $4 per MMBtu (see Table 12). Storage resources are assumed to have only fixed cost, but no operating cost. All exports are assumed to yield revenues of $30 per MWh.

In this study, annual GHG emissions are compared against 1990 emission levels, when the emissions for the Greater Northwest region was 60 million metric tons. GHG emissions are calculated for each thermal resource depending on the fuel type. For natural gas plants, an emission rate of 117 lb. of CO_2 per MMBtu of natural gas is assumed, yielding 0.371 metric tons of CO_2 per MWh of electricity generated from natural gas (assumed 7,000 Btu/kWh heat rate). For coal plants, an emission rate of 1.0 ton of CO_2 per MWh of electricity generated from coal is assumed.

5 Results

5.1 Short-Term Outlook (2018)

The 2018 system (today's system) in the study region is supplied by a mix of various resources, as described in Section 4.2. The annual electricity load for the study region is 247 TWh with a winter peak demand of 43 GW. Hydro energy provides the plurality of generation capacity with significant contributions from natural gas, coal and wind generation.

Resource adequacy conclusions vary depending on what metric is used for evaluation. The region has sufficient capacity to meet the current standard used by the NWPCC of 5% annual loss of load probability (LOLP). The region does not have sufficient capacity to meet the 2.4 hrs./yr. LOLE standard used in this study. In other words, most loss of load is concentrated in a few number of years which matches intuition for a system that is dependent upon the annual hydro cycle and susceptible to drought conditions. Full reliability statistics for the Greater Northwest region are shown in Table 13.

Table 13. 2018 Reliability Statistics

Metric	Units	Value
Annual LOLP (%)	%	3.7%
Loss of Load Expectation (LOLE)	hrs/yr	6.5
Expected Unserved Energy (EUE)	MWh/yr	5,777
Normalized EUE	%	0.003%
1-in-2 Peak Load	GW	43
PRM Requirement	% of peak	12%
Total Effective Capacity Requirement	GW	48

Table 14. 2018 Load and Resource Balance

Load			Load GW
Peak Load			42.1
Firm Exports			1.1
PRM (12%)			5.2
Total Requirement			**48.4**
Resources	**Nameplate GW**	**Effective %**	**Effective GW**
Coal	10.9	100%	10.9
Gas	12.2	100%	12.2
Biomass & Geothermal	0.6	100%	0.6
Nuclear	1.2	100%	1.2
Demand Response	0.6	50%	0.3
Hydro	35.2	53%	18.7
Wind	7.1	7%	0.5
Solar	1.6	12%	0.2
Storage	0	—	0
Total Internal Generation	**69.1**		**44.7**
Firm Imports	3.4	74%	2.5
Total Supply	**72.5**		**47.2**
Surplus/Deficit			
Capacity Surplus/Deficit			**-1.2**

In order to meet an LOLE target of 2.4 hrs./yr., a planning reserve margin (PRM) of 12% is required. The PRM is calculated by dividing the quantity of effective capacity needed to meet the LOLE target by the median peak load, then subtracting one. This result is lower than many individual utilities currently hold within the region (typical PRM ~15%) due to the load and resource diversity across the geographically large Greater Northwest region. As shown in Table 14, the total effective capacity (47 GW) available is slightly lower than the total capacity requirement (48 GW) which is consistent with the finding that the system is not sufficiently reliable to meet a 2.4 hrs./yr. LOLE target. The effective capacity percent contributions from wind and solar are shown to be 7% and 12%, respectively. These relatively low values stem primarily from the non-coincidence of wind and solar production during high load events in the Greater Northwest region, notably very cold winter mornings and evenings.

It should be noted that the effectiveness of firm capacity is set to 100% by convention in calculating a PRM. The contribution of variable resources is then measured relative to firm capacity, incorporating the effect of forced outage rates for firm resources.

5.2 Medium-Term Outlook (2030)

The Greater Northwest system in 2030 is examined under two scenarios:

+ **Reference**
    - Planned coal retirements; new gas gen for reliability
+ **No Coal**
    - All coal retired; new gas gen for reliability

The resulting generation portfolios in both scenarios (both of which meet the 2.4 hrs./yr. LOLE reliability standard) are shown in Figure 12 alongside the 2018 system for context. To account for the load growth by 2030, 5 GW of net new capacity is required to maintain reliability. In the *Reference* Scenario where 3 GW of coal is retired, 8 GW of new firm capacity is needed by 2030 for reliability. Similarly, the *No Coal* Scenario (where all 11 GW of coal is retired) results in 16 GW of new firm capacity need by 2030. The study assumes all the new capacity in the 2030 timeframe need is met through additional natural gas build. It should be noted that regardless of what resource mix is built to replace the retirement of coal, the siting, permitting, and construction of these new resources will take significant time so planning for these resources needs to begin well before actual need. The portfolio tables for each scenario are summarized in Appendix A.2.

Figure 12: Generation Portfolios in 2030

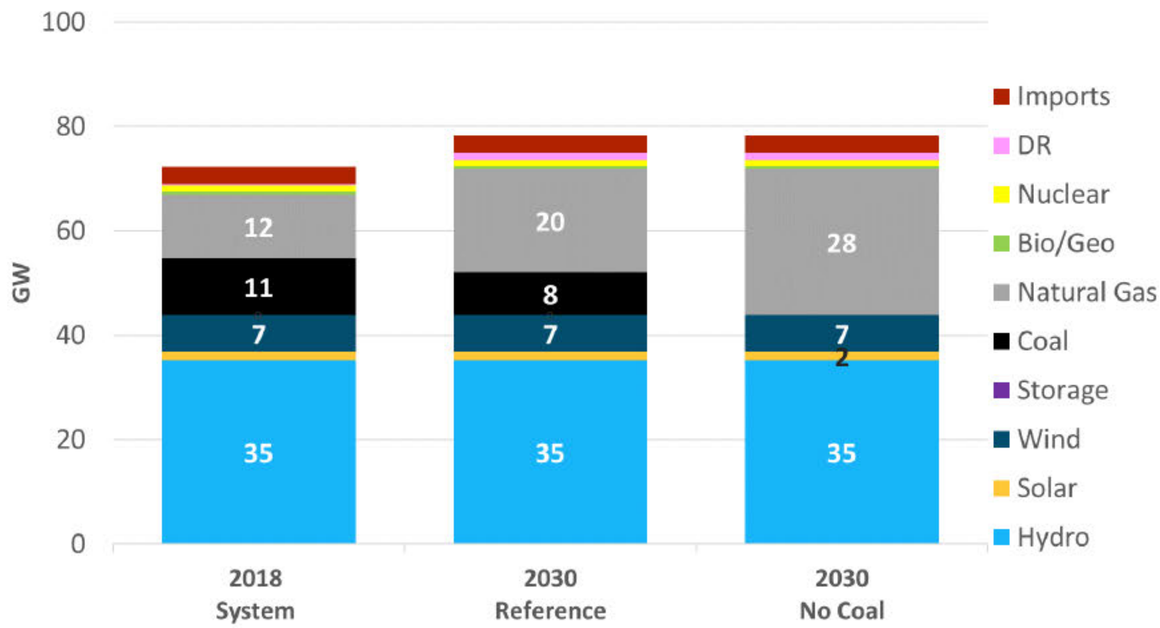


Table 15. 2030 Generation Portfolio: Key Metrics

Metric	2030 Reference	2030 No Coal
GHG-Free Generation (%)	61%	61%
GHG Emissions (MMT CO_2 / year)	67	42
% GHG Reduction from 1990 Level	-12%[16]	31%

[16] Negative value for %GHG reduction from 1990 level indicates that emissions are above 1990 level

As these metrics show, without either natural gas replacement of coal capacity or significant increase in renewable energy, GHG emissions are forecasted to rise in the 2030 timeframe. However, repowering coal with natural gas has the potential to reduce GHG emissions by 31% below 1990 levels.

In order to meet an LOLE target of 2.4 hrs/yr, the region requires a planning reserve margin (PRM) in 2030 of 12%.

Table 16. 2030 Load and Resource Balance, Reference Scenario

Load			Load MW
Peak Load			45.9
Firm Exports			1.1
PRM (12%)			5.8
Total Requirement			**52.9**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	8.2	100%	8.2
Gas	19.9	100%	19.9
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	2.2	45%	1.0
Hydro	35.2	53%	18.7
Wind	7.1	9%	0.6
Solar	1.6	14%	0.2
Storage	0	—	0
Total Internal Generation	**76.1**		**50.5**
Firm Imports	3.4	74%	2.5
Total Supply	**79.5**		**52.9**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3 Long-Term Outlook (2050)

The Greater Northwest system in 2050 is examined under a range of decarbonization scenarios, relative to 1990 emissions.

- 60% GHG Reduction
- 80% GHG Reduction
- 90% GHG Reduction
- 98% GHG Reduction
- 100% GHG Reduction

The portfolio for each decarbonization scenario was developed using the methodology described in Section 3.1.3. To summarize this process, RECAP iteratively adds carbon-free resources (wind, solar storage) to reduce GHG in a manner that maximizes the effective capacity of these carbon-free resources, thus minimizing the residual need for firm natural gas capacity. Once a cost-effective portfolio of carbon-free resources has been added to ensure requisite GHG reductions, the residual need for natural gas generation capacity is calculated to ensure the entire portfolio meets a 2.4 hrs./yr. LOLE standard.

5.3.1 ELECTRICITY GENERATION PORTFOLIOS

All the 2050 decarbonization portfolios are shown together in Figure 13. Higher quantities of renewable and energy storage are required to achieve deeper levels of decarbonization, which in turn provide effective capacity to the system and allow for a reduction in residual firm natural gas capacity need, relative to the reference case. Detailed portfolio results tables for each scenario are provided in Appendix A.2.

Figure 13: Generation Portfolios for 2050 Scenarios

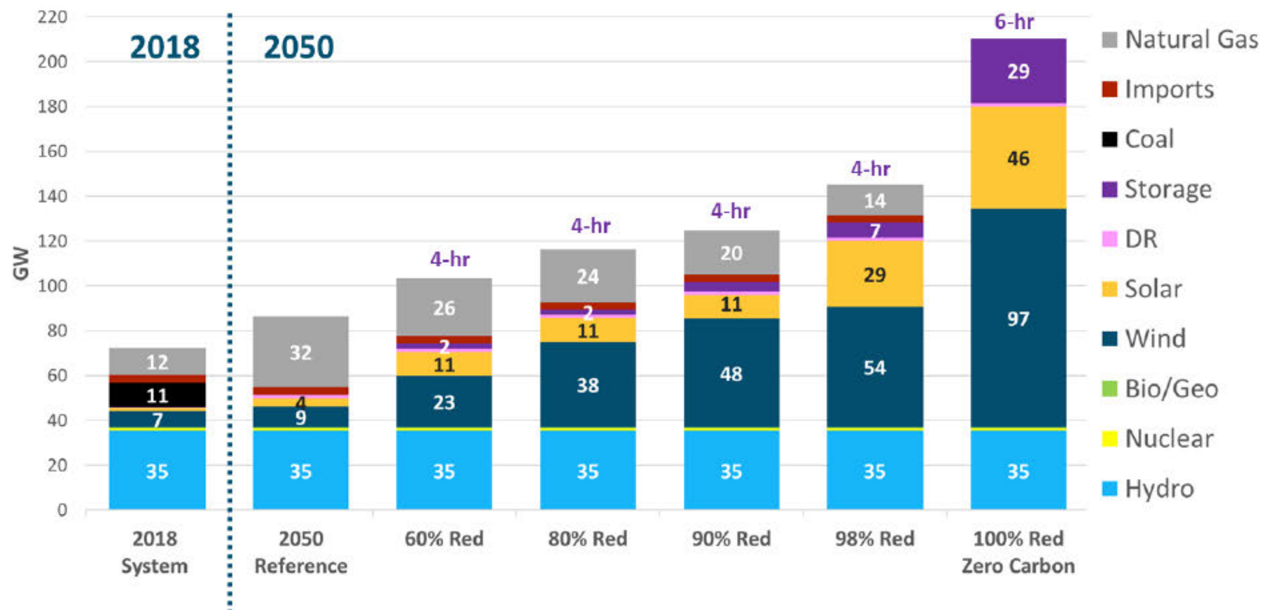


Table 17. 2050 Decarbonization Scenarios: Key Generation Metrics

			GHG Reduction Scenarios				
Metric	Units	Reference Scenario	60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
GHG Emissions	MMT/yr	50	25	12	6	1	0
GHG Reductions	% below 1990	16%	60%	80%	90%	98%	100%
GHG-Free Generation	% of load	60%	80%	90%	95%	99%	100%
Clean Portfolio Standard	% of sales	63%	86%	100%	108%	117%	123%
Annual Renewable Curtailment	% of potential	Low	Low	4%	10%	21%	47%

Table 17 evaluates the performance of each decarbonization portfolio along several key generation metrics that were described in detail in Section 3.4.

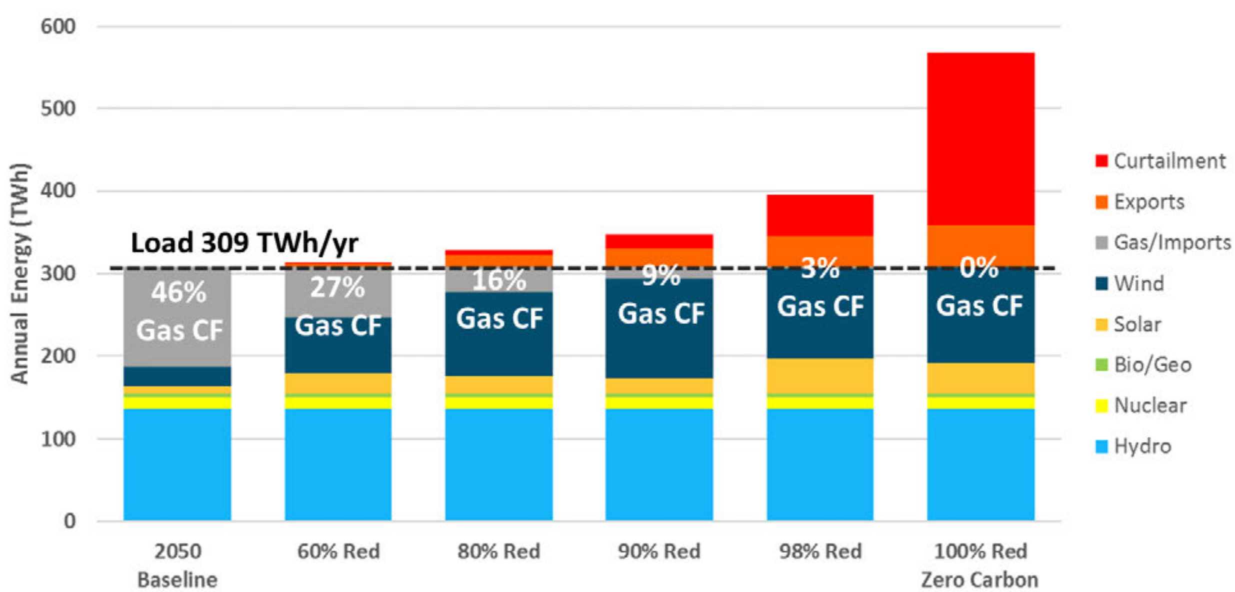
Analyzing the portfolio of each decarbonization scenario and resulting performance metrics yields several interesting observations.

