Portland General Electric Company
Legal Department
121 SW Salmon Street • 1WTC1301 • Portland, Oregon 97204
Phone 503-464-8926 • Fax 503-464-2200
portlandgeneral.com

Douglas C. Tingey
Associate General Counsel
doug.tingey@pgn.com

September 26, 2019

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, OR 97308-1088

Re: **UE 358 – PORTLAND GENERAL ELECTRIC COMPANY,** Advice No. 19-02, New Load Direct Access Program

Dear Filing Center:

Enclosed for filing in the above-captioned docket is Portland General Electric Company's Cross-Examination Exhibits (Exhibits 400-403; PGE/403 has attachments A-E). Two paper copies of this filing will follow by U.S. Mail because the filing is over 100 pages.

Thank you for your assistance.

Sincerely,

DCT

Douglas C. Tingey
Associate General Counsel

DCT:hp
Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 358

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Advice No. 19-02, New Load Direct Access Program.	**CROSS-EXAMINATION EXHIBITS OF PORTLAND GENERAL ELECTRIC COMPANY**

Pursuant to the Administrative Law Judge's ruling of August 16, 2019, Portland General Electric Company ("PGE") submits the following cross-examination exhibit list and cross-examination exhibits not previously filed in this case for the Commission hearing scheduled on October 17, 2019.

Cross-Examination Exhibit	Description
PGE/400	OPUC Staff Response to PGE Data Request DR 001
PGE/401	OPUC Staff Response to PGE Data Request DR 005
PGE/402	OPUC Staff Response to PGE Data Request DR 006
PGE/403	PGE Response to OPUC Staff Data Request DR 026 with Attachments A-E

DATED this 26th day of September, 2019.

Respectfully submitted,

Douglas C. Tingey, OSB No. 044366
Associate General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8926 (Telephone)
(503) 464-2200 (Fax)
doug.tingey@pgn.com

CERTIFICATE OF SERVICE

I hereby certify that I served two paper copies of the foregoing **PORTLAND GENERAL ELECTRIC COMPANY'S CROSS-EXAMINATION EXHIBITS** on the Public Utility Commission of Oregon, Attention: Filing Center, P.O. Box 1088, Salem, OR 97308 on the date indicated below by U.S. mail for Docket No. UE 358.

Dated this 26th day of September, 2019.

Helen Parker

Helen Parker
Legal Assistant
Portland General Electric Company
121 SW Salmon St., 1WTC1301
Portland, OR 97204
(503) 464-7044 (Telephone)
(503) 464-2200 (Fax)
helen.parker@pgn.com

Date: August 1, 2019

TO:
KARLA WENZEL
MANAGER, PRICING AND TARIFFS
121 SW SALMON ST, 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com;

FROM: Scott Gibbens
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 358 - PGE Data Request filed July 18, 2019

Data Request No 01:

1. See page Gibbens/12, lines 9-22: Please provide all analysis and workpapers which led Staff to the conclusion that the RAD would not be needed outside of emergency service.

Staff Response No 01:

1. As stated in Staff's testimony, we are "unable to envision a scenario in which the capacity secured via the RAD would be necessary outside of a NLDA customer returning to PGE prior to the standard three-year waiting period." After reviewing the Company's testimony and through discussions regarding the RAD, Staff continues to be unable to determine a scenario in which the capacity product secured in the RAD would be utilized for electricity service delivery to a specific DA customer, outside of an emergency scenario. Staff's thought process is outlined as follows.
    1. In order for a rate to be fair, just and reasonable, the customer must derive some benefit from the rate or charge. PGE argues the payment of the RAD is necessary to secure capacity resources.
    2. Under normal conditions (i.e. non-emergency), a DA customer receives its power from an ESS, and is not being served by PGE.
    3. PGE's approved DA program and applicable tariffs require a 3 year notice for return to cost of service rates, during which time the customer pays rates that the Company has advocated for, and the Commission has approved, as being fair, just and reasonable to cover the costs that customer is placing on PGE's system.
    4. Staff is unable to identify an incremental service provided by the RAD that a DA customer would be receiving from PGE, particularly one that is not otherwise covered by the Company's proposed RIC charge or the Company's current tariffs that require notice prior to returning to COS rat

Date: August 1, 2019

TO:
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pge.opuc.filings@pgn.com;

FROM: Scott Gibbens
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 358 - PGE Data Request filed July 18, 2019

Data Request No 05:

5. In Gibbens/17, lines 3-6: Does the Commission require ESSs to conduct long- term resource capacity/adequacy planning? If no, what changes would be necessary for the Commission to do so?

Staff Response No 05:

5. Staff objects to this question to the extent that it seeks attorney-client privileged communications and/or calls for a legal conclusion.

   Without raising said objections, it is Staff's understanding that the Commission does not currently require ESSs to conduct long-term resource capacity/adequacy planning. I am unable to provide an answer as to what would be necessary for the Commission to do so. Staff intends to address issues regarding the Commission's authority in legal briefing.

Date: August 1, 2019

TO:
KARLA WENZEL
MANAGER, PRICING AND TARIFFS
121 SW SALMON ST, 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com;

FROM: Scott Gibbens
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 358 - PGE Data Request filed July 18, 2019

Data Request No 06:

6. See Gibbens/17, lines 7-10: Provide all data and evidence which demonstrates the customers sophistication.

Staff Response No 06:

6. The referenced testimony is based on the general understanding in the UM 1837 and AR 614 proceedings that the threshold size for participation in the NLDA program was chosen based in part due to the customers' sophistication in planning and negotiating. This understanding was also shared by the Commission in regards to PGE's GEAR program, which stated in Order 19-075 that customers of this size are "capable of negotiating sophisticated PPA arrangements." Staff finds that the NLDA program itself allows a customer of sufficient size to source and procure its own power, based on its ability to make its own business decisions, it is also capable of making decisions about the reliability and means to achieve said reliability. Both decisions are based on analysis which requires the participant to identify costs and risks associated with the power they utilize.

September 25, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 358
PGE Response to OPUC Data Request No. 026
Dated September 18, 2019

Request:

Please refer to PGE/300, Sims – Tinker/7. PGE cites the Northwest Power and Conservation Council's (NWPCC) draft Resource Adequacy Assessment as its basis for the claim that RA is a pressing issue and should be addressed in the context of this docket. Does PGE also agree, that in the same referenced presentation, the NWPCC also notes that it is working on an updated "New GENESYS" model that while not fully vetted, estimates a 0% inferred LOLP in 2024 in the reference case?

Response:

The referenced draft Resource Adequacy Assessment ('Draft Assessment') identifies a 7-8% LOLP in 2021. The same document provides an update to Resource Adequacy Steering Committee members on the progress toward developing a new resource adequacy assessment model ('New GENESYS') to be used in future resource adequacy assessments. As highlighted in the Draft Assessment, "The New GENESYS has NOT yet been fully vetted for use to assess resource adequacy." (Emphasis original.) Further, "Until the new GENESYS is fully vetted, the classic GENESYS model will be used for assessments."

The Draft Assessment does share New GENESYS estimates of how Northwest LOLP would be diminished were the region to rely upon 8647 MW of out-of-region import capability for resource adequacy purposes (as opposed to 3400 MW of maximum import capability as is assumed in the existing Draft Assessment). The Draft Assessment suggests approximately 0% LOLP in 2024 if the region's resource adequacy demands can be met by over 8500 MW of imports from other regions. PGE is contributing to the NWPCC's efforts to review import capability assumptions for New GENESYS. At this time, PGE does not believe it is advisable for the NWPCC to increase reliance on extra-regional, unspecified resources to address local resource adequacy requirements. Importantly, the Draft Assessment does not suggest that an ability for the region to rely upon import capability replaces the need to actively plan and procure resources to meet regional resource adequacy needs.

Furthermore, as demonstrated in the following attachments to this response, other entities have engaged in resource adequacy and supply assessments which highlight similar concerns regarding increases in loss of load metrics.

1) Attachment 026-A contains a January 2019 presentation summarizing a resource adequacy study performed by Energy+Environmental Economics (E3). Slide 25 summarizes the adequacy assessment for 2018 and estimates a loss of load expectation (LOLE) of 6.5 in 2018. The full study is provided in Attachment 026-B.
2) Attachment 026-C contains the PNUCC Northwest Regional Forecast of Power Loads and Resources. Pages 8 through 11 contain load resource balance tables for 2019-2029 annual energy, 2019-2020 monthly energy, 2020-2029 winter peak, and 2020-2029 summer peak respectively.
3) Attachment 026-D contains a September 2019 briefing on post 2020 grid operational outlook made to the California Independent System Operator (CAISO) Board of Governors. Slide 6 articulates planned summer peak shortfalls in CAISO in 2020 of 2,300 MW and increasing to 4,700MW in 2022. Additionally, the CEO report provided to the CAISO Board of Governors at the same briefing, identified the following situation during 2019[1]:

   > *"Overall summer operating conditions have been mild though there have been a few days where load levels reached over 44,000 MWs. On those days, operators had very little margin over the net peak (after the sun begins to set). As an example, on September 3, 2019, operators had to seek additional imports from around the West. Even after doing so, the system had only 114 MWs of capacity remaining before deploying reserves during hour ending 20 (8:00 p.m.). The system peak that day was 44,148 MW."*

4) Attachment 026-E contains the "External Study E. Market Capacity Study" from PGE's 2019 IRP. The study was performed by E3 and is a two-part study consisting of a review of recent regional adequacy assessments and a heuristic model of regional capacity. Section 5 of the study contains the modeling results, which reflect the following timing of capacity deficits:

[1] http://www.caiso.com/Documents/CEOReport-Sep2019.pdf

Scenario	First Year of Capacity Deficit	
	Winter	Summer
Low Need Scenario	2026	2029
Base Case	**2021**	**2026**
High Need Scenario	2021	2023

As noted in the 2019 IRP, the study provides E3's recommended market capacity assumptions and the recommendations were incorporated into PGE's capacity adequacy assessments.

PGE strongly notes that many resource adequacy studies do not consider California and its significant impact to the region, particularly during summer months.

UE 358

Attachment 026-A

Provided in Electronic Format

January 2019 Resource Adequacy Presentation

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

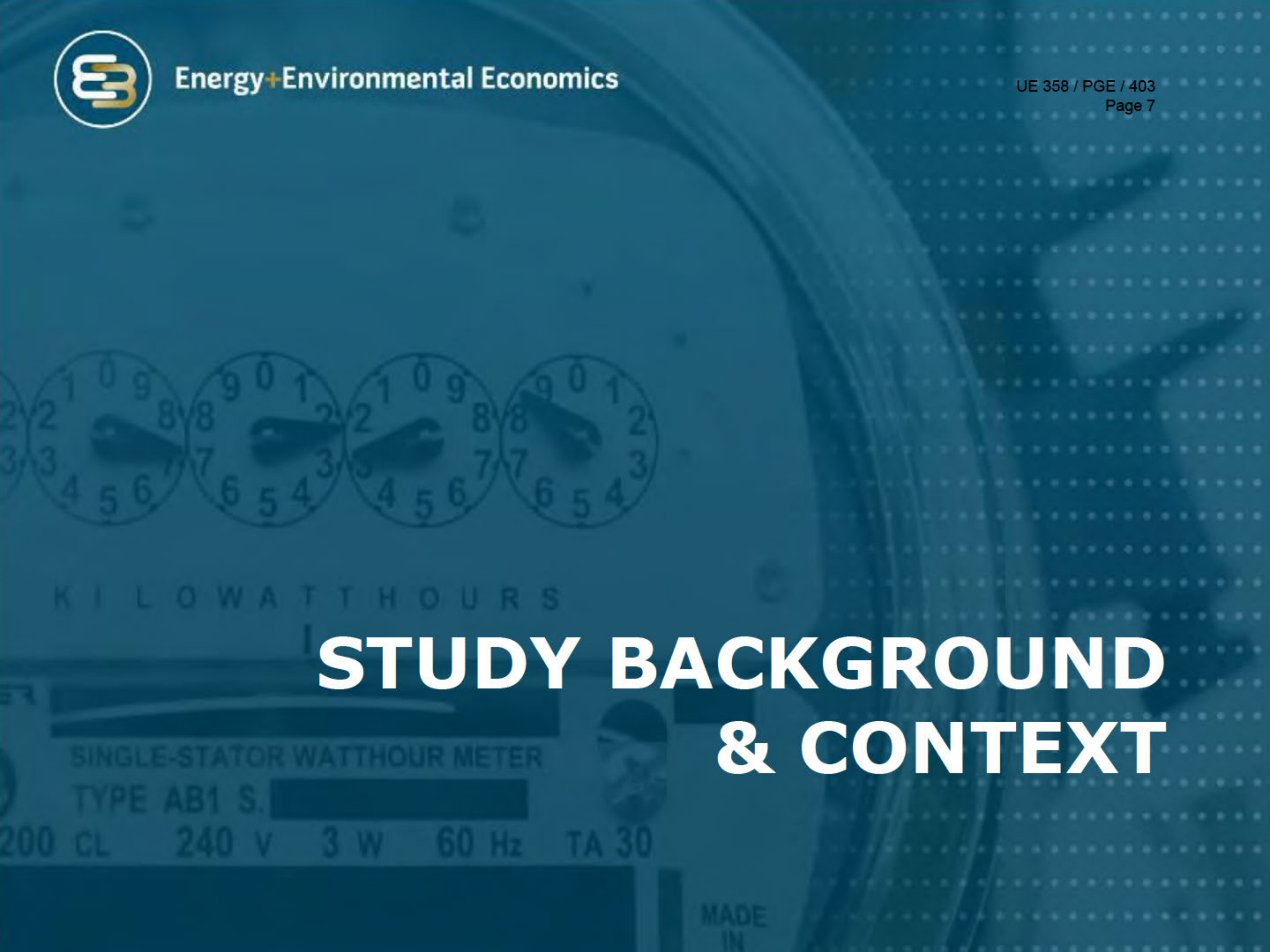
Serving Load Reliably under a Changing Resource Mix

January 2019

Arne Olson, Sr. Partner
Zach Ming, Managing Consultant

Outline

- **Study Background & Context**
- **Methodology & Key Inputs**
- **Results**
  - 2018
  - 2030
  - 2050
  - Capacity contribution of wind, solar, storage and demand response
- **Reliability Planning Practices in the Pacific Northwest**
- **Key Findings**



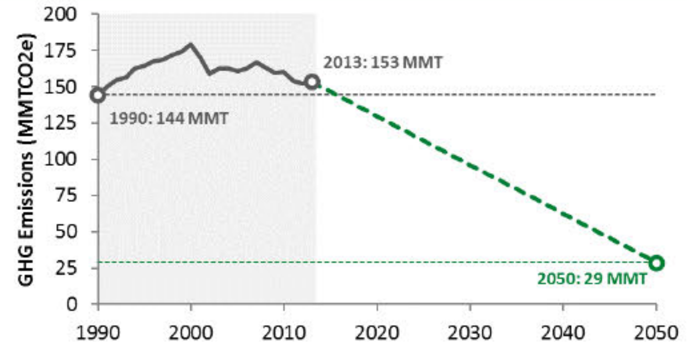
STUDY BACKGROUND & CONTEXT

About This Study

+ The Pacific Northwest is expected to undergo significant changes to its generation resource mix over the next 30 years due to changing economics and more stringent policy goals

- Increased penetration of wind and solar generation
- Retirements of coal generation
- Questions about the role of new natural gas generation

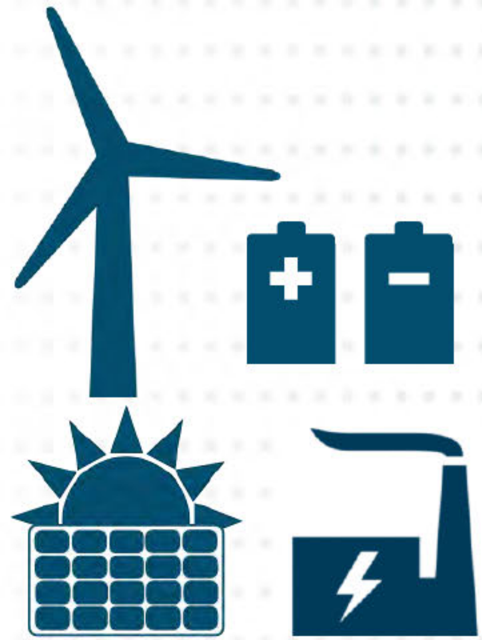
Historical and Projected GHG Emissions for OR and WA



+ This raises questions about the region's ability to serve load reliably as firm generation is replaced with variable resources

+ This study was sponsored by 13 Pacific Northwest utilities to examine Resource Adequacy under a changing resource mix

- How to maintain Resource Adequacy in the 2020-2030 time frame under growing loads and increasing coal retirements
- How to maintain Resource Adequacy in the 2040-2050 time frame under stringent carbon abatement goals



Study Sponsors

+ **This study was sponsored by Puget Sound Energy, Avista, NorthWestern Energy and the Public Generating Pool (PGP)**

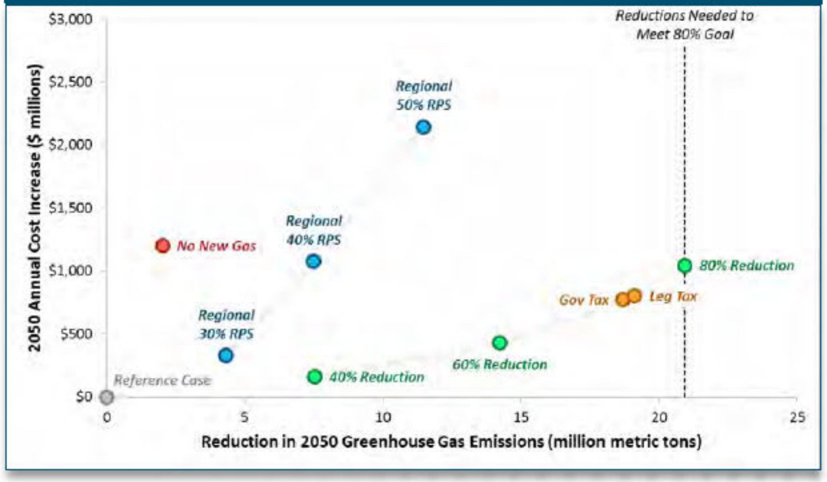
- PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington.

E3 thanks the staff of the Northwest Power and Conservation Council for providing data and technical review

Relationship to Prior E3 Work

+ **In 2017-2018, E3 completed a series of studies for PGP and Climate Solutions to evaluate the costs of alternative electricity decarbonization strategies in Washington and Oregon**
  - The studies found that the least-cost way to reduce carbon is to replace coal with a mix of conservation, renewables and gas generation
  - Firm capacity was assumed to be needed for long-run reliability, however the study did not look at that question in depth

2017 E3-PGP Low Carbon Study



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

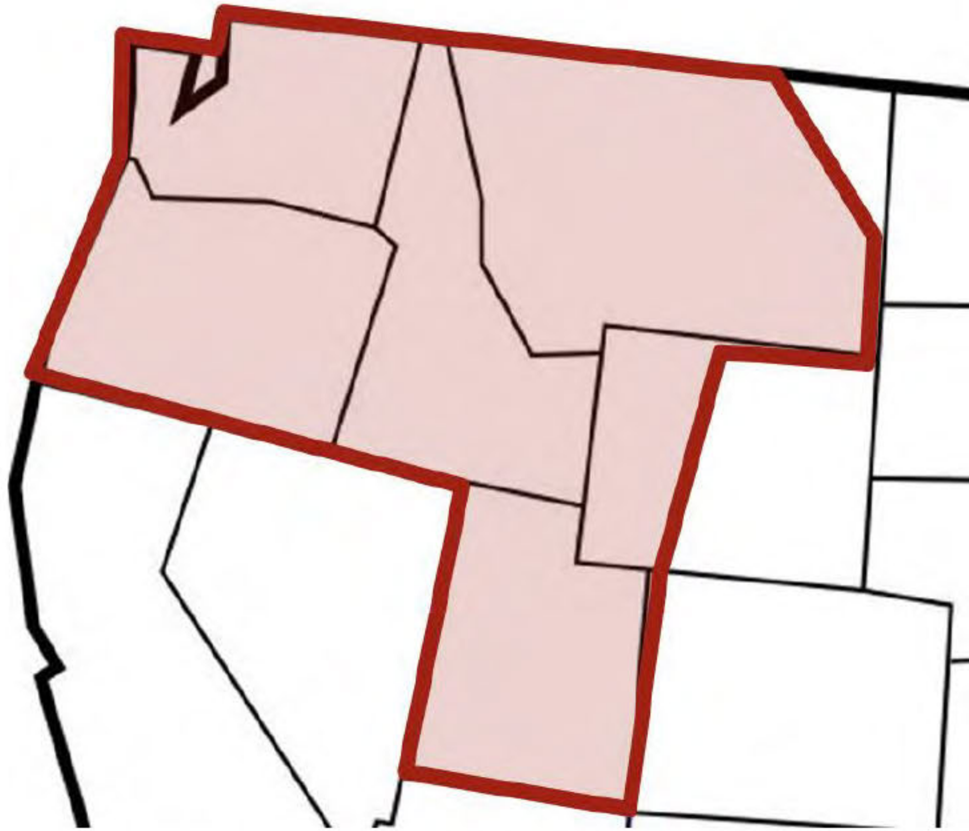
+ **This study builds on the previous analysis by focusing on long-run reliability**
  - How much capacity is needed to serve peak load under a range of conditions in the NW?
  - How much capacity can be provided by wind, solar, storage and demand response?
  - What combination of resources would be needed for reliability under low or zero carbon?
+ **The conclusions from this study broadly align with the previous results**

Long-run Reliability and Resource Adequacy

- **This study focuses on long-run (planning) reliability, a.k.a. Resource Adequacy (RA)**
  - A system is "Resource Adequate" if it has sufficient capacity to serve load across a broad range of weather conditions, subject to a long-run standard for frequency of reliability events, for example 1-day-in-10 yrs.
- **There is no mandatory or voluntary national standard for RA**
  - Each Balancing Authority establishes its own standard subject to oversight by state commissions or locally-elected boards
  - North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC) publish information about Resource Adequacy but have no formal governing role
- **Study uses a 1-in-10 standard of no more than 24 hours of lost load in 10 years, or no more than 2.4 hours/year**
  - This is the most common standard used across the industry

Study Region – The Greater NW

- **The study region consists of the U.S. portion of the Northwest Power Pool (excluding Nevada)**
- **It is assumed that any resource in any area can serve any need throughout the Greater NW region**
  - Study assumes no transmission constraints or transactional friction
  - Study assumes full benefits from regional load and resource diversity
  - The system as modeled is more efficient and seamless than the actual Greater NW system



Balancing Authority Areas include: Avista, Bonneville Power Administration, Chelan County PUD, Douglas County PUD, Grant County PUD, Idaho Power, NorthWestern Energy, PacifiCorp (East & West), Portland General Electric, Puget Sound Energy, Seattle City Light, Tacoma Power, Western Area Power Administration

Individual utility impacts will differ from the regional impacts

- **Cost impacts in this study are presented from a societal perspective and represent an aggregation of all costs and benefits within the Greater NW region**
  - Societal costs include all investment (i.e. "steel-in-the-ground") and operational costs (i.e. fuel and O&M) that are incurred in the region
- **Cost of decarbonization may be higher or lower for individual utilities as 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 be different for each utility**
  - Individual systems will need a higher reserve margin than the Greater NW region due to smaller size and less diversity
  - Capacity contribution of renewables will be different for individual utilities due to differences in the timing of peak loads and renewable generation production

METHODOLOGY & KEY INPUTS

This study utilizes E3's Renewable Energy Capacity Planning (RECAP) Model

+ **Resource adequacy is a critical concern under high renewable and decarbonized systems**
  - Renewable energy availability depends on the weather
  - Storage and Demand Response availability depends on many factors
+ **RECAP evaluates adequacy through time-sequential simulations over thousands of years of plausible load, renewable, hydro, and stochastic forced outage conditions**
  - Captures thermal resource and transmission forced outages
  - Captures variable availability of renewables & correlations to load
  - Tracks hydro and storage state of charge

Storage **Hydro** **DR**

RECAP calculates reliability metrics for high renewable systems:

- **LOLP: Loss of Load Probability**
- **LOLE: Loss of Load Expectation**
- **EUE: Expected Unserved Energy**
- **ELCC: Effective Load-Carrying Capability for hydro, wind, solar, storage and DR**
- **PRM: Planning Reserve Margin needed to meet specified LOLE**

Information about E3's RECAP model can be found here:
https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

RECAP Methodology and Data Sources

+ **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
  - Hourly wind and solar generation profiles are drawn from simulations created by the National Renewable Energy Laboratory and paired with historical weather days through an E3-created day-matching algorithm
  - 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
  - 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
+ **RECAP calculates whether there are sufficient resources available to serve load during each hour over thousands of simulations**

RECAP evaluates the availability of energy supplies to meet loads using an 8-step calculation process

Step 1
Calculate Hourly Load

Step 2
Calculate Renewable Profiles

Step 3
Calculate Available Dispatchable Generation

Step 4
Hydro Dispatch

Step 5
Calculate Available Transmission

Step 6
Dispatch Storage

Step 7
Dispatch Demand Response

72°

Step 8
Calculate Loss of Load

RECAP calculates a number of metrics that are useful for resource planning

- **Annual Loss of Load Probability (aLOLP) (%):** is the probability of a shortfall (load plus reserves exceed generation) in a given year
- **Annual Loss of Load Expectation (LOLE) (hrs/yr):** is total number of hours in a year wherein load plus reserves exceeds generation
- **Annual Expected Unserved Energy (EUE) (MWh/yr):** is the expected unserved load plus reserves in MWh per year
- **Effective Load Carrying Capability (ELCC) (%):** is 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 and demand response)
- **Planning Reserve Margin (PRM) (%):** is the resource margin above 1-in-2-year peak load, in %, that is required in order to maintain acceptable resource adequacy

Additional metric definitions used for scenario development

- **GHG Reduction %** is the reduction below 1990 emission levels for the study region
  - The study region emitted 60 million metric electricity sector emissions in 1990
- **CPS %** is the total quantity of GHG-free generation divided by retail electricity sales
  - “Clean Portfolio Standard” includes renewable energy plus hydro and nuclear
  - Common policy target metric, including California’s SB 100
- **GHG-Free Generation %** is the total quantity of GHG-free generation, *minus* exported GHG-free generation, divided by total wholesale load
  - Assumed export capability up to 6,000 MW
- **Renewable Curtailment %** is the total quantity of wind/solar generation that is not delivered or exported divided by total wind/solar generation

RECAP vs. RESOLVE: How are the models different?

+ **RESOLVE is an <u>economic model</u> that selects optimal resource portfolios that minimize costs over time**
  - Selects optimal portfolio of renewable, conventional and energy storage resources
  - Reliability is addressed through high-level assumptions about long-run reliability needs via a PRM constraint
  - Independent simulations of 40 carefully selected and weighted operating days

+ **RECAP is a <u>reliability model</u> that calculates how much effective capacity is needed to meet peak loads**
  - Calculates system-wide Planning Reserve Margin and other long-run reliability statistics
  - Economics are addressed through high-level assumptions about resource cost and availability
  - Time-sequential simulations of thousands of operating years selected randomly

E3 often uses RESOLVE and RECAP in tandem to develop portfolios that are least-cost with robust long-run reliability

<u>RESOLVE</u>
Electricity Capacity Expansion

↕

<u>RECAP</u>
Electricity Resource Adequacy

Demand forecast is consistent with PGP study

- **Demand forecast is benchmarked against multiple long-term projections**
  - Both Pre- and Post-EE
- **Load profiles are held constant throughout the analysis period**
  - No assumptions about changing load shapes due to climate change
- **Electrification is only included to the extent that it is reflected in these load growth forecasts**
  - Load growth includes impact of 1.1 million electric vehicles by 2030
  - Heavy electrification of buildings, vehicles, or industry would increase RA requirements beyond what this study shows

Source	Pre EE	Post EE
PNUCC Load Fcst	1.7%	0.9%
BPA White Book	1.1%	—
NWPCC 7th Plan	0.9%	0.0%
TEPPC 2026 CC	—	1.3%
E3 Assumption	**1.3%**	**0.7%**

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

The study considers Resource Adequacy needs under multiple scenarios representing alternative resource mixes

2018-2030 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
2018 Case[4]	-6%	71%	75%	63
2030 Reference Case[4]	-12%	61%	65%	67
2030 Coal Retirement	30%	61%	65%	42

2050 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
Reference Case	16%	60%	63%	50
60% GHG Reduction	60%	80%	86%	25
80% GHG Reduction	80%	90%	100%	12
90% GHG Reduction	90%	95%	108%	6
98% GHG Reduction	98%	99%	117%	1
100% GHG Reduction	100%	100%	123%	0

[1]Greater NW Region 1990 electricity sector emissions = 60 MMT/yr
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load
[3]CPS % = renewable/hydro/nuclear generation divided by retail electricity sales
[4]2018 and 2030 cases assumes coal capacity factor of 60%

New wind and solar resources are added across a geographically diverse footprint

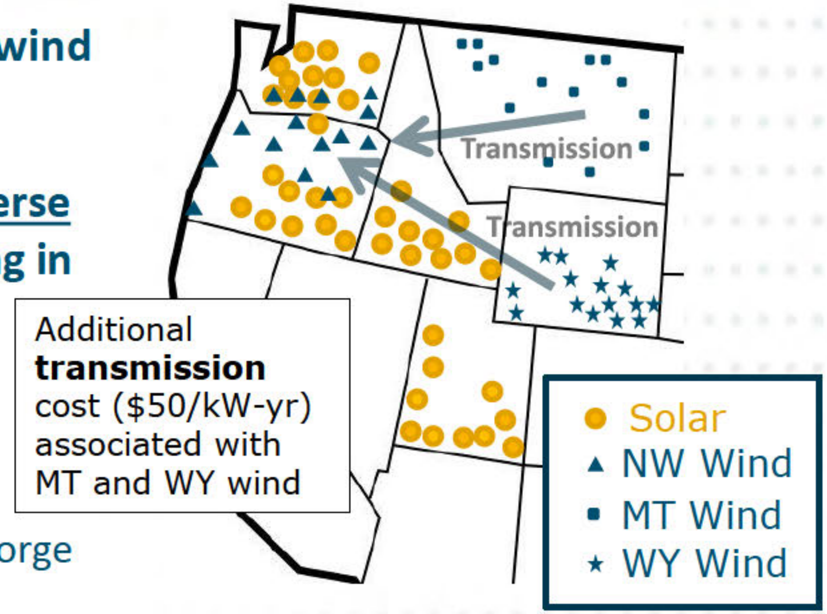
+ **The study considers additions nearly 100 GW of wind and 50 GW of solar across the six-state region**

+ **The portfolios studied are <u>significantly more diverse</u> than the renewable resources currently operating in the region**

  - Each dot in the map represents a location where wind and solar is added in the study
  - NW wind is more diverse than existing Columbia Gorge wind

+ **New renewable portfolios are within the bounds of current technical potential estimates, but are nearly an order of magnitude higher than other studies have examined**

+ **The cost of new transmission is assumed for delivery of remote wind and solar generation but siting and construction is not studied in detail**



NREL Technical Potential (GW)

State	Wind
WA	18
OR	27
CA	34
ID	18
MT	944
WY	552
UT	13
Total	**1588**

https://www.nrel.gov/docs/fy12osti/51946.pdf

Resource Cost Assumptions

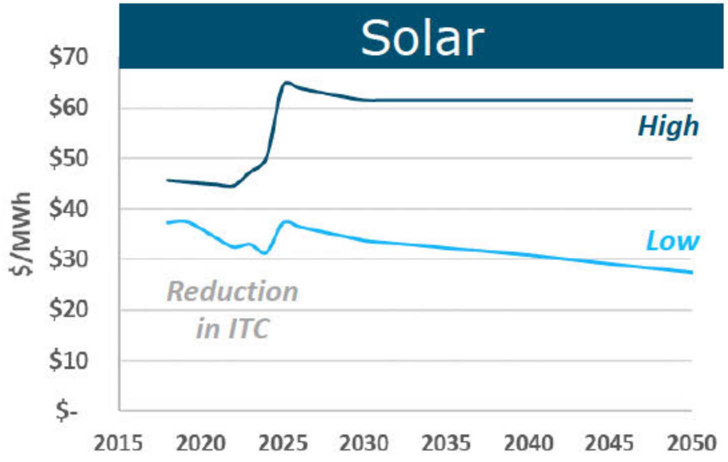
$2016

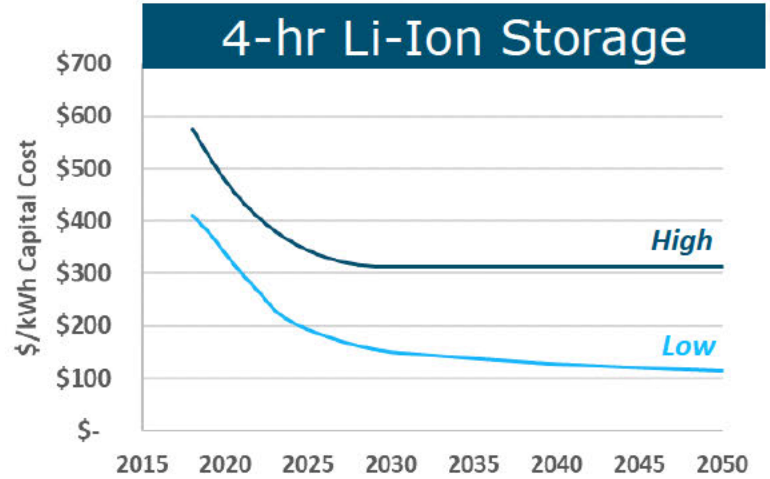
Technology	Unit	Resource Cost: High	Resource Cost: Low	Transmission	Notes
Solar PV	*$/MWh*	$59	$32	$8	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 27%
NW Wind	*$/MWh*	$55	$43	$6	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 37%
MT/WY Wind	*$/MWh*	$48	$37	$19	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 43%
Battery - Capacity	*$/kW-yr*	$30	$5		High Source: PGP Study; Low Source: Lazard LCOS Mid Case 4.0
Battery – Energy	*$/kWh-yr*	$41	$23		High Source: PGP Study; Low Source: Lazard LCOS Mid Case 4.0
Clean Baseload	*$/MWh*	$91	$91		$800/kW-yr; Technology unspecified
Natural Gas Capacity	*$/kW-yr*	$150	$150		7,000 Btu/kWh heat rate; $5/MWh var O&M
Gas Price	*$/MMBtu*	$4	$2		Corresponds to $33/MWh and $19/MWh variable cost of natural gas (gas price * heat rate + var O&M)
Biogas Price	*$/MMBtu*	$39	$39		

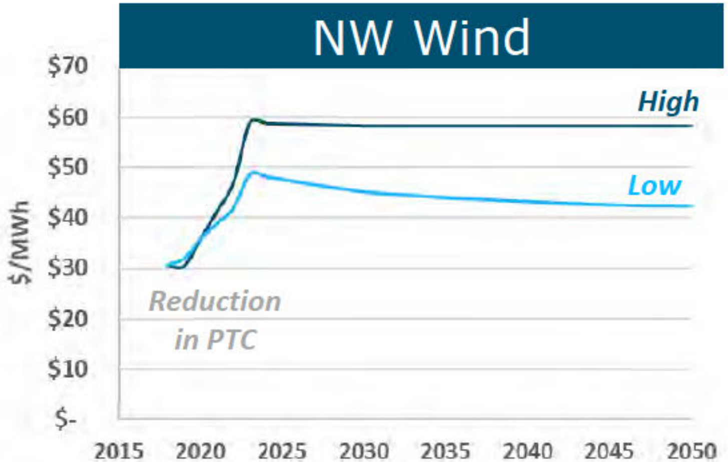
Costs shown are the average cost over the 2018-2050 timeframe; trajectories in following slide

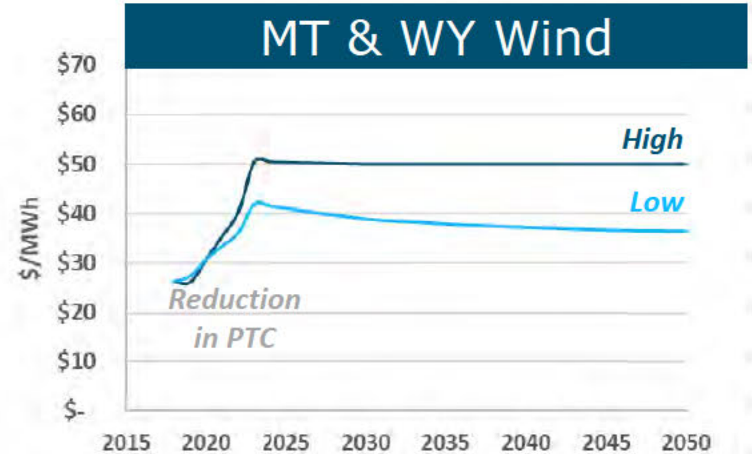
Note: RECAP is primarily a loss-of-load probability model that calculates resource *availability* over thousands of simulated years. RECAP does estimate least-cost *dispatch* and *capacity expansion* but this functionality does not involve optimization and is necessarily approximate

Resource Cost Assumptions





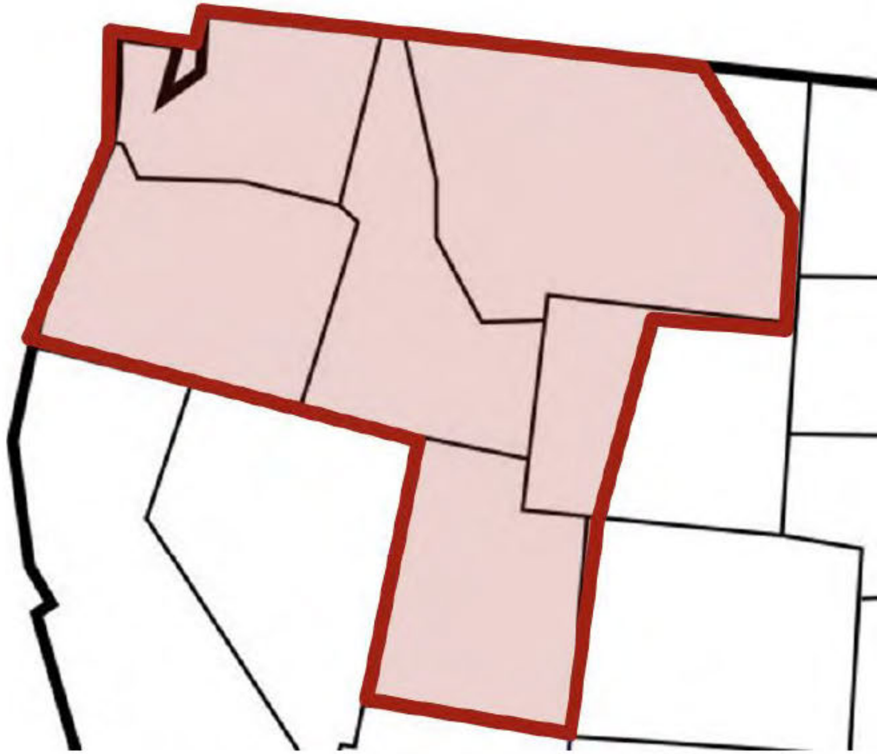




Shown in 2016 dollars

Imports/Exports

- **Import assumptions are consistent with NWPCC GENESYS model**
  - Monthly import availability
    - 2,500 MW from Nov – Mar
    - 1,250 MW in Oct
    - Zero from Apr – Sep
  - Hourly import availability
    - 3,000 MW in Low Load Hours (HE 22 – HE 5)
  - Monthly + hourly import availabilities are additive but in any given hour total import capability is limited to 3,400 MW
- **For 100% GHG-free scenario, no imports are assumed in order to ensure no imported GHG emissions**
- **6,000 MW export capability in all hours**



All region outside the Greater NW region is modeled as a single 'external' zone.
MT Wind and WY Wind are included in the NW zone and not in the 'external' zone.