+ On retiring all 11 GW of coal by 2050 in the *Reference* scenario, the Greater Northwest system requires 20 GW of new capacity in order to meet the 2.4 hrs./yr. LOLE standard used in the study. This suggests that 9 GW of net new firm capacity is needed to account for load growth through 2050.
+ The integration of more renewables and conservation policies provides the energy needed to serve loads in a deeply decarbonized future, but new gas-fired generation capacity is needed for relatively short, multi-day events with low renewable generation, high loads, and low hydro availability.
+ To reduce GHG emissions to 80% below 1990 levels, RECAP chooses to build 38 GW of wind, 11 GW of solar, and 2 GW of 4-hour storage. In addition to this renewable build, 12 GW of new firm capacity is required for reliability (after retaining all the existing natural gas plants) which is assumed to be met through natural gas build. The generation portfolio under 80% Reduction Scenario results in a 100% clean portfolio standard and 90% GHG-free generation.
+ RECAP achieves deeper levels of decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) by overbuilding renewables with 54 GW of wind, 29 GW of solar, and 7 GW of 4-hour storage. Annual renewable oversupply becomes significant (at 21%). Nevertheless, the system still requires an additional gas build of 2 GW after retaining all existing natural gas plants, to ensure reliability during periods of low renewable generation. The capacity factor for these gas plants is extremely low (3%), underlining their importance for reliability.
+ The 100% GHG Reduction Scenario (Zero Carbon Scenario) results in no GHG emissions from the electricity sector. The generation portfolio consists only of renewables (97 GW of wind and 46 GW of solar) and energy storage (29 GW of 6-hour storage). Ensuring a reliable system using only renewables and energy storage requires a significant amount of renewable overbuild – resulting

in nearly half of all the generated renewable energy to be curtailed. Compared to the 98% GHG Reduction Scenario (which results in 99% GHG-free generation), the Zero Carbon Scenario requires almost double the quantity of renewables and even greater quantity of energy storage.

With increases in renewable generation, generation from natural gas plants decreases. Due to negligible operating costs associated with renewable production, it is cost optimal to use as much renewable generation as the system can. During periods of prolonged low renewable generation when energy storage is depleted, natural gas plants can ramp up to provide the required firm capacity to avoid loss-of-load events. In the deep decarbonization scenarios, gas is utilized sparingly and even results in very low capacity factors (such as 9% and 3%). However, RECAP chooses to retain (and even build) natural gas as the most cost-effective resource to provide reliable firm capacity. Renewable overbuild also results in significant amounts of curtailment.

Figure 14: Annual generation mix across the scenarios



A planning reserve margin of 7% to 9% is required to meet the 1-in-10 reliability standard in 2050 depending on the scenario. Accounting for a planning reserve margin, the total capacity requirement (load plus planning reserve margin) in 2050 is 57-59 GW. As shown in Table 18, this capacity requirement is met through a diverse mix of resources. Variable or energy-limited resources such as hydro, wind, solar and storage contribute only a portion of their entire nameplate capacity (ELCC) towards resource adequacy. Load and resource tables for the 80% and 100% Reduction scenarios are shown below.

Table 18. 2050 Load and Resource Balance, 80% Reduction scenario

Load			**Load MW**
Peak Load			52.8
Firm Exports			1.1
PRM (9%)			4.9
Total Requirement			**58.8**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	23.5	100%	23.5
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	53%	18.7
Wind	38.0	19%	7.2
Solar	10.6	19%	2.0
Storage	2.2	73%	1.6
Total Internal Generation	**116.8**		**56.3**
Firm Imports	3.4	74%	2.5
Total Supply	**120.2**		**58.8**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

Table 19. 2050 Load and Resource Balance, 100% Reduction scenario

Load			Load MW
Peak Load			52.8
Firm Exports			1.1
PRM (7%)			4.0
Total Requirement			**58.0**
Resources	**Nameplate MW**	**Effective %**	**Effective MW**
Coal	0	—	0
Gas	0	—	0
Bio/Geo	0.6	100%	0.6
Nuclear	1.2	100%	1.2
DR	5.5	29%	1.6
Hydro	35.2	57%	20.1
Wind	97.4	22%	21.5
Solar	45.6	16%	7.3
Storage	28.7	20%	5.7
Total Internal Generation	**214.2**		**58.0**
Firm Imports	0	—	0
Total Supply	**214.2**		**58.0**
Surplus/Deficit			
Capacity Surplus/Deficit			**0.0**

5.3.2 ELECTRIC SYSTEM COSTS

System costs are estimated using the methodology and cost assumptions described in Section 4.3.1.1 and Section 4.4. Electric system costs represent the cost of decarbonization relative to the 2050 *Reference* scenario, and so by definition all annual and unit cost increases in this scenario are zero. The 2050 *Reference* scenario does require significant investment in new resources in order to reliably meet load growth and existing RPS policy targets, so the zero incremental cost is not meant to make any assessment on the absolute change (or lack thereof) in total electric system costs or rates by 2050.

Table 20 evaluates the performance of 2050 decarbonization scenarios along two cost metrics for both a low and high set of cost assumptions.

Table 20: 2050 Decarbonization Scenarios: Key Cost Metrics

				GHG Reduction Scenarios				
Metric		Units	Reference Scenario	60% Red.	80% Red.	90% Red.	98% Red.	100% Red.
Annual Cost Increase	Lo	$BB/yr	—	$0	$1	$2	$3	$16
	Hi	*(vs. Ref)*		$2	$4	$5	$9	$28
Unit Cost Increase	Lo	$/MWh	—	$0	$3	$5	$10	$52
	Hi	*(vs. Ref)*		$7	$14	$18	$28	$89

Analyzing the cost results for each decarbonization scenario yields several interesting observations

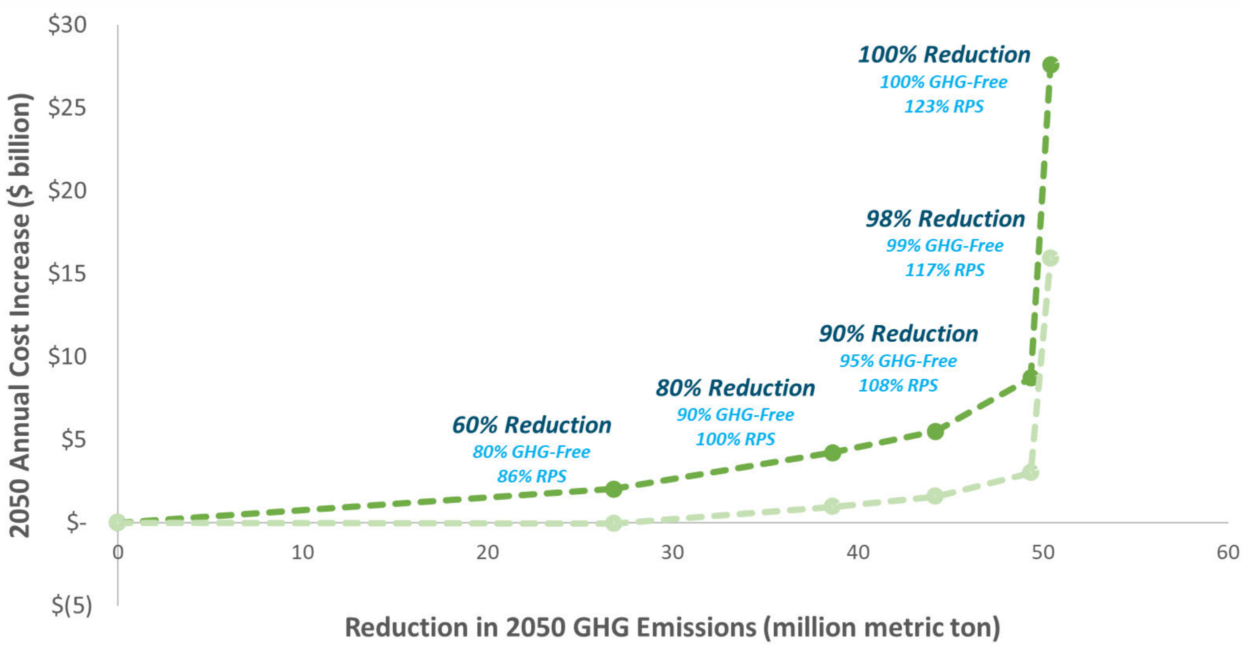
+ To reduce GHG emissions to 80% below 1990 levels, a portfolio of wind/solar/storage can be obtained at an additional annual cost of $1 to $4 billion ($3 to $14/MWh) after accounting for the avoided costs of new gas build and utilization. Assuming an existing average retail rate of $0.10/kWh, this implies an increase of 3%-14% in real terms relative to the *Reference* Scenario. Because the 80% reduction scenario achieves a 100% clean portfolio standard (as shown in Section 5.3.1), this scenario is compelling from both a policy perspective and a cost perspective in balancing multiple objectives across the Greater Northwest region.

+ Deep decarbonization (GHG emissions 98% below 1990 level down to 1.0 MMT GHG/yr) of the Greater Northwest system can be obtained at an additional annual cost of $3 to $9 billion ($10 to $28/MWh), i.e., the average retail rates increase 10%-28% in real terms relative to the *Reference* Scenario. This suggests that deep decarbonization of the Greater Northwest system can be achieved at moderate additional costs, assuming that natural gas capacity is available as a resource option to maintain reliability during prolonged periods of low renewable production.
+ The 100% GHG Reduction Scenario requires a significant increase in wind, solar and storage to eliminate the final 1% of GHG-emitting generation. An additional upfront investment of $100 billion to $170 billion is required, relative to the 98% GHG Reduction scenario. Compared to the *Reference* Scenario, the Zero Carbon Scenario requires an additional annual cost of $16 to $28 billion ($52 to $89/MWh), i.e., the average retail rates nearly double.

Costs for individual utilities will vary and may be higher or lower than the region as a whole. This report does not address allocation of cost between utilities.

As shown in Figure 15, the cost increases of achieving deeper levels of decarbonization become increasingly large as GHG emissions approach zero. This is primarily due to the level of renewable overbuild that is required to ensure reliability and the increasing quantities of energy storage required to integrate the renewable energy.

Figure 15: Cost of GHG reduction



The marginal cost of GHG reduction represents the incremental cost of additional GHG reductions at various levels of decarbonization. Figure 16 and Figure 17 both show the increasing marginal cost of GHG abatement at each level of decarbonization. At very deep levels of GHG reductions, the marginal cost of carbon abatement greatly exceeds the societal cost of carbon emissions, which generally ranges from $50/ton to $250/ton[17], although some academic estimates range up to $800/ton[18].

[17] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[18] https://www.nature.com/articles/s41558-018-0282-y

Figure 16: Marginal Cost of GHG Reduction: 60% Reduction To 98% Reduction

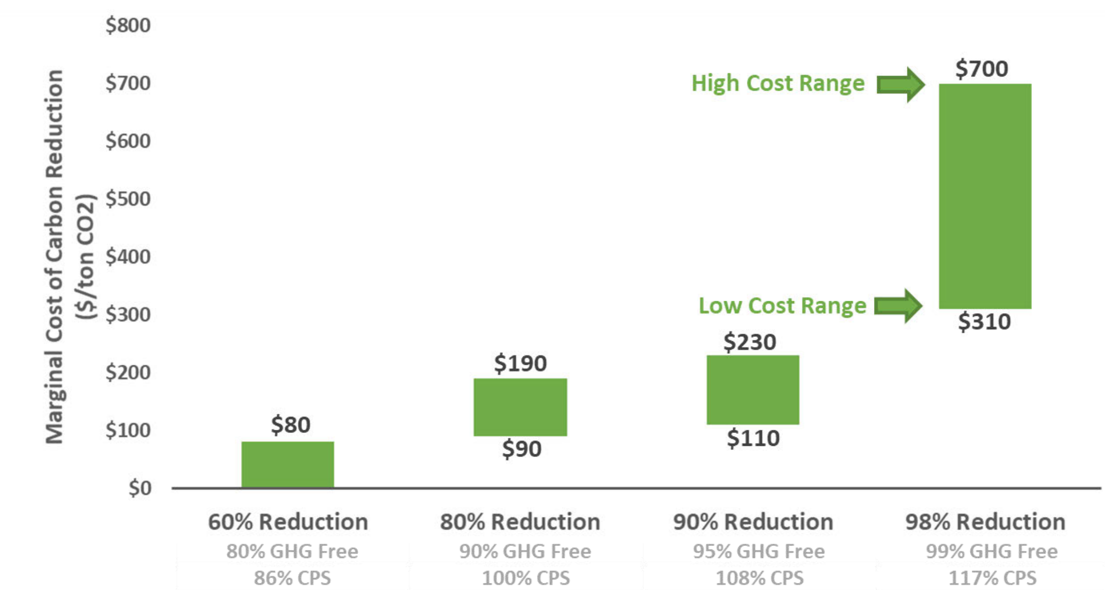
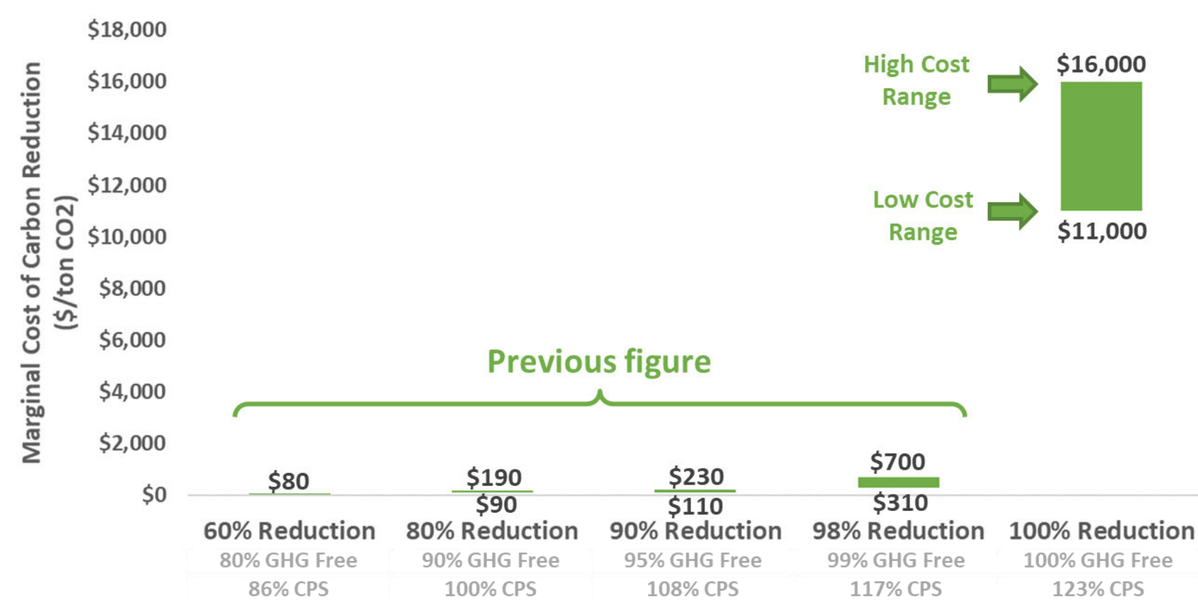


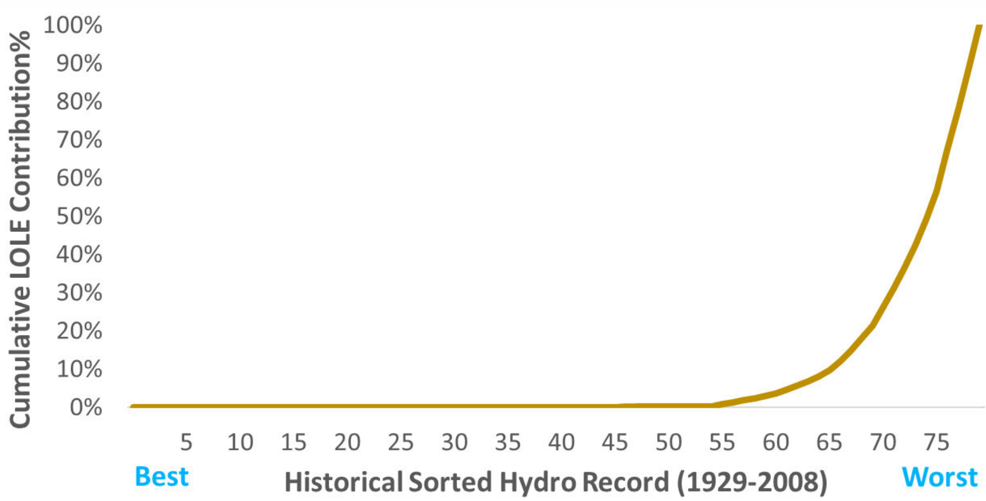
Figure 17: Marginal Cost of GHG Reduction: 60% Reduction to 100% Reduction



5.3.3 DRIVERS OF RELIABILITY CHALLENGES

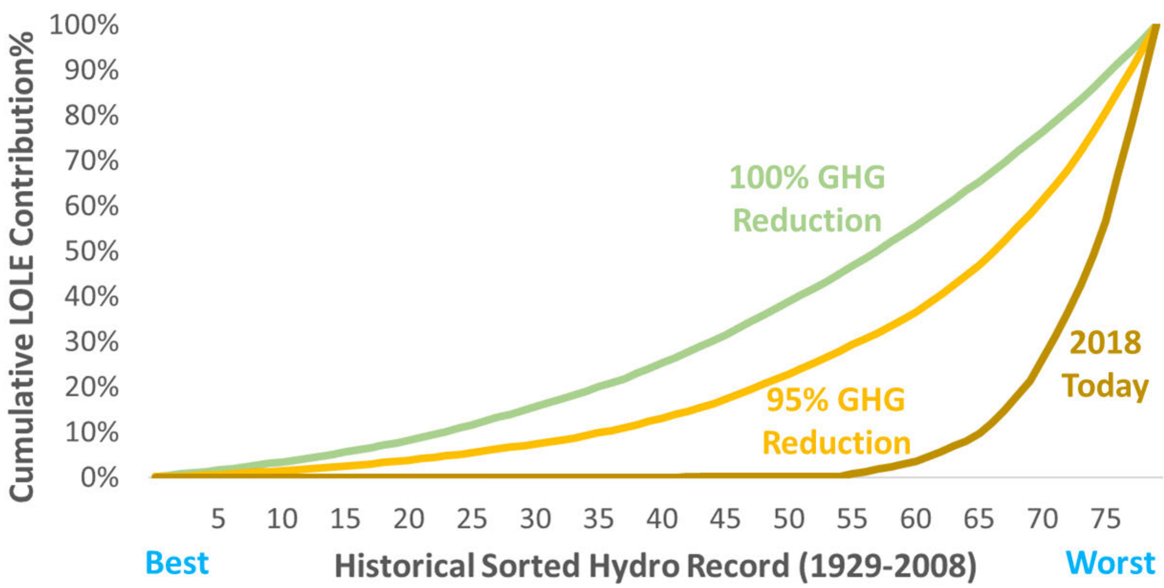
The major drivers of loss of load in the Greater Northwest system include high load events, prolonged low renewable generation events, and drought hydro conditions. In today's system where most generation is dispatchable, prolonged low renewable generation events do not constitute a large cause of loss-of-load events. Rather, the largest cause of loss-of-load events stem from the combination of high load events and drought hydro conditions. This relationship between contribution to LOLE and hydro conditions is highlighted in Figure 18 which shows nearly all loss of load events concentrated in the worst 25% of hydro years.

Figure 18. 2018 System Loss-of-Load Under Various Hydro Conditions



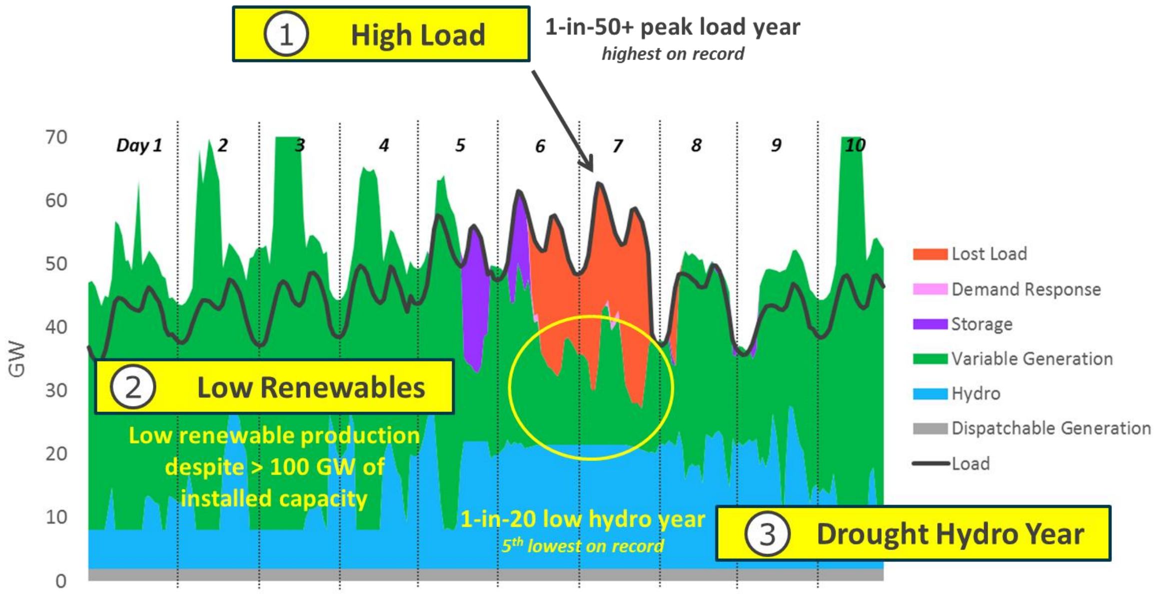
At very high renewable penetrations, in contrast, prolonged low renewable generation events usurp drought hydro conditions as the primary driver of reliability challenges. Figure 19 shows that at high levels of GHG reductions, loss-of-load is much less concentrated in the worst hydro years as prolonged low renewable generation events can create loss-of-load conditions in any year.

Figure 19. 2018 System GHG Reduction Scenarios Loss-of-Load Under Various Hydro Conditions



In practice, these prolonged periods of low renewable output manifest via multi-day winter storms that inhibit solar production over very wide geographic areas or large-scale high-pressure systems associated with low wind output. Figure 20 presents an example of multiday loss-of-load in a sample week in 2050 in the 100% GHG Reduction scenario. In a system without available dispatchable resources to call during such events, low solar radiation and wind speed can often give rise to severe loss-of-load events, especially when renewable generation may be insufficient to serve all load and storage quickly depletes. As shown in the example, over 100 GW of total installed renewables can only produce less than 10 GW of output in some hours. It is the confluence of events like these that drive the need for renewable overbuild to mitigate these events, which in turn leads to the very high costs associated with ultra-deep decarbonization.

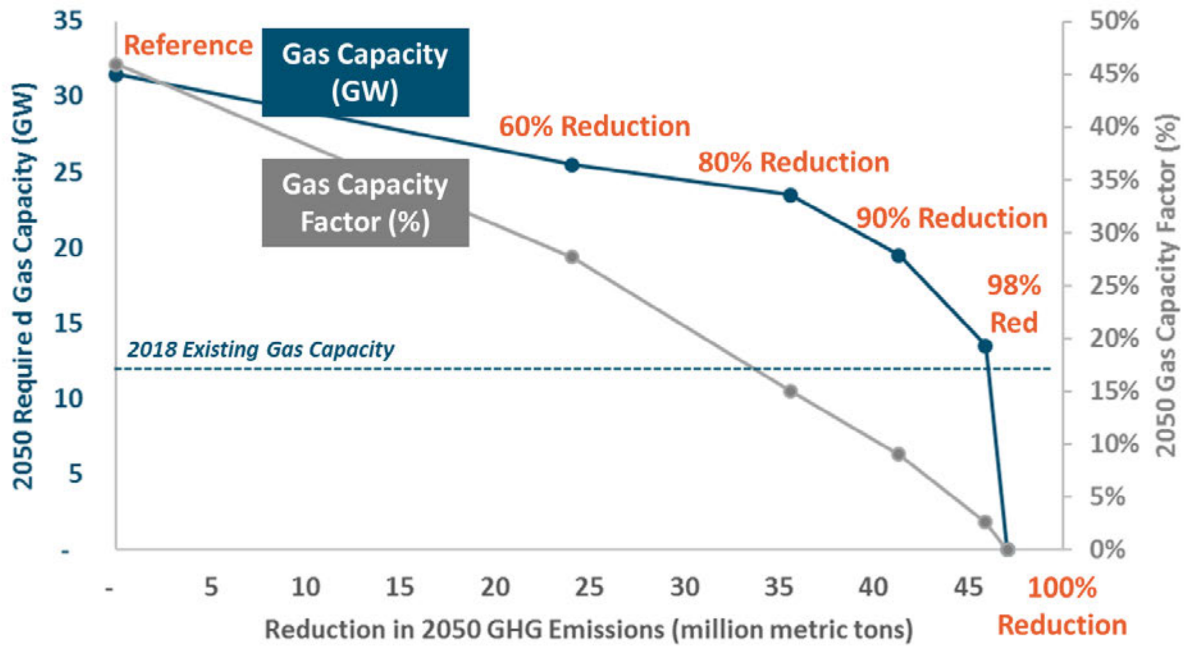
Figure 20: Loss-of-load Example in a Sample Week



5.3.4 ROLE OF NATURAL GAS GENERATION CAPACITY

The significant buildout of renewables and storage to meet decarbonization targets contributes to the resource adequacy needs of the system and reduces the need for thermal generation. However, despite the very large quantities of storage and renewables in all the high GHG reduction scenarios, a significant amount of natural gas capacity is still needed for reliability (except for the 100% GHG Reduction scenario where natural gas combustion is prohibited). Even though the system retains significant quantities of gas generation capacity for reliability, the capacity factor utilization of the gas fleet decreases substantially at higher levels of GHG reductions as illustrated in Figure 21. It is noteworthy that all scenarios except 100% GHG reductions require more gas capacity than exists in 2018, assuming all coal (11 GW) is retired.

Figure 21: Natural Gas Required Capacity in Different 2050 Scenarios



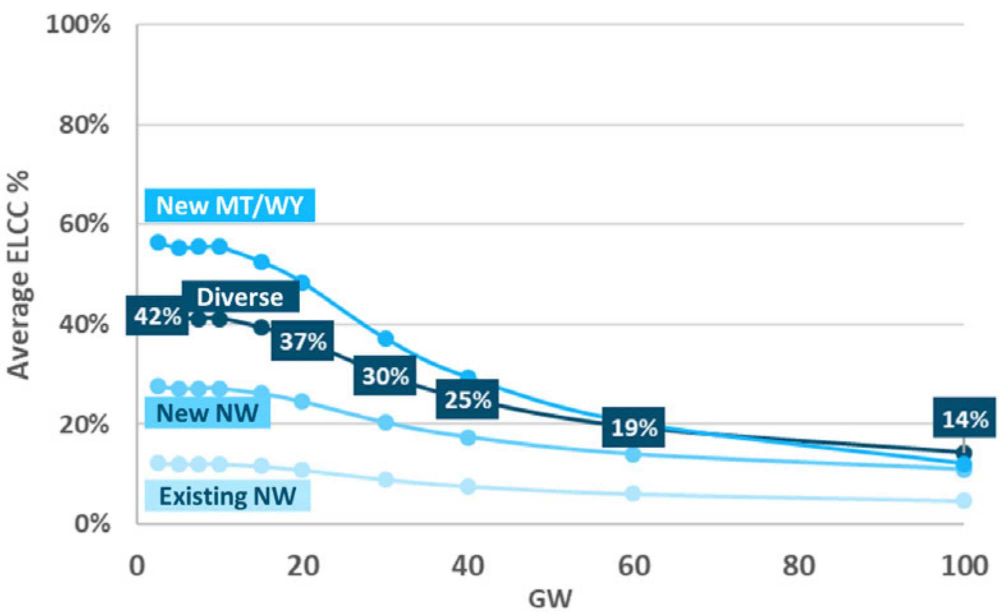
5.3.5 EFFECTIVE LOAD CARRYING CAPABILITY

Effective Load Carrying Capability (ELCC) is a metric used in the electricity industry to quantify the additional load that can be met by an incremental generator while maintaining the same level of system reliability. Equivalently, ELCC is a measure of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, storage, or demand response.