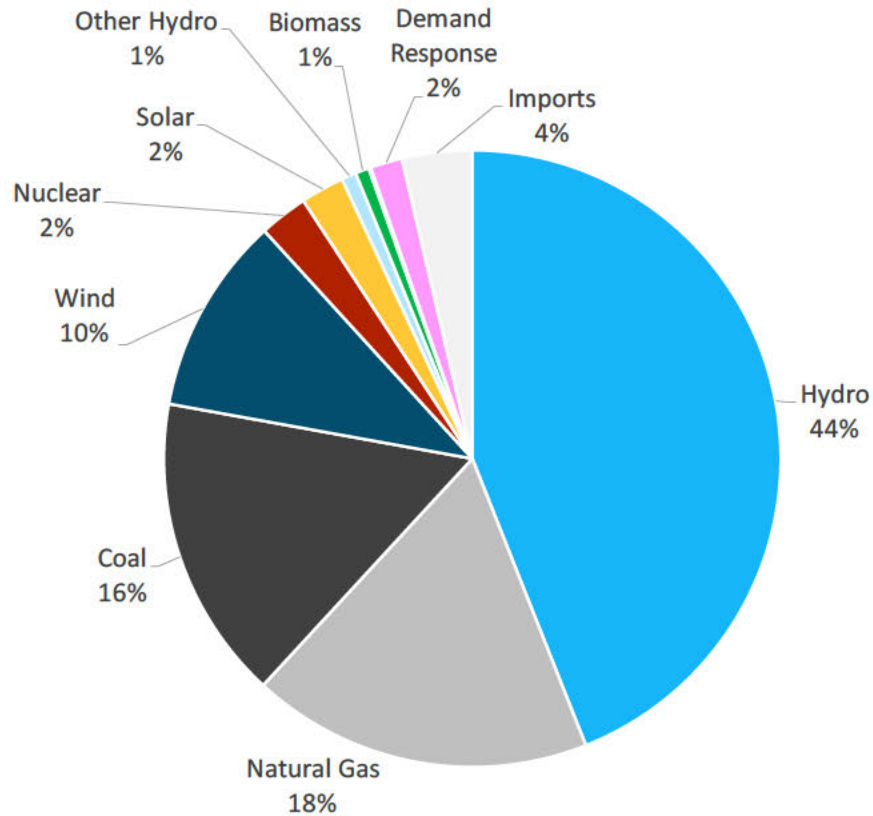
2018 RESULTS

2018 System

+ **2018 Baseline system includes 24 GW of thermal generation, 35 GW of hydro generation, and 7 GW of wind generation**
  - Sources: GENESYS database for NWPCC region and TEPPC anchor dataset for other select NWPP BAAs
+ **By 2023, approximately 1,800 MW of coal generation is expected to retire**
+ **2018 Loads: 246 TWh/yr, 43 GW peak**

Resource	2018 Nameplate MW
Hydro[1]	34,697
Natural Gas	12,181
Coal	10,895
Wind	7,079
Nuclear	1,150
Solar	1,557
Other Hydro[2]	524
Biomass	489
Geothermal	80
Demand Response[3]	299
Imports[4]	2,500

Capacity Mix %



[1]Hydro is modeled as energy budgets for each month and does not use nameplate capacity
[2]Other hydro is hydro outside NWPCC region
[3]Demand Response: max 10 calls, each call max duration = 4 hours
[4]Imports are zero for summer months (Jun, Jul, Aug, Sep) except during off-peak hours
NOTE: Storage assumed to be insignificant in the current system

2018 system is in very tight load-resource balance

- A planning reserve margin of 12% is required to meet 1-in-10 reliability standard
- The 2018 system does not meet 1-in-10 reliability standard (2.4 hrs./yr.)
- The 2018 system does meet Northwest Power and Conservation Council standard for Annual LOLP (5%)

	Reliability Metrics
Annual LOLP	3.7%
LOLE (hrs./year)	**6.5**
EUE (MWh/year)	5,777
EUE norm (EUE/Load)	0.003%
1-in-2 Peak Load (GW)	43
Required PRM to meet 2.4 LOLE	12%
Required Firm Capacity (GW)	48

2018 Load and Resource Balance

	2018
Load (GW)	
Peak Load	43
PRM (%)	*12%*
PRM	5
Total Load Requirement	48

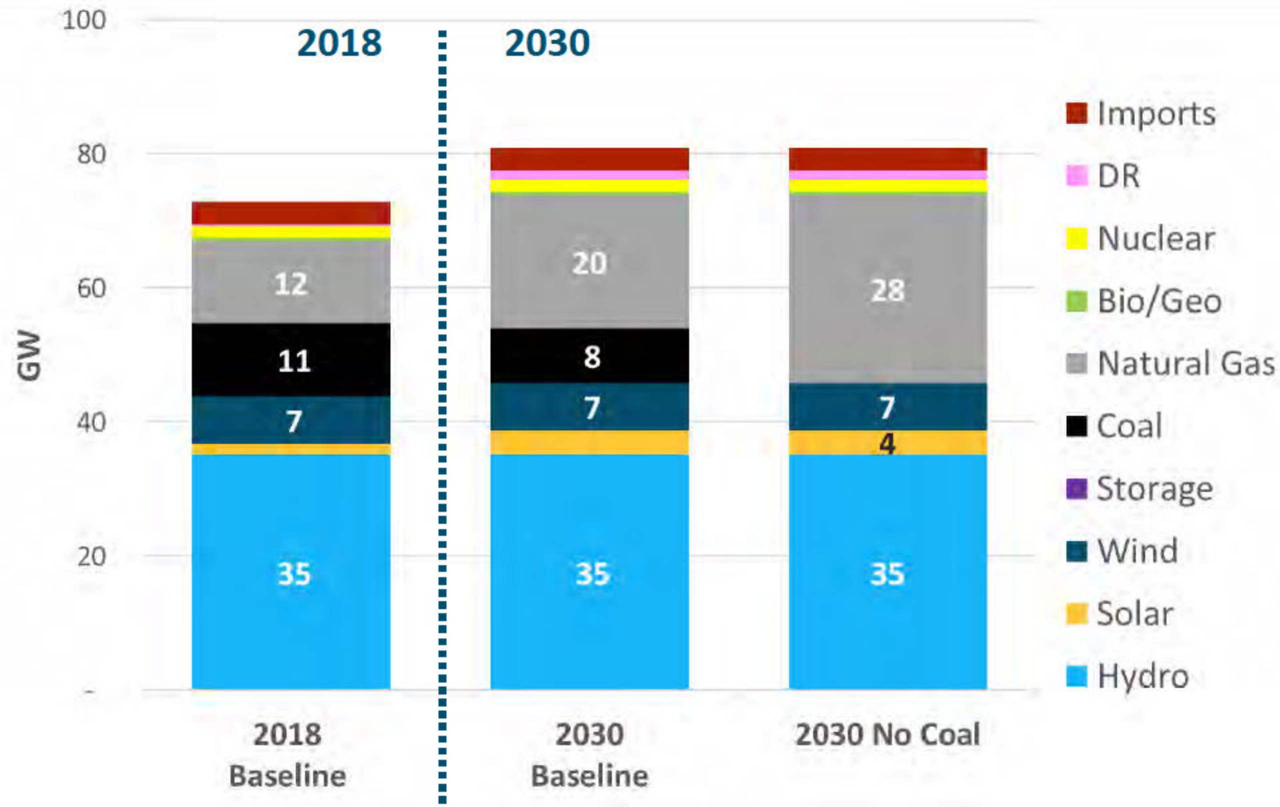
Resources / Effective Capacity (GW)	2018	Nameplate Capacity (GW)	ELCC* (%)	Capacity Factor (%)
Coal	11			
Gas	12			
Bio/Geo	1			
Imports	3			
Nuclear	1			
DR	0.3			
Hydro	18	*35*	*53%*	*44%*
Wind	0.5	*7.1*	*7%*	*26%*
Solar	0.2	*1.6*	*12%*	*27%*
Storage	0			
Total Supply	47			

Wind and solar contribute little effective capacity with ELCC* of 7% and 12%

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

2030 RESULTS

2030 Portfolios



	2030 Baseline	2030 No Coal
GHG Free Generation (%)	61%	61%
Carbon (MMT CO2)	67	42
% GHG Reduction from 1990 Level	-12%*	31%

**Assumes 60% coal capacity factor*

5 GW net new capacity by 2030 is needed for reliability (450 MW/yr)

With planned coal retirements of 3 GW, 8 GW of new capacity by 2030 is needed (730 MW/yr)

If all coal is retired, then 16 GW new capacity is needed (1450 MW/yr)

The Northwest system will need 8 GW of new effective capacity by 2030

- The 2030 system does not meet 1-in-10 reliability standard (2.4 hrs./yr.)
- The 2030 system does not meet standard for Annual LOLP (5%)
- Load growth and planned coal retirements lead to the need for 8 GW of new effective capacity by 2030

	2030 No Net New Capacity	2030 with 5 GW Net New Capacity
Annual LOLP (%)	48%	2.8%
LOLE (hrs/yr)	106	2.4
EUE (MWh/yr)	178,889	1,191
EUE norm (EUE/load)	0.07%	0.0004%

2030 Load and Resource Balance

	2030
Load (GW)	
Peak Load (Pre-EE)	50
Peak Load (Post-EE)	47
PRM	*12%*
PRM	5
Total Load Requirement	52

Resources / Effective Capacity (GW)		Nameplate Capacity (GW)	ELCC (%)	Capacity Factor (%)
Coal	8			
Gas	20			
Bio/Geo	0.6			
Imports	2			
Nuclear	1			
DR	1.0			
Hydro	19	*35*	*56%*	*44%*
Wind	0.6	*7.1*	*9%*	*26%*
Solar	0.2	*1.6*	*14%*	*27%*
Storage	0			
Total Supply	52			

Wind and solar contribute little effective capacity with ELCC* of 9% and 14%

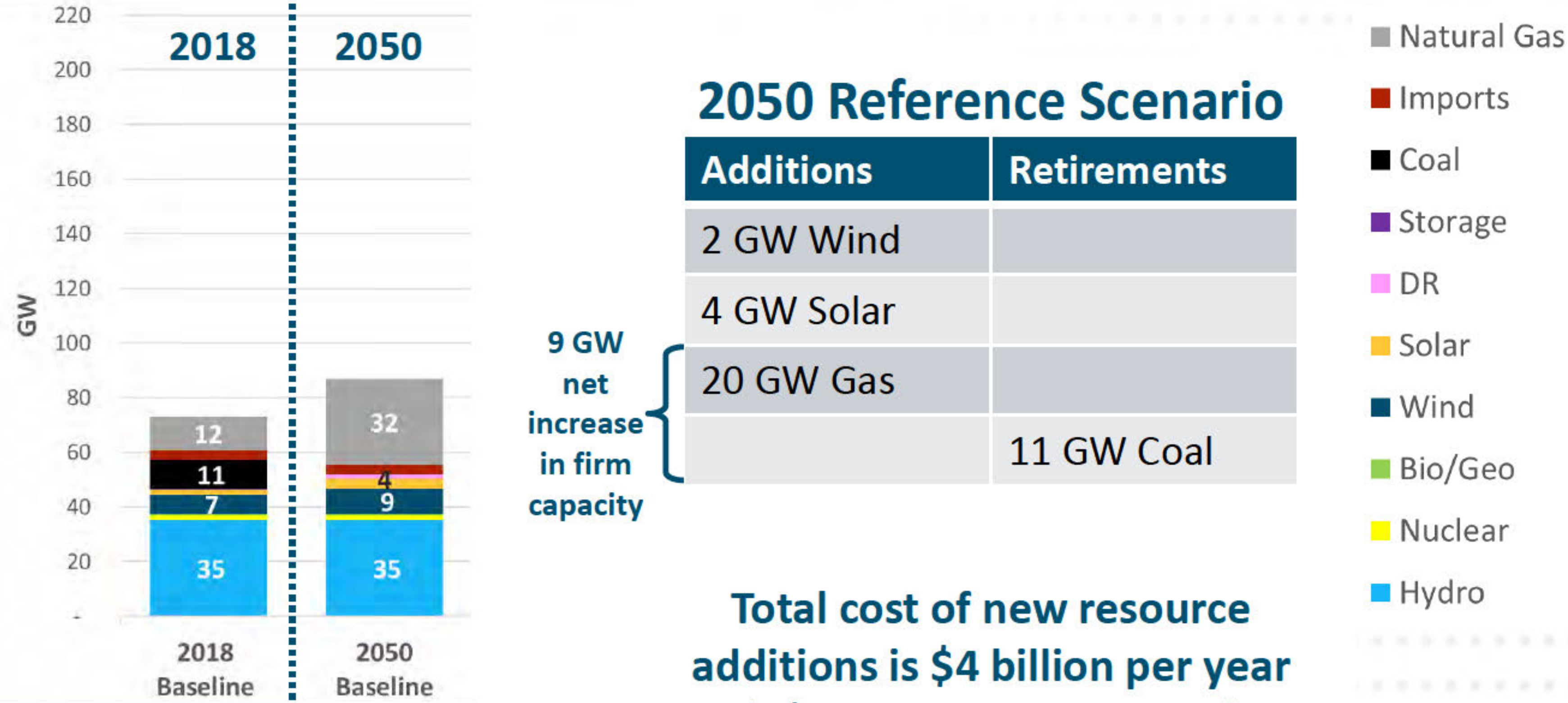
8 GW new gas capacity needed by 2030

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

Energy+Environmental Economics

2050 RESULTS

Scenario Summary
Greater NW System in 2050



Carbon (MMT CO2)	50
CPS (%)[1]	63%
GHG Free Generation (%)[2]	60%
Annual Renewable Curtailment (%)	Low
Annual Cost Delta ($B)	Base
Additional Cost ($/MWh)	Base
% GHG Reduction from 1990 level	16%
Gas Capacity Factor (%)	46%

2050 Reference Scenario

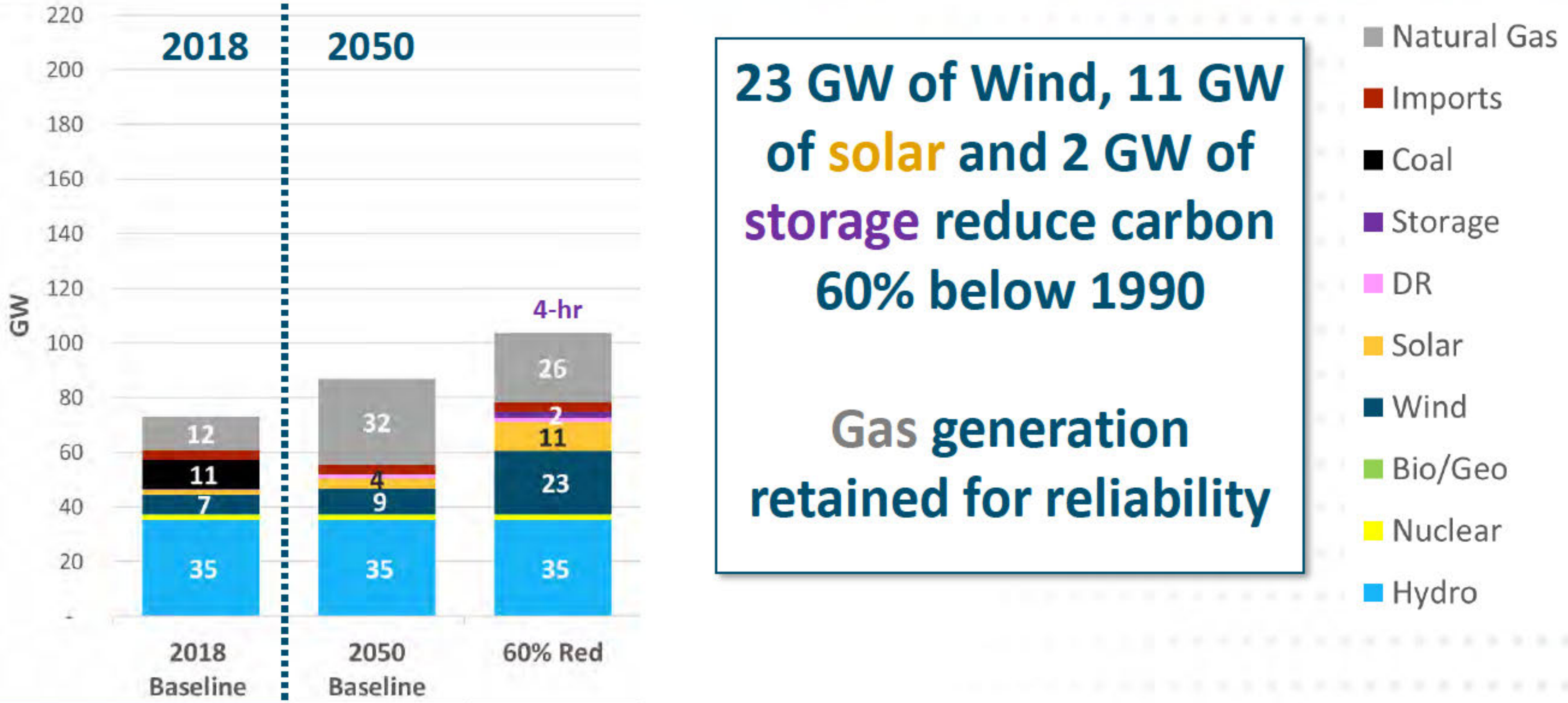
Additions	Retirements
2 GW Wind	
4 GW Solar	
20 GW Gas	
	11 GW Coal

9 GW net increase in firm capacity

Total cost of new resource additions is $4 billion per year (~$30 billion investment)

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary
Greater NW System in 2050



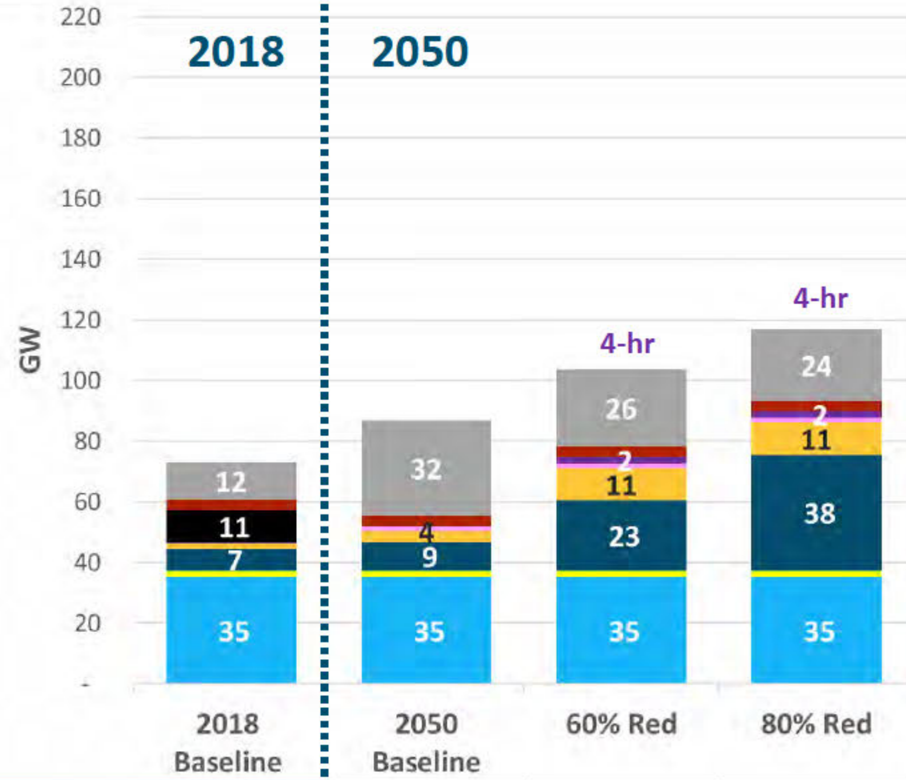
23 GW of Wind, 11 GW of solar and 2 GW of storage reduce carbon 60% below 1990

Gas generation retained for reliability

	2050 Baseline	60% Red
Carbon (MMT CO2)	50	25
CPS (%)[1]	63%	86%
GHG Free Generation (%)[2]	60%	80%
Annual Renewable Curtailment (%)	Low	Low
Annual Cost Delta ($B)	Base	$0 - $2
Additional Cost ($/MWh)	Base	$0 - $7
% GHG Reduction from 1990 level	16%	60%
Gas Capacity Factor (%)	46%	27%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary
Greater NW System in 2050



Additional wind added for carbon reductions

24 GW of gas generation retained for reliability

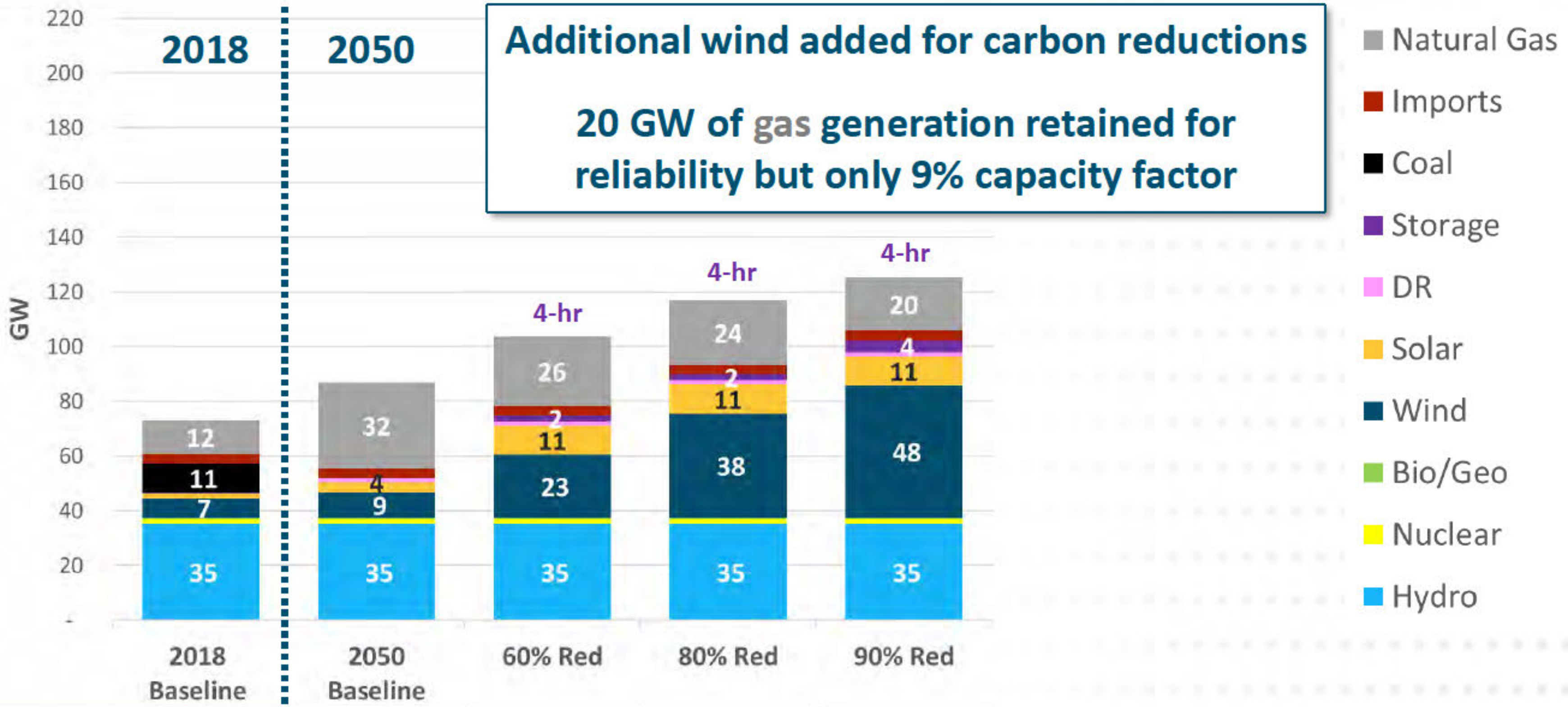
Carbon (MMT CO2)	50	25	12
CPS (%)[1]	63%	86%	100%
GHG Free Generation (%)[2]	60%	80%	90%
Annual Renewable Curtailment (%)	Low	Low	4%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14
% GHG Reduction from 1990 level	16%	60%	80%
Gas Capacity Factor (%)	46%	27%	16%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary
Greater NW System in 2050

Additional wind added for carbon reductions

20 GW of gas generation retained for reliability but only 9% capacity factor

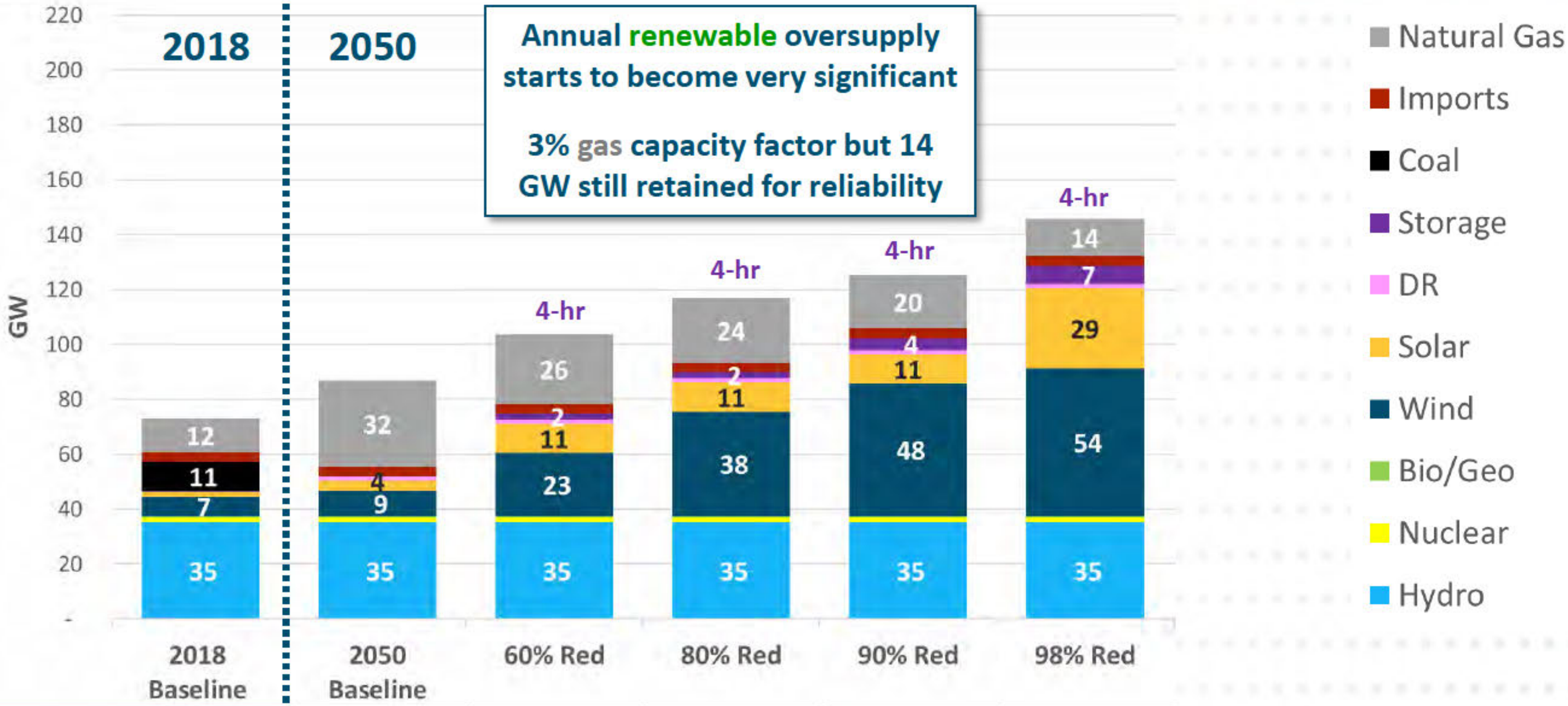


	2050 Baseline	60% Red	80% Red	90% Red
Carbon (MMT CO2)	50	25	12	6
CPS (%)[1]	63%	86%	100%	108%
GHG Free Generation (%)[2]	60%	80%	90%	95%
Annual Renewable Curtailment (%)	Low	Low	4%	10%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18
% GHG Reduction from 1990 level	16%	60%	80%	90%
Gas Capacity Factor (%)	46%	27%	16%	9%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Scenario Summary

Greater NW System in 2050

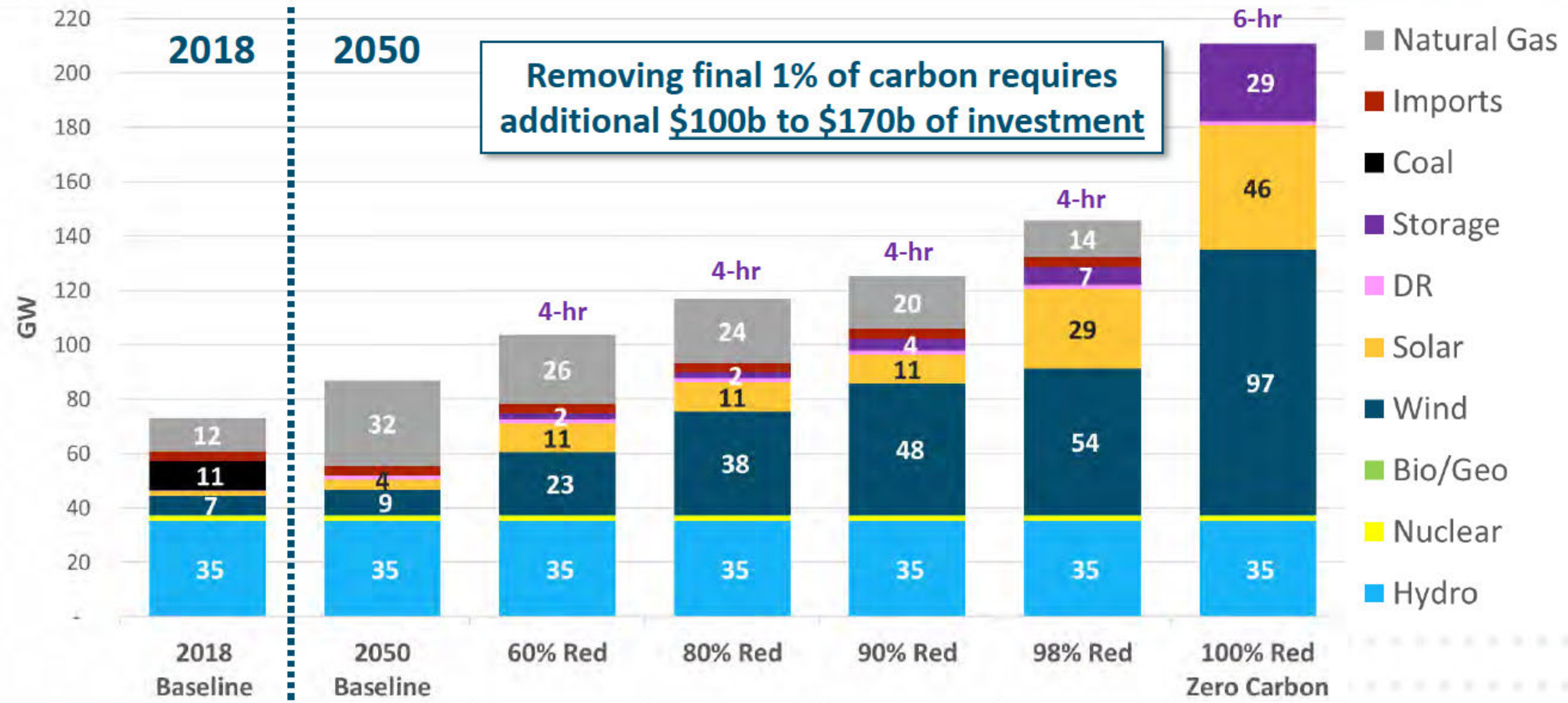


	2050 Baseline	60% Red	80% Red	90% Red	98% Red
Carbon (MMT CO2)	50	25	12	6	1
CPS (%)[1]	63%	86%	100%	108%	117%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%
Gas Capacity Factor (%)	46%	27%	16%	9%	3%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales

[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

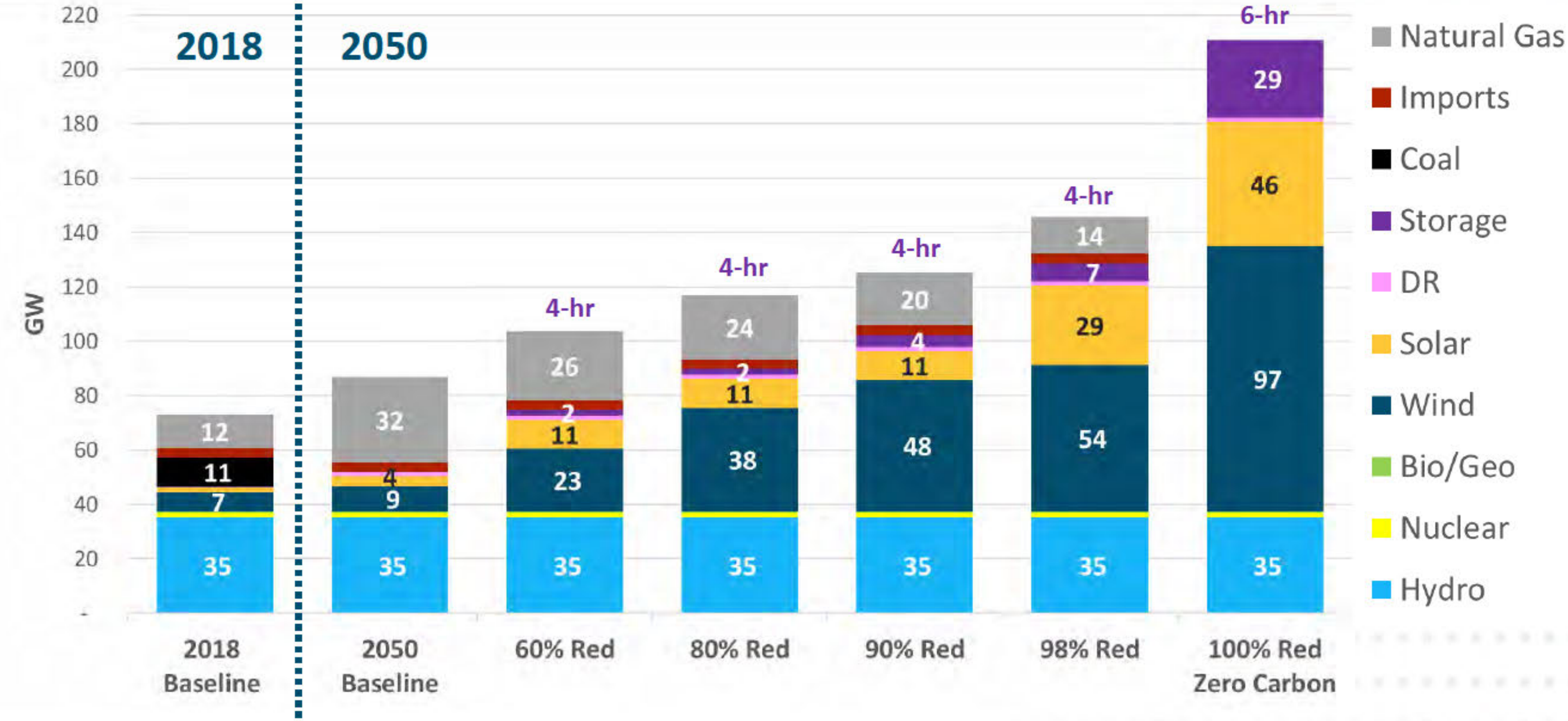
Scenario Summary
Greater NW System in 2050



Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

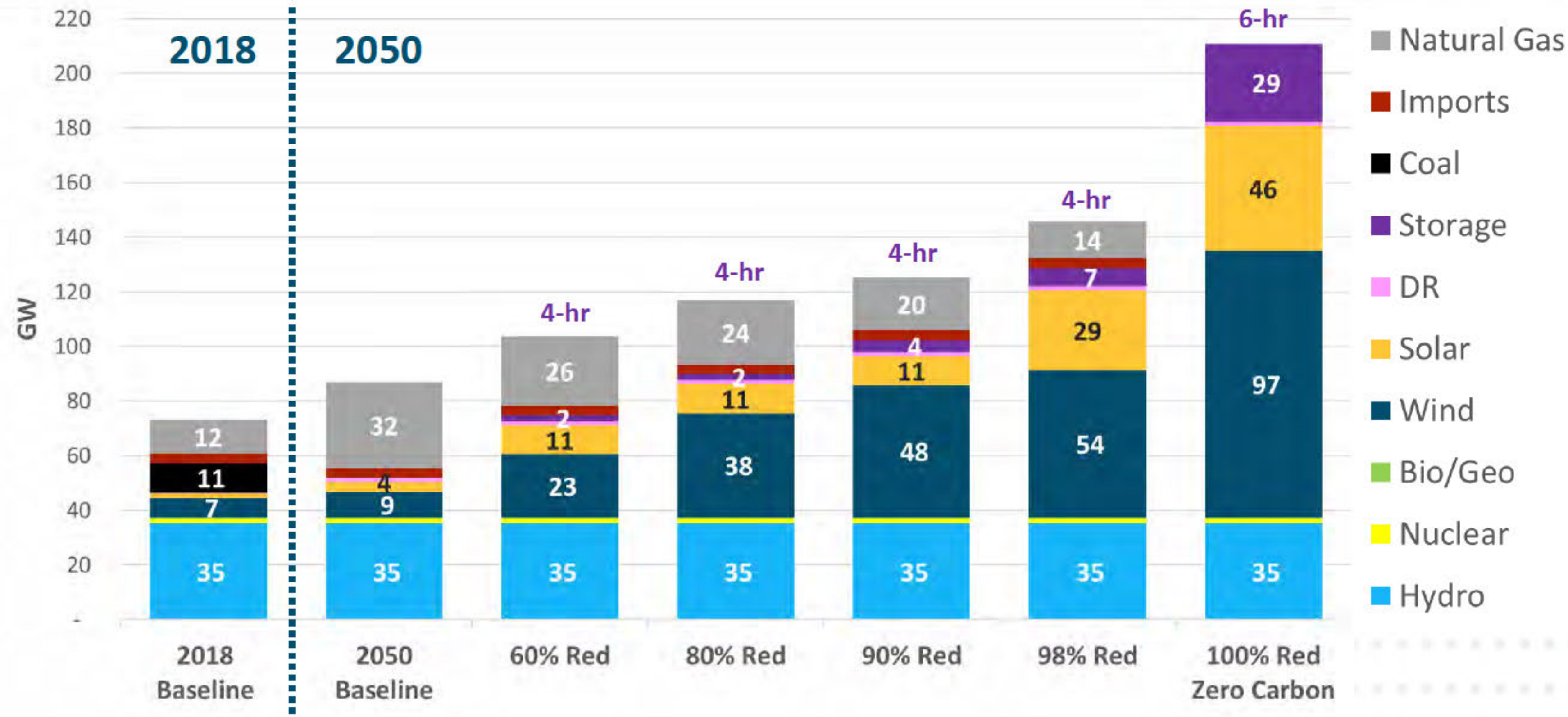
Scenario Summary
2050 Emissions Reductions



Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

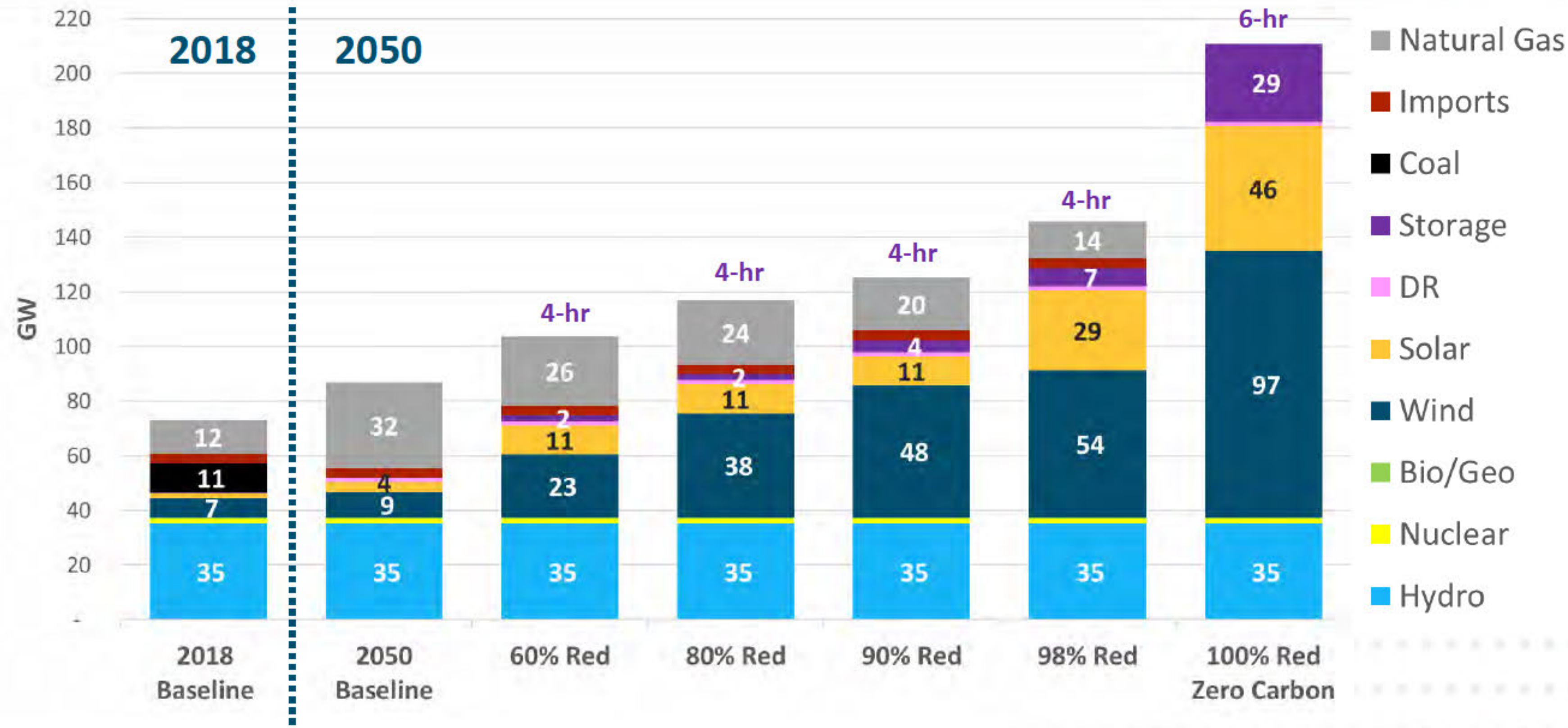
Scenario Summary
2050 Resource Use



Renewable Capacity (GW)	13	34	49	59	83	143
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Gas Capacity (GW)	32	26	24	20	14	0
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

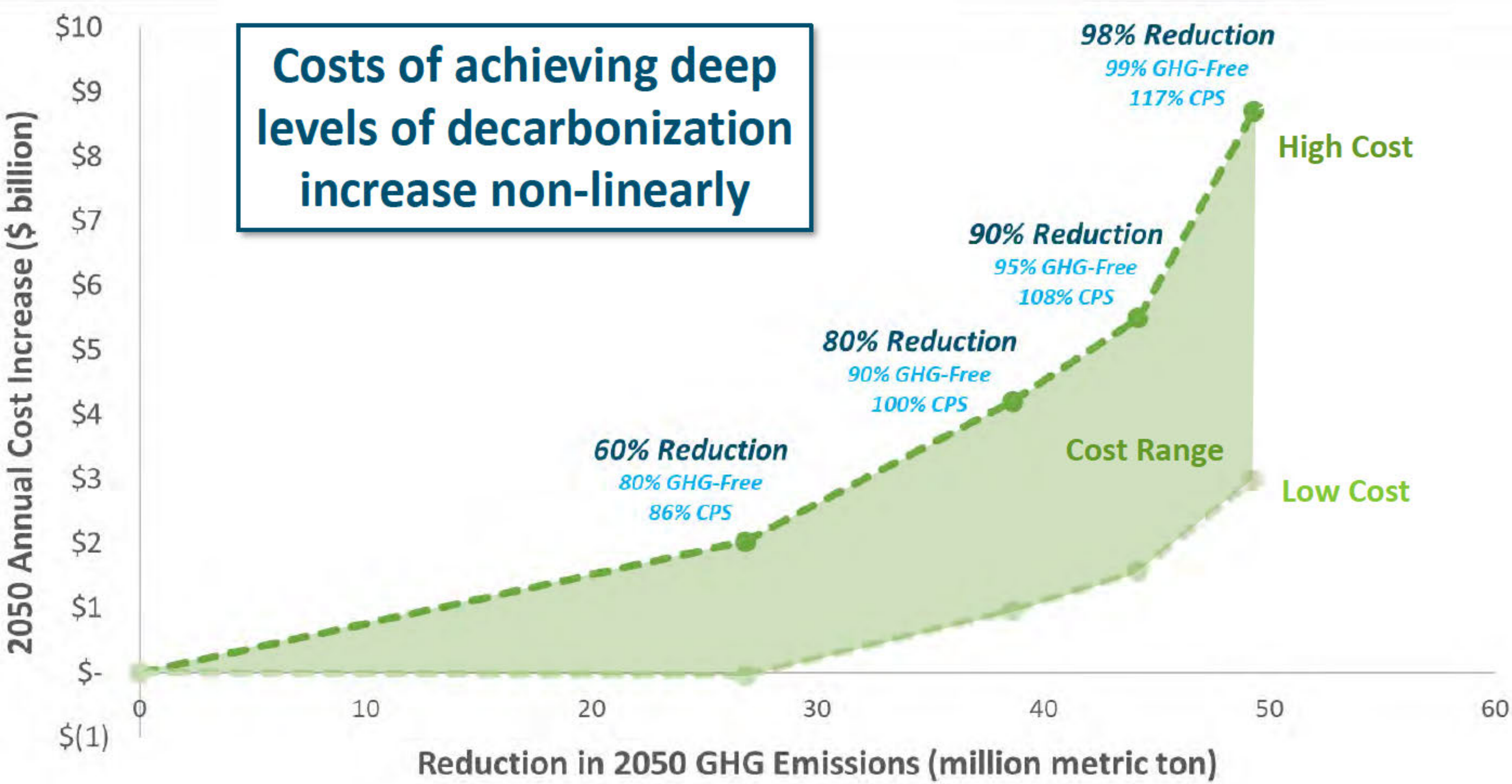
Scenario Summary
2050 Costs



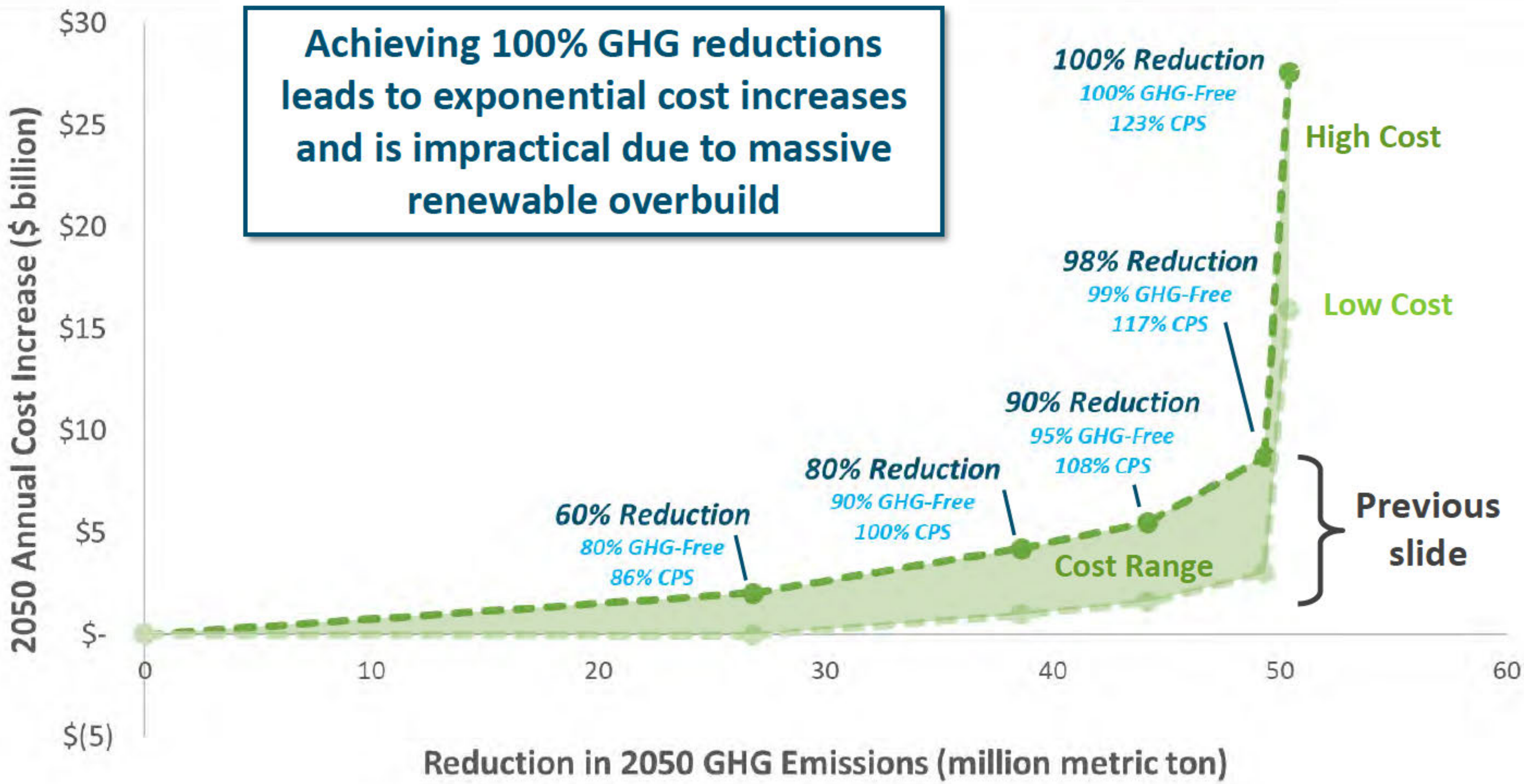
Marginal Carbon Reduction Cost ($/Metric Ton)	Base	$0 - $80	$90 - $190	$110 - $230	$310 - $700	$11,000 – $16,000
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

Cost of GHG Reduction

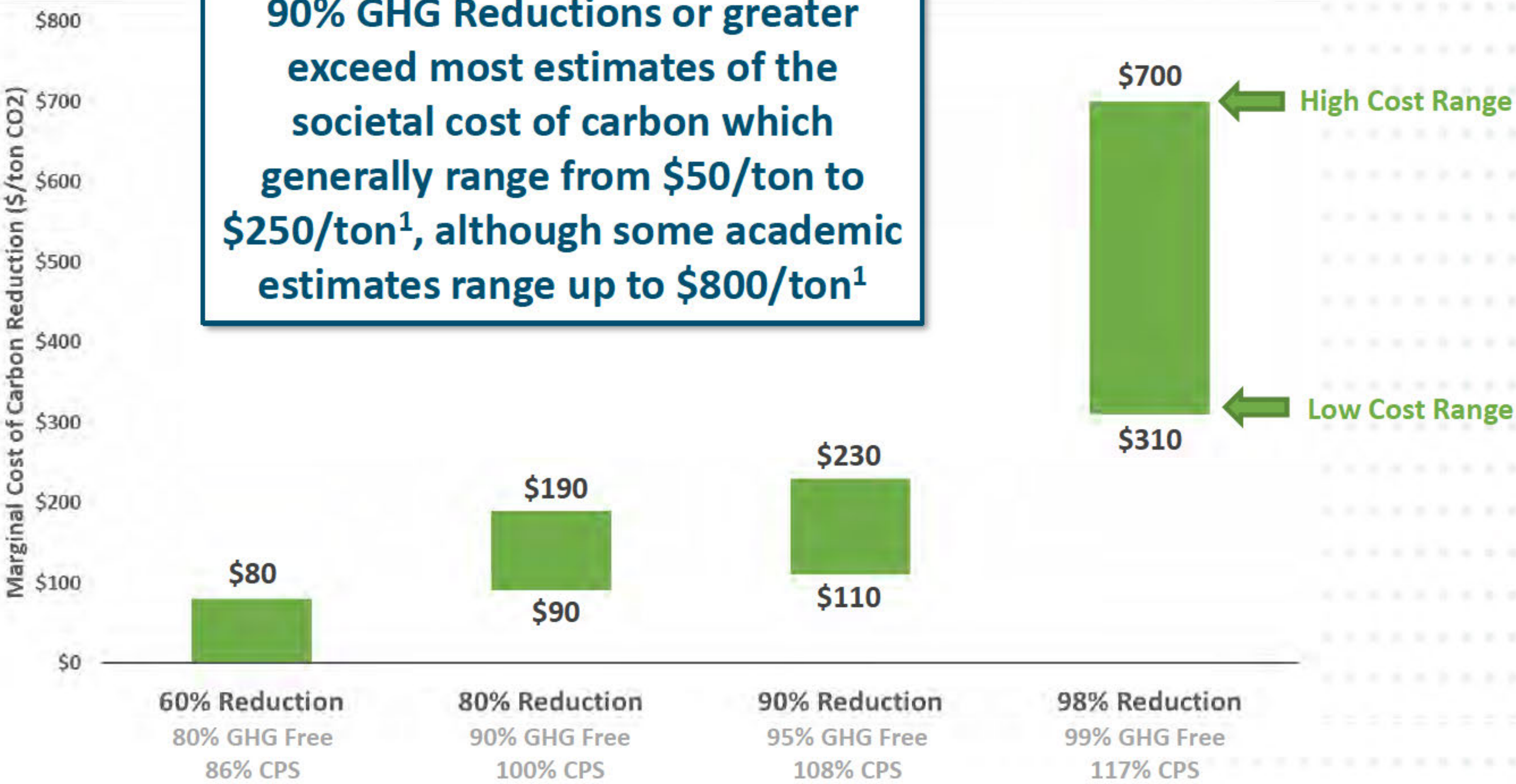


Cost of GHG Reduction



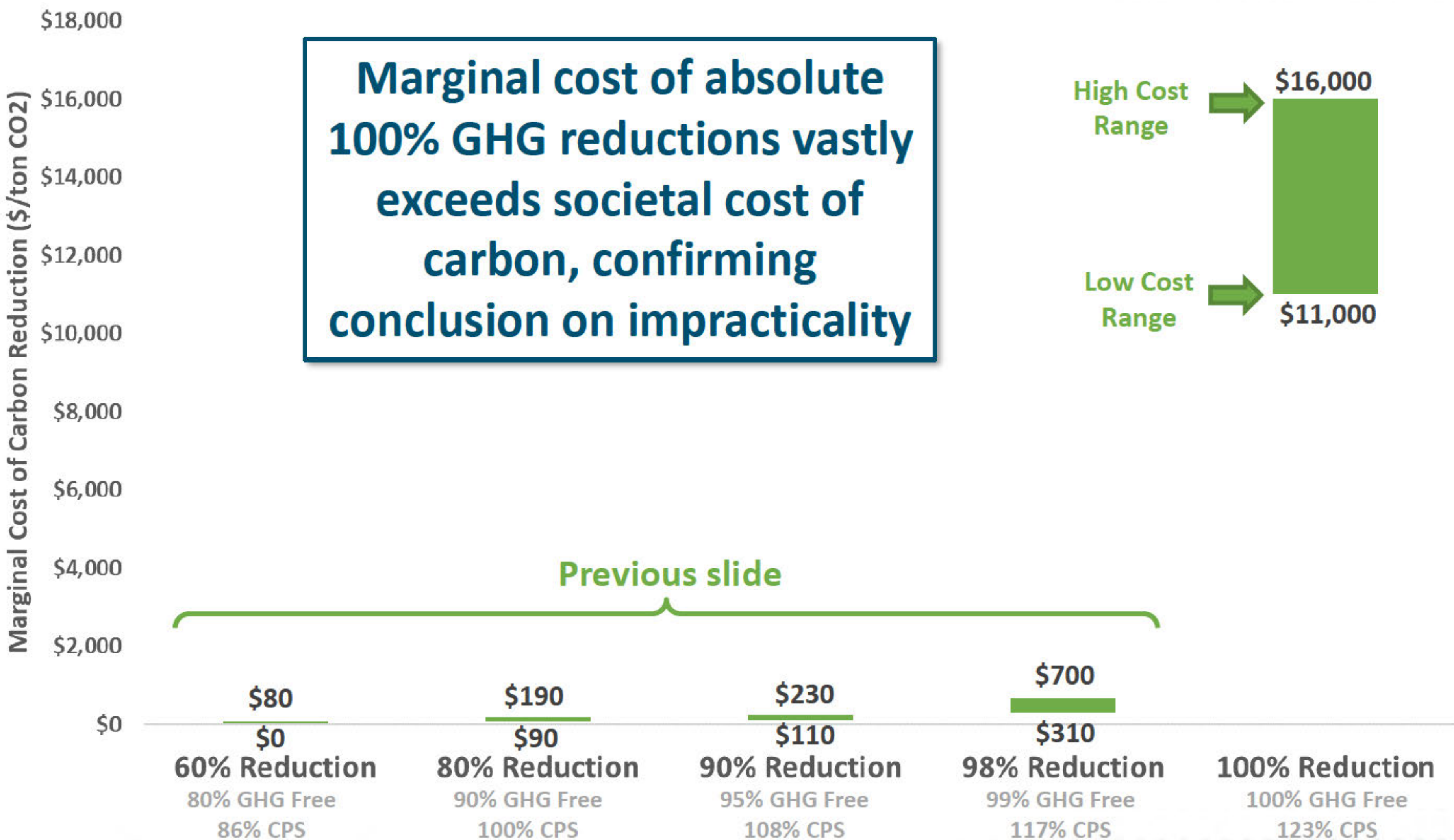
Marginal Cost of GHG Reduction

Marginal cost of CO2 reductions at 90% GHG Reductions or greater exceed most estimates of the societal cost of carbon which generally range from \$50/ton to \$250/ton[1], although some academic estimates range up to \$800/ton[1]

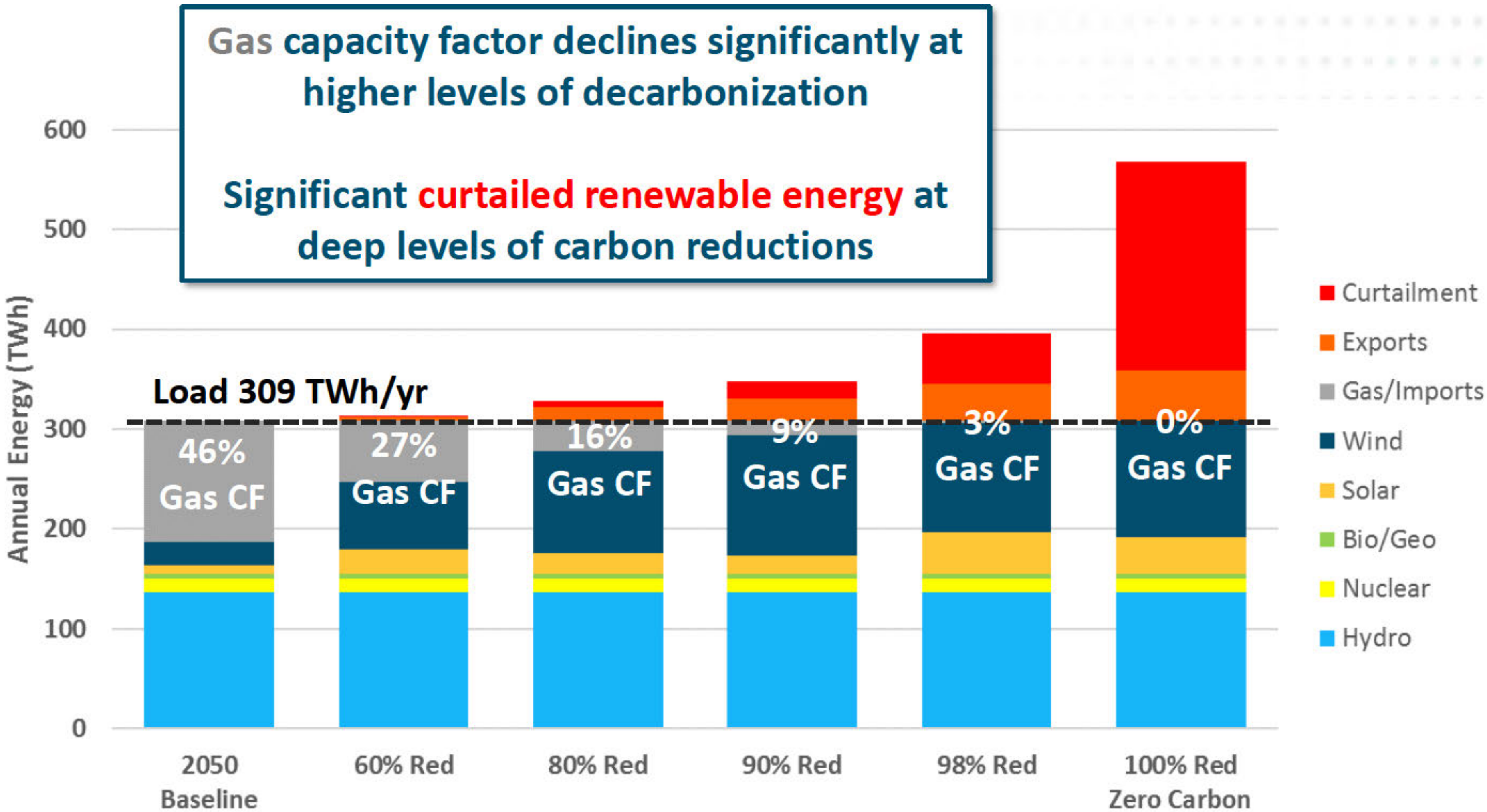


[1] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html; https://www.nature.com/articles/s41558-018-0282-y

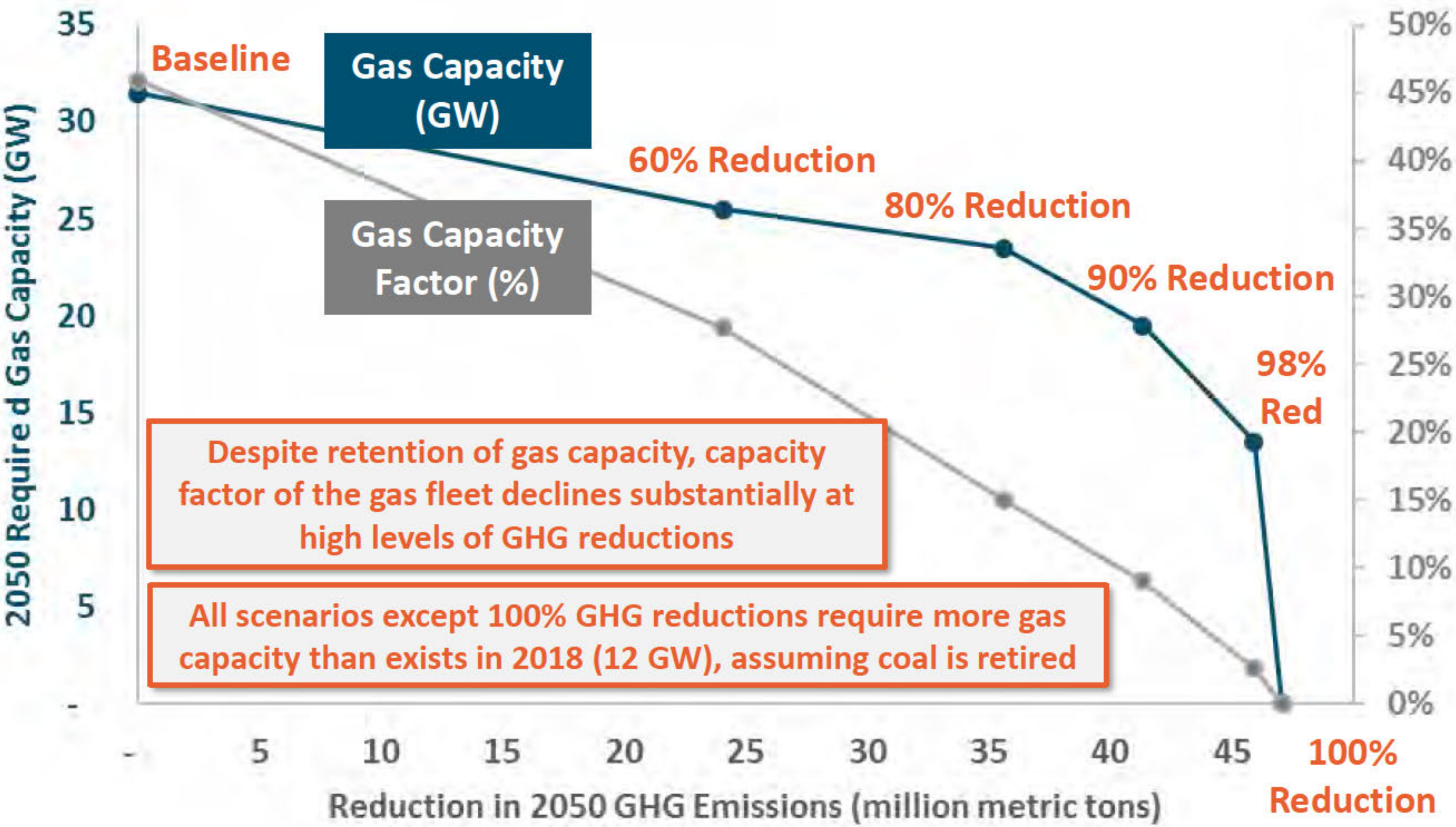
Marginal Cost of GHG Reduction



2050 Annual Energy Balance



Gas capacity is still needed for reliability under deep decarbonization despite lower utilization



2050 Load and Resource Balance

	2050		
	80% Reduction	90% Reduction	100% Reduction
Load (GW)			
Peak (Pre-EE)	65	65	65
Peak (Post-EE)	54	54	54
PRM (%)	*9%*	*9%*	*7%*
PRM	5	5	4
Total Load Requirement	59	59	57

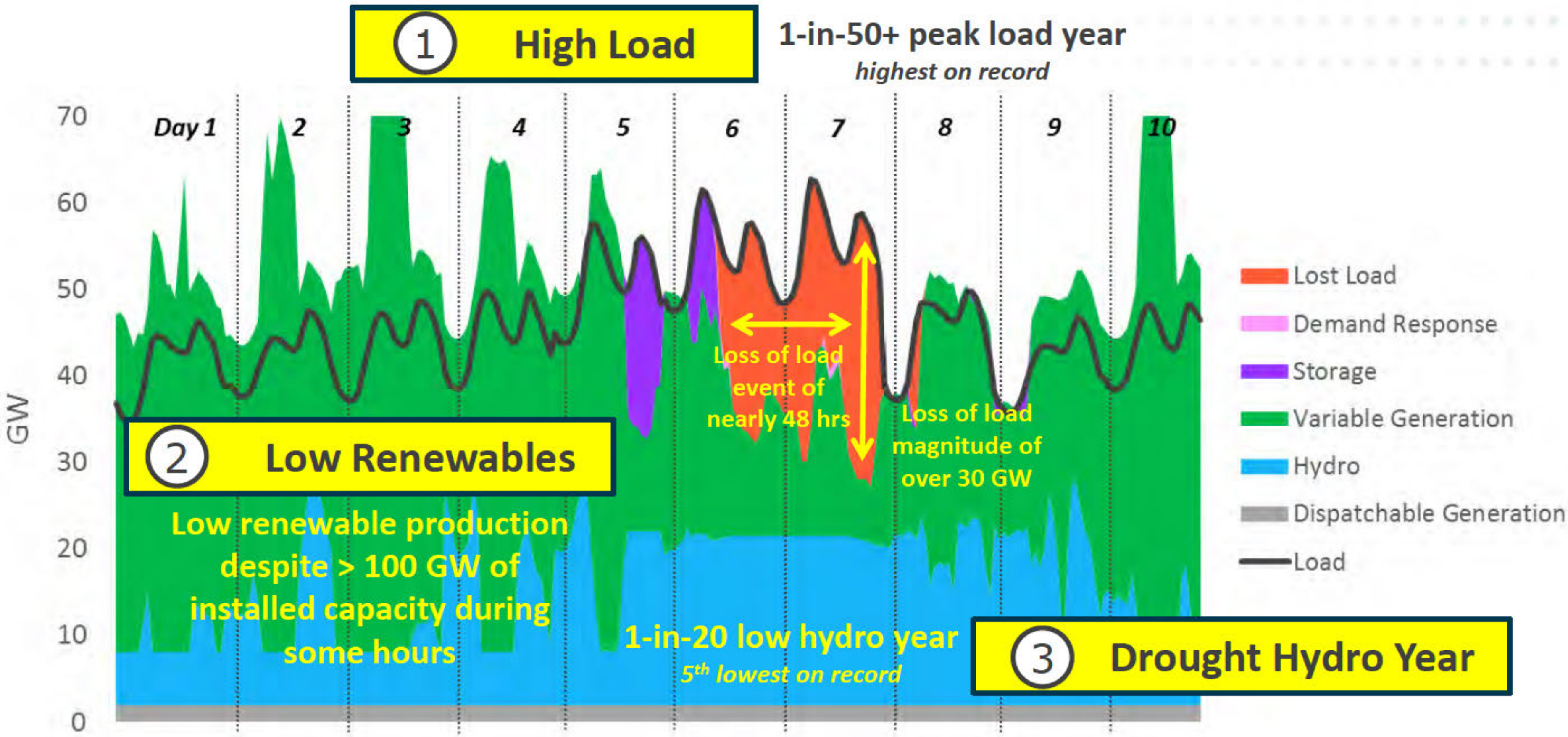
Resources / Effective Capacity (GW)			
Coal	0	0	0
Gas	24	20	0
Bio/Geo	0.6	0.6	0.6
Imports	2	2	0
Nuclear	1	1	1
DR	1	1	1
Hydro	20	20	20
Wind	7	11	21
Solar	2.0	2.2	7.5
Storage	1.6	1.8	5.8
Total Supply	59	59	57

	Nameplate Capacity (GW)			ELCC (%)			Capacity Factor (%)		
	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.
Hydro	*35*	*35*	*35*	*58%*	*58%*	*57%*	*44%*	*44%*	*44%*
Wind	*38*	*48*	*96*	*19%*	*22%*	*22%*	*35%*	*36%*	*37%*
Solar	*11*	*11*	*46*	*19%*	*21%*	*16%*	*27%*	*27%*	*27%*
Storage	*2.2*	*4.4*	*29*	*71%*	*41%*	*20%*	*N/A*	*N/A*	*N/A*