5.3.5.1 Wind ELCC

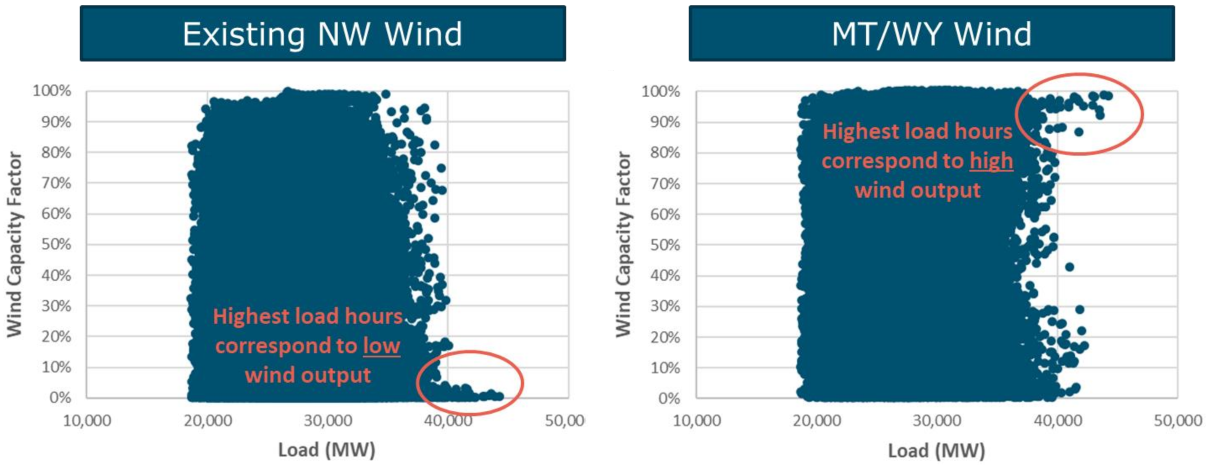
Wind resources in this study are grouped and represented as existing Northwest (Oregon and Washington) wind, new Northwest wind, and new Wyoming and Montana wind. The ELCC curves of each representative wind resource and as well as the combination of all three resources (i.e., "Diverse") are shown in Figure 22.

Figure 22: Wind ELCC at Various Penetrations



These results are primarily driven by the coincidence of wind production and high load events. Existing wind in the Northwest today, primarily in the Columbia River Gorge, has a strong negative correlation with peak load events that are driven by low pressures and cold temperatures. Conversely, Montana and Wyoming wind does not exhibit this same correlation and many of the highest load hours are positively correlated with high wind output as illustrated in Figure 23.

Figure 23: Load and Wind Correlation (Existing NW Wind and New MT/WY Wind)



Comparing and contrasting the ELCC of different wind resources yields several interesting findings:

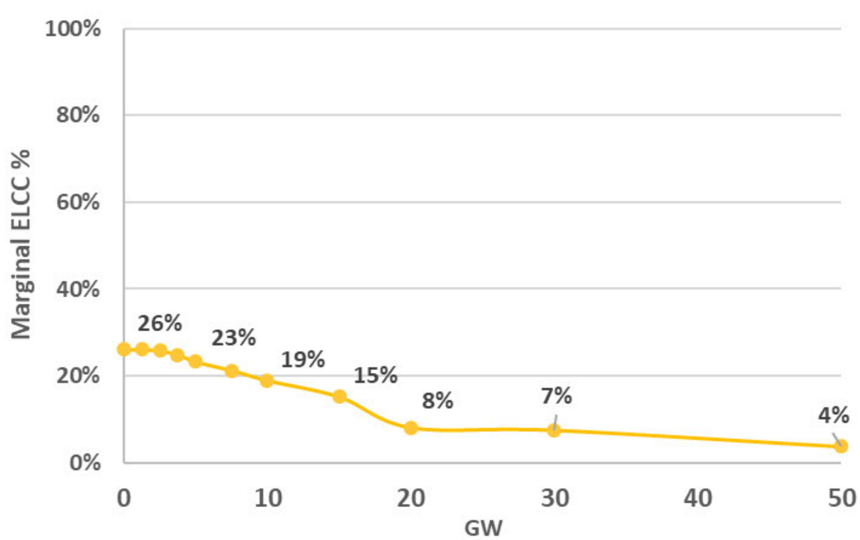
- The wide discrepancy between the "worst" wind resource (existing NW) and the "best" wind resource (new MT/WY) is primarily driven by the correlation of the wind production and peak load events in Washington and Oregon. Existing NW wind is almost entirely located within the Columbia River Gorge which tends to have very low wind output during the high-pressure weather systems associated with the Greater Northwest cold snaps that drive peak load events. Conversely, MY/WY wind is much less affected by this phenomenon due largely to geographic distance, and wind output tends to be highest during the winter months when the Northwest is most likely to experience peak load events.
- All wind resources experience significant diminishing returns at high levels of penetration. While wind may generate significant energy during the system peak, ultimately the net load peak that drives ELCC will shift to an hour with low wind production and reduce the effectiveness with which wind can provide ELCC. Diversity mitigates the rate of decline of ELCC.
- New NW wind has notably higher ELCC values than existing NW wind due to both improvements in turbine technology but also through larger geographic diversity of wind development within the Northwest region but outside of the Columbia River Gorge.

+ Diverse wind (combination of all three wind groups) yields the highest ELCC values at high penetrations. This is because even the best wind resources experience periods of low production and additional geographic diversity can help to mitigate these events and improve ELCC.

5.3.5.2 Solar ELCC

Solar resources in this study are grouped and represented as existing solar and new solar which is built across the geographically diverse area of Idaho, Washington, Oregon, and Utah. In general, solar provides lower capacity value than wind due to the negative correlation between winter peak load events and solar generation which tends to be highest in the summer. Like wind, solar ELCC also diminishes as more capacity is added. Figure 24 shows this information for the ELCC of new solar in the Greater Northwest region.

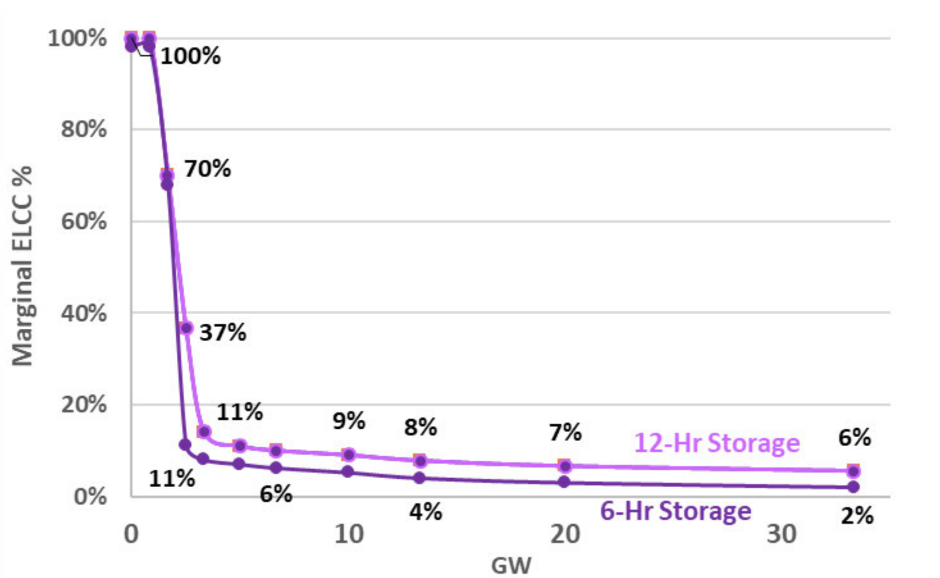
Figure 24: Solar ELCC at Various Penetrations



5.3.5.3 Storage ELCC

At small initial penetrations, energy storage can provide nearly 100% ELCC as a substitute for peaking generation that only needs to discharge for a small number of hours. However, at higher penetrations, the required duration for storage to continue to provide ELCC to the system diminishes significantly. This is primarily due to the fact that storage does not generate energy and ELCC is a measure of perfect capacity which can reliably generate energy. This result holds true for both shorter duration (6-hr) and longer duration (12-hr) storage which represents the upper end of duration for commercially available storage technologies. Figure 25 highlights the steep diminishing returns of storage toward ELCC.

Figure 25: Storage ELCC at Various Penetrations



This steeply-declining ELCC value for diurnal energy storage is particularly acute in the Pacific Northwest. This has to do with the fact that there is a significant quantity of energy storage implicit with the 35-GW hydro system in the region. The Federal Columbia River Power System is already optimized over multiple days, weeks and months within the bounds of non-power constraints such as flood control, navigation and fish & wildlife protections. Significant quantities of energy are stored in hydroelectric reservoirs today and dispatched when needed to meet peak loads. Thus, additional energy storage has less value for providing resource adequacy in the Northwest than it does in regions that have little or no energy storage today.

5.3.5.4 Demand Response ELCC

Demand response (DR) represents a resource where the system operator can call on certain customers during times of system stress to reduce their load and prevent system-wide loss-of-load events. However, DR programs have limitations on how often they can be called and how long participants respond when they are called. DR in this study is represented as having a maximum of 10 calls per year with each call lasting a maximum of 4 hours. This is a relatively standard format for DR programs, although practice varies widely across the country. This study also assumes perfect foresight of the system operator such that a DR call is never "wasted" when it wasn't actually needed for system reliability.

Figure 26: Cumulative and Marginal ELCC of DR

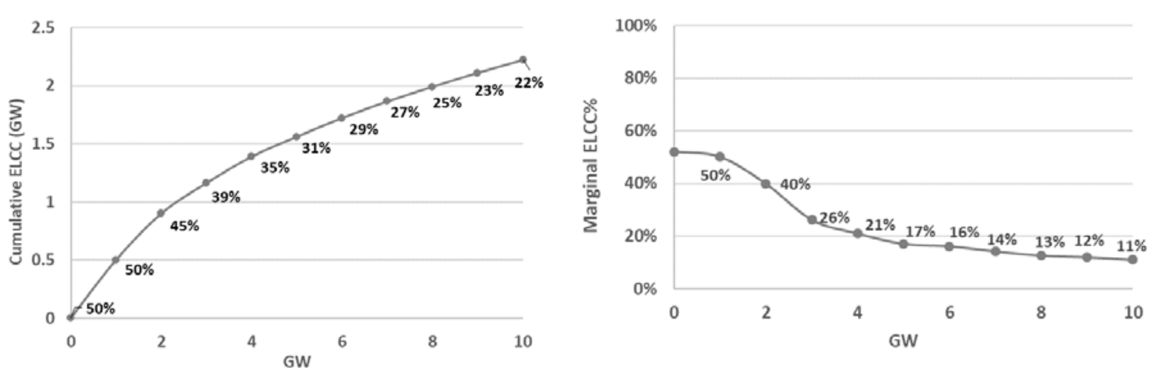


Figure 26 shows the cumulative and marginal ELCC of DR at increasing levels of penetration. Due to the limitations on the number of calls and duration of each call, DR has an initial ELCC of approximately 50%. Similar to energy storage, conventional 4-hour DR has less value in the Pacific Northwest than in other regions due to the flexibility inherent in the hydro system. Also, the capacity value of DR declines as the need for duration becomes longer and longer.

5.3.5.5 ELCC Portfolio Effects

Grouping different types of renewable resources, energy storage, and DR together often creates synergies between the different resources such that the combined ELCC of the entire portfolio is more than the sum of any resource's individual contribution. For example, solar generation can provide the energy that storage needs to be effective and storage can provide the on-demand dispatchability that solar needs to be effective. This resulting increase in ELCC is referred to as the diversity benefit.

Figure 27 shows the average ELCC for each resource type both on a stand-alone basis and also with a diversity allocation that accrues to each resource when they are added to a portfolio together.

Figure 27: ELCC of Solar, Wind, and Storage with Diversity Benefits

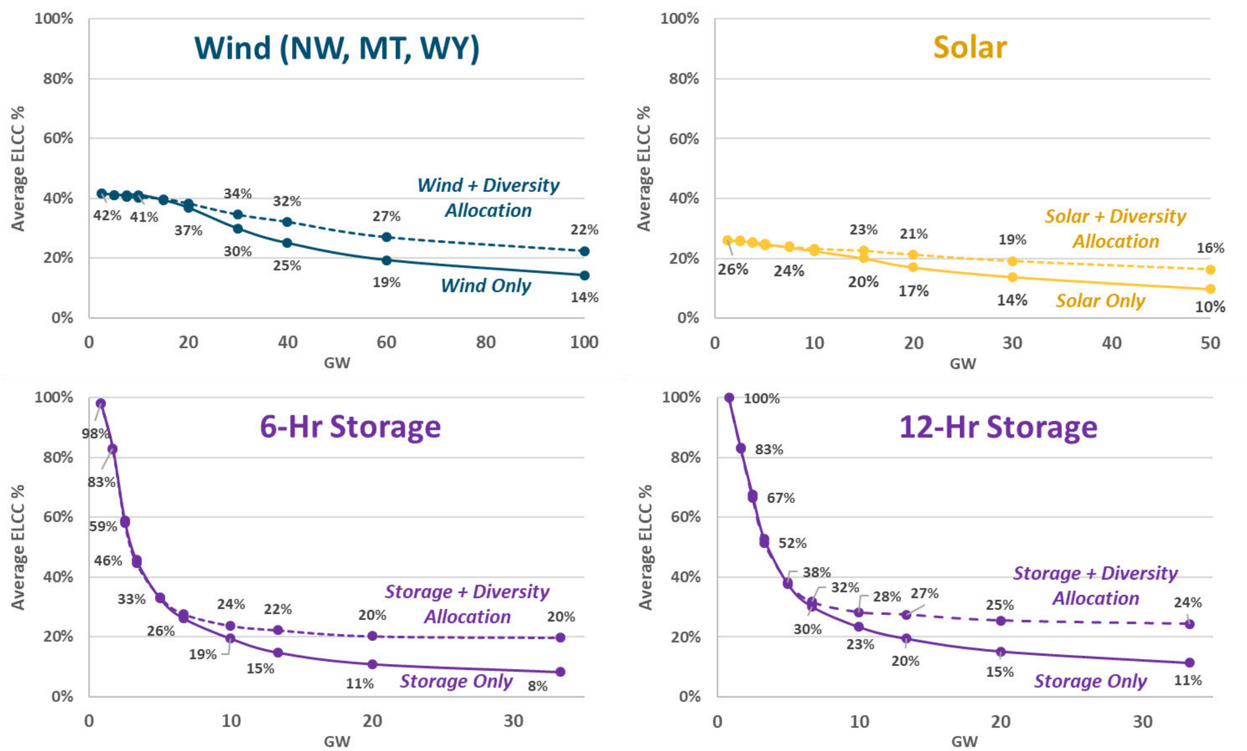
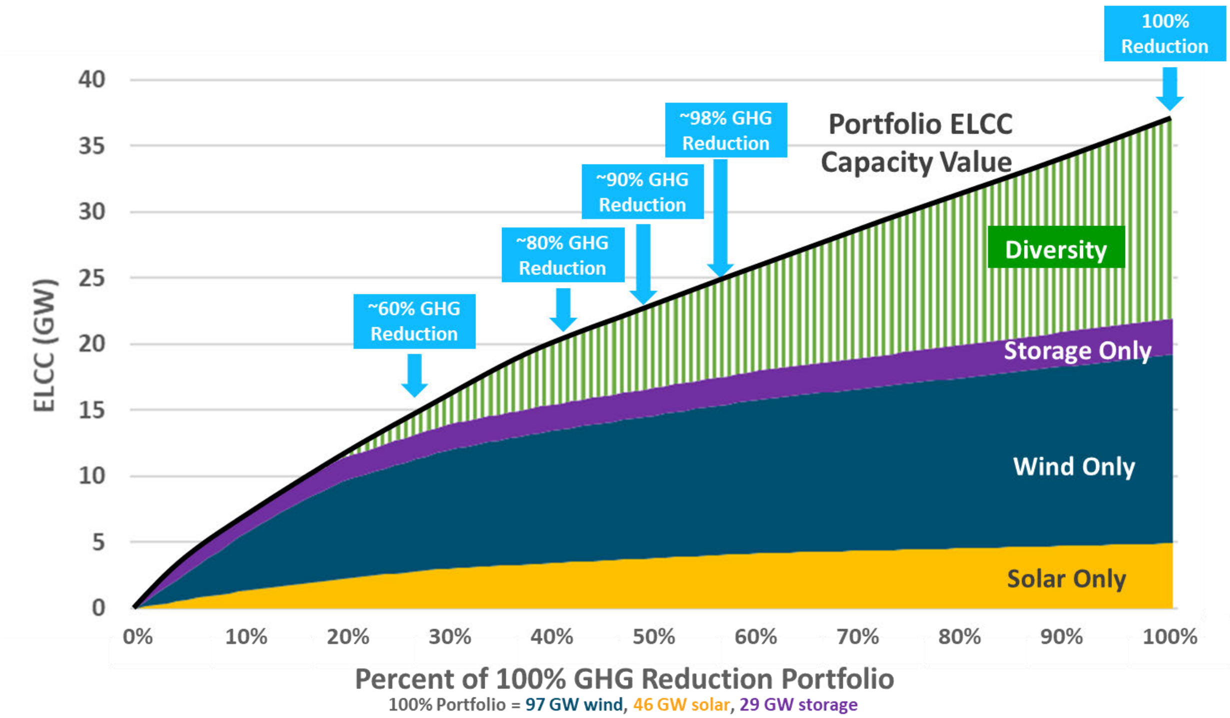


Figure 28 presents the cumulative portfolio ELCC of wind, solar, and storage up to the penetrations required to reliably serve load in a 100% GHG Reduction scenario. At high penetrations of renewables and storage, most of the ELCC is realized through diversity, although it still requires approximately 170 GW of nameplate renewable and storage resources to provide an equivalent of 37 GW of firm ELCC capacity that is required to retire all fossil generation. However, unlike adding these resources on a standalone basis, a combined portfolio continues to provide incremental ELCC value of approximately 20% of nameplate even at very high levels of penetration.

Figure 28: ELCC of Different Portfolios in 2050



5.3.6 SENSITIVITY ANALYSIS

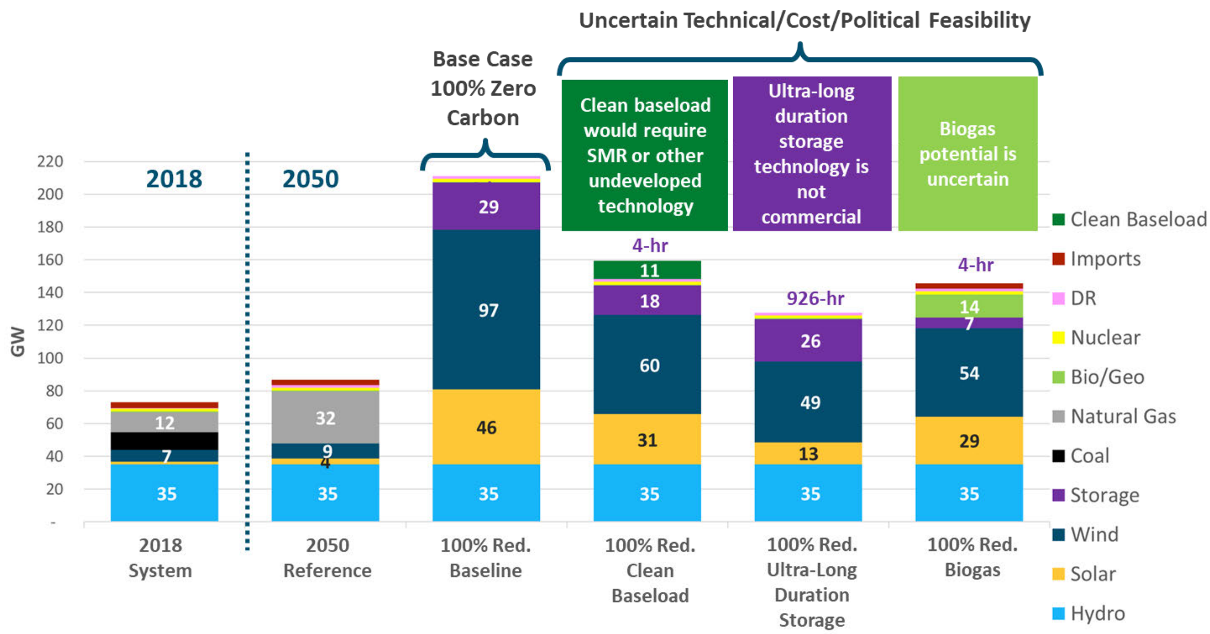
This study also explores the potential resource adequacy needs of a 100% GHG free electricity system recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. Specifically, the alternative resources analyzed are: clean baseload, ultra-long duration storage, and biogas which are further described in Table 21.

Table 21: Sensitivity Descriptions

Sensitivity Name	Description
Clean Baseload	Assesses the impact of technology that generates reliable baseload power with zero GHG emissions. This scenario might require a technology such as a small modular nuclear reactor (SMR), fossil generation with 100% carbon capture and sequestration, or other undeveloped or commercially unproven technology.
Ultra-Long Duration Storage	Assesses the impact of an ultra-long duration electric energy storage technology (e.g., 100's of hours) that can be used to integrate wind and solar. This technology is not commercially available today at reasonable cost.
Biogas	Assesses the impact of a GHG free fuel (e.g., biogas, renewable natural gas, etc.) that could be used with existing dispatchable generation capacity.

All three of these alternative technology options have the potential to greatly reduce the required renewable overbuild of the system as shown in Figure 29. This is achieved because each of these technologies is dispatchable and can generate energy during prolonged periods of low wind and solar production when short-duration energy storage would become depleted.

Figure 29: 2050 100% GHG Reduction Sensitivity Portfolio Results



While these alternative technologies clearly highlight the benefits, there are significant technical feasibility, economic, and political feasibility hurdles that stand in the way of large-scale adoption of these alternatives at the present time. In particular, clean baseload would require some technology such as small modular nuclear reactors which is not yet commercially available. Geothermal could provide a clean baseload resources but is limited in technical potential across the region. Fossil generation with carbon capture and sequestration (CCS) is another potential candidate, but the technology is not widely deployed, the cost at scale is uncertain, and current CCS technologies do not achieve a 100% capture rate. Ultra-long duration storage (926 hours) is not commercially available at reasonable cost assuming the technology is limited to battery storage or other commercially proven technologies. Biogas potential is also uncertain and there will be competition from other sectors in the economy to utilize what may be available. A detailed table of installed nameplate capacity for each portfolio is summarized in Appendix A.2.

Table 22 shows key cost metrics for the 100% GHG Reduction sensitivity scenarios. For consistency with the base case scenarios, all costs are relative to the 2050 *Reference* scenario.

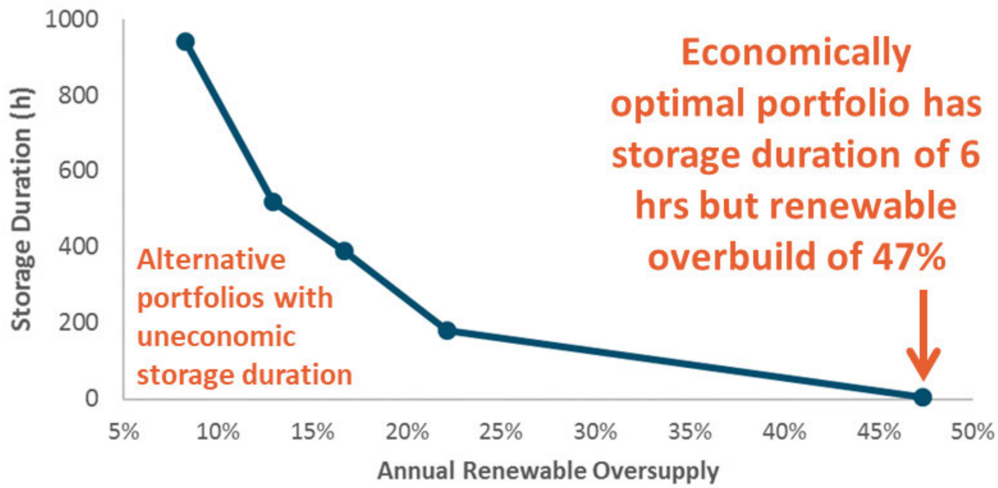
Table 22. 100% GHG Reduction Sensitivity Key Cost Metrics

Metric	100% GHG Reduction Baseline	100% GHG Reduction Clean Baseload	100% GHG Reduction Ultra-Long Duration Storage	100% GHG Reduction Biogas
Carbon Emissions (MMT CO_2 / year)	0	0	0	0
Annual Incremental Cost ($B)	$12- $28	$11-$22	$370-$920	$2 - $10
Annual Incremental Cost ($/MWh)	$39-$91	$36-$70	$1,200-$3,000	$5 - $32

Analyzing the portfolio and key cost metrics for each of the 100% GHG Reduction sensitivity cases yields several notable observations.

+ In the Clean Baseload sensitivity, the availability of a carbon-free source of baseload generation dramatically reduces the amount of investment in variable renewables and storage needed to maintain reliability: adding 11 GW of clean baseload resource displaces a portfolio of 15 GW solar, 37 GW wind, and 11 GW of storage. In the context of a highly renewable grid, baseload resources that produce energy round-the-clock—including during periods when variable resources are not available—provide significant reliability value to the system. However, at an assumed price of $91/MWh, the scenario still results in considerable additional costs to ratepayers of between $11-22 billion per year relative to the Reference Scenario.
+ The Ultra-Long Duration Storage sensitivity illustrates a stark direct relationship between the magnitude of renewable overbuild and the storage capability of the system: limiting renewable curtailment while simultaneously serving load with zero carbon generation reliability requires energy storage capability of a duration far beyond today's commercial applications (this relationship is further explored in Figure 30 below). Without significant breakthrough in storage technologies, such a portfolio is beyond both technical and economic limits of feasibility.

Figure 30: Tradeoff between Renewable Curtailment and Storage Duration



+ The Biogas sensitivity demonstrates the relatively high value of the potential option to combust renewable natural gas in existing gas infrastructure. In this scenario, 14 GW of existing and new gas generation capacity is retained by 2050, serving as a reliability backstop for the system during periods of prolonged low renewable output by burning renewable gas. This sensitivity offers the lowest apparent cost pathway to a zero-carbon electric system because biogas generation does not require significant additional capital investments. While the biogas fuel is assumed to be quite expensive on a unit cost basis, the system doesn't require very much fuel, so the total cost remains reasonable. Moreover, biogas generation uses the same natural gas delivery and generation infrastructure as the Reference Case, significantly reducing the capital investments required. However, the availability of sufficient biomass feedstock to meet the full needs of the electric sector remains an uncertainty. Moreover, there may be competing uses for biogas in the building and industrial sectors that inhibit the viability of this approach.

6 Discussion & Implications

6.1 Land Use Implications of High Renewable Scenarios

Renewables such as wind and solar generation require much greater land area to generate equivalent energy compared to generation sources such as natural gas and nuclear. In the deep decarbonization scenarios, significant amount of land area is required for renewable development. In the 100% GHG Reduction Scenario, estimates of total land use vary from 3 million acres to 14 million acres which is equivalent to 20 to 100 times the land area of Portland and Seattle combined. This is almost three times the land use required under the 80% GHG Reduction scenario.

Table 23. Renewable Land Use in 2050

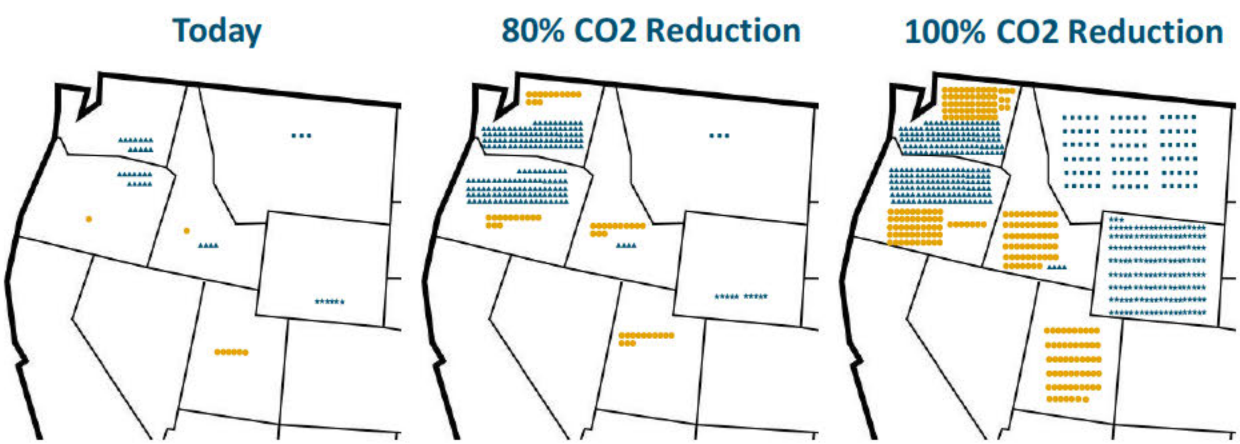
2050 Scenario	Units	Solar Total Land Use	Wind – Direct Land[19] Use	Wind – Total Land[20] Use
80% GHG Reduction	Thousand acres	84	94	1,135 – 5,337
100% GHG Reduction	Thousand acres	361	241	2,913 – 13,701

Even though such vast expanses of land are available, achieving very high levels of decarbonization would require extensive land usage for such large renewable development. Additionally, significant quantities of land would be required to site the necessary transmission to deliver the renewable energy.

[19] Direct land use is defined as disturbed land due to physical infrastructure development and includes wind turbine pads, access roads, substations and other infrastructure
[20] Total land use is defined as the project footprint as a whole and is the more commonly cited land-use metric associated with wind plants. They vary with project and hence as presented as a range
Both direct and total land use for wind is sourced from NREL's technical report: https://www.nrel.gov/docs/fy09osti/45834.pdf
Land use for solar is sourced from NREL's technical report: https://www.nrel.gov/docs/fy13osti/56290.pdf

Figure 31 highlights the scale of renewable development that would be required to achieve 100% GHG reductions via only wind, solar, and storage. Each dot in the map represents a 200 MW wind or solar farm. Note that sites are not to scale or indicative of site location.