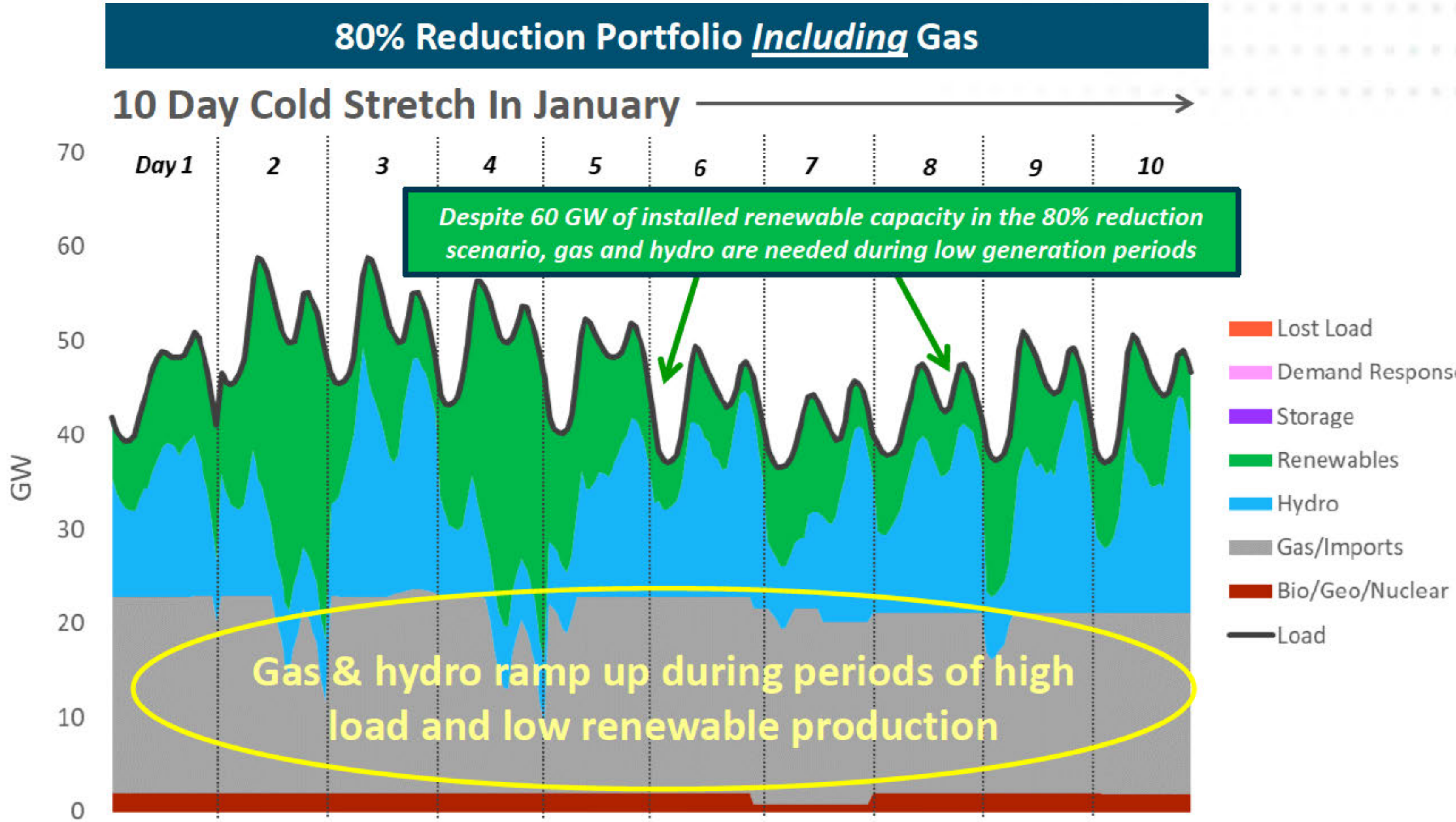
Wind ELCC* values are higher than today due to significant contribution from MT/WY wind

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

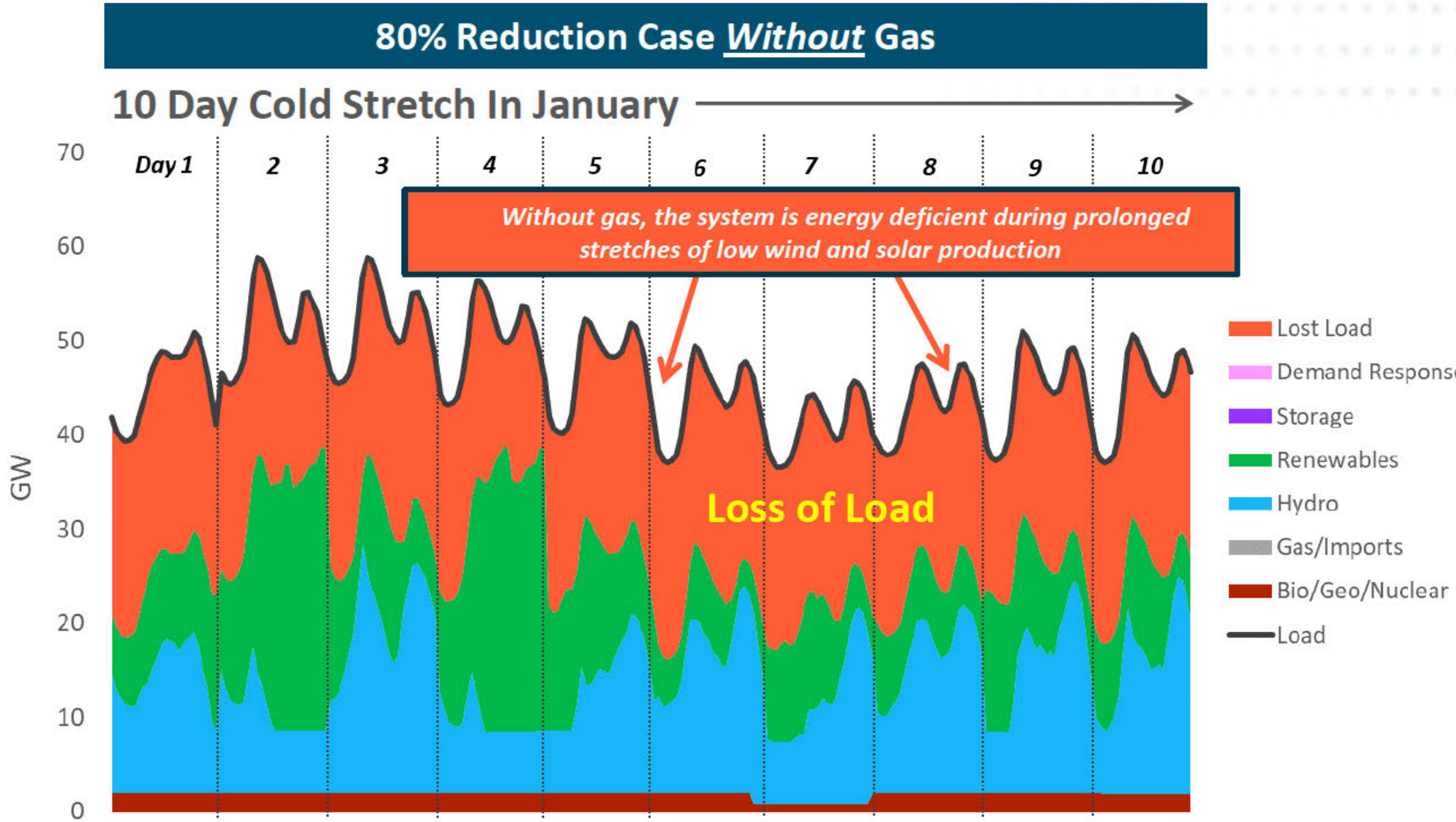
The Stressful Tri-Fecta



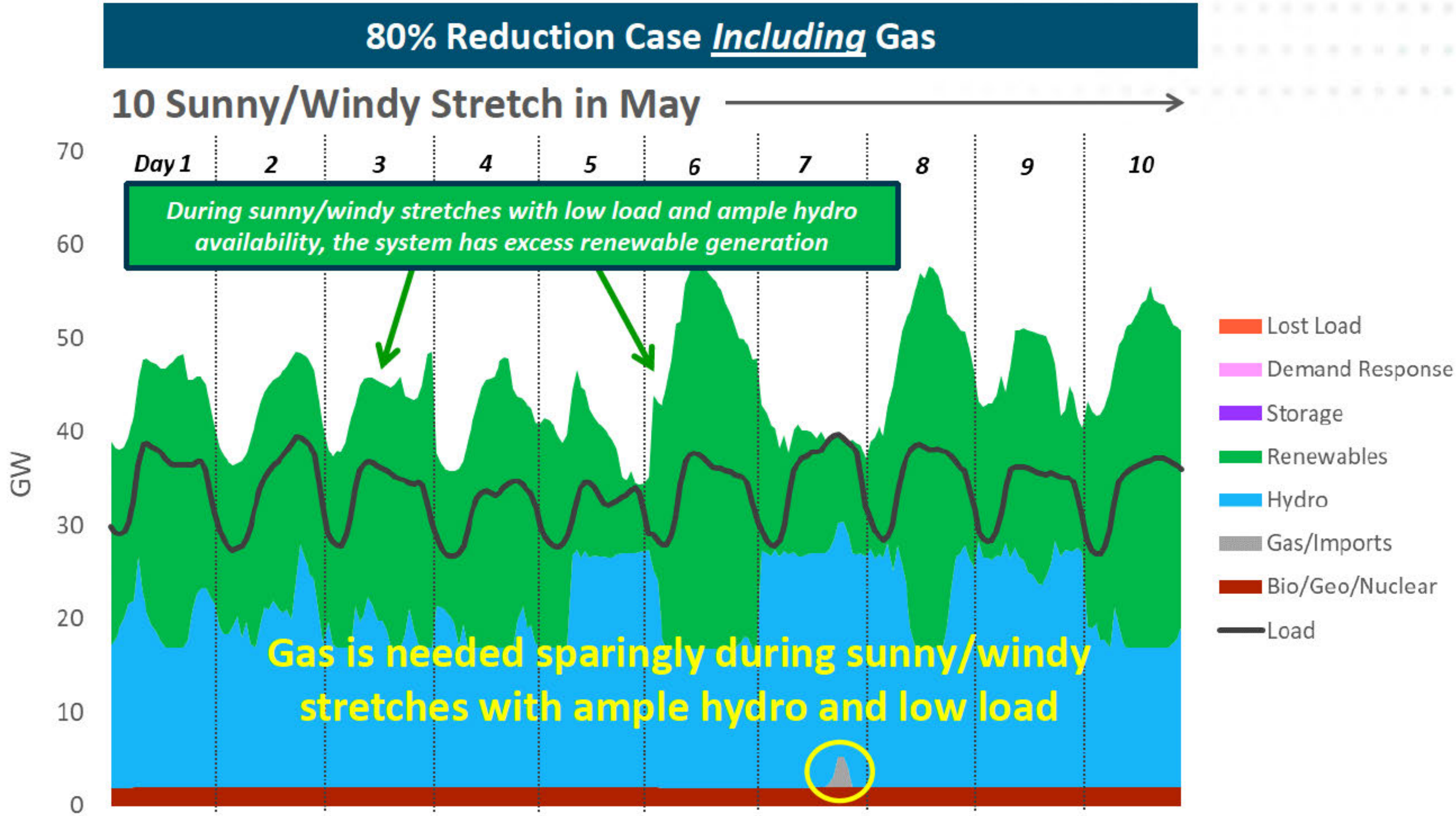
Illustrating the Need for Firm Capacity – January



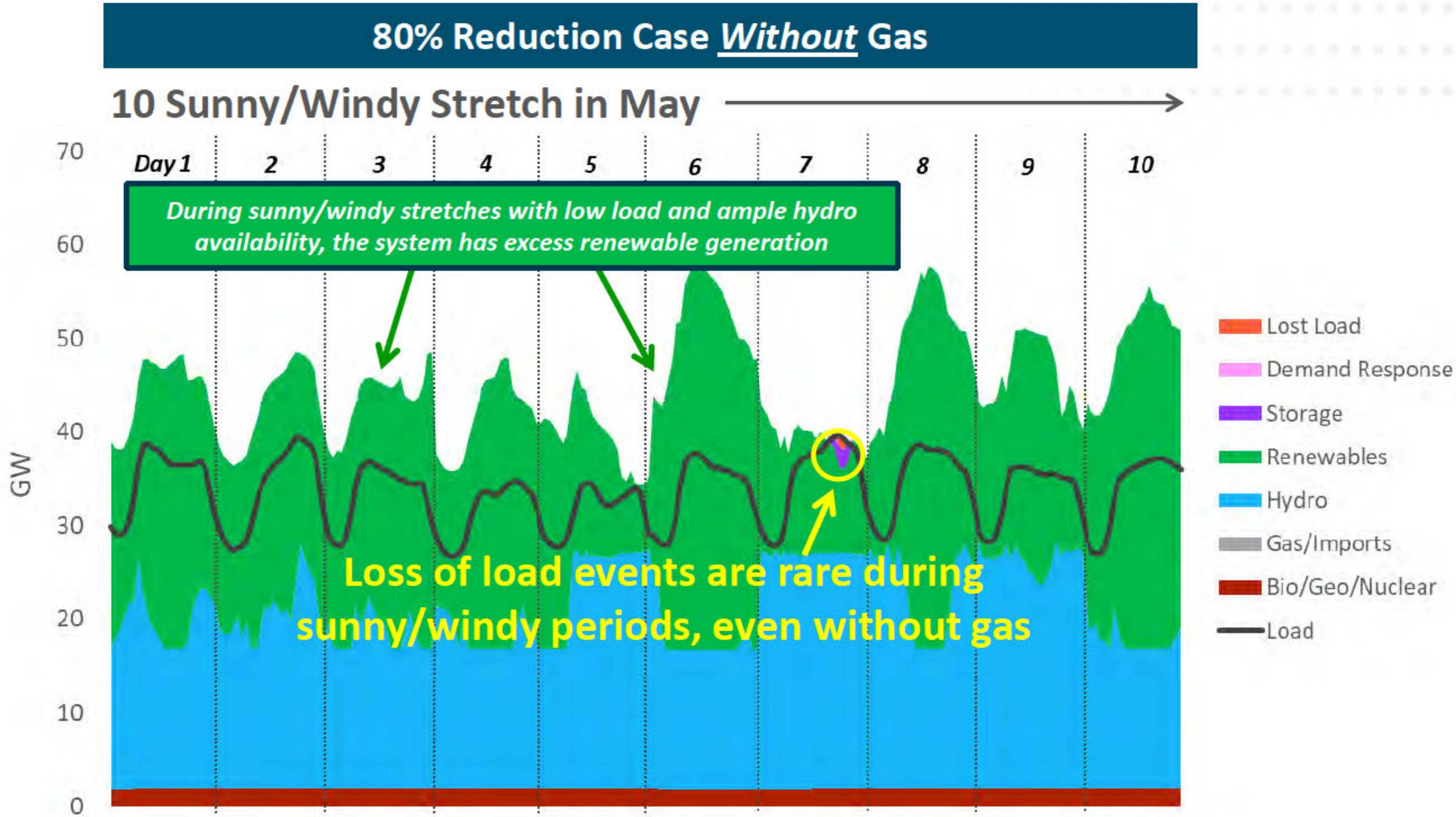
Illustrating the Need for Firm Capacity – January



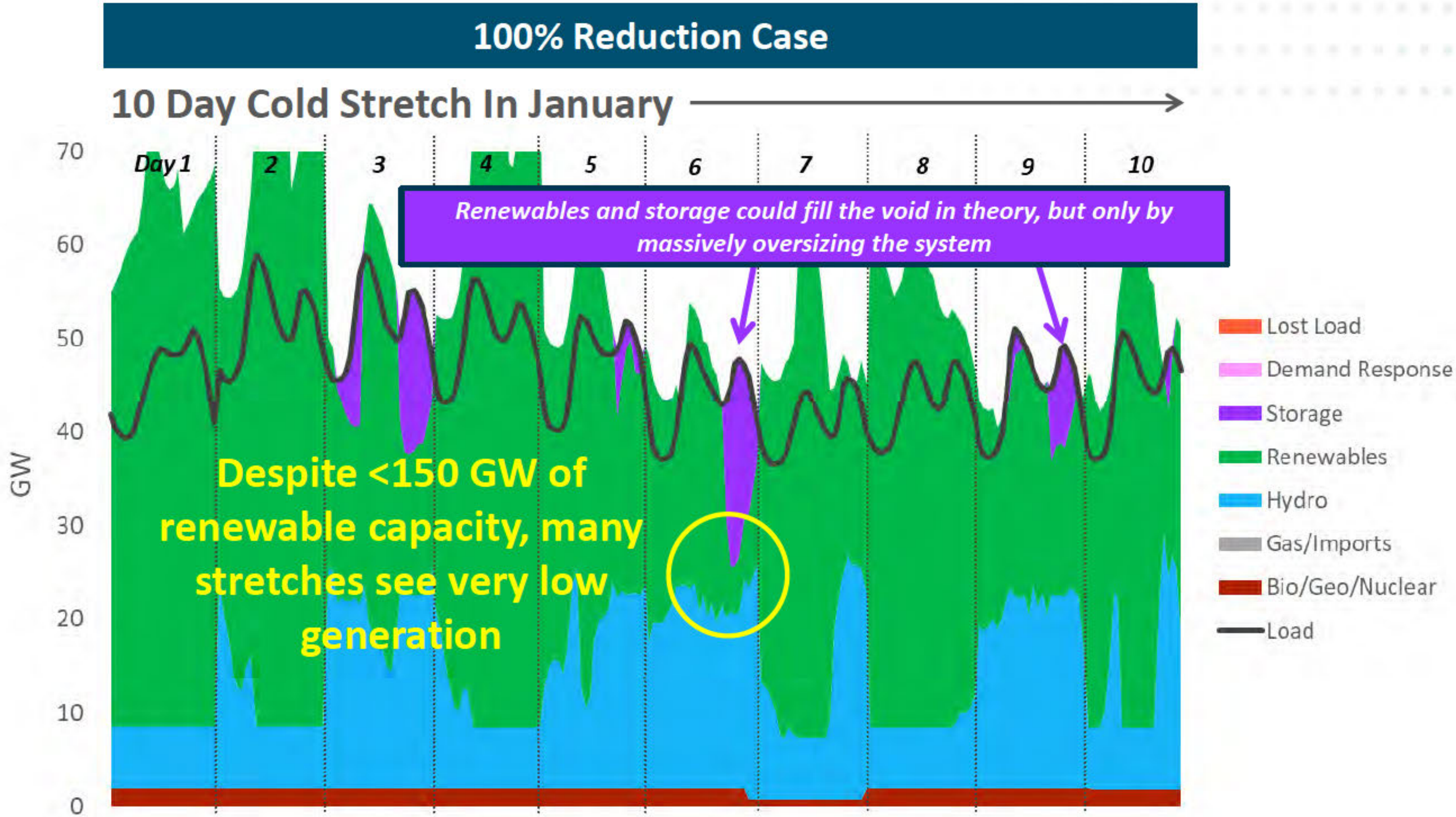
Illustrating the Need for Firm Capacity – May



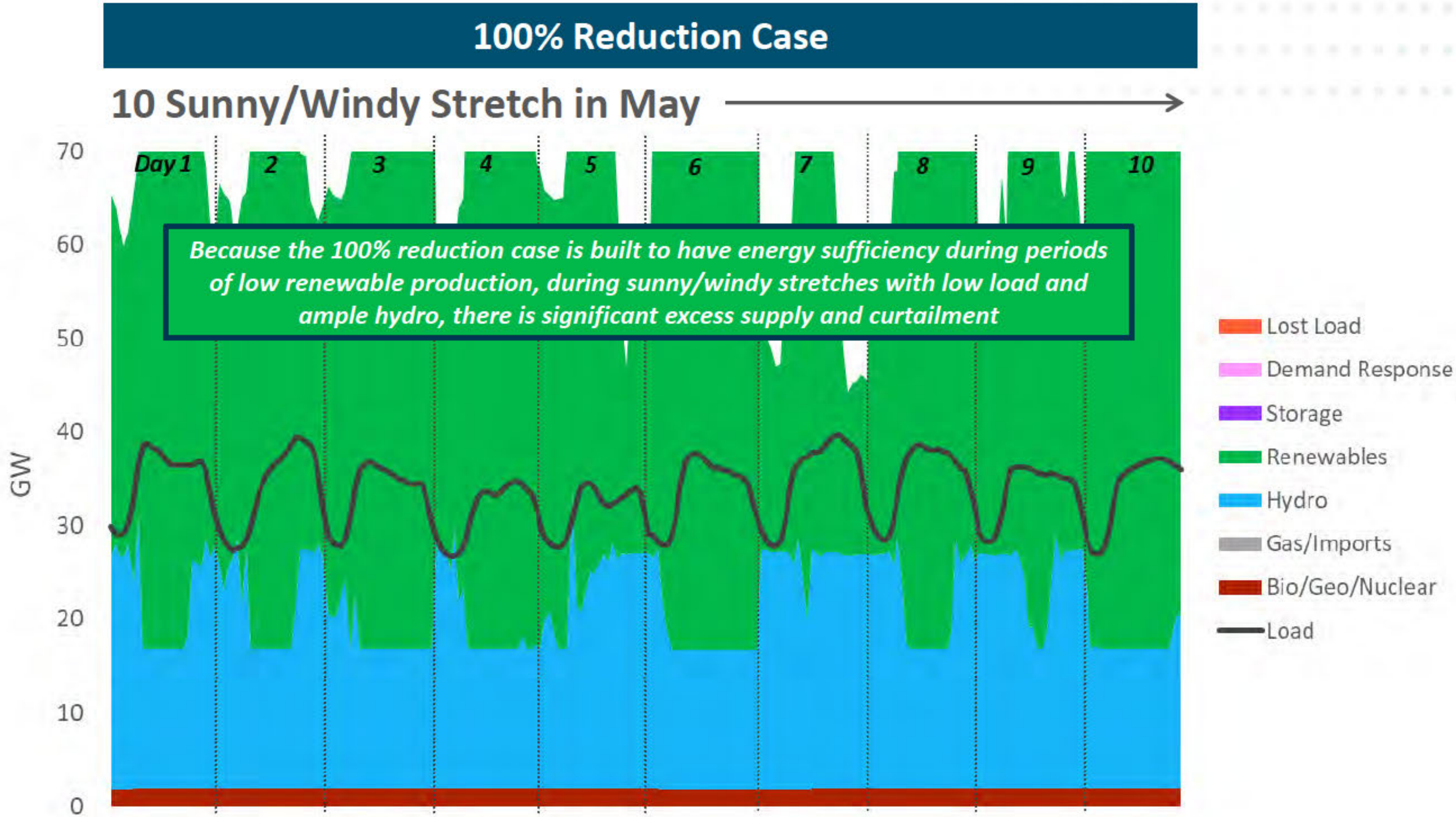
Illustrating the Need for Firm Capacity – May



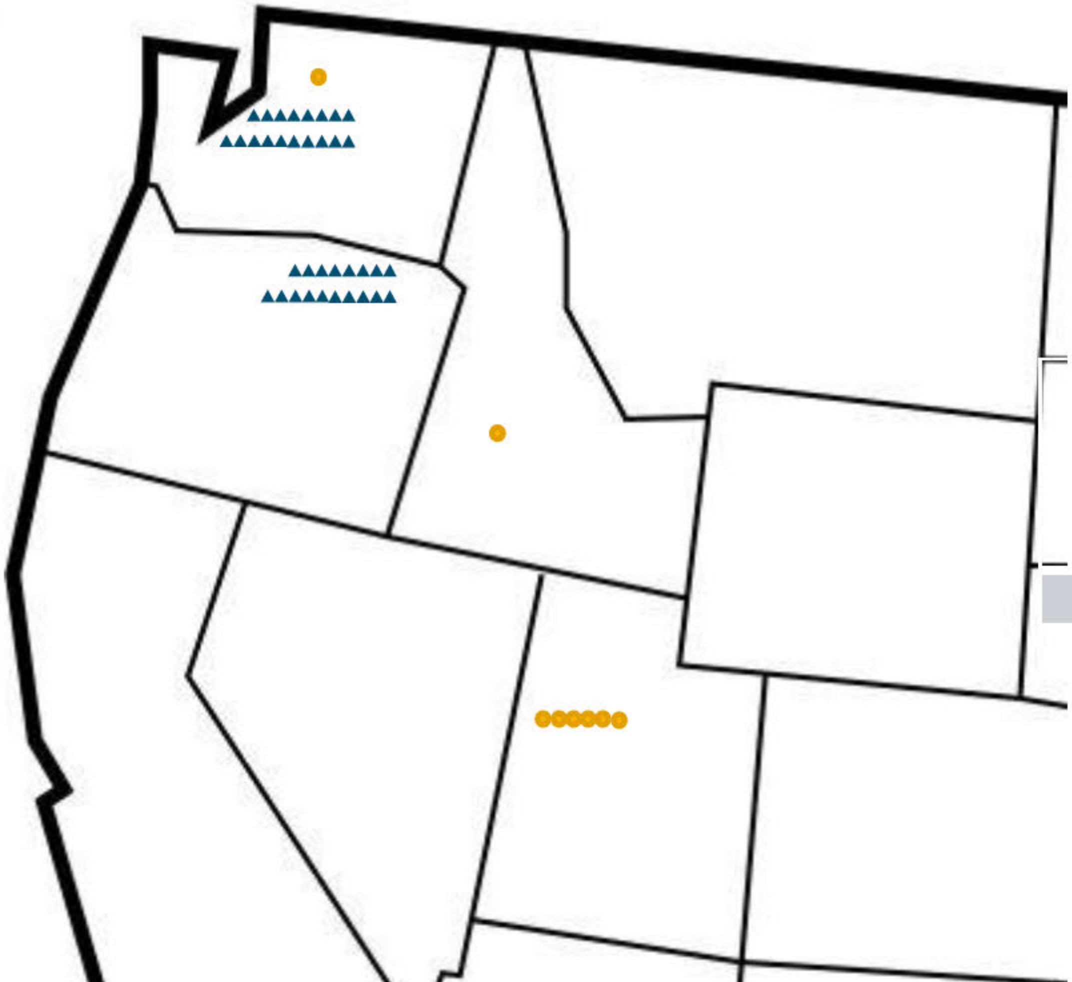
Illustrating the Need for Firm Capacity – January



Illustrating the Need for Firm Capacity – May



Renewable Land Use
2018 Installed Renewables



Technology	Nameplate GW
● Solar	1.6
▲ NW Wind	7.1
■ MT Wind	0
★ WY Wind	2

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind – Total Land Use (thousand acres)
Today	12	19	223 – 1,052

Land use today ranges from

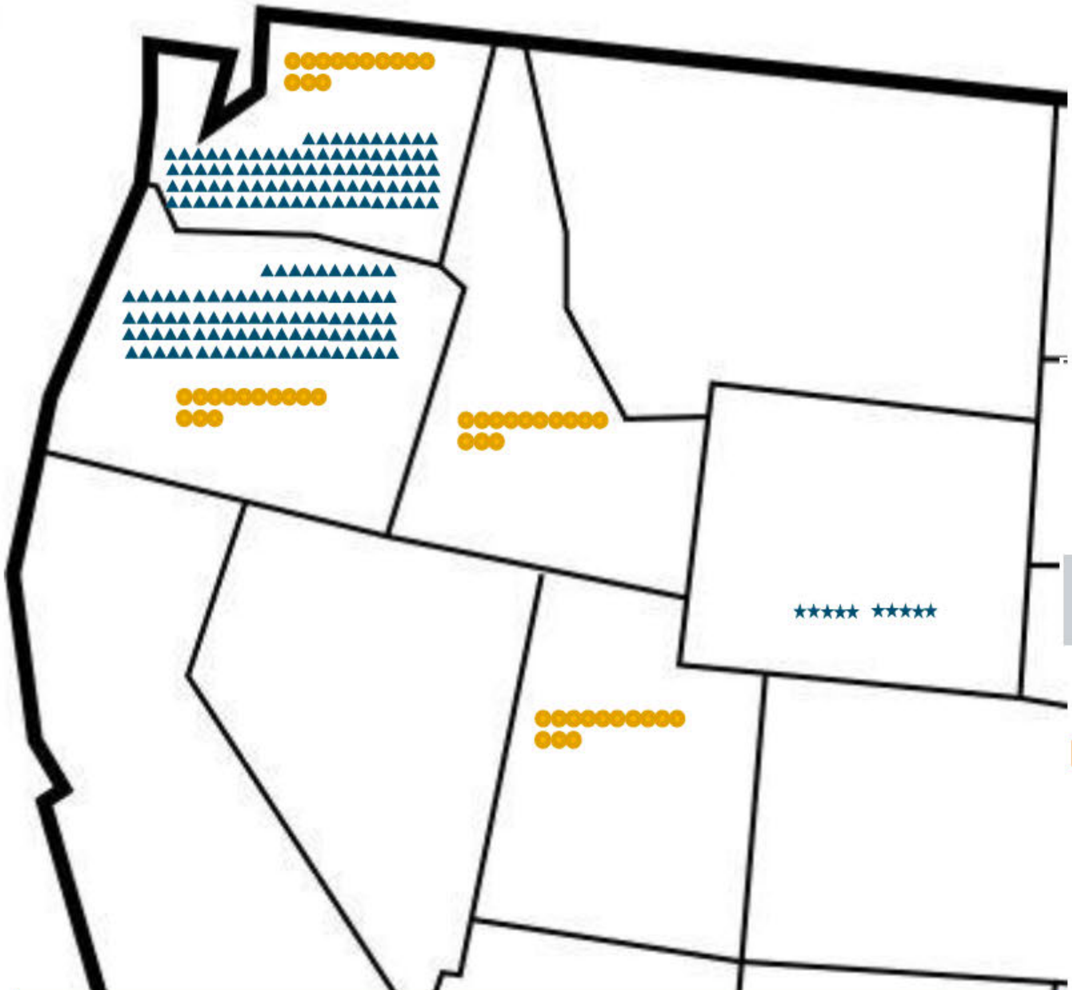
1.6 to 7.5x

the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

Renewable Land Use
80% Reduction in 2050



Technology	Nameplate GW
● Solar	11
▲ NW Wind	36
▪ MT Wind	0
★ WY Wind	2

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind - Total Land Use (thousand acres)
80% Red	84	94	1,135 – 5,337

Land use in 80% Reduction case ranges from

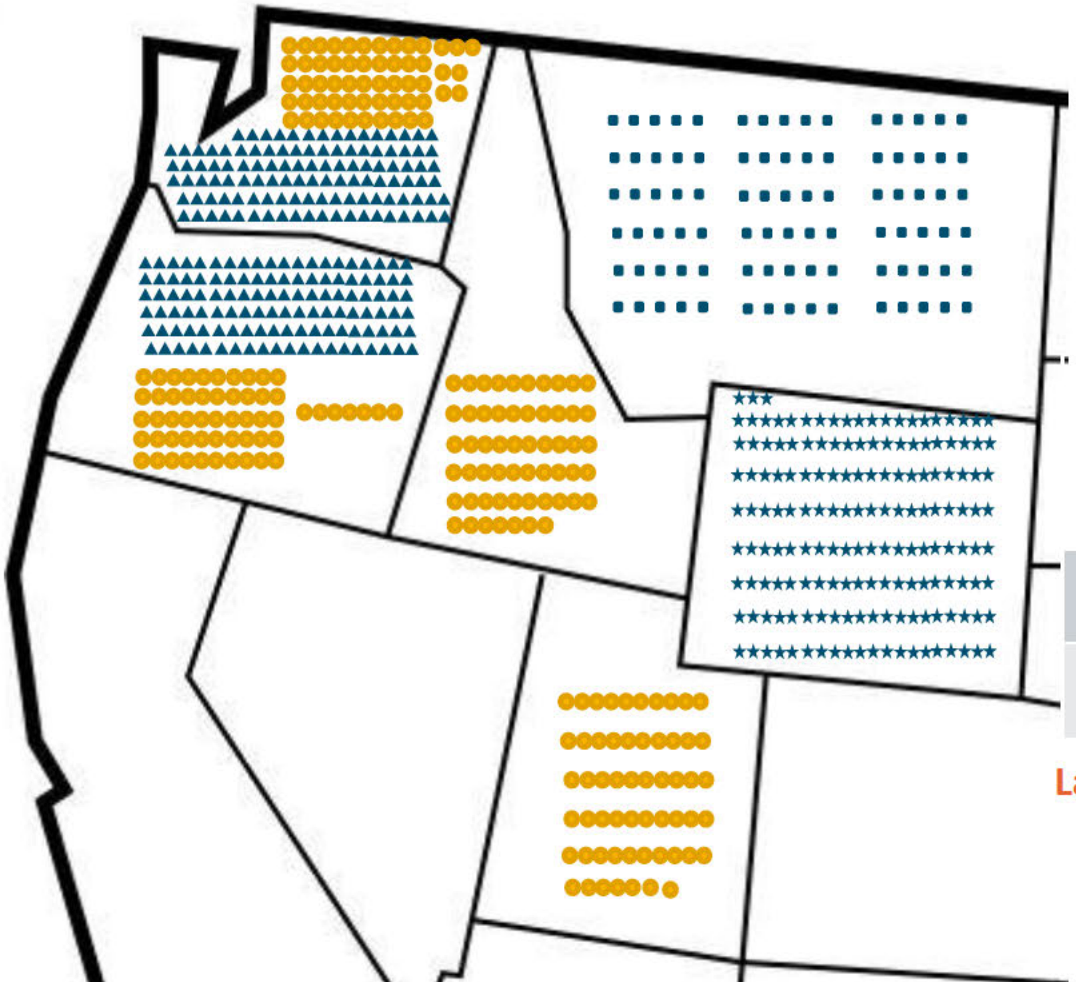
8 to 37x

the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

Renewable Land Use
100% Reduction in 2050



Technology	Nameplate GW
● Solar	46
▲ NW Wind	47
▪ MT Wind	18
⋆ WY Wind	33

	Solar Total Land Use (thousand acres)	Wind - Direct Land Use (thousand acres)	Wind - Total Land Use (thousand acres)
80% Clean	84	94	1,135 – 5,337
100% Red	361	241	2,913 – 13,701

Land use in 100% Reduction case ranges from

20 to 100x

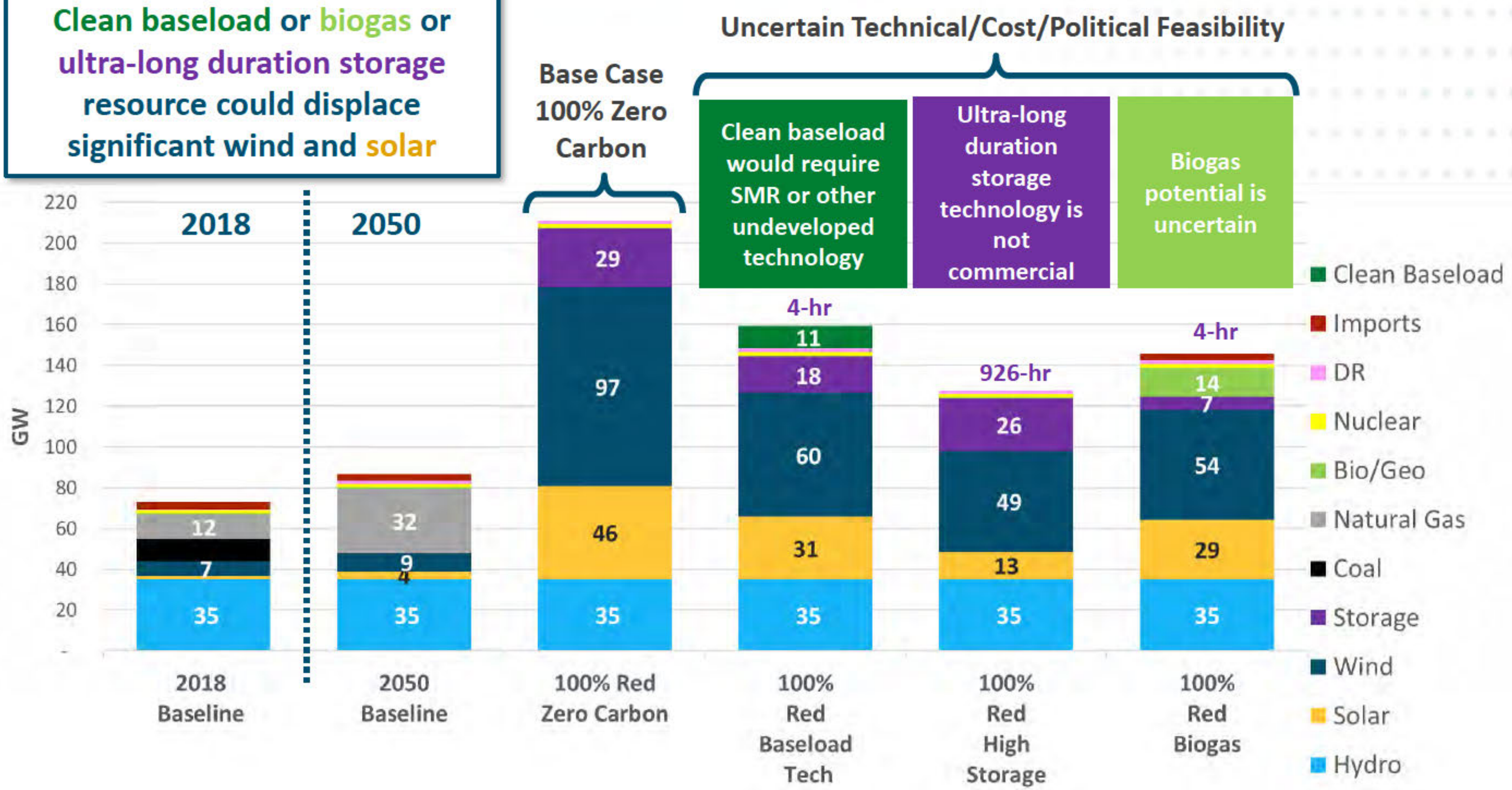
the area of Portland and Seattle combined

Each point on the map indicates 200 MW.
Sites not to scale or indicative of site location.

Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

100% Reduction Portfolio Alternatives in 2050

Clean baseload or biogas or ultra-long duration storage resource could displace significant wind and solar

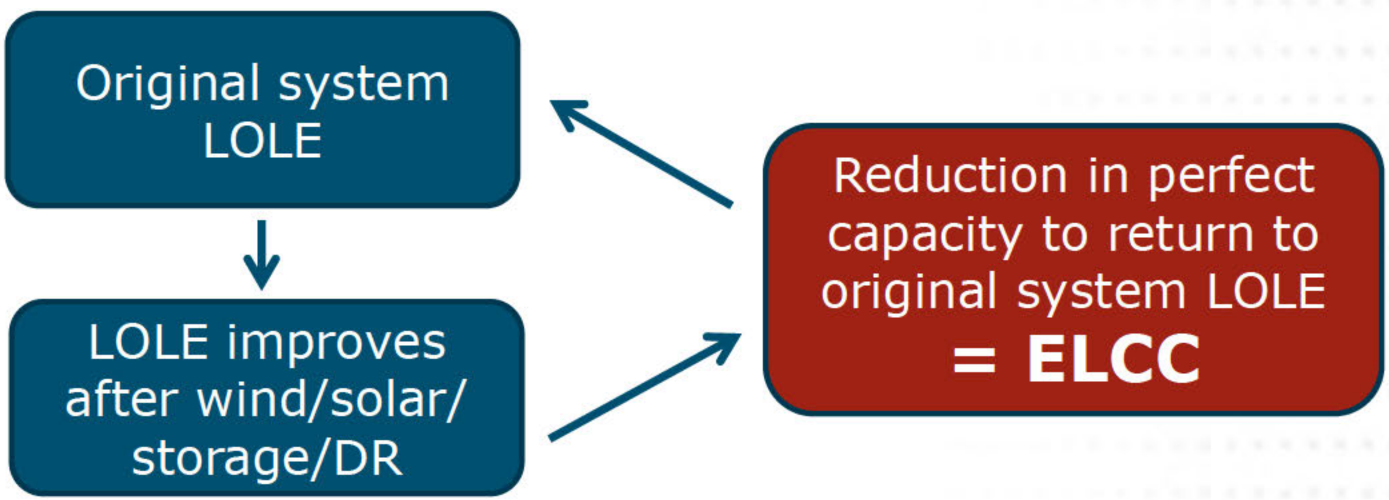


	2050 Baseline	100% Red Zero Carbon	100% Red Baseload Tech	100% Red High Storage	100% Red Biogas
Carbon (MMT CO2)	50	0	0	0	0
Annual Cost Delta ($B)	Base	$16- $28	$14-$21	$550-$990	$4 - $9
Additional Cost ($/MWh)	Base	$52-$89	$46-$69	$1,800-$3,200	$14 - $30

CAPACITY CONTRIBUTION OF WIND, SOLAR, STORAGE AND DEMAND RESPONSE

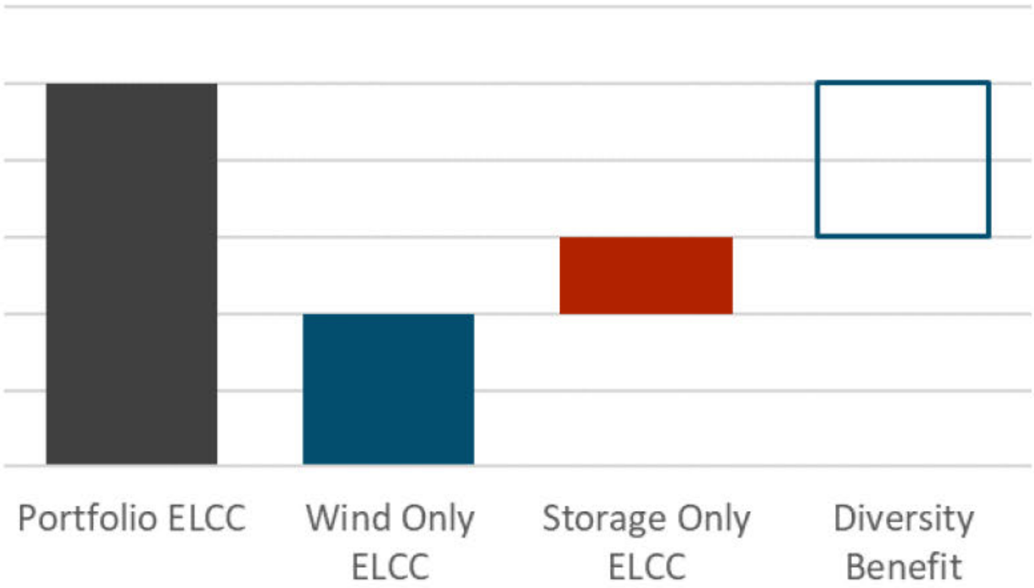
"ELCC" is used to determine effective capacity contribution from wind, solar, storage and demand response

- Effective load carrying capability (ELCC) is the quantity of 'perfect capacity' that could be replaced or avoided with dispatch-limited resources such as wind, solar, hydro, storage or demand response while providing equivalent system reliability
- The following slides present ELCC values calculated using the 2050 80% GHG Reduction Scenario as the baseline conditions

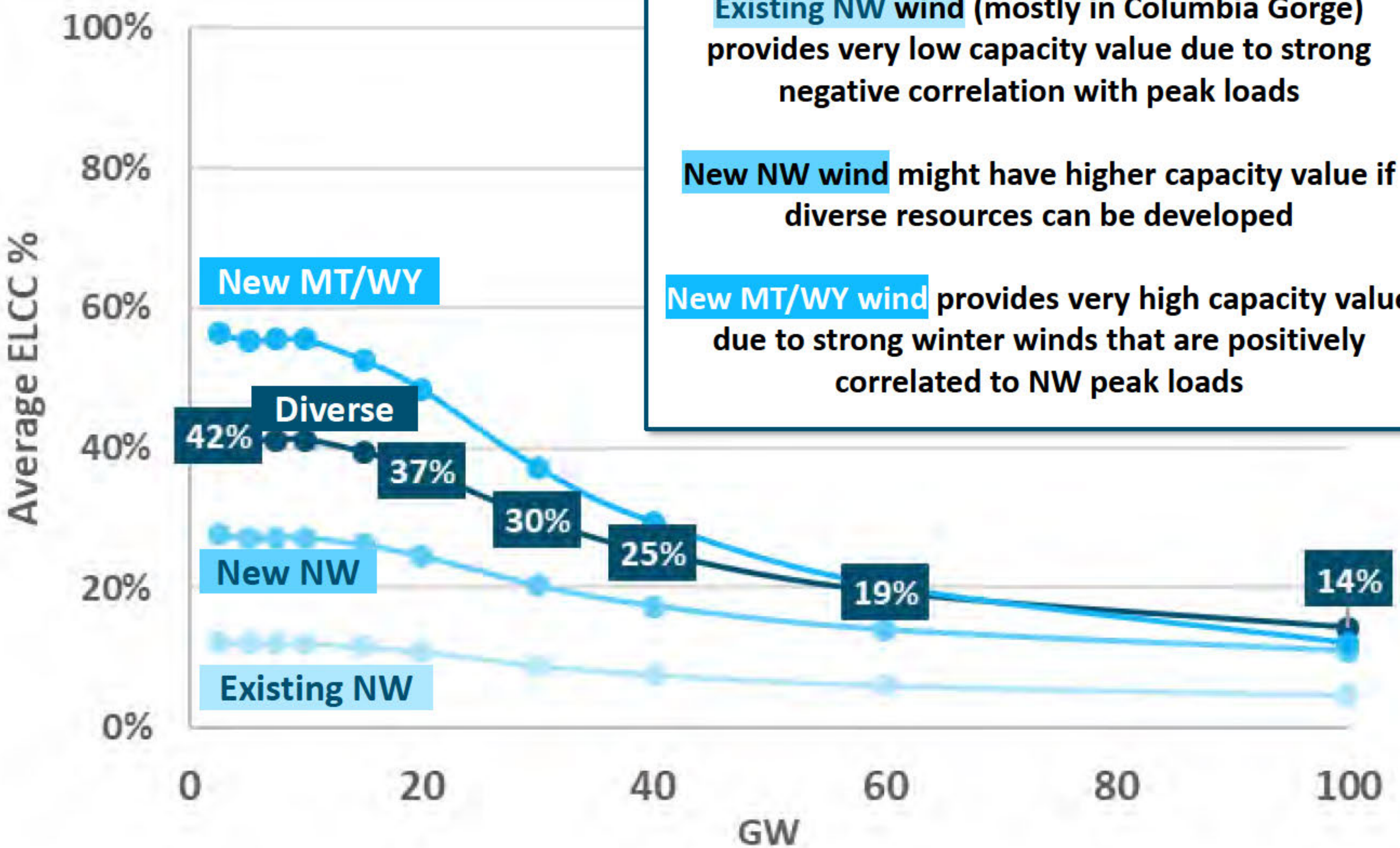


Portfolio ELCC & Diversity

- Determining the ELCC of individual resources is not straightforward due to complex interactive effects
- The ELCC of a portfolio of resources can be more than the sum of its parts if the resources are complementary, e.g., daytime solar + nighttime wind
- The incremental capacity contribution of new wind, solar and storage declines as a function of penetration



Wind ELCC varies widely by location

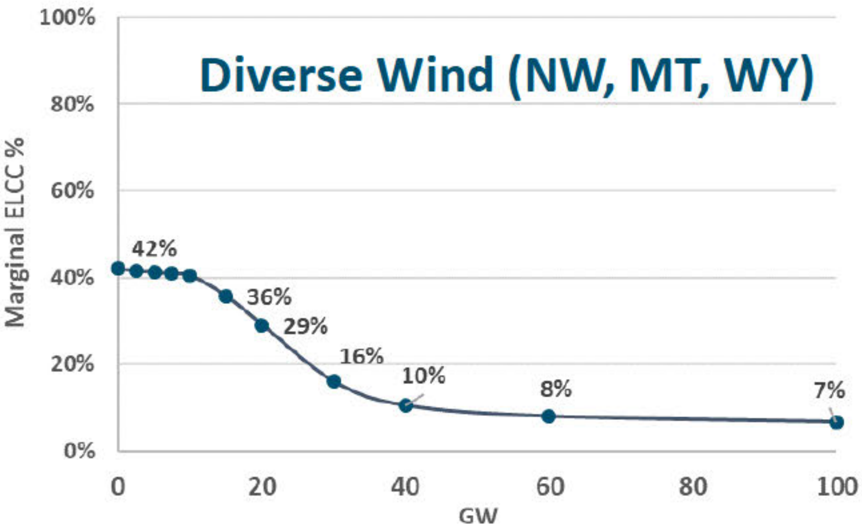


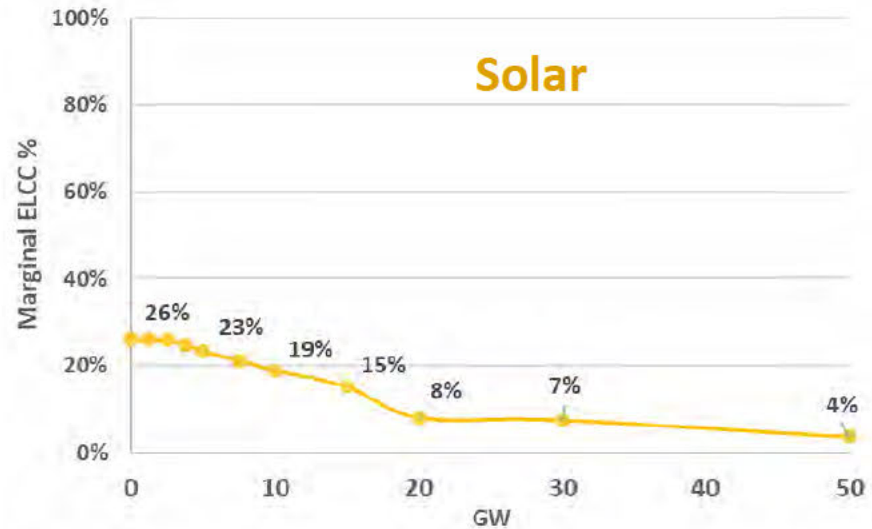
Existing NW wind (mostly in Columbia Gorge) provides very low capacity value due to strong negative correlation with peak loads

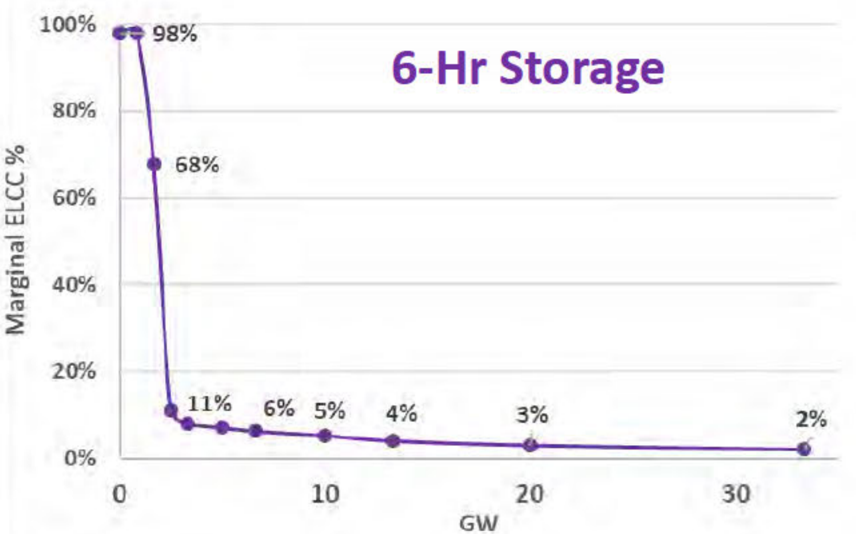
New NW wind might have higher capacity value if diverse resources can be developed

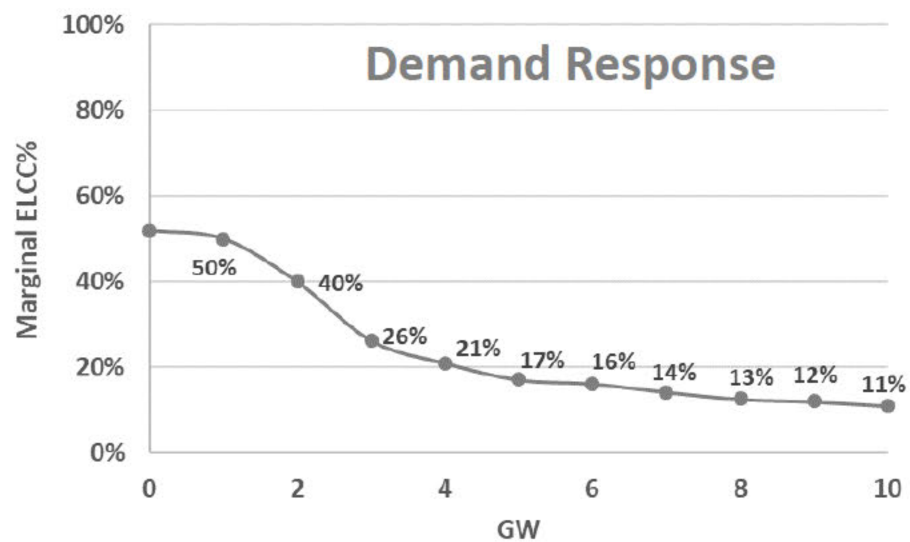
New MT/WY wind provides very high capacity value due to strong winter winds that are positively correlated to NW peak loads

Wind, solar and storage all exhibit diminishing ELCC values as more capacity is added

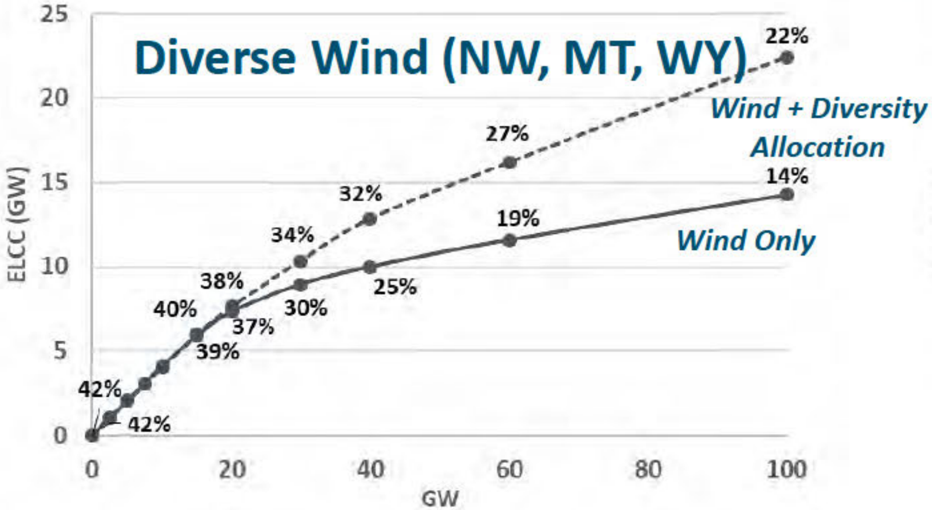


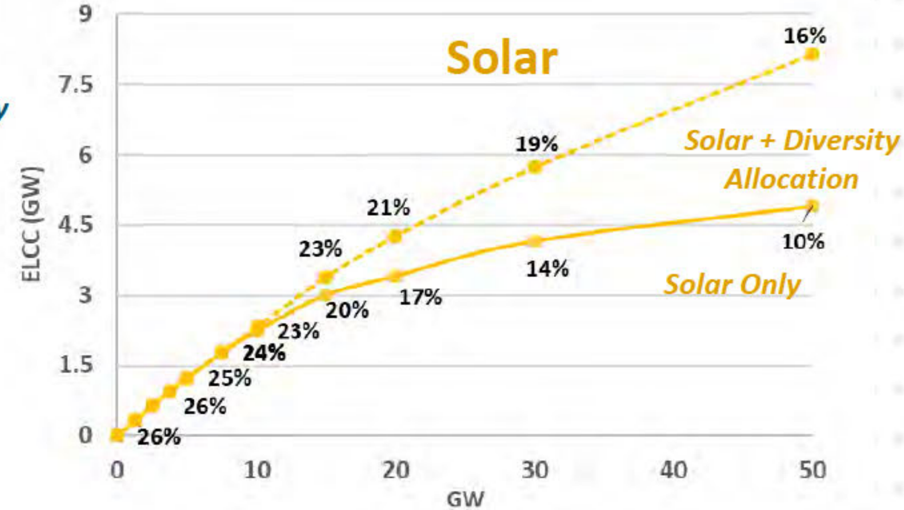


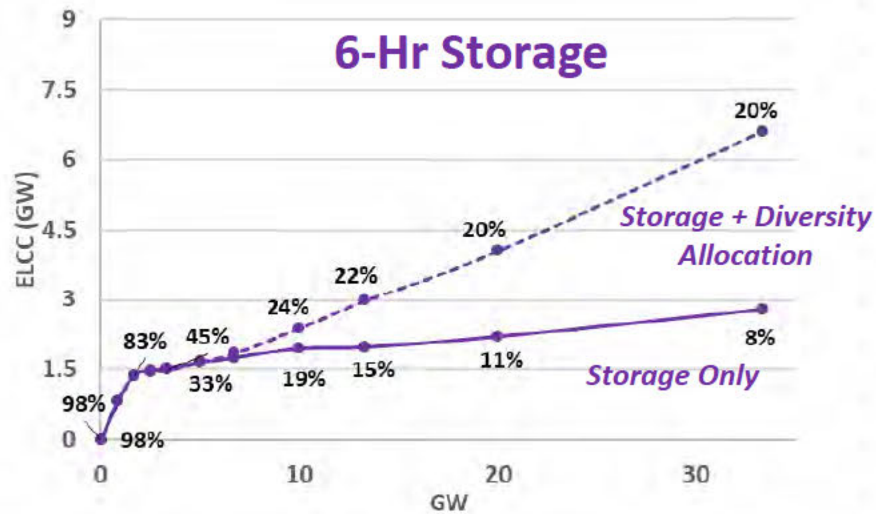




Cumulative ELCC Potential for Wind/Solar/Storage

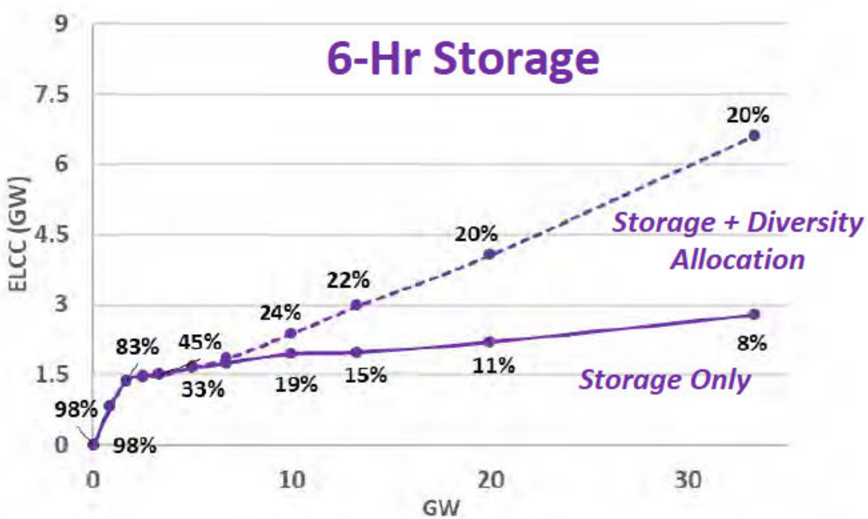


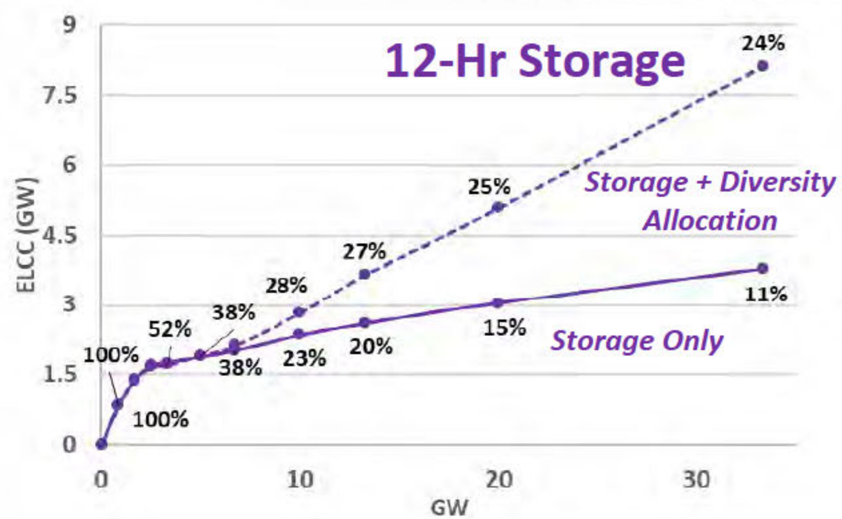




Value of Storage Duration

- **Increasing the duration of storage provides additional ELCC capacity value, but there are still strong diminishing returns even for storage up to a duration of 12-hours**

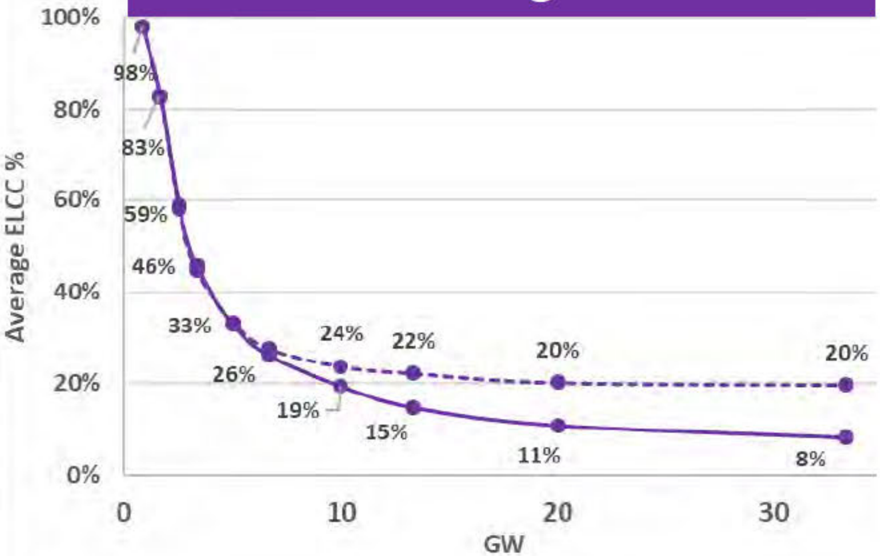




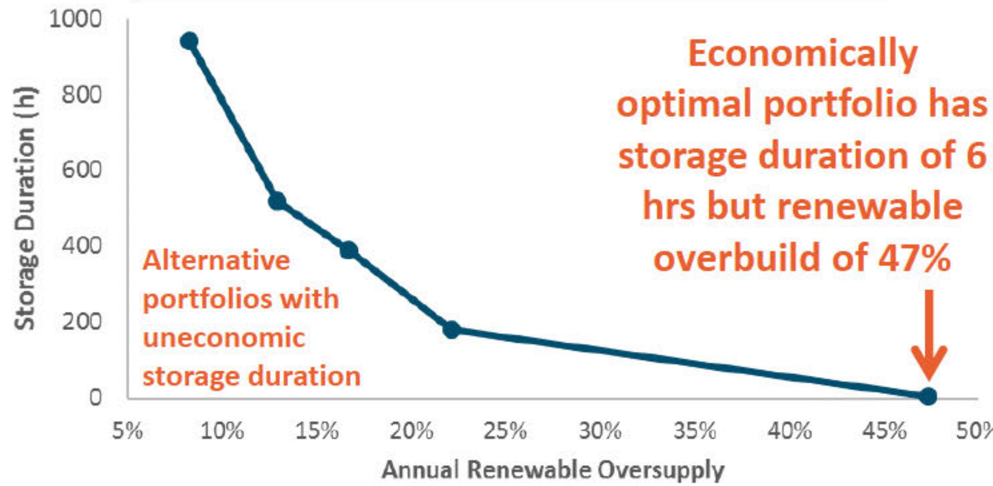
Energy storage is limited in its ability to provide firm generation

- In a high-renewable electricity system, there must be firm energy to generate during multi-day and multi-week stretches of low renewable energy production
- For storage to provide reliable capacity during these periods, it must have a fleetwide duration of 100-1000 hours
- In Current storage technology (Li-ion, flow batteries, pumped hydro), is not capable of providing this duration economically; most storage today has 1 to 10 hr duration
- Because storage does not have the required duration, a 100% zero carbon system must build twice as much renewable energy as is required on an annual basis to ensure low production periods have sufficient energy

6-Hr Storage ELCC



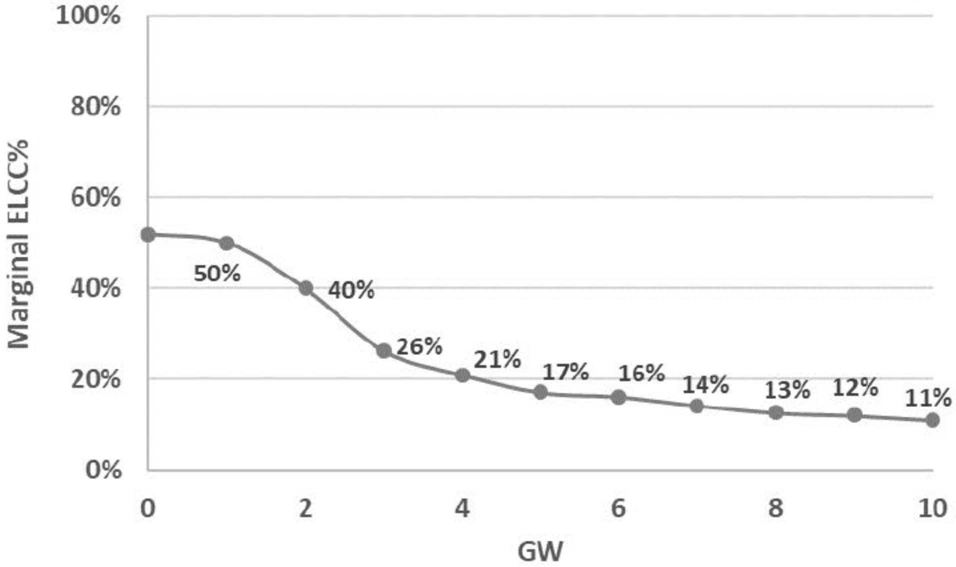
100% Zero Carbon Portfolios



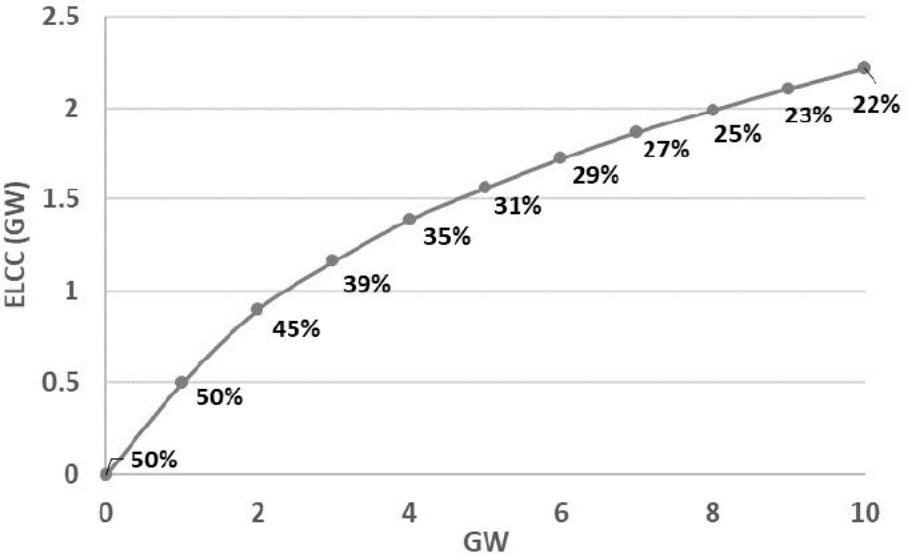
Demand response is limited in its ability to provide firm generation

- Demand response is capable of providing capacity for limited periods of time, making it difficult to substitute for firm generation when energy is needed for prolonged periods of time
- DR assumption: 10 calls per year, 4 hours per call
- Results shown for the 2050 system

DR Marginal ELCC %



DR Cumulative ELCC MW



Energy+Environmental Economics

RELIABILITY PLANNING PRACTICES IN THE PACIFIC NORTHWEST

Reliability Standards

- **This study uses a reliability standard of 2.4 hrs/yr LOLE**
  - Corresponds to 1-day-in-10 year loss of load
- **The Northwest Power and Conservation Council uses a reliability standard of 5% loss of load probability (LOLP) per year**
  - Currently considering moving from an LOLP to LOLE standard
- **At high penetrations of renewable energy, loss of load events become larger in magnitude, suggesting simply measuring the hrs/yr (LOLE) of lost load may be insufficient**
- **MWh/yr of expected unserved energy (EUE) is a less common reliability metric in the industry but captures the magnitude of outages**

Exploring an EUE (MWh/yr) based reliability standard may help to more accurately characterize the reliability of a system that relies heavily on energy-limited resources (e.g. hydro, wind, solar)

Regional Planning Reserve sharing system may be beneficial

- Current planning practices in the NW do not have a centralized capacity counting mechanism
- Many LSE's rely on front-office transactions that risk double-counting available surplus generation capacity
- This analysis shows that new firm capacity is needed in the NW in the near term and significant new firm resources are needed in the long-term depending on coal retirements

The region may benefit from and should investigate a formal mechanism for sharing planning reserves to ensure resource adequacy that would both 1) standardize the attribution of capacity value across entities and 2) realize benefits of load & resource diversity among LSE's in region

KEY FINDINGS

Key Findings (1 of 2)

1. **It is possible to maintain Resource Adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient <u>firm capacity</u> is available during periods of low wind, solar and hydro production**
   - Natural gas generation is the most economic source of firm capacity, and adding new gas *capacity* is not inconsistent with deep reductions in carbon emissions
   - 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) gas or coal generation with carbon capture and sequestration, (3) ultra-long duration electricity storage, and (4) replacing conventional natural gas with carbon-neutral gas
2. **It would be <u>extremely costly and impractical</u> 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**
3. **The Northwest is anticipated to need <u>new capacity in the near-term</u> in order to maintain an acceptable level of Resource Adequacy after planned coal retirements**

Key Findings (2 of 2)

4. **Current planning practices risk underinvestment in new capacity required to ensure Resource Adequacy at acceptable levels**

   - Reliance on "market purchases" or "front office transactions" 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
   - However, because the region lacks a formal mechanism for counting physical firm capacity, there is a risk that reliance on market transactions may result in double-counting of available surplus generation capacity
   - 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
   - The region might benefit from and should investigate a formal mechanism for sharing of 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

The results/findings in this analysis represent the Greater NW region in aggregate, but results may differ for individual utilities

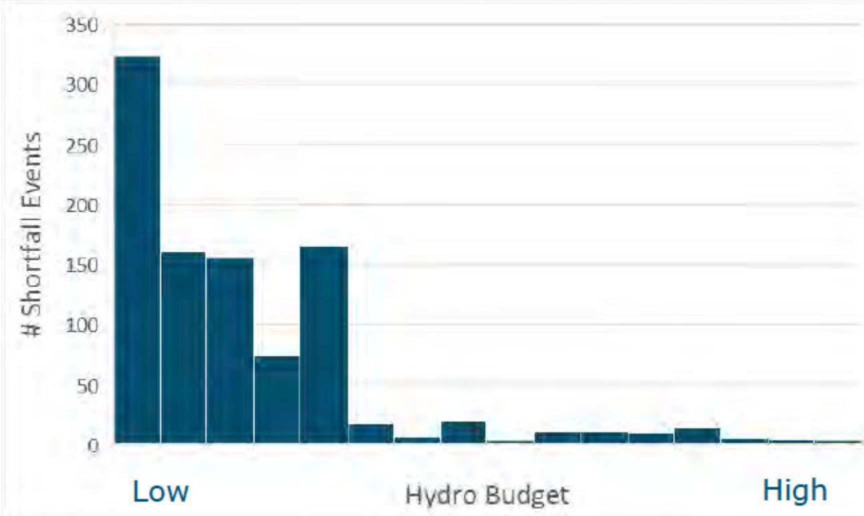
APPENDIX

Energy+Environmental Economics

ROLE OF HYDRO IN MEETING RESOURCE ADEQUACY NEEDS

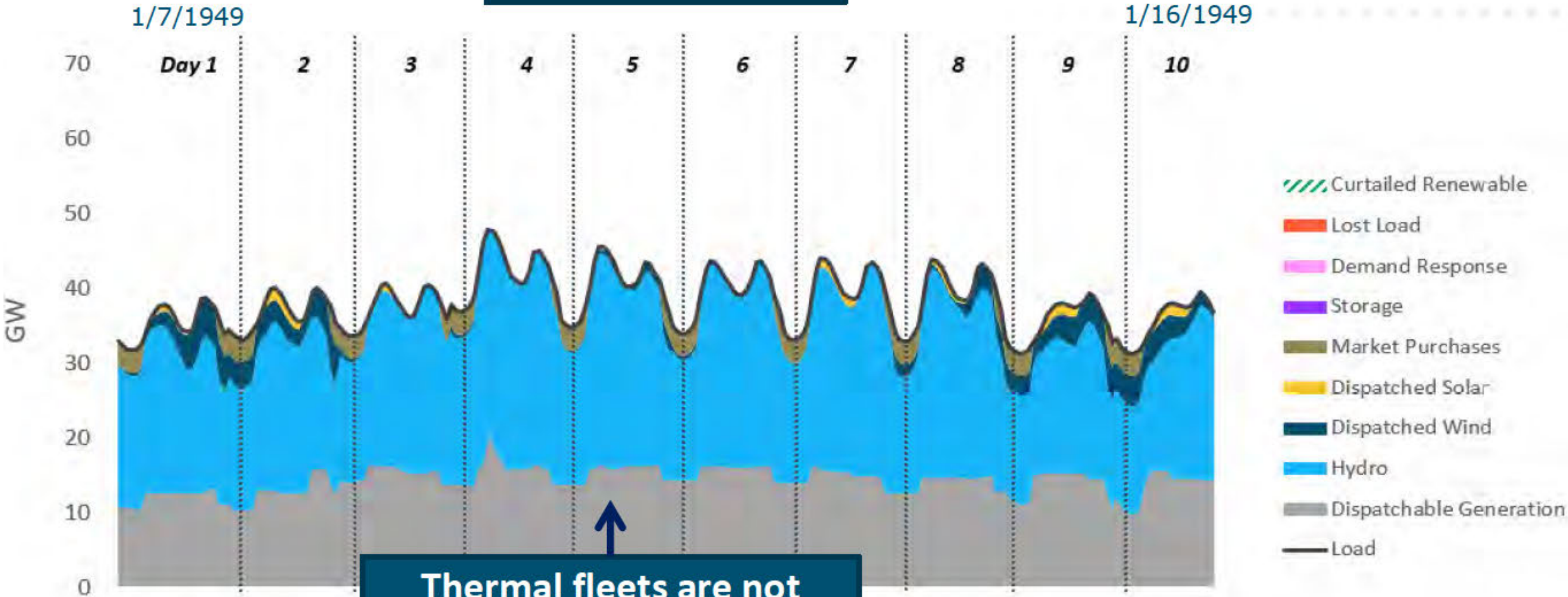
Low Hydro Years: Low Reliability

- **Most shortfall events occur during low hydro years**
  - 25% of all events occur in lowest 5 of 80 hydro years
  - 96% of all events occur in lowest 25 of 80 hydro years
- **Hydro conditions are a major factor for NW system reliability in 2018**
- **As renewable penetration increases, renewable production becomes a bigger factor for NW system reliability**
- **High correlation between shortfalls and low hydro years results in consistent values for annual LOLP using GENESYS and RECAP**



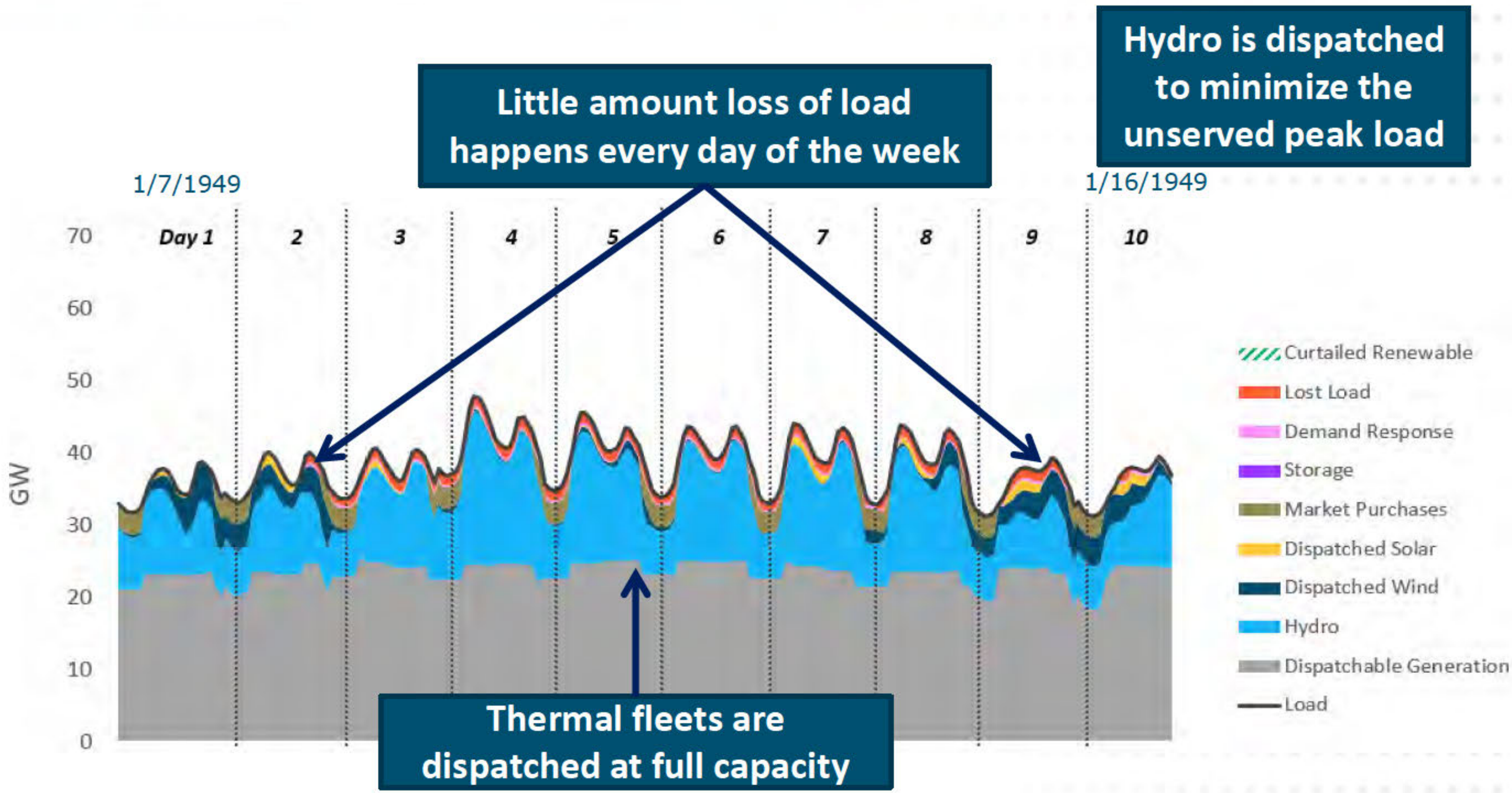
Today's System with Median Hydro

No loss of load event in this week



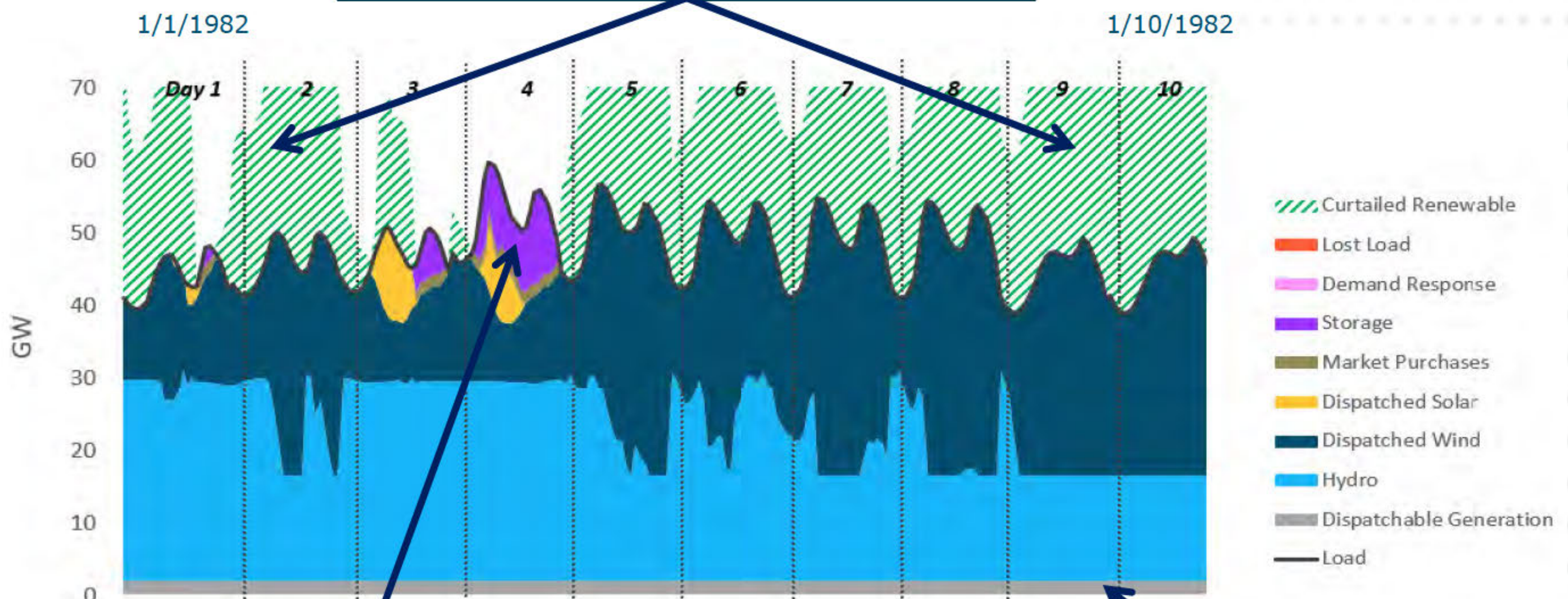
Thermal fleets are not dispatched at full capacity

Today's System with Low Hydro



2050 System with Median Hydro

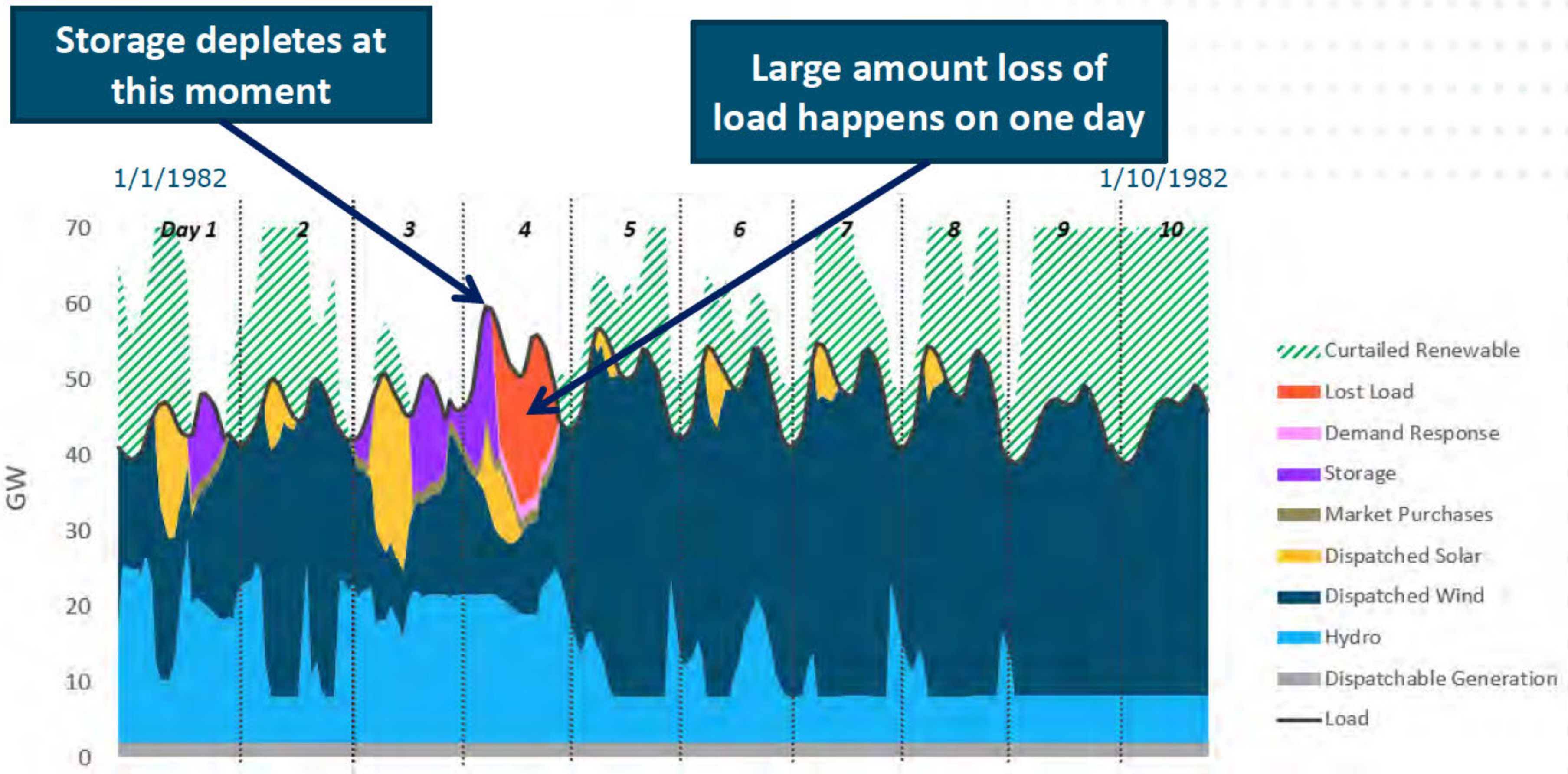
No loss of load event and with a large amount of renewable curtailment



Storage is dispatched during low renewable hours

Very little dispatchable generation in 100% clean system

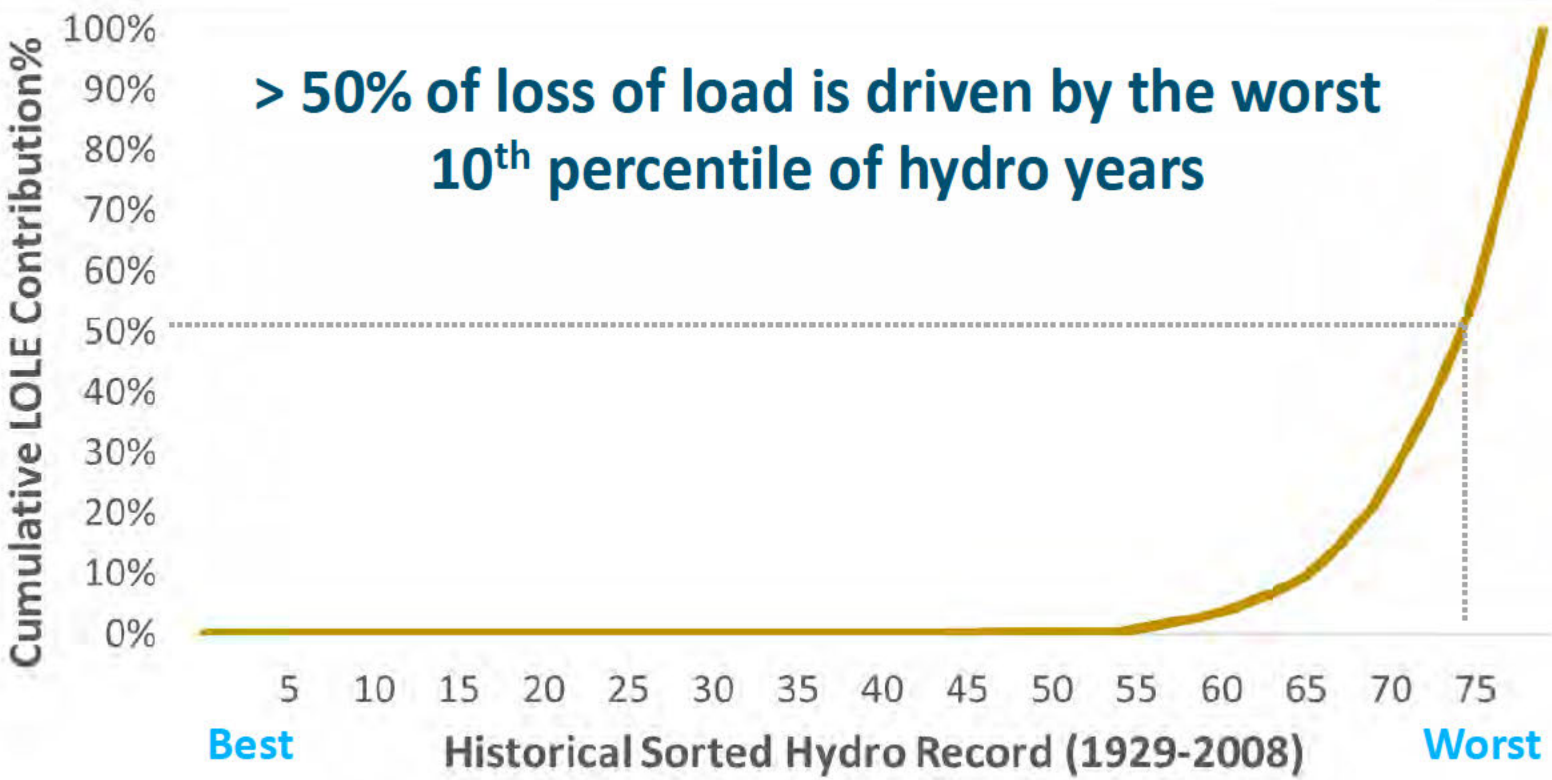
2050 System with Low Hydro



Loss of load is mainly driven by low renewable generation plus drought hydro condition

2018 Hydro Analysis

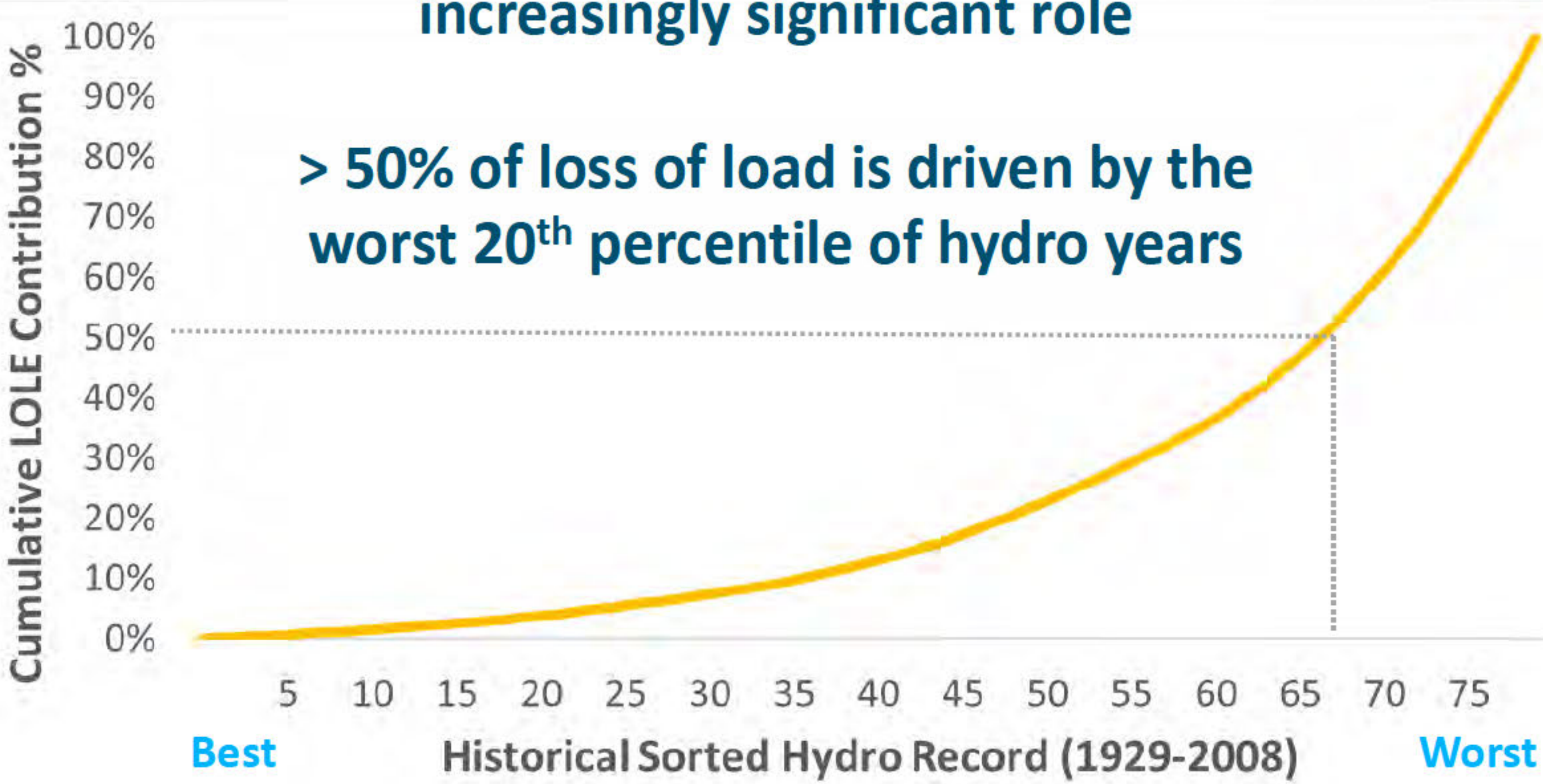
In today's system, nearly all loss of load is driven by low hydro years which is the single most variable factor in the system



2050 - 95% Clean Hydro Analysis

In a 95% clean system, hydro is still the dominant driver of loss of load, but renewable intermittency plays an increasingly significant role

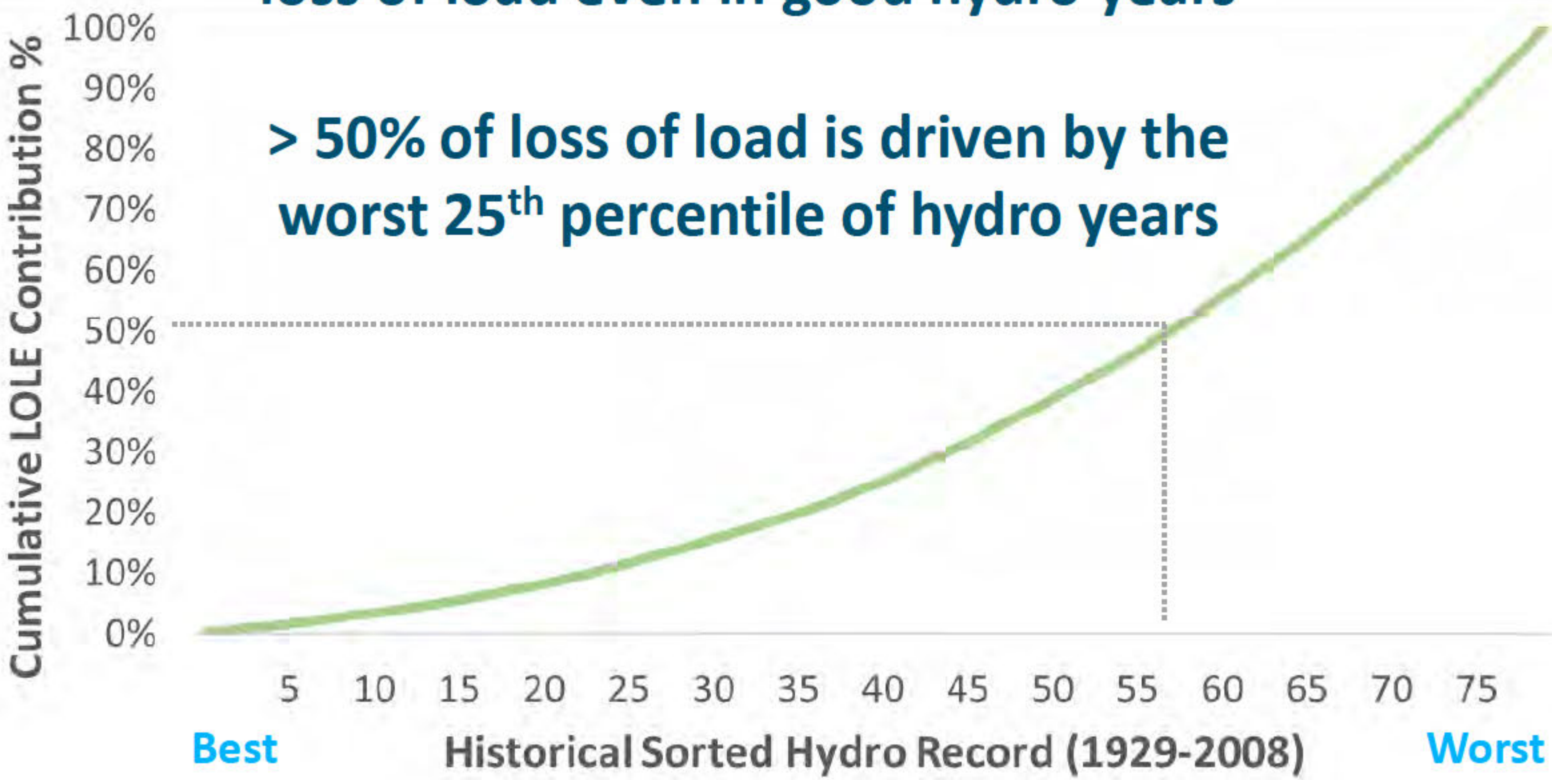
> 50% of loss of load is driven by the worst 20th percentile of hydro years



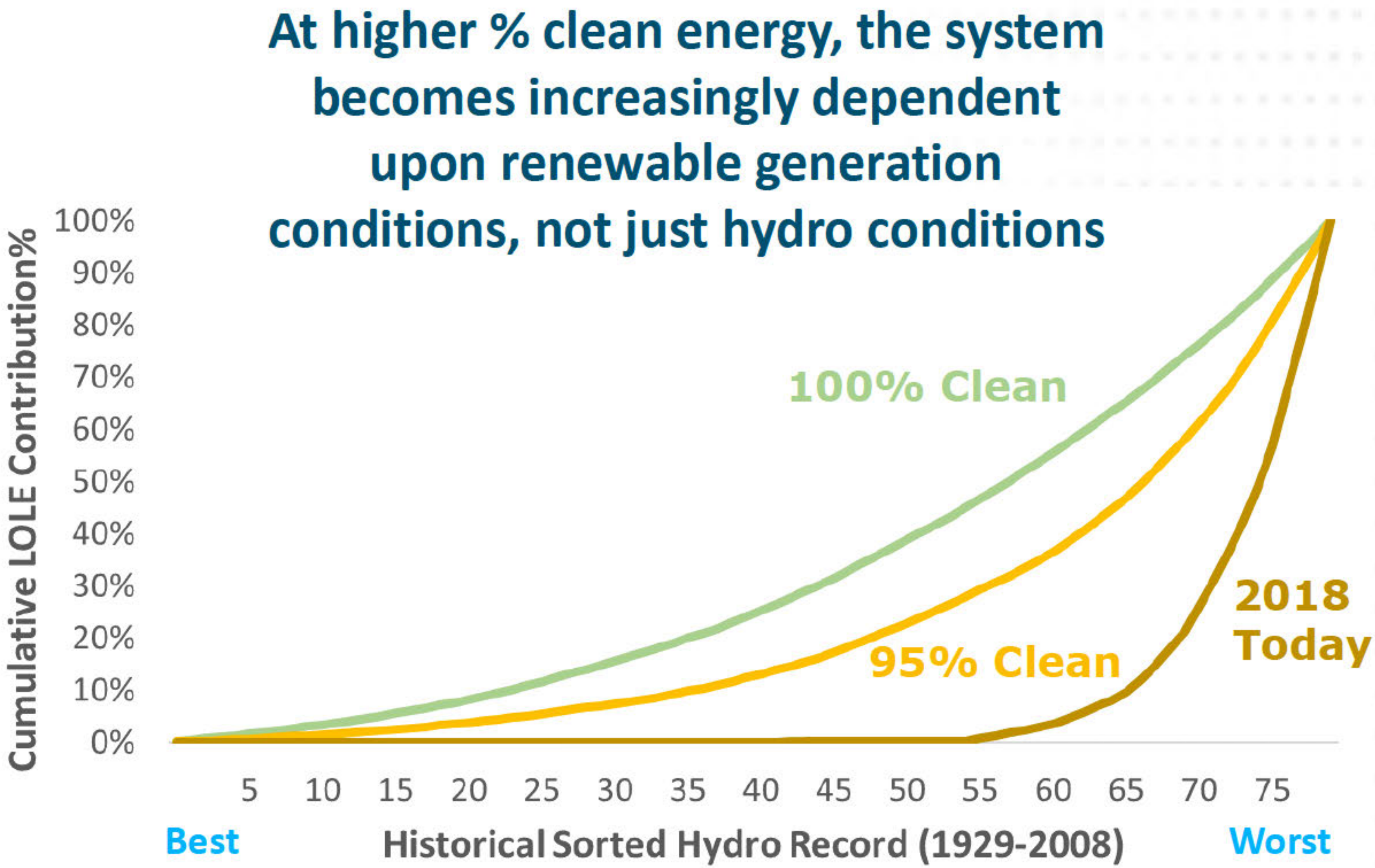
2050 - 100% Clean Hydro Analysis

In a 100% clean system, hydro is still the dominant driver of loss of load, but low renewable events can cause loss of load even in good hydro years

> 50% of loss of load is driven by the worst 25th percentile of hydro years



Hydro Analysis

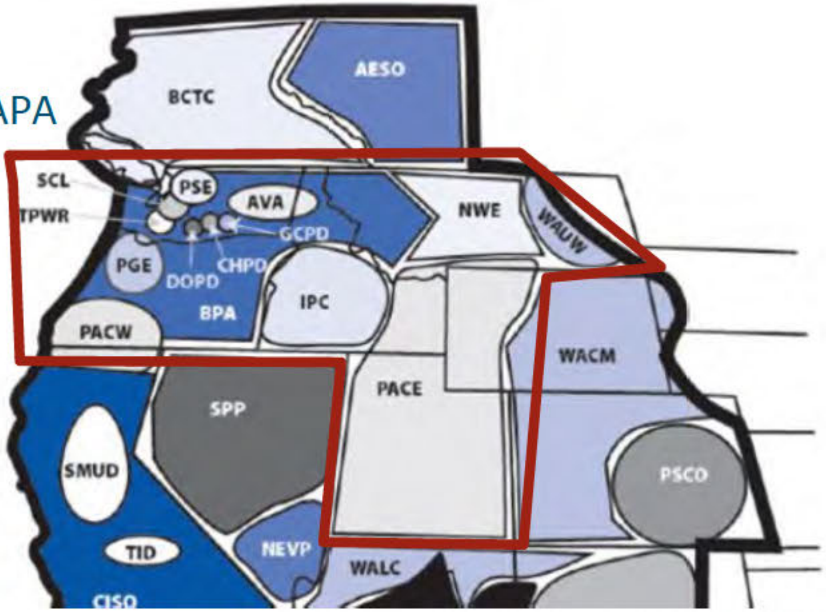


Energy+Environmental Economics

RECAP TECHNICAL DETAILS

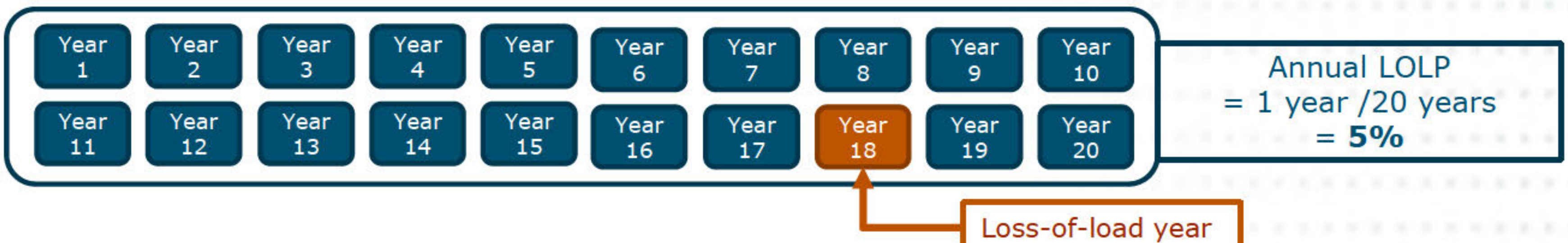
Modeling Region

+ **Modeling region is Northwester Power & Conservation Council + Select Northwest Power Pool load areas**
+ **Load areas included (17)**
  - AVA – Avista
  - BPAT – Bonneville
  - CHPD – Chelan
  - DOPD – Douglas
  - GCPD – Grant
  - IPFE – Idaho Power
  - IPMV – Magic Valley
  - IPTV – Treasure Valley
  - NWMT – Northwestern
  - PACE – PacifiCorp East
  - PACW – PacifiCorp West
  - PGE – Portland General
  - PSEI – Puget Sound
  - SCL – Seattle
  - TPWR – Tacoma
  - WAUW, WWA – WAPA



Reliability Metrics

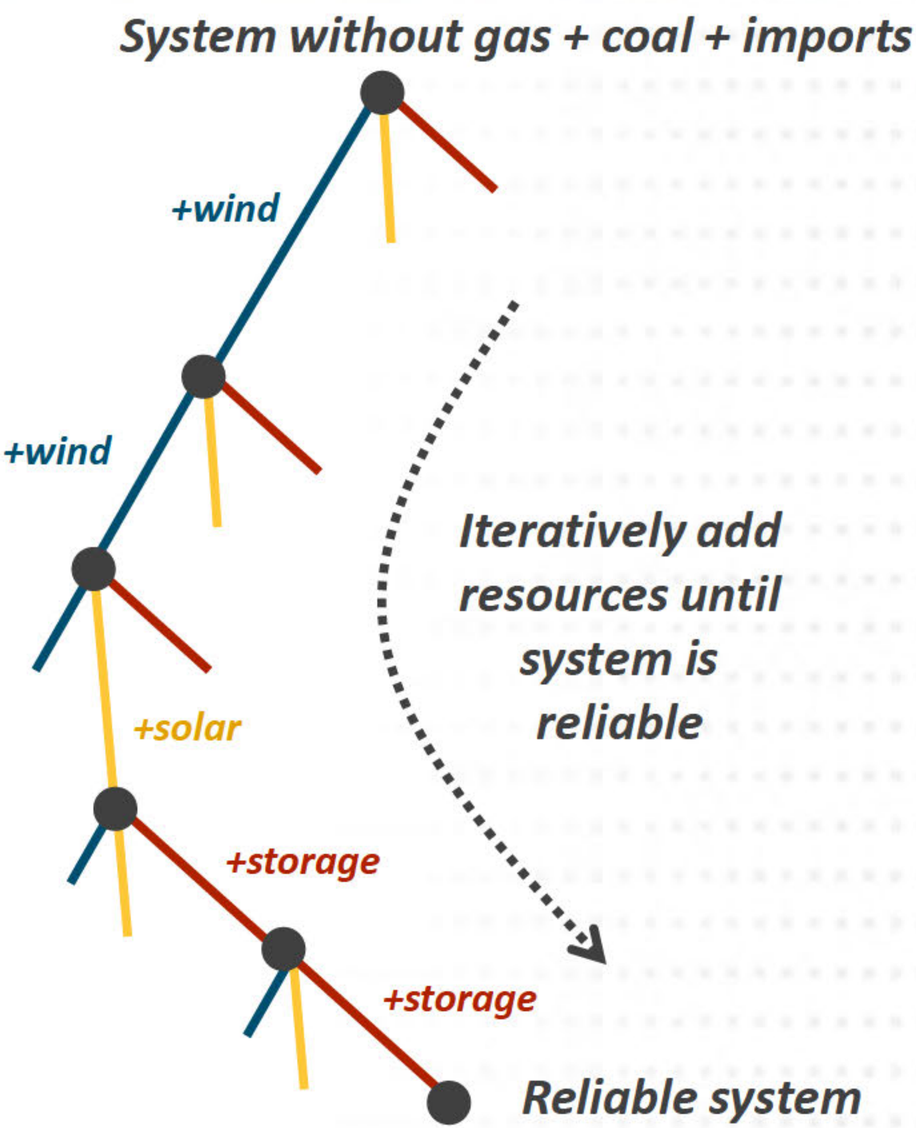
- **NWPCC has adopted a 5% annual loss of load probability (aLOLP)**
  - Every 1 in 20 years can result in a shortfall



- **Council to review reliability standard in 2018 to include seasonal adequacy targets**
- **Loss of load expectation (LOLE) measured in hrs/yr and expected unserved energy (EUE) measured in MWh/yr are other common metrics**
- **NWPCC reports LOLE and EUE, but does not have an explicit standard for these metrics**
  - 0.1 to 2.4 hrs/yr is the most common range for LOLE