Figure 31: Map of Renewable Land Use Today and in 80% and 100% GHG Reduction Scenario. Each dot represents one 200 MW power plant (blue = wind, yellow = solar)



6.2 Reliability Standards

Determining the reliability standard to which each electricity system plans its resource adequacy is the task of each individual Balancing Authority as there is no mandatory or voluntary national standard. There are several generally accepted standards used in resource adequacy across North America, with the most common being the "1-in-10" standard. There is, however, a range of significant interpretations for this metric. Some interpret it as one loss-of-load ***day*** every ten years. Some interpret it as one loss-of-load ***event*** every ten years. And some interpret it as one loss-of-load ***hour*** every ten years. The translation of these interpretations into measurable reliability metrics further compounds inconsistency across jurisdictions. However, the ultimate interpretation of most jurisdictions ultimately boils down to the use of one of four reliability metrics:

+ **Annual Loss of Load Probability (aLOLP)**
    - The probability in a year that load + reserves exceed generation at any time
+ **Loss of Load Frequency (LOLF)**
    - The total number of events in a year where load + reserves exceed generation
+ **Loss of Load Expectation (LOLE)**
    - The total number of hours in a year where load + reserves exceed generation
+ **Expected Unserved Energy (EUE)**
    - The total quantity of unserved energy in a year when load + reserves exceed generation

Each of these metrics provides unique insight into the reliability of the electric system and provides information that cannot be ascertained by simply using the other metrics. At the same time, each of the metrics is blind to many of the factors that are ascertained through the other metrics.

The NWPCC sets reliability standards for the Pacific Northwest to have an annual loss of load probability (aLOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, this metric does not provide any information on the number of events, duration of events, or magnitude of events that occur during years that experience loss of load. While this metric has generally served the region well when considering that the biggest reliability drive (hydro) was on an annual cycle, this metric becomes increasingly precarious when measuring a system that is more and more dependent upon renewables.

This study uses loss of load expectation (LOLE), because it is a more common metric that is used by utilities and jurisdictions across the country. Unlike aLOLP, LOLE does yield insight on the duration of events which can help to provide greater detail whether or not a system is adequately reliable.

However, LOLE does not capture the magnitude of events when they occur and thus misses a potentially large measure of reliability as compared to a metric such as EUE. EUE captures the total quantity of energy that is expected to go unserved each year. While this metric is not perfect, it is likely the most robust metric in terms of measuring the true reliability of an electric system, particularly in a system that is energy-constrained. Despite these attributes, EUE is not commonly used as a reliability metric in the industry today.

RECAP calculates all the aforementioned reliability metrics and can be used to compare and contrast their performance across different portfolios. Table 24 shows the four reliability metrics across different 2050 decarbonization scenarios.

Table 24: Reliability Statistics Across 2050 Decarbonization Portfolios

Reliability Metric	Units	2050 Reference	80% GHG Red.	100% GHG Red.
aLOLP	%/yr	3.6%	8.1%	10.5%
LOLF	#/yr	0.16	0.29	0.13
LOLE	hrs/yr	2.4	2.4	2.4
EUE	GWh/yr	1.0	2.0	19.0

Because the portfolios were calibrated to meet a 2.4 hrs./yr. LOLE standard, all portfolios yield exactly this result. However, this does not mean that all portfolios are equally reliable. Notably, the 100% GHG Reduction scenario has nearly 20 times the quantity of expected unserved energy (EUE) as compared to the reference scenario. The value of unserved energy varies widely depending on the customer type and outage duration; studies typically put the value between $5,000 and $50,000/MWh. This means that the economic cost of unserved energy in the 2050 Reference Scenario is between $5 million and $50 million per year. However, in the 100% GHG Reduction Scenario, which meets the same target for LOLE, the value of unserved energy could be nearly $1 billion annually.

This gives an important insight to some of the qualities of a system that is highly dependent upon dispatch-limited resources. For a traditional system that is composed mainly of dispatchable generation (coal, natural gas, nuclear, etc.), the primary reliability challenge is whether there is enough capacity to serve peak load. Even if the peak is slightly higher than expected or power plants experience forced outages and are unavailable to serve load, the difference between available generation and total load should be relatively small. Conversely, for a system that is highly dependent upon variable generation and other dispatch limited generation, there is a much greater chance that the sum of total generation could be *significantly* lower than total load. This phenomenon was highlighted in Section 5.3.3. The reliability statistics above confirm this intuition by highlighting how aLOLP, LOLF, and LOLE are each uniquely inadequate to fully capture the reliability of a system that is highly dependent upon variable renewable energy. For a system that is heavily dependent on variable generation, EUE may be a more useful reliability metric than the conventional LOLE metrics.

6.3 Benefits of Reserve Sharing

One of the simplifying assumptions made in this study to examine reliability across the Greater Northwest is the existence of a fully coordinated planning and operating regime within the region. In reality, however, responsibility for maintaining reliability within the system is distributed among individual utilities and balancing authorities with oversight from state utility commissions. The current distributed approach to reliability planning has two interrelated shortcomings:

1) Because the region's utilities each plan to meet their own needs, they may not rigorously account for the natural load and resource diversity that exists across the footprint. If each utility built physical resources to meet its own need, the quantity of resources in the region would greatly exceed what would be needed to meet industry standards for loss-of-load.

2) As an informal mechanism for taking advantage of the load and resource diversity that exists in the region, many utilities rely on front-office transactions (FOTs) or market purchases instead of physical resources, as was discussed in Section 2. This helps to reduce costs to ratepayers of maintaining reliability by avoiding the construction of capacity resources. However, as the region transitions from a period of capacity surplus to one of capacity deficit, and because there is no uniform standard for capacity accreditation, there is a risk that overreliance on FOTs could lead to underinvestment in resources needed to meet reliability standards.

Formal regional planning reserve sharing could offer multiple benefits in the Greater Northwest by taking advantage of load and resource diversity that exists across the region. A system in which each utility builds physical assets to meet its own needs could result in overcapacity, because not every system peaks at the same time. Planning to meet regional coincident peak loads requires less capacity than meeting each individual utility's peak loads. Further, surplus resources in one area could be utilized to meet a deficit in a neighboring area. Larger systems require lower reserve margins because they are less vulnerable to individual, large contingencies. A regional entity could adopt more sophisticated practices and computer models than individual utilities and manage capacity obligation requirements independent from the utilities.

Table 25 provides a high-level estimate of the benefits that could accrue if the Northwest employed a formal planning reserve sharing system. The benefits are divided into (1) benefits due to switching from individual utility peak to regional peak and (2) benefits due to lower target PRM.

A regional planning reserve sharing system could be established in the Greater Northwest. A regional entity could be created as a voluntary organization of utilities and states/provinces. The regional entity would perform loss-of-load studies for the region and calculate the regional PRM and develop accurate methods for estimating capacity credit of hydro and renewables. The entity would create a forward capacity procurement obligation based on studies and allocate responsibility based on their share of the regional requirement.

Table 25. Possible Benefits from a Regional Planning Reserve Sharing System in the Northwest[21]

Capacity Requirement	BPA + Area	NWPP (US)
Individual Utility Peak + 15% PRM (MW)	33,574	46,398
Regional Peak + 15% PRM (MW)	32,833	42,896
Reduction (MW)	741	3,502
Savings ($MM/year)	***$89***	***$420***
	BPA + Area	**NWPP (US)**
Regional Peak + 12% PRM (MW)	31,977	41,777
Reduction (MW)	1,597	4,621
Savings ($MM/year)	***$192***	***$555***

Rules similar to other markets could be made for standardized capacity accreditation of individual resources such as dispatchable generation, hydro generation, variable generation, demand response and energy storage. Tradable capacity products could be defined based on the accredited capacity.

A regional entity could be formed by voluntary association in the Greater Northwest. It could be governed by independent or stakeholder board. Alternatively, new functionality could be added to the existing reserve sharing groups such as Northwest Power Pool (NWPP) and Southwest Reserve Sharing Group, which expand their operating reserve sharing to include planning reserve sharing. It would not require setting up a regional system operator immediately and PRM sharing could be folded into a regional system operator if and when it forms.

[21] Calculated regional and non-coincident peaks using WECC hourly load data averaged over 2006-2012. Savings value estimated using capacity cost of $120/kW-yr. Assumes no transmission constraints within the region. Ignores savings already being achieved through bilateral contracts

7 Conclusions

The Pacific Northwest is expected to undergo significant changes to its electricity generation resource mix over the next 30 years due to changing economics of resources and more stringent environmental policy goals. In particular, the costs of wind, solar, and battery storage have experienced significant declines in recent years, a trend that is expected to continue. Greenhouse gas and other environmental policy goals combined with changing economics have put pressure on existing coal resources, and many coal power plants have announced plans to retire within the next decade.

As utilities become more reliant on intermittent renewable energy resources (wind and solar) and energy-limited resources (hydro and battery storage) and less reliant on dispatchable firm resources (coal), questions arise about how the region will serve future load reliably. In particular, policymakers across the region are considering many different policies – such as carbon taxes, carbon caps, renewable portfolio standards, limitations on new fossil fuel infrastructure, and others – to reduce greenhouse gas emissions in the electricity sector and across the broader economy. The environmental, cost, and reliability implications of these various policy proposals will inform electricity sector planning and policymaking in the Pacific Northwest.

This study finds that deep decarbonization of the Northwest grid is feasible without sacrificing reliable electric load service. But this study also finds that, absent technological breakthroughs, achieving 100% GHG reductions using *only* wind, solar, hydro, and energy storage is both impractical and prohibitively expensive. Firm capacity – capacity that can be relied upon to produce energy when it is needed the most, even during the most adverse weather conditions – is an important component of a deeply-decarbonized grid. Increased regional coordination is also a key to ensuring reliable electric service at reasonable cost under deep decarbonization.

7.1 Key Findings

1. It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient **firm capacity** is available during periods of low wind, solar, and hydro production;
    - Natural gas generation is the most economic source of firm capacity today;
    - Adding new gas generation capacity is not inconsistent with deep reductions in carbon emissions because the significant quantities of zero-marginal-cost renewables will ensure that gas is only used during reliability events;
    - Wind, solar, demand response, and short-duration energy storage can contribute but have important limitations in their ability to meet Northwest Resource Adequacy needs;
    - Other potential low-carbon firm capacity solutions include (1) new nuclear generation, (2) fossil generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas such as hydrogen or biogas.
2. It would be **extremely costly and impractical** to replace all carbon-emitting firm generation capacity with solar, wind, and storage, due to the very large quantities of these resources that would be required;
    - Firm capacity is needed to meet the new paradigm of reliability planning under deep decarbonization, in which the electricity system must be designed to withstand prolonged periods of low renewable production once storage has depleted; renewable overbuild is the most economic solution to completely replace carbon-emitting resources but requires a 2x buildout that results in curtailment of almost half of all wind and solar production.
3. The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of Resource Adequacy after planned coal retirements.
4. Current planning practices risk underinvestment in the new capacity needed to ensure Resource Adequacy at acceptable levels;

- Reliance on market purchases or front-office transactions (FOTs) reduces the cost of meeting Resource Adequacy needs on a regional basis by taking advantage of load and resource diversity among utilities in the region;
- Capacity resources are not firm without a firm fuel supply; investment in fuel delivery infrastructure may be required to ensure Resource Adequacy even under a deep decarbonization trajectory;
- Because the region lacks a formal mechanism for ensuring adequate physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity;
- The region might benefit from and should investigate a formal mechanism to share planning reserves on a regional basis, which may help ensure sufficient physical firm capacity and reduce the quantity of capacity required to maintain Resource Adequacy

Appendix A. Assumption Development Documentation

A.1 Baseline Resources

Table 26. NW Baseline Resources Installed Nameplate Capacity (MW) by Year.

Category	Resource Class	2018	2030	2050
Thermal	Natural Gas	12,181	19,850	31,500
	Coal	10,895	8,158	0
	Nuclear	1,150	1,150	1,150
	Total	**24,813**	**29,745**	**33,237**
Firm Renewable	Geothermal	79.6	79.6	79.6
	Biomass	489.2	489.2	489.2
Variable Renewables	Wind	7,079	7,079	9,205
	Solar	1,557	1,557	3,593
Hydro	Hydro	35,221	35,221	35,221
Storage	Storage	0	0	0
DR	Shed Demand Response	600	2,200	5,500
Imports	Imports*	3,400	3,400	3,400

*Imports consist of market purchases and non-summer firm imports. For more details, please refer to Imports section.

A.2 Portfolios of Different Scenarios

Table 27. Portfolios for 2030 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	No Coal
Solar	1.6	1.6
Wind	7.1	7.1
DR	2.2	2.2
Hydro	35.2	35.2
Coal	8.2	-
Natural Gas	19.9	28.0
Nuclear	1.2	1.2
Bio/Geo	0.6	0.6
Storage	-	-
Imports	3.4	3.4

Table 28. Portfolios for 2050 scenarios – Installed Nameplate Capacity (GW) by Scenario

Resource Class	Reference	60% GHG Reduction	80% GHG Reduction	90% GHG Reduction	98% GHG Reduction	100% GHG Reduction
Solar	3.6	10.6	10.6	10.6	29.2	45.6
Wind	9.2	22.9	38.0	48.2	53.8	97.4
DR	5.5	5.5	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2	35.2	35.2
Coal	-	-	-	-	-	-
Natural Gas	31.5	25.5	23.5	19.5	13.5	-
Nuclear	1.2	1.2	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6	0.6	0.6
Storage	-	2.2 (4-hr)	2.2 (4-hr)	4.4 (4-hr)	6.7 (4-hr)	28.7 (6-hr)
Imports	3.4	3.4	3.4	3.4	3.4	-

Table 29. Zero Carbon Sensitivity Portfolios in 2050– Installed Nameplate Capacity (GW) by Scenario

Resource Class	100% GHG Reduction Renewables	100% GHG Reduction Baseload Tech	100% GHG Reduction Long Duration Storage	100% GHG Reduction Biogas
Solar	45.6	30.7	13.5	29.2
Wind	97.4	60.5	49.2	53.8
DR	5.5	5.5	5.5	5.5
Hydro	35.2	35.2	35.2	35.2
Coal	-	-	-	-
Natural Gas	-	-	-	13.5
Nuclear	1.2	1.2	1.2	1.2
Bio/Geo	0.6	0.6	0.6	0.6
Storage	28.7 (6-hr)	18.0 (4-hr)	25.9 (926-hr)	6.7 (4-hr)
Clean Baseload	-	11.3	-	-
Imports	-	-	-	-

Appendix B. RECAP Model Documentation

B.1 Background

RECAP is a loss-of-load-probability model developed by E3 to examine the reliability of electricity systems under high penetrations of renewable energy and storage. In this study, RECAP is used to assess reliability using the *loss-of-load expectation* (LOLE) metric. LOLE measures the expected number of hours/yr when load exceeds generation, leading to a loss-of-load event.