Smart Search Functionality

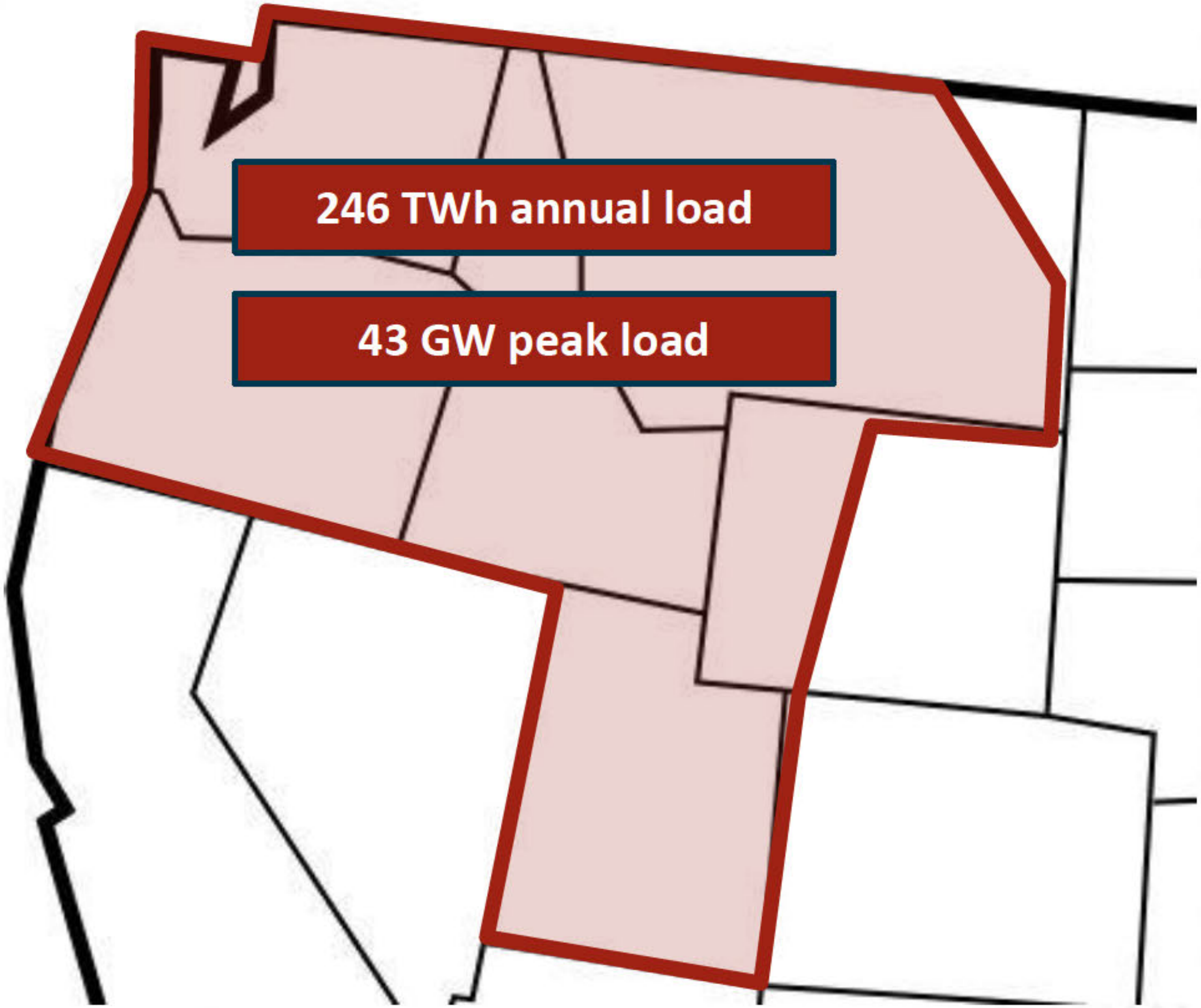
- Smart search functionality iteratively evaluates the reliability contribution of adding quantities of equal cost carbon free resources and selecting the resource with the highest contribution
- This allows the model to select a cost optimal portfolio of resources that provides adequate reliability



RECAP Data Sources

- **Hourly load profiles**
  - NOAA weather data (1950-2017)
  - WECC hourly load data (2014-2017)
- **Renewable generation**
  - NREL Wind Toolkit (2007-2013)
  - NREL National Solar Radiation Data Base (1998-2014)
  - NWPCC Hydro data
- **Generating resources**
  - WECC TEPPC
  - Future portfolios will be informed by RESOLVE outputs from PGP Low Carbon study

Greater NW Region



Load

- **Initial runs were completed using 2017 load levels**
  - Annual Load: 246 TWh
  - Median Peak Load: 42,860 MW
- **Future load growth was assumed to be 0.7%/yr post-2023**
- **2014-2017 WECC actual hourly load data was used to train neural network model to produce hourly loads for historical weather years**
  - BTM solar was added back to historical loads

	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

Simulated Load

+ Neural Network Inputs

	2018	2030	2050
Median 1-in-2 Peak (GW)	43	47	54
Annual Load (TWh)	247	269	309

+ Load growth was assumed to be 0.7%/yr post-2023

+ 2014-2017 WECC actual hourly load data was used to train neural network model to produce hourly loads for historical weather years

- BTM solar was added back to historical loads

	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
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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

Wind

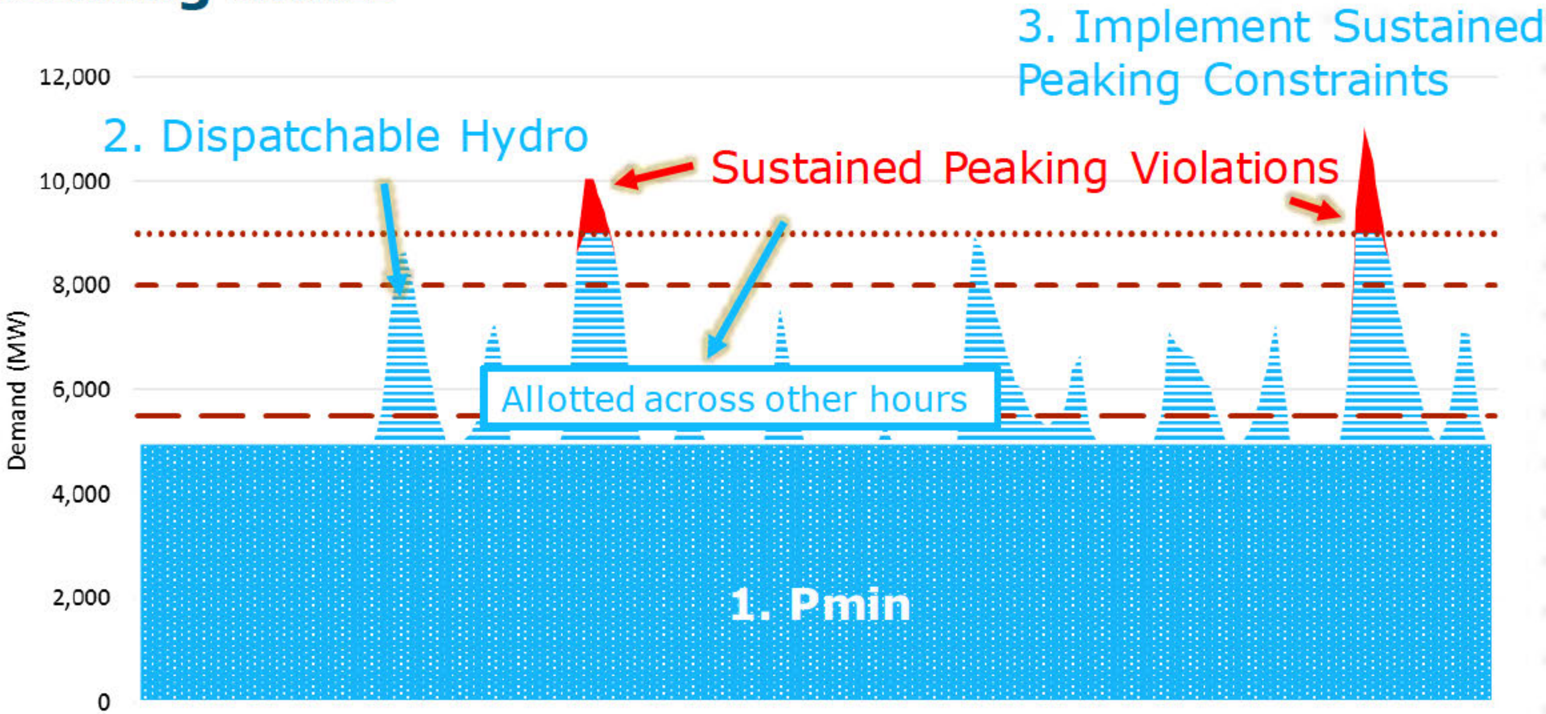
+ **Wind profiles are simulated output from existing and new sites based on NREL's mesoscale meteorological modeling from historical years 2007-2012**

Average Wind Capacity Factor

	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	0.34	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.31	0.3	0.3	0.3	0.31	0.31	0.32	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Feb	0.28	0.28	0.28	0.27	0.27	0.27	0.26	0.26	0.24	0.23	0.23	0.24	0.24	0.24	0.24	0.24	0.25	0.27	0.27	0.28	0.28	0.28	0.28	0.28
Mar	0.31	0.31	0.31	0.31	0.3	0.3	0.3	0.28	0.28	0.28	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.3	0.3	0.31	0.31	0.31	0.31
Apr	0.31	0.31	0.31	0.3	0.3	0.3	0.27	0.26	0.25	0.25	0.25	0.25	0.25	0.26	0.26	0.27	0.28	0.28	0.29	0.3	0.3	0.31	0.31	0.31
May	0.29	0.29	0.29	0.29	0.28	0.26	0.23	0.22	0.22	0.21	0.21	0.21	0.21	0.22	0.23	0.24	0.26	0.27	0.27	0.29	0.29	0.29	0.29	0.29
Jun	0.31	0.31	0.3	0.3	0.29	0.26	0.23	0.22	0.22	0.21	0.21	0.21	0.22	0.23	0.25	0.26	0.28	0.29	0.3	0.32	0.33	0.33	0.32	0.32
Jul	0.25	0.24	0.24	0.23	0.22	0.19	0.16	0.15	0.14	0.13	0.13	0.13	0.14	0.15	0.17	0.19	0.21	0.23	0.24	0.26	0.26	0.26	0.25	0.25
Aug	0.25	0.25	0.24	0.24	0.23	0.22	0.19	0.17	0.16	0.15	0.14	0.14	0.15	0.16	0.18	0.2	0.22	0.23	0.24	0.26	0.26	0.26	0.25	0.25
Sep	0.19	0.19	0.19	0.19	0.18	0.18	0.17	0.15	0.14	0.13	0.13	0.13	0.14	0.15	0.15	0.17	0.18	0.19	0.2	0.21	0.2	0.2	0.19	0.19
Oct	0.25	0.25	0.24	0.24	0.24	0.23	0.23	0.22	0.2	0.2	0.2	0.2	0.21	0.21	0.21	0.22	0.22	0.23	0.24	0.24	0.24	0.24	0.24	0.25
Nov	0.29	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.28	0.28	0.28
Dec	0.32	0.32	0.31	0.31	0.31	0.31	0.31	0.3	0.3	0.29	0.28	0.27	0.27	0.27	0.27	0.28	0.29	0.3	0.3	0.31	0.31	0.31	0.31	0.31

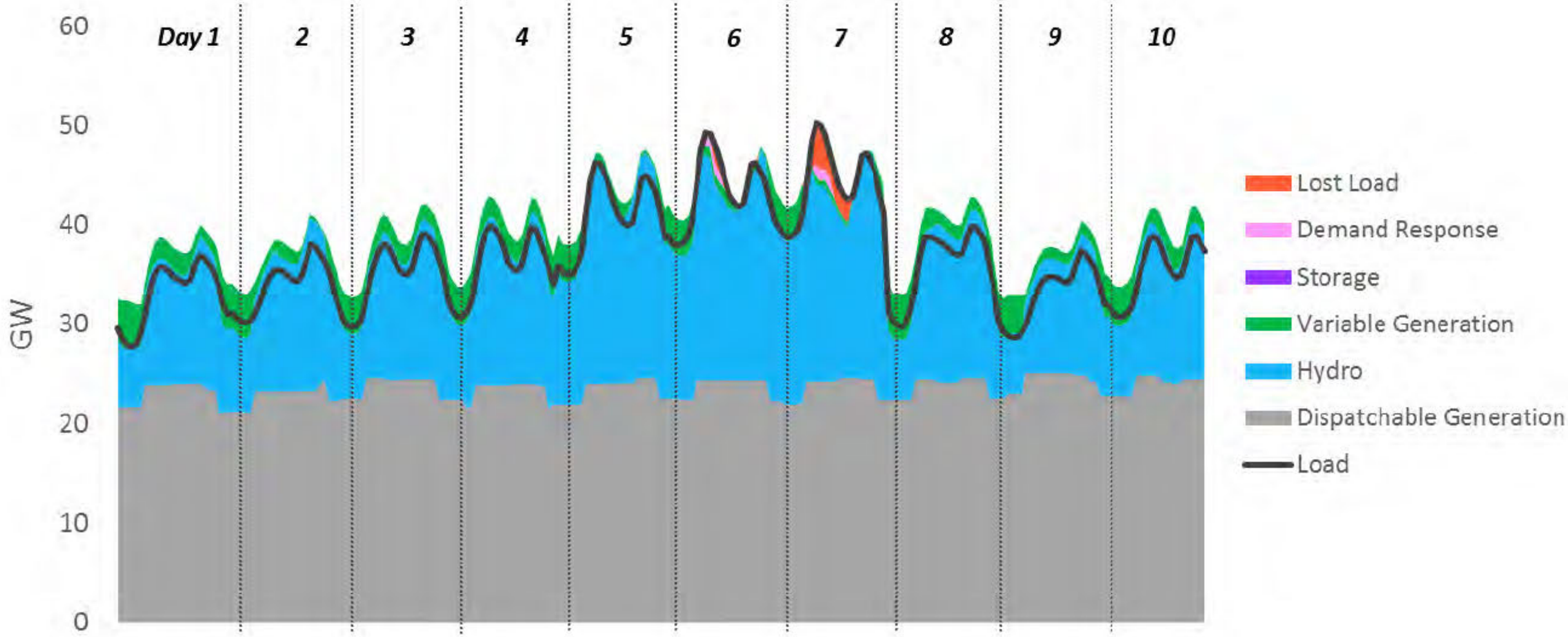
Hydro

- **Hydro availability is determined randomly from historical hydro conditions (1929-2008) using data from NWPCC**
- **Monthly hydro budgets allocated in four weekly periods and are dispatched to meet net load subject to sustained peaking limits**



2023 System: Week with Loss of Load

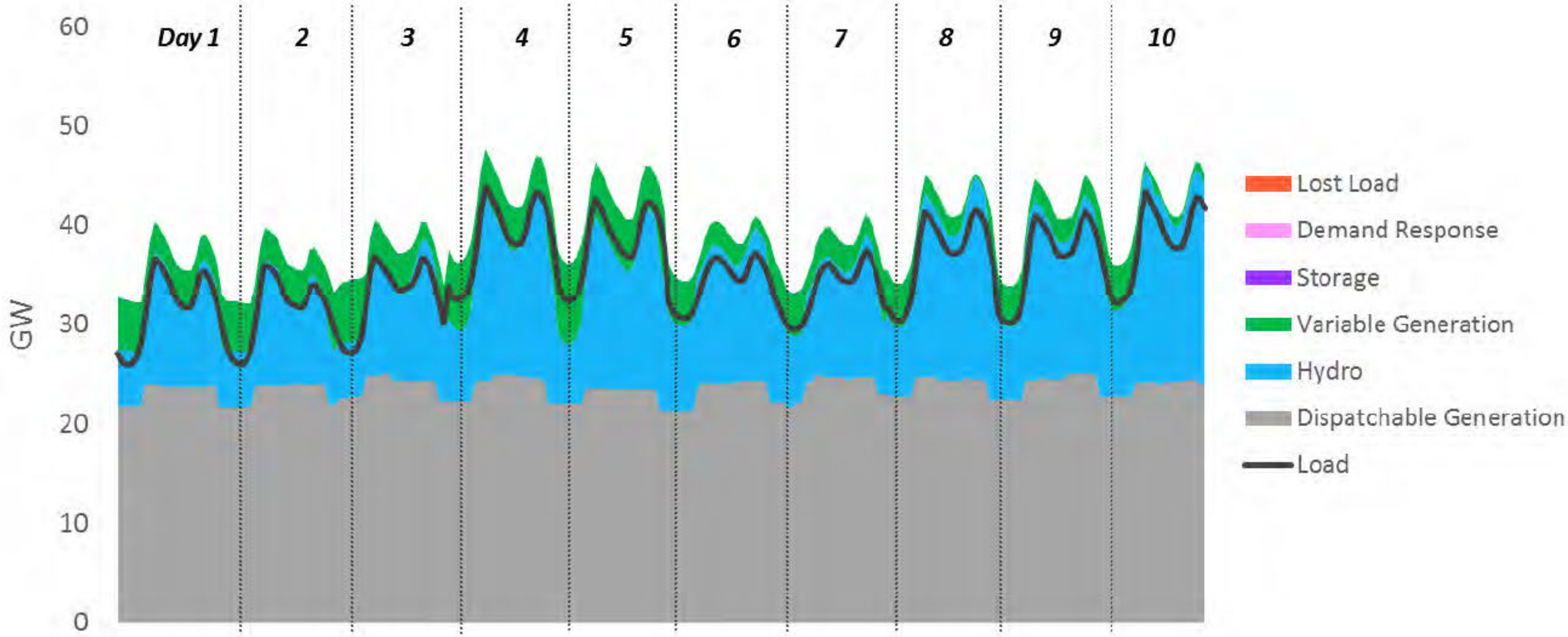
Highest load shortfall event: (Jan 1 – Jan 10, Temp Year: 1982)



<u>Note</u>:
- Dispatchable Generation - includes thermal, geothermal, nuclear, run-of-river hydro, and imports
- Variable Generation – includes wind, solar and spot market purchases (in low-load hours)
- Hydro – includes all non-ROR hydro
- DR – 80 calls of 4 hour duration and 142.5 MW

2023 System: Week with no Loss of Load

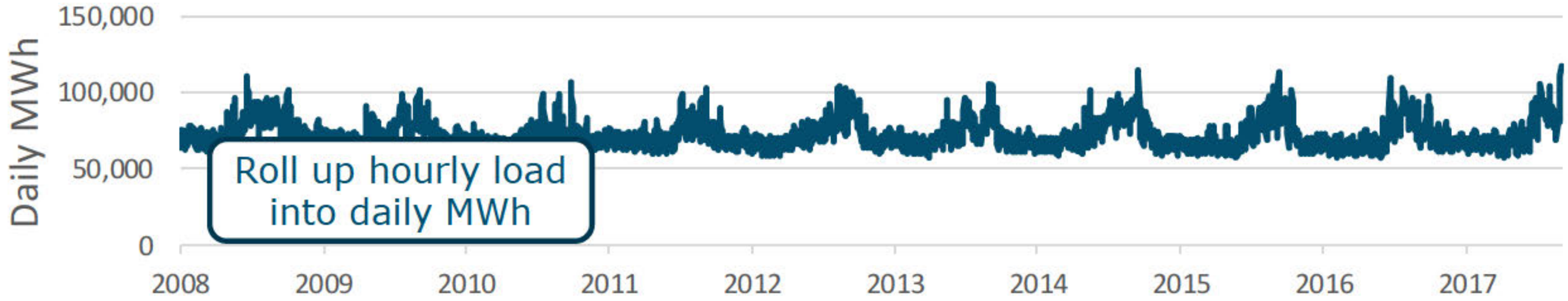
No load shortfall: (Feb 1 – Feb 10, Temp Year: 1982)



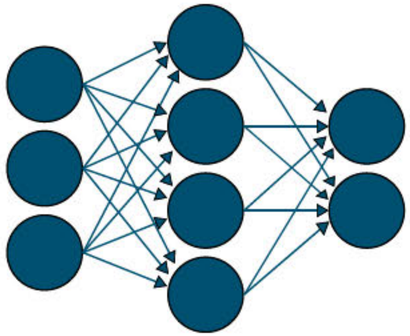
<u>Note</u>:

- Dispatchable Generation - includes thermal, geothermal, nuclear, run-of-river hydro, and imports
- Variable Generation – includes wind, solar and spot market purchases (in low-load hours)
- Hydro – includes all non-ROR hydro
- DR – 80 calls of 4 hour duration and 142.5 MW

Running Neural Network Model



Run neural network model to establish relationship between daily gross load and the following factors



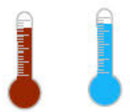
Max & Min Daily Temp

Month & Day-Type

Day Index for Economic Growth

Training the Model

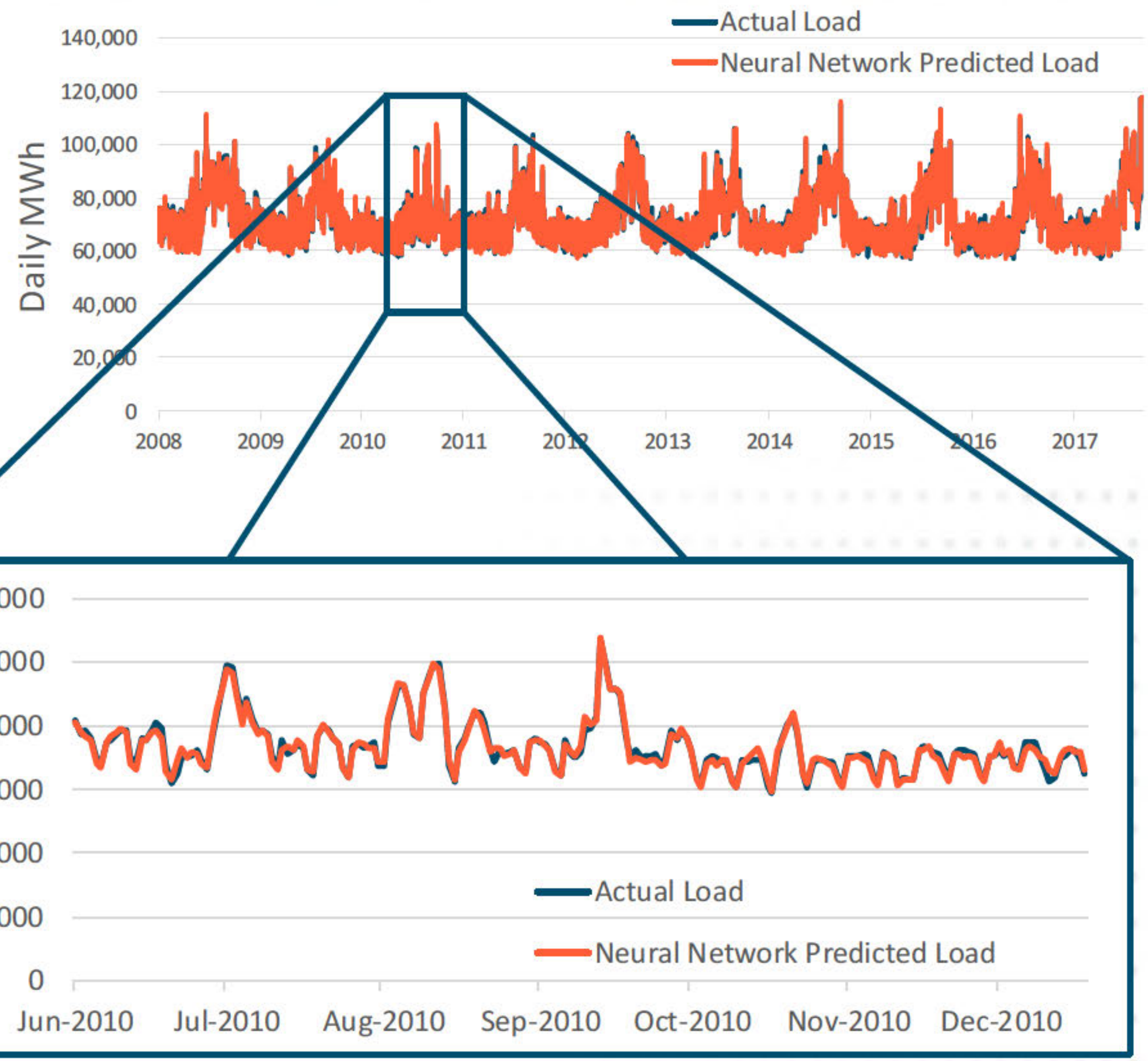
Use historical temperatures and calendar to 'train' NN model



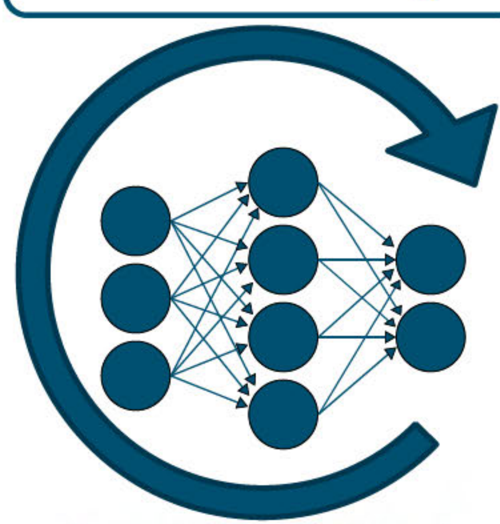
Max & Min Daily Temp

Month & Day-Type

Day Index for Economic Growth



Iterate until model coefficients converge



Daily Load Simulations

1950
Jan

Historical Calendar

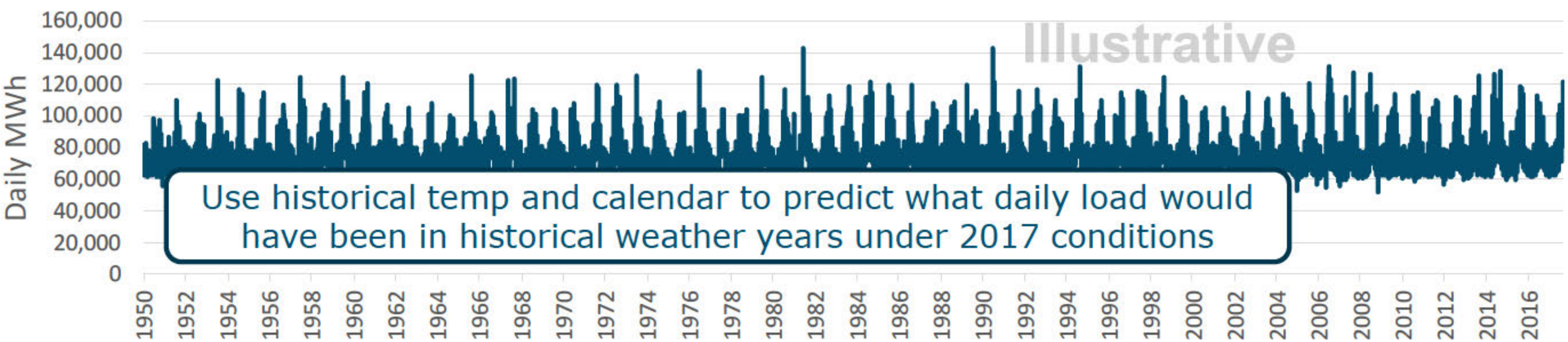
2017
Sep

Max & Min
Daily Temp

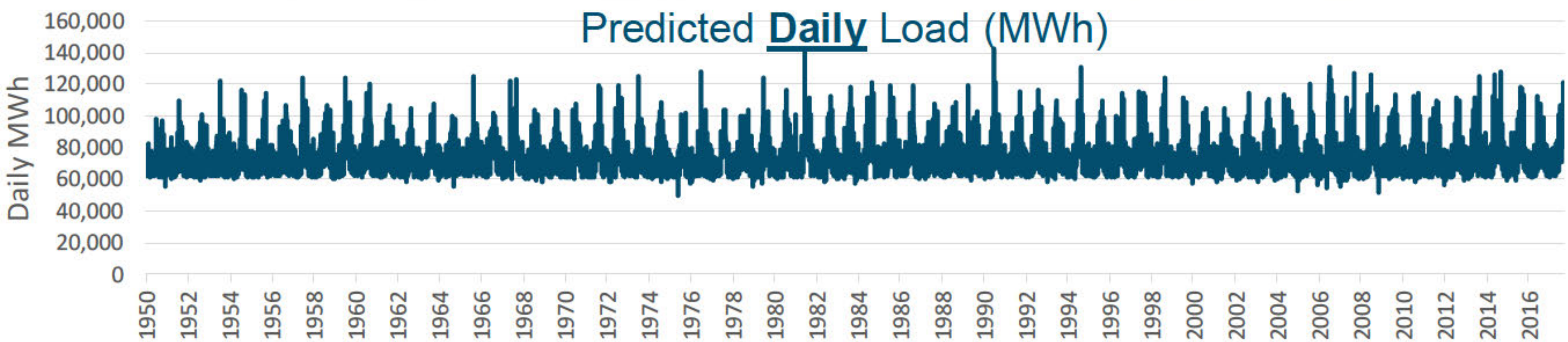
Historical Temperature Record

Max & Min
Daily Temp

2017 Economic Conditions

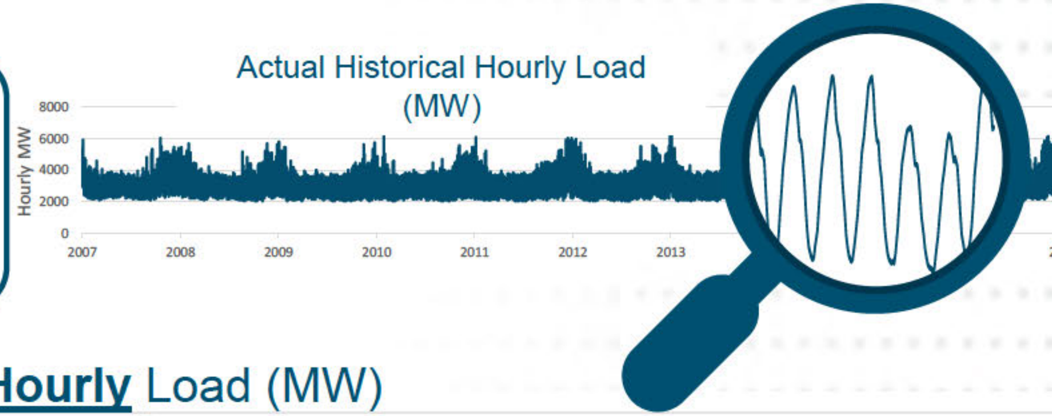


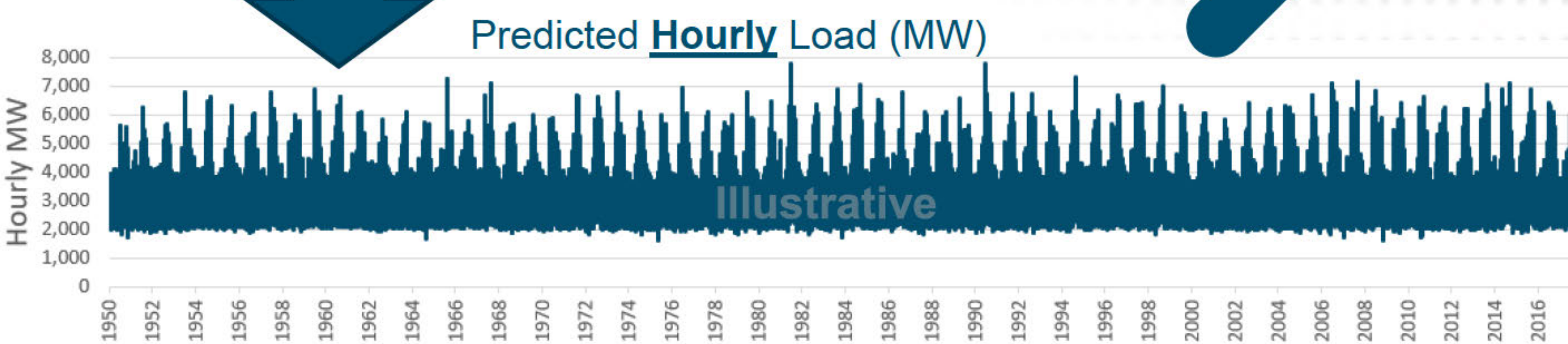
Converting Daily Energy to Hourly Load



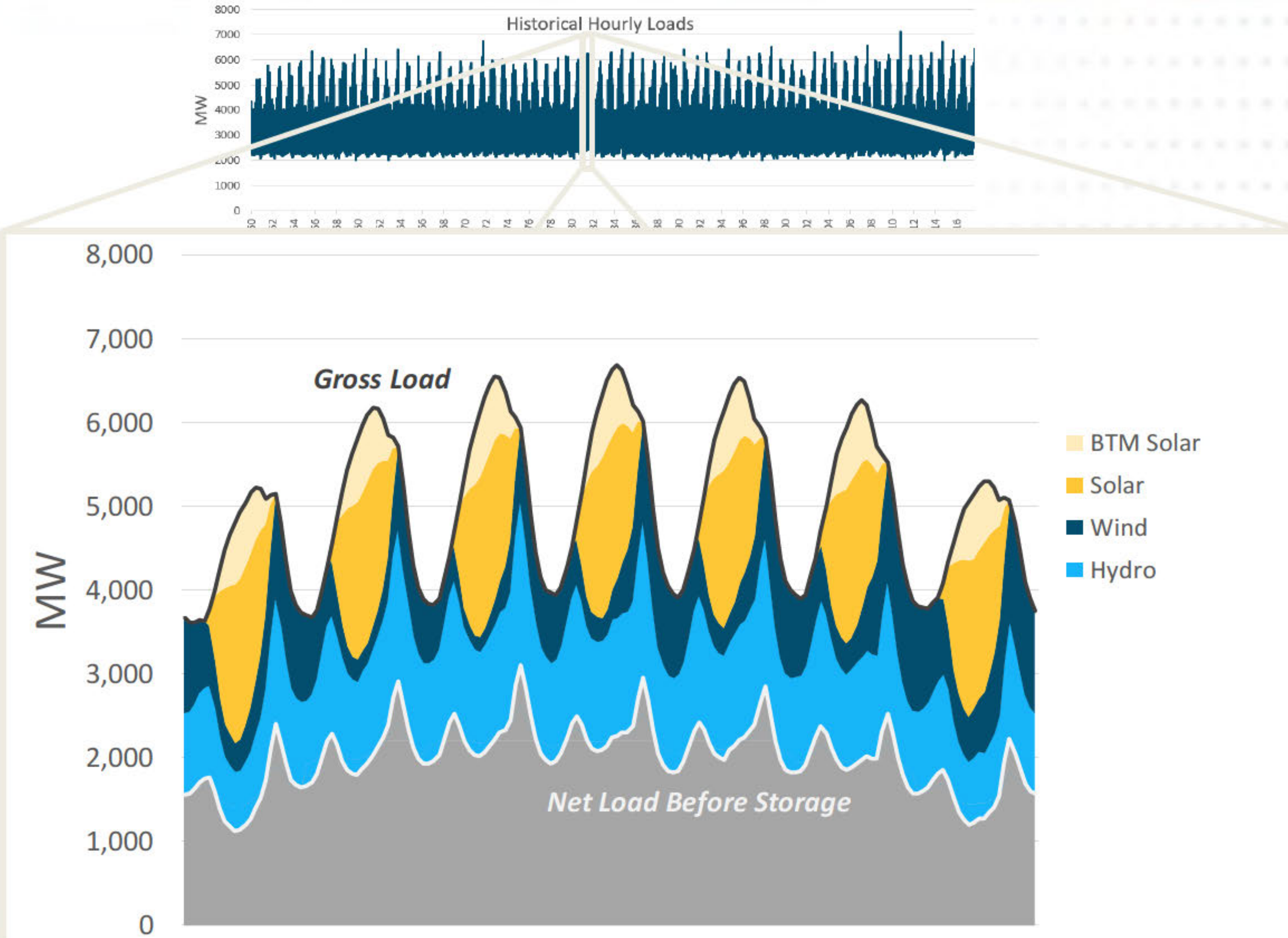
- Convert predicted daily load into hourly load by finding historical day with most similar daily load and using that hourly shape
- Constrained to search over identical day-type within +/-15 days

AUG
Weekday





Calculating Renewable Resources



Energy+Environmental Economics

Predicting Renewable Output

INPUT: example hourly historical renewable production data (solar)