LOLE is one of the most commonly used metrics within the industry across North America to measure the resource adequacy of the electricity system. LOLE represents the reliability over many years and does not necessarily imply that a system will experience loss-of-load every single year. For example, if an electricity system is expected to have two 5-hour loss-of-load events over a ten-year period, the system LOLE would be 1.0 hr./yr LOLE (10 hours of lost load over 10 years).

There is no formalized standard for LOLE sufficiency promulgated by the North American Electric Reliability Coordinating Council (NERC), and the issue is state-jurisdictional in most places expect in organized capacity markets. In order to ensure reliability in the electricity system, the Northwest Power and Conservation Council (NWPCC) set reliability standards for the Pacific Northwest. The current reliability standard requires the electricity system to have an annual loss of load probability (annual LOLP) to be below 5%. This would mean loss-of-load events occur, on average, less than once in 20 years. However, in a system with high renewables, LOLE is a more robust reliability metric.

B.2 Model Overview

RECAP calculates LOLE by simulating the electric system with a specific set of generating resources and economic conditions under a wide variety of weather years, renewable generation years, hydro years, and stochastics forced outages of generation and transmission resources, while accounting for the correlation and relationships between these. By simulating the system thousands of times under different combinations of these conditions, RECAP is able to provide a statistically significant estimation of LOLE.

B.2.1 LOAD

E3 modeled hourly load for the northwest under current economic conditions using the weather years 1948-2017 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

+ Max and min daily temperature (including one and two-day lag)
+ Month (+/- 15 calendar days)
+ Day-type (weekday/weekend/holiday)
+ Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1948-2017) under current economic conditions. The final step converts these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (10 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1948-2017 under today's economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This 'base' load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification. Load modification through demand response is captured through explicit analysis of this resource in Section 0.

Operating reserves of 1,250 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 1,250 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

B.2.2 DISPATCHABLE GENERATION

Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states developed using NWPCC data. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).

B.2.3 TRANSMISSION

RECAP is a zonal model that models the northwest system as one zone without any internal transmission constraints. Imports are assumed to be available as mentioned in Imports Section 4.2.3.

B.2.4 WIND AND SOLAR PROFILES

Hourly wind and solar profiles were simulated at all wind and solar sites across the northwest. Wind speed and solar insolation data was obtained from the NREL Western Wind Toolkit[22] and the NREL Solar Prospector Database[23], respectively and transformed into hourly production profiles using the NREL System Advisor Model (SAM). Hourly wind speed data was available from 2007-2012 and hourly solar insolation data was available from 1998-2014.

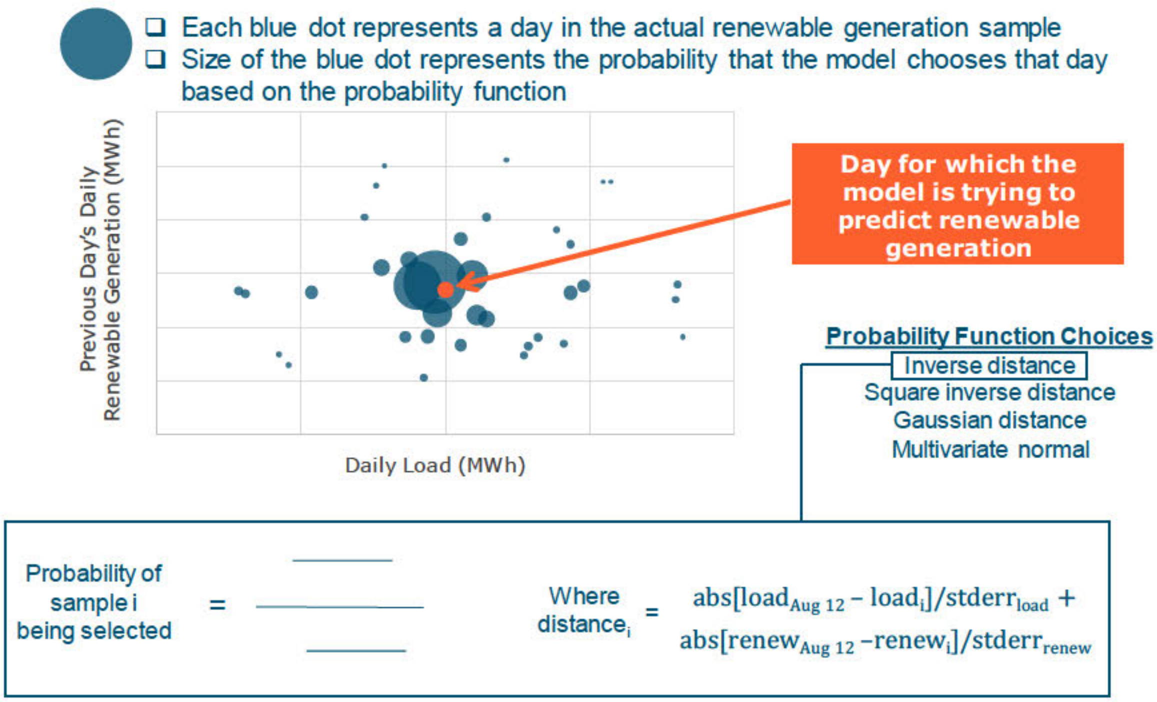
A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data i.e., years with available renewable data. For each day in the historical load profile (1948-2017), the model stochastically selects a wind profile and a solar profile using an inverse distance function with the following factors:

+ Season (+/- 15 days)
    - Probability is 1 inside this range and 0 outside of this range
+ Load
    - For winter peaking systems like the northwest, high load days tend to have low solar output
+ Previous Day's Renewable Generation
    - High wind or solar days have a higher probability of being followed by a high wind or solar day, and vice versa. This factor captures the effect of a multi-day low solar or low wind event that can stress energy-limited systems that are highly dependent on renewable energy and/or energy storage.

A graphic illustrating this process is shown in Figure 32

[22] https://www.nrel.gov/grid/wind-toolkit.html
[23] https://nsrdb.nrel.gov/

Figure 32: Renewable Profile Selection Process



B.2.5 HYDRO DISPATCH

Dispatchable hydro generation is a hybrid resource that is limited by weather (rainfall) but can still be dispatched for reliability within certain constraints. It is important to differentiate this resource from non-dispatchable hydro such as many run-of-river systems that produce energy when there is hydro available, similar to variable wind and solar facilities, especially in a system like northwest which has an abundance of hydro generation.

To determine hydro availability, the model uses a monthly historical record of hydro production data from NWPCC's records from 1929 – 2008. The same data is used to model hydro generation in NWPCC's GENESYS model. For every simulated load year, a hydro year is chosen stochastically from the historical database. The study assumes no significant hydro build in the future and no correlation with temperature, load or renewable generation. Once the hydro year is selected, the monthly hydro budgets denote the amount of energy generated from hydro resources in that month. Since RECAP optimizes the hydro dispatch to minimize loss-of-load, providing only monthly budgets can dispatch hydro extremely flexibly. For example, some of the hydro can be held back to be dispatched during generator outages. Such high flexibility in hydro dispatch is not representative of the current northwest hydro system. Therefore, the monthly budget is further divided into weekly budgets to ensure hydro dispatch is in line with operating practices in the northwest.

In addition to hydro budgets, hydro dispatch has other upstream and downstream hydrological and physical constraints that are modeled in a hydrological model by NWPCC. RECAP does not model the complete hydrological flow but incorporates all the major constraints such as sustained peaking (maximum generation and minimum generation) limits. Sustained peaking maximum generation constraint results in the average hydro dispatch over a fixed duration to be under the limit. Similarly, minimum generation constraints ensure average dispatch over a fixed duration is above the minimum generation sustainable limits. Sustainable limits are provided over 1-hour, 2-hour, 4-hour and 10-hour durations.

The weekly budgets and sustained peaking limits together make the hydro generation within RECAP representative of the actual practices associated with hydro generation in the northwest. Output from RECAP are benchmarked against hydro outputs from NWPCC's GENESYS model.

B.2.6 STORAGE

The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives.)

B.2.7 DEMAND RESPONSE

The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

B.2.8 LOSS-OF-LOAD

The final step in the model calculates loss-of-load if there is insufficient available dispatchable generation, renewables, hydro, storage, and demand response to serve load + operating reserves.

Appendix C. Renewable Profile Development

The electricity grid in the Greater Northwest consists of significant quantities of existing wind and solar generation. Significant new renewable build is expected to be built in the future, as explored in this study. Representing the electricity generation from both existing and future renewable (solar and wind) resources is fundamental to the analysis in this study. In this appendix section, the process of developing these renewable profiles for both existing and new renewable resources is elaborated.

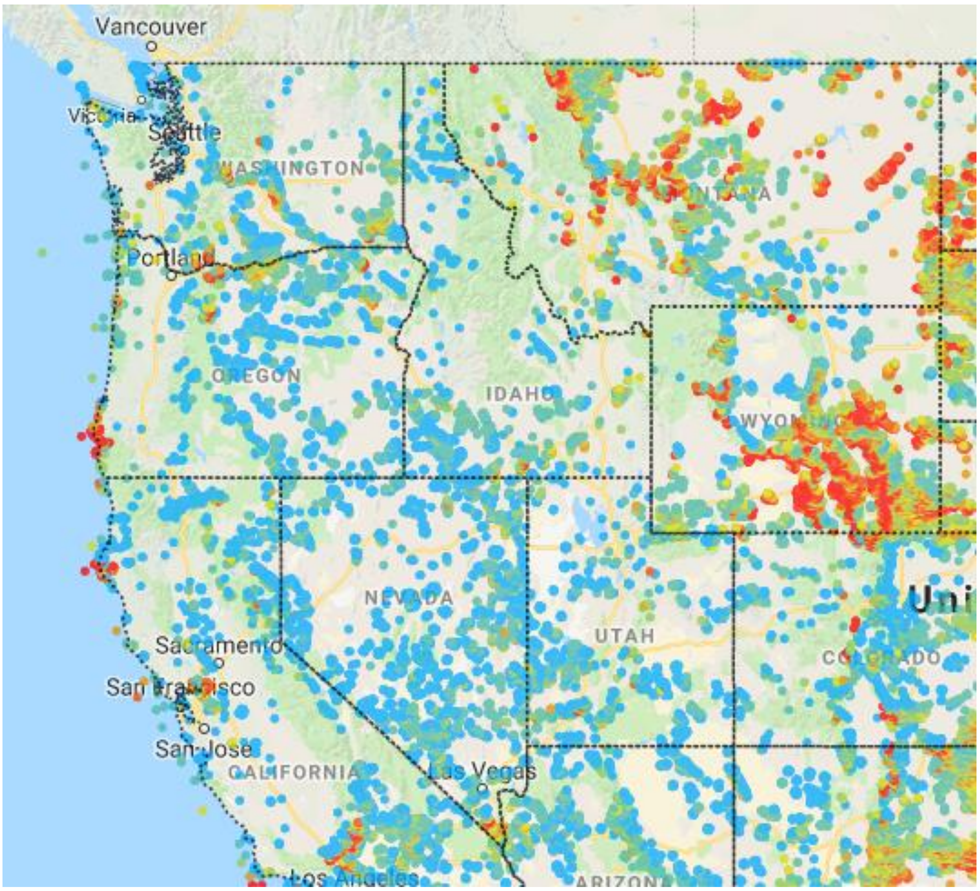
C.1 Wind Profiles

C.1.1 SITE SELECTION

Existing wind site locations (latitude and longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. New candidate wind sites are identified based on the highest average wind speed locations across the Greater Northwest region using data published by NREL[24] (see Figure 33).

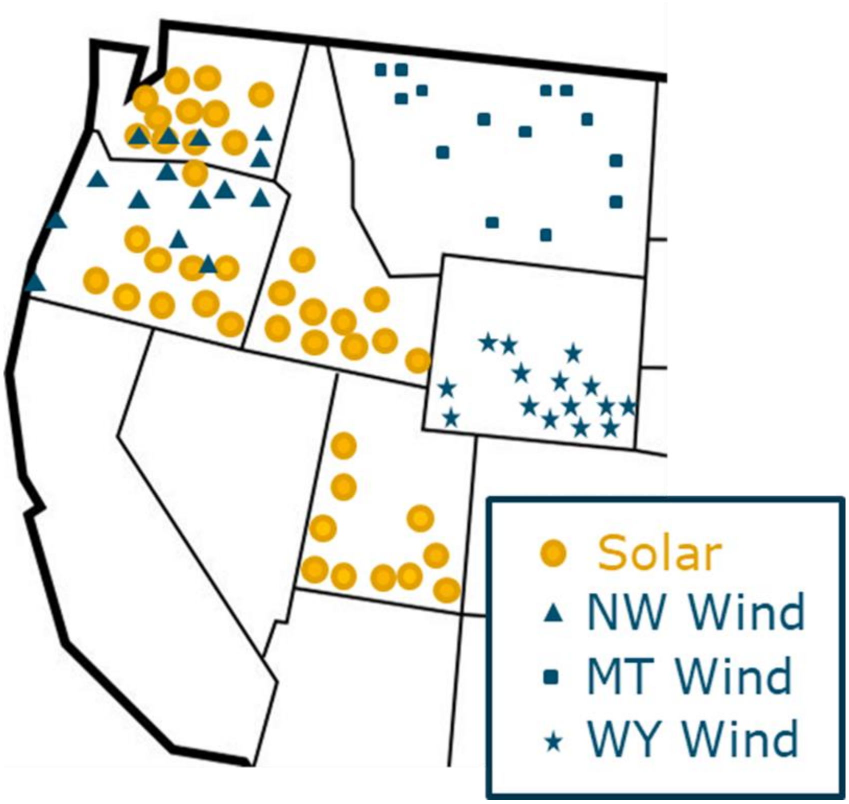
[24] https://maps.nrel.gov/wind-prospector/

Figure 33: Wind speed data in the northwest (Source: NREL)



While striving to place new candidate wind sites in the windiest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in wind generation (e.g. the likelihood that the wind will be blowing in one location even when it is not in another). The new candidate sites used in this study are shown in Figure 34. New sites were aggregated geographically into three single resources that were used in the study modeling: Northwest, Montana, and Wyoming. For example, Montana wind in the study is represented as a single profile with new wind turbines installed proportionally across the various “blue squares” shown in Figure 34.

Figure 34: New Candidate Solar and Wind Sites



C.1.2 PROFILE SIMULATION

NREL's Wind Integration National Dataset (WIND) Toolkit[25] contains historical hourly wind speed data from 2007-2012 for every 2-km x 2-km grid cell in the continental United States. This data is downloaded for each selected site location (both existing and new sites).

[25] https://www.nrel.gov/grid/wind-toolkit.html

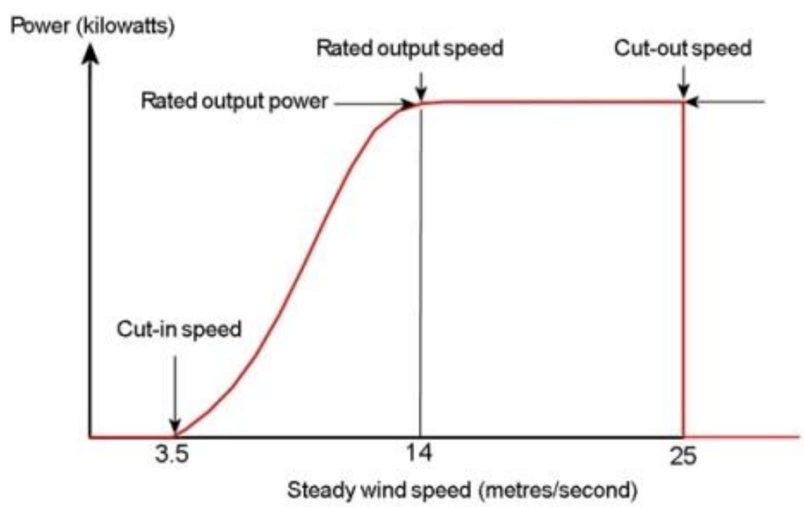
The amount of electricity generated from a wind turbine is a function of wind speed and turbine characteristics, such as the turbine hub height (height above the ground), and the turbine power curve (the mapping of the windspeed to the corresponding power output). Wind speeds increase with height above the ground. Since all NREL WIND data is reported at 100-meters, the wind profile power law is used to scale wind speeds to different heights, depending on the height of the turbine being modeled. This relationship is modeled as:

$$\frac{wind\ speed \quad height\ x}{wind\ speed \quad heigh\ y} = \left(\frac{height\ x}{height\ y}\right)^{wind\ shear\ coefficient}$$

A wind shear coefficient of 0.143 is used in this study.

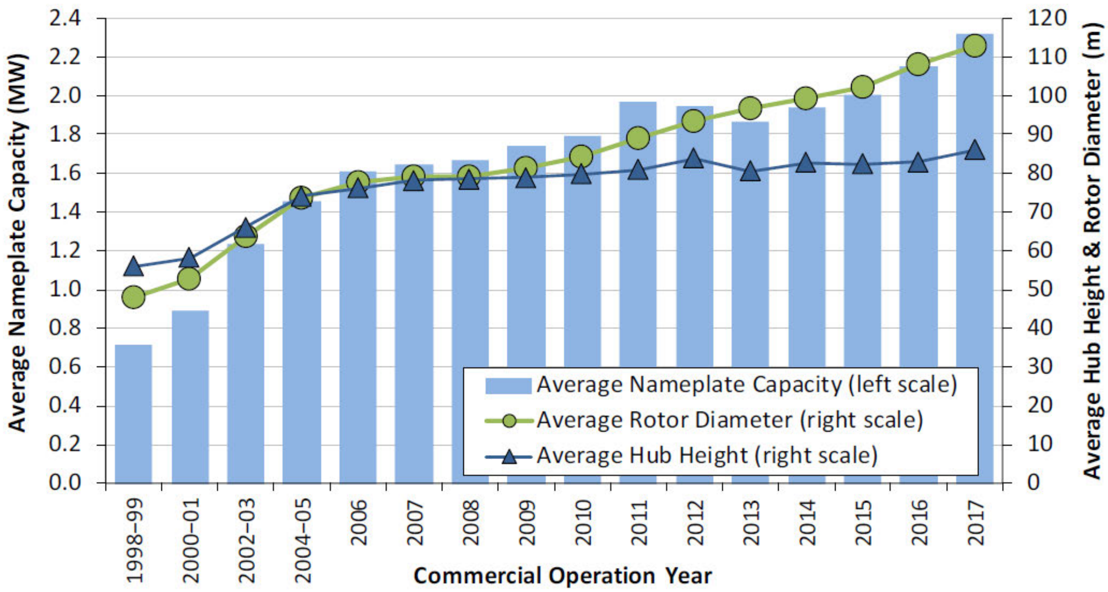
A typical power curve is shown in Figure 35. Turbine power curves define the cut-in speed (minimum windspeed for power generation), rated speed (minimum wind speed to achieve maximum turbine output), cut-out speed (maximum wind speed for power generation) and power generation between the cut-in speed and rated speed.

Figure 35: Typical Wind Turbine Power Curve



With the advancement of wind turbine technology, hub heights have increased over the years (see Figure 36). For existing wind resources, the hub heights are assumed to be the annual average hub height based on the install year. For new turbines, hub height is assumed to be 100 meters.

Figure 36: Average turbine nameplate capacity, rotor diameter and hub height for land-based wind project in the US



For existing turbines, *Nordic 1000 54m 1 MW (MT)* turbine power curve generates wind profiles that benchmark well to the historical generation profiles. The validation process of turbine power curve selection is described in greater detail in Section C.1.3. For new turbines, NREL standard power turbine curves are used to produce future wind profiles.

The wind generation profiles simulation process can be performed for each 2 km X 2 km grid cell and are usually limited to maximum power of 8 - 16 MW due to land constraints and the number of turbines that can fit within that area. However, each wind site that is selected as described in Section C.1.1 (shown in Figure 34), was modeled as 3 GW of nameplate installed wind capacity and encompasses hundreds of adjacent grid cells from the NREL WIND Toolkit database. Note that the actual installed wind capacity varies by scenario in the study and so these 3 GW profiles were scaled up and down to match the installed capacity of each specific scenario. The adjacent grid cells are chosen such that they are the closest in geographical distance from the first wind site location (first grid cell). Representing a single wind site using hundreds of grid cells represents wind production more accurately and irons out any local production spikes that are limited to only a few grid cells in the NREL WIND Toolkit database.

C.1.3 VALIDATION

BPA publishes historical wind production data[26] in its service territory. This data is used to identify a turbine power curve that best benchmarks wind energy production from existing projects as simulated using historical wind speed data. Three turbine power curves were tested – *GE 1.5SLE 77m 1.5mW (MG)*, *Nordic 1000 54m 1Mw (MT)*, and *NREL standard.* Based on annual capacity factors and hourly generation matching, *Nordic 1000 54m 1Mw (MT)* turbine was selected to represent existing wind turbines in the study. These benchmarking results are illustrated in Figure 37 and Figure 38.

[26] https://transmission.bpa.gov/business/operations/wind/

Figure 37: Comparison of Annual Wind Capacity Factors for Benchmarking

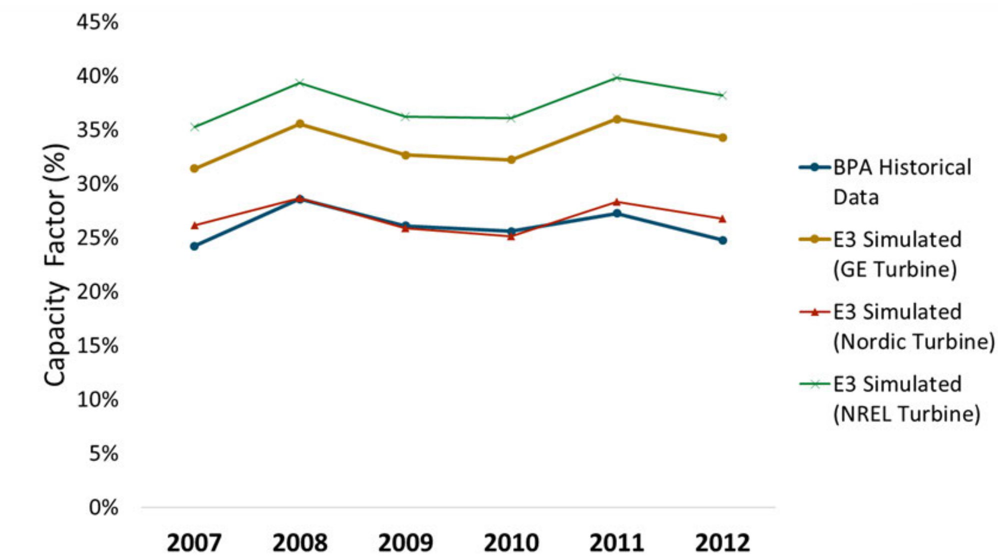
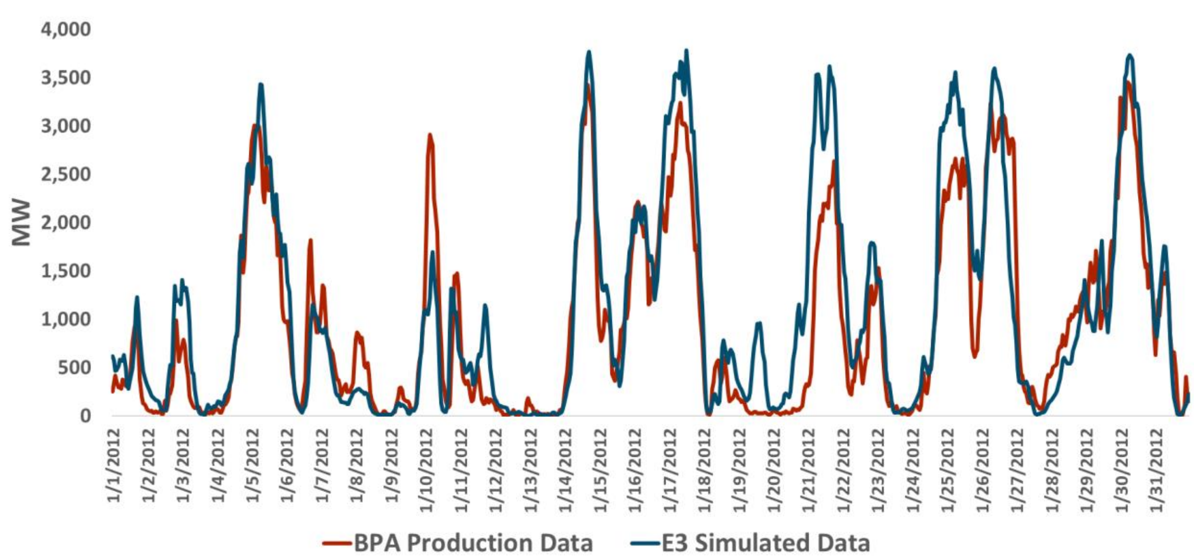


Figure 38: Comparison of Hourly Historical Wind Generation to Simulated Wind Generation for January 2012



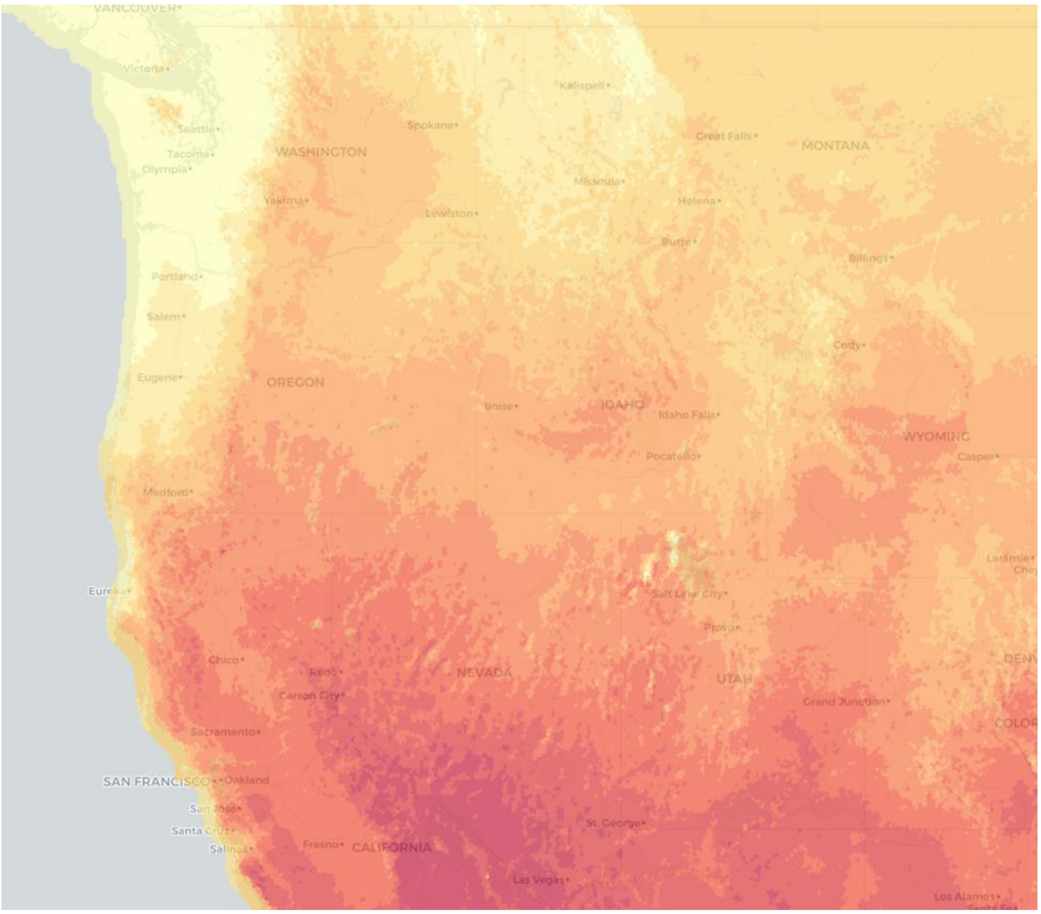
C.2 Solar Profiles

C.2.1 SITE SELECTION

Existing solar site locations (latitude, longitude) in the study region are obtained from NWPCC's generator database and WECC's Anchor Data Set. To build new candidate solar resources in the future, the best solar sites in the region are identified based on the highest insolation from the solar maps published by NREL[27] (see Figure 39). While striving to place new candidate wind sites in the sunniest locations, the new candidate sites are spread across each state in a way that they span a large geographical area in order to capture diversity in solar generation (e.g. the likelihood that the sun will be shining in one location even when it is not in another). The future solar sites used in this study are shown in Figure 34.

[27] https://maps.nrel.gov/nsrdb-viewer/

Figure 39: Solar insolation data in the northwest (Source: NREL)



C.2.2 PROFILE SIMULATION

NREL Solar Prospector Database [28] includes historical hourly solar insolation data: global horizontal irradiance (GHI), direct normal irradiance (DNI), diffuse horizontal irradiance (DHI), and solar zenith angle from 1998-2014. This data is downloaded for all each selected site location (both existing and new).

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[28] https://nsrdb.nrel.gov/

The hourly insolation data is then converted to hourly production profiles using the NREL System Advisor Model (SAM) simulator. Additional inputs used are tilt, inverter loading ratio and tracking type. All panels are assumed to have a tilt equal to the latitude of their location. The study assumes an inverter loading ratio of 1.3 and that all solar systems are assumed to be single-axis tracking. The NREL SAM simulator produces an hourly time series of generation data that is used to represent the electricity generation from the solar sites in this study.

Forty sites are aggregated to represent the solar candidate resource used in this study. These sites are evenly distributed in the four states of Oregon, Washington, Idaho, and Utah as shown in Figure 34.