1998	2012
Jan	Dec

OUTPUT: predicted 24-hr renewable output profile for each day of historical load

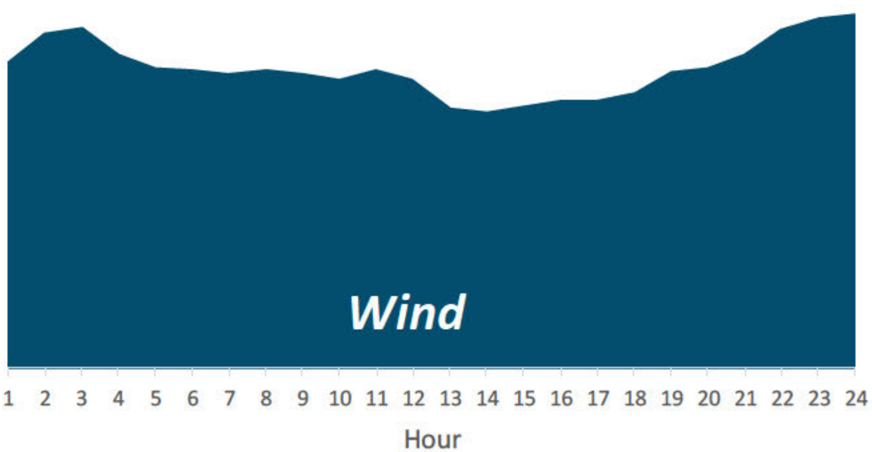
1950	2017
Jan	Sep

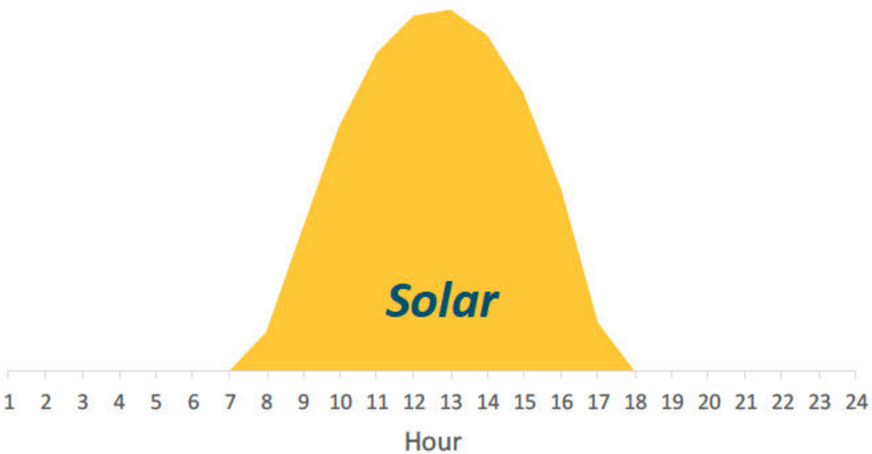
+ **Renewable generation is uncertain, but its output is correlated with many factors**
  - Season
    - Eliminate all days in historical renewable production data not within +/- 15 calendar days of day trying to predict
  - Load
    - High load days tend to have high solar output and can have mixed wind output
    - Calculate difference between load in day trying to predict and historical load in the renewable production data sample
  - Previous day's renewable generation
    - Captures effect of a multi-day heatwave or multi-day rainstorm
    - Calculate difference between previous day's renewable generation and previous day's renewable generation in renewable production data sample

Renewable Profile Output

- **Once a historical date has been randomly selected based on probability, the renewable output profiles from *that day* are used in the model**

Renewable Output Profiles on Aug 12, 1973

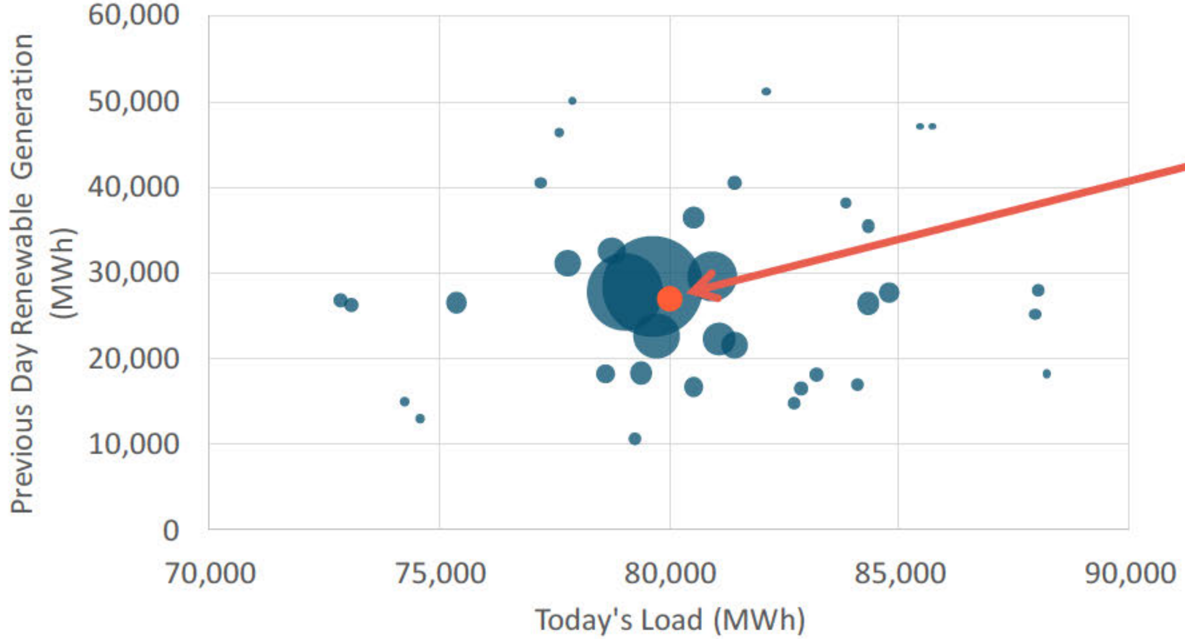




- **Renewable profile development is done in aggregate for each resource type in order to capture correlation between solar generators**

Predicting Renewable Output

- Each blue dot represents a day in the historical sample
- Size of the blue dot represents the probability that the model chooses that day



Aug 12, 1973	
Daily Load	80,000 MWh
Previous-Day Renewable Generation	27,000 MWh

Probability Function Choices

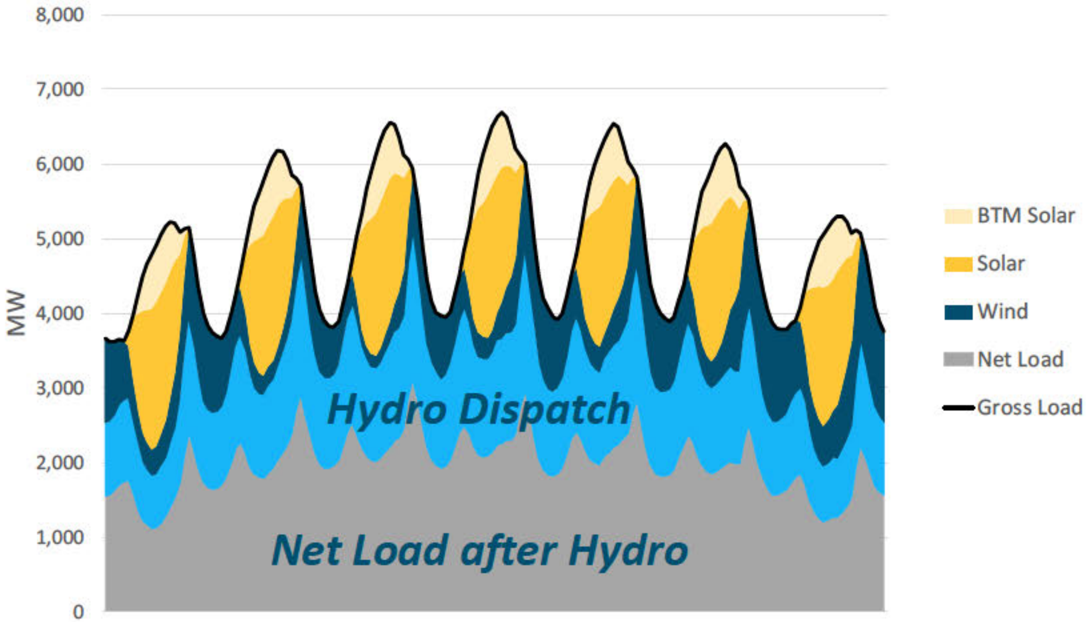
- Inverse distance
- Square inverse distance
- Gaussian distance
- Multivariate normal

Probability of sample i being selected $= \dfrac{\dfrac{1}{Distance_i}}{\sum_{j=1}^{n} \dfrac{1}{Distance_j}}$

Where $distance_i$ $= abs[load_{Aug\ 12} - load_i]/stderr_{load} + abs[renew_{Aug\ 12} - renew_i]/stderr_{renew}$

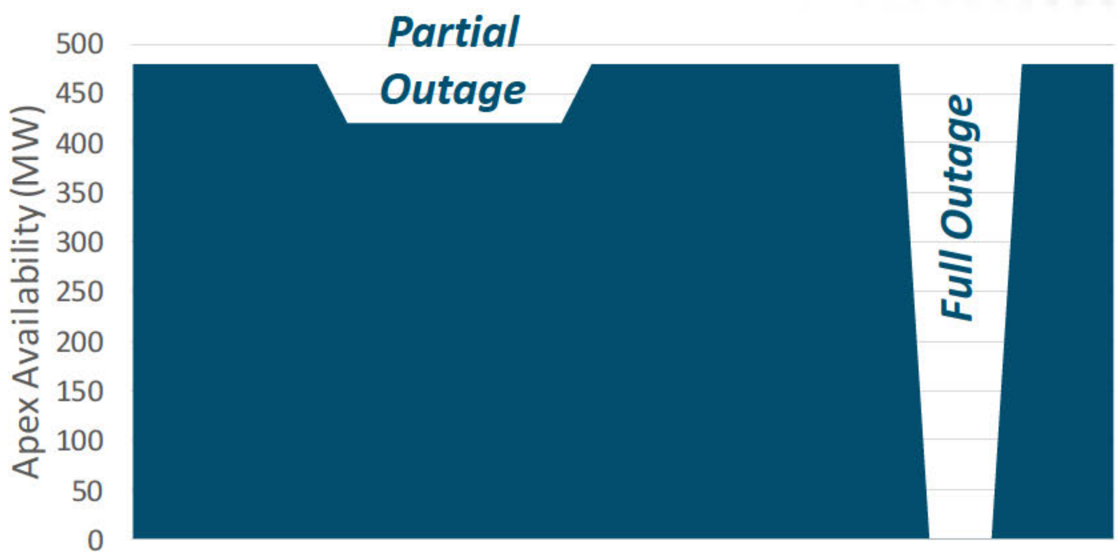
Hydro Dispatch

- Predicted renewable generation is subtracted from gross load to yield net load for each historical day
- Historical hydro MWh availability is allocated to each month based on historical hydro record
- Hydro availability is allocated evenly across all days in the month
- Hydro dispatches proportionally to net load subject to Pmin and Pmax constraints



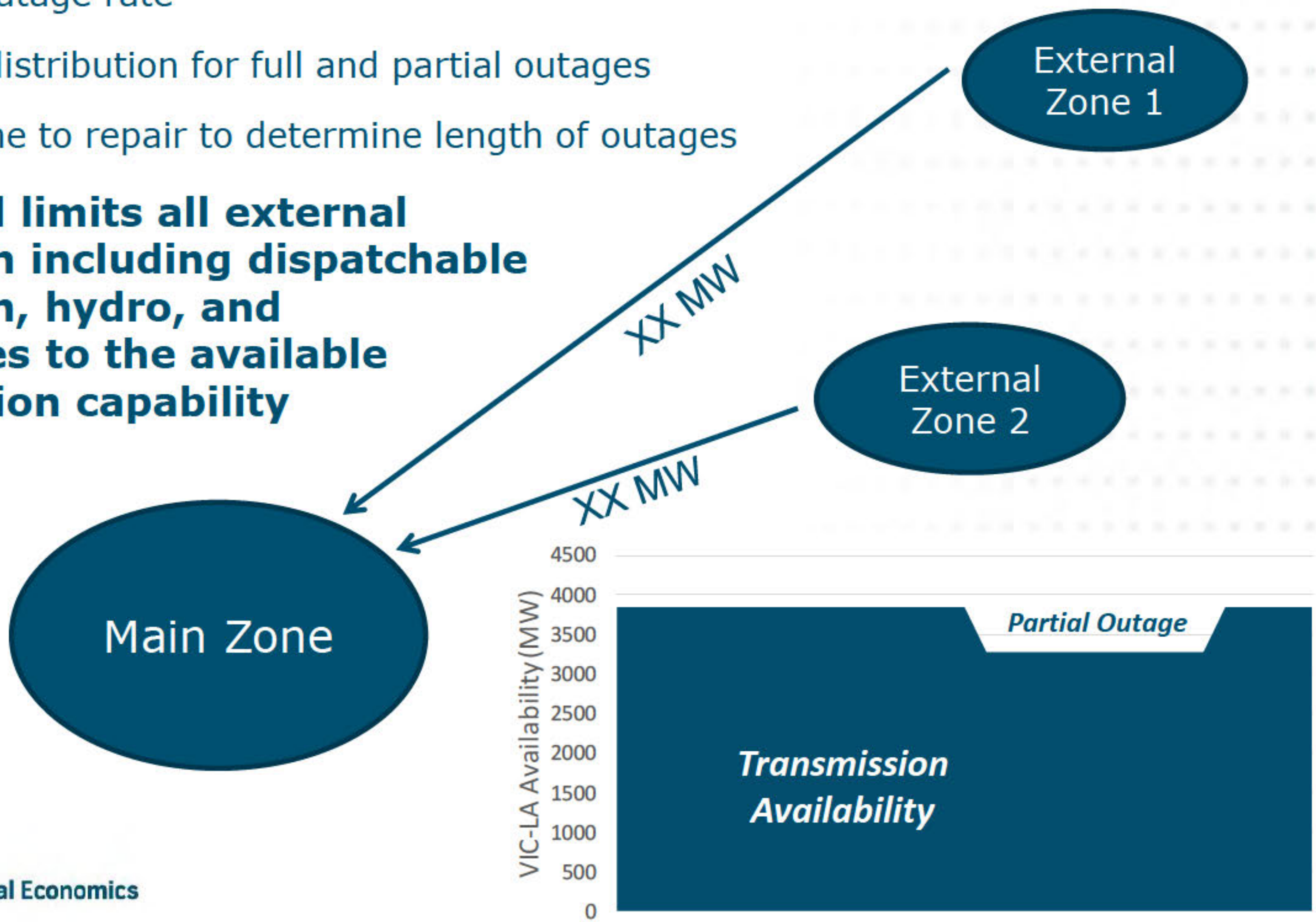
Available Generation

- For all dispatchable generation, the model uses the net dependable capacity of the generator
- Using the forced outage rate of each generator, random outages are introduced to create a stochastic set of available generators
- Outage distribution functions are used to simulate full and partial outages
- Mean time to repair functionalizes whether there are more smaller duration outages or fewer longer duration outages
- This is done independently for each generator and then summed across all generators



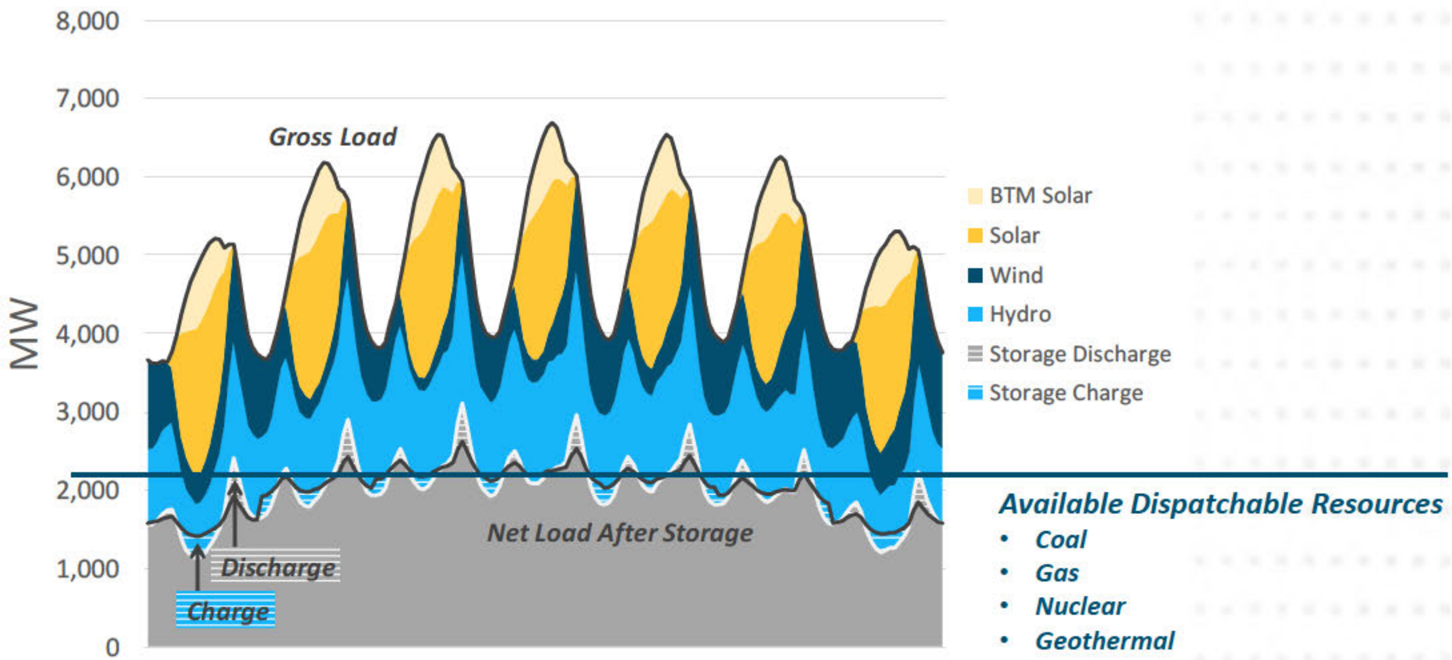
Transmission

- **The model uses identical logic as for generators to determine available capacity on each transmission 'line' into the main zone**
  - Forced outage rate
  - Outage distribution for full and partial outages
  - Mean time to repair to determine length of outages
- **The model limits all external generation including dispatchable generation, hydro, and renewables to the available transmission capability**



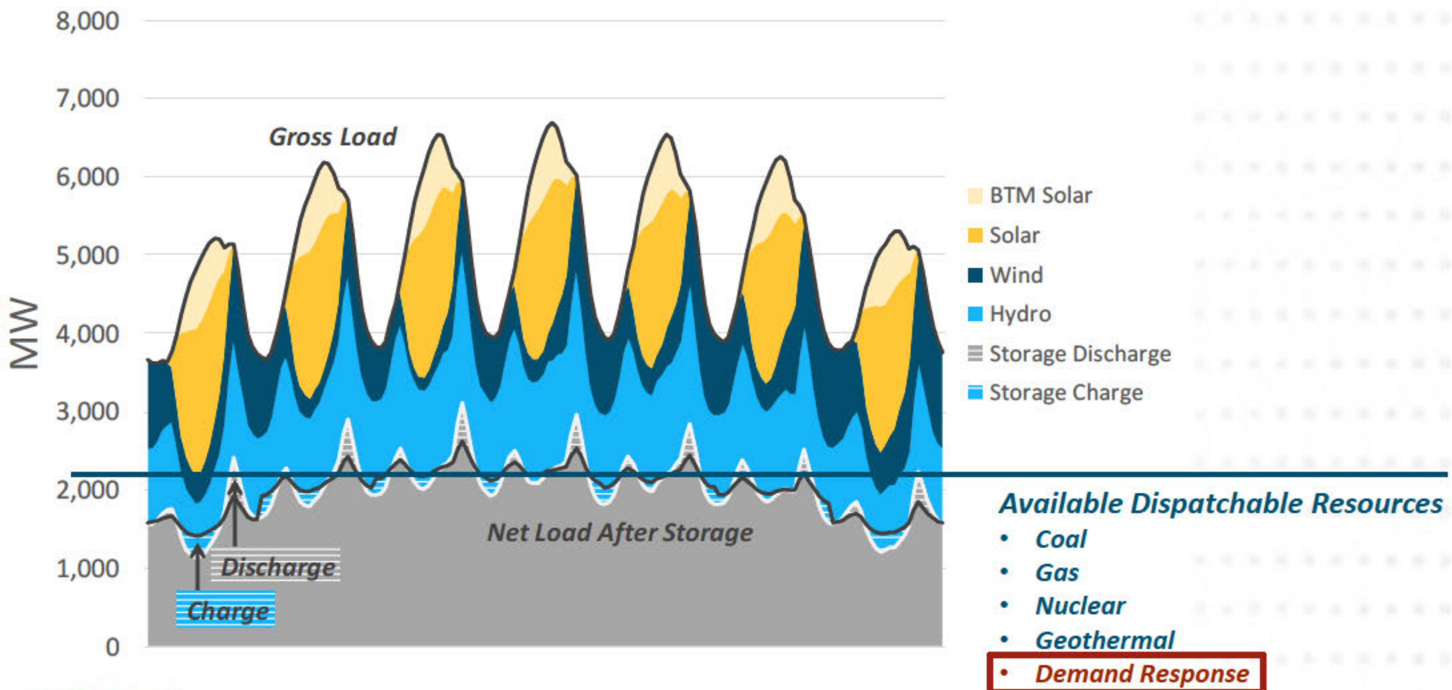
Storage

- Storage is dispatched for reliability purposes only in this model
- When net load is greater than available generation, storage always discharges if state of charge is greater than zero
- When net load is less than zero storage always charges
- When net load is greater than zero, storage charges from dispatchable generation if state of charge is below 100% (or other user specified threshold)



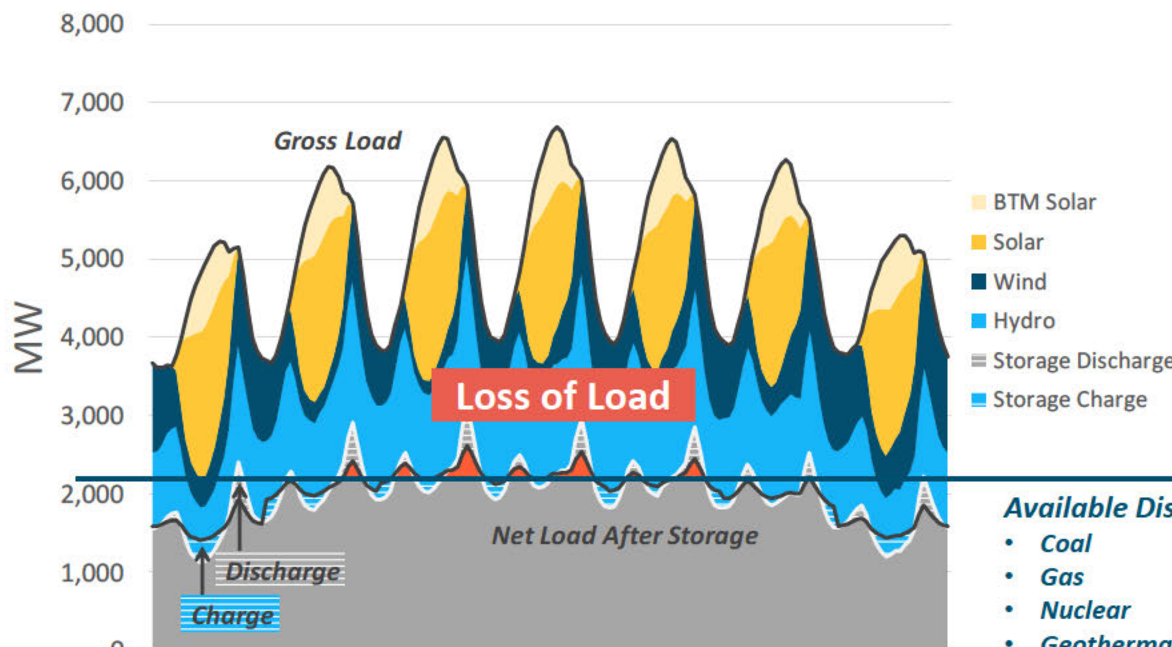
Demand Response

- Demand response is treated as the dispatchable resource of last resort – if net load after storage is greater than available dispatchable resources it is added to available resources
- Each DR resource has prescribed number of hours with a limited quantity of available calls per year



Calculating Loss of Load

- Any residual load that cannot be served from all available resource is counted as lost load
- Loss of load expectation (LOLE) is the number of hours of lost load per year



Available Dispatchable Resources

- ***Coal***
- ***Gas***
- ***Nuclear***
- ***Geothermal***
- ***Demand Response***

Thank You!

Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
Web http://www.ethree.com

Arne Olson, Senior Partner (arne@ethree.com)
Zach Ming, Managing Consultant (zachary.ming@ethree.com)

UE 358

Attachment 026-B

Provided in Electronic Format

Full Resource Adequacy Study

Resource Adequacy in the Pacific Northwest

March 2019

Energy+Environmental Economics

Resource Adequacy in the Pacific Northwest

March 2019

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
415.391.5100
www.ethree.com

Project Team:
Zach Ming
Arne Olson
Huai Jiang
Manohar Mogadali
Nick Schlag

Table of Contents

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;

- 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.

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.

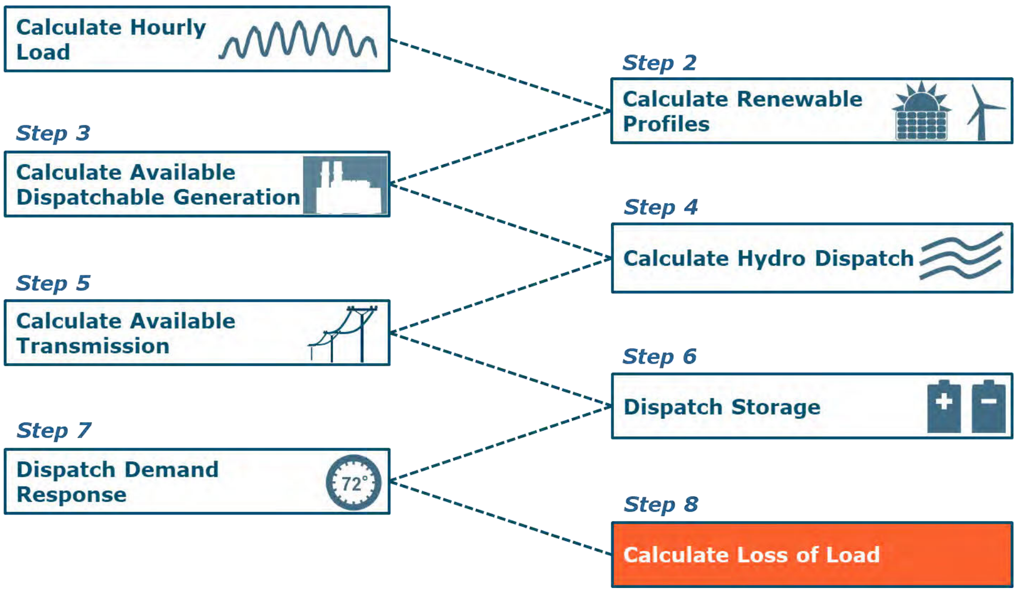
RECAP was specifically designed to calculate the reliability of electric systems operating under high penetrations of renewable energy and storage. Correlations enforced within the model capture linkage among load, weather, and renewable generation conditions. Time-sequential simulation tracks the state 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.

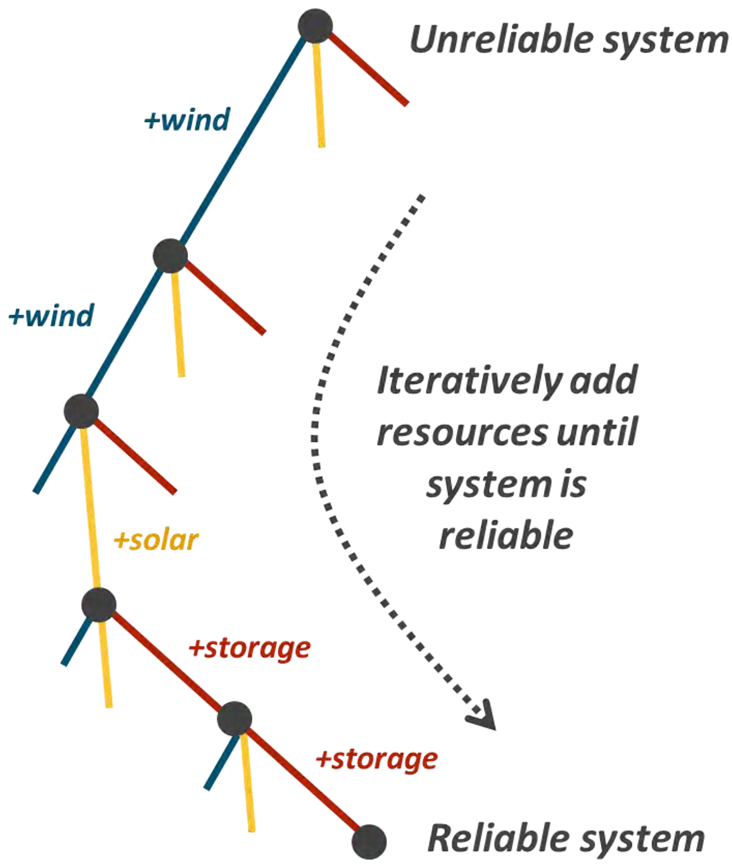
To develop each 2050 decarbonization portfolio, RECAP calculates the reliability of the system in 2050 after forecasted load growth and the removal of all fossil generation but the maintenance of all existing carbon-free resources. Unsurprisingly, these portfolios are significantly less reliable than 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.

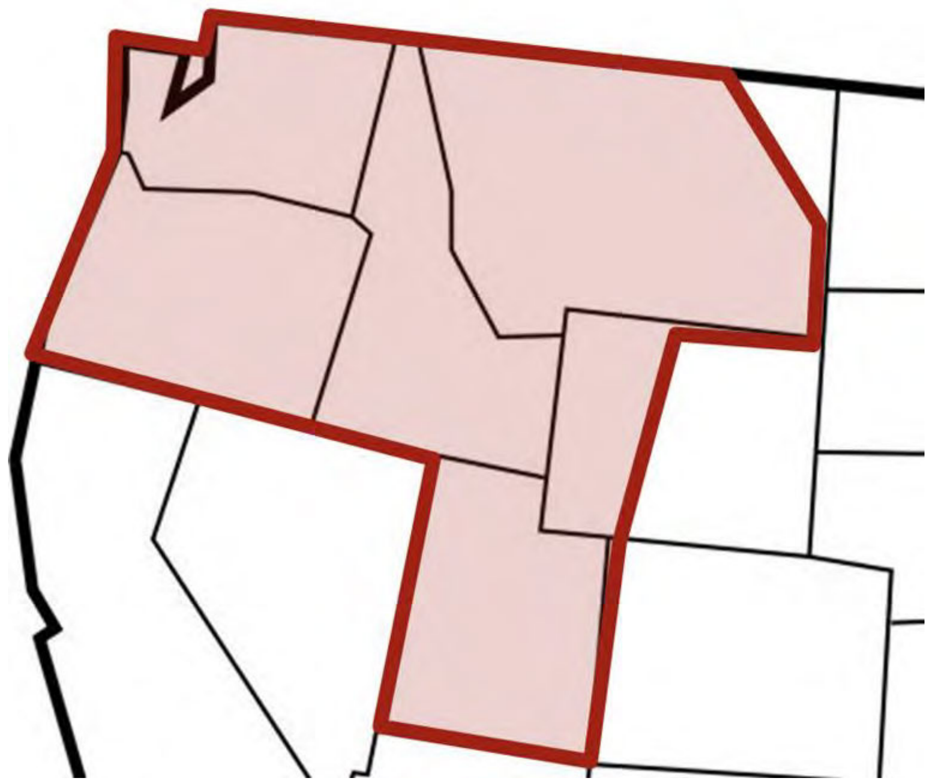
Figure 2: RECAP Portfolio Development Process



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

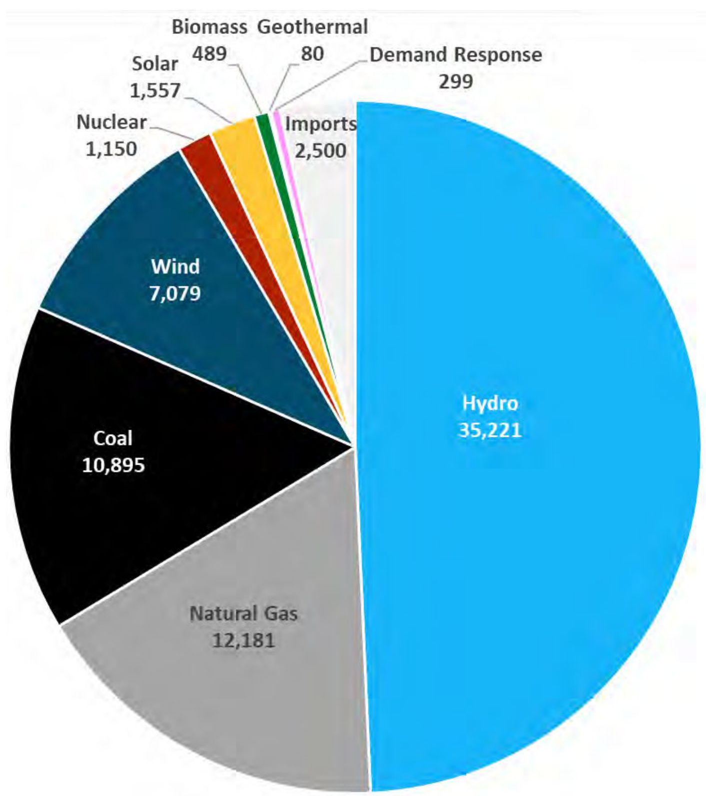
4.2 Existing Resources

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

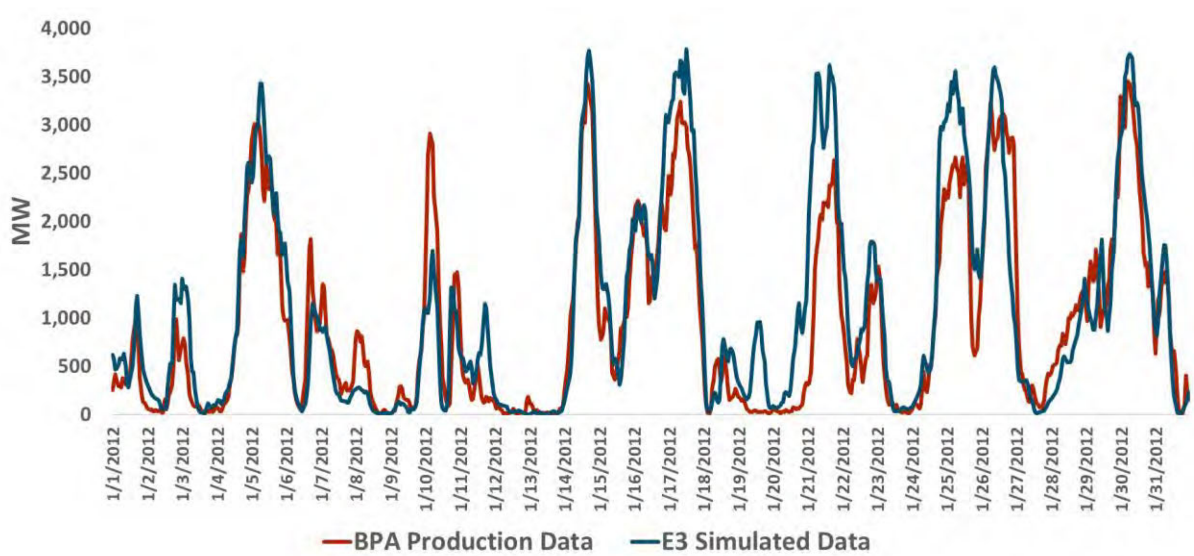
Hourly wind and solar data were collected for each existing resource in the combined dataset at the location of the resource. For wind, NREL's Wind Integration National Dataset Toolkit was used which includes historical hourly wind speed data from 2007-2012. For solar, NREL's Solar Prospector Database 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)

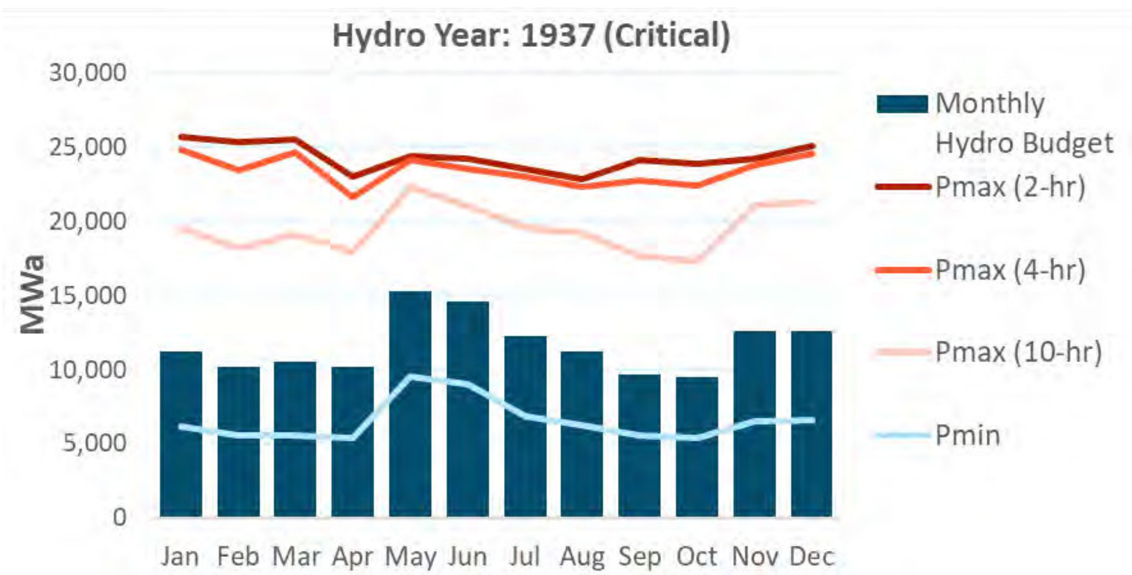


Figure 8: Monthly budgets, sustained peaking limits and minimum outputs levels for 1996 (high hydro)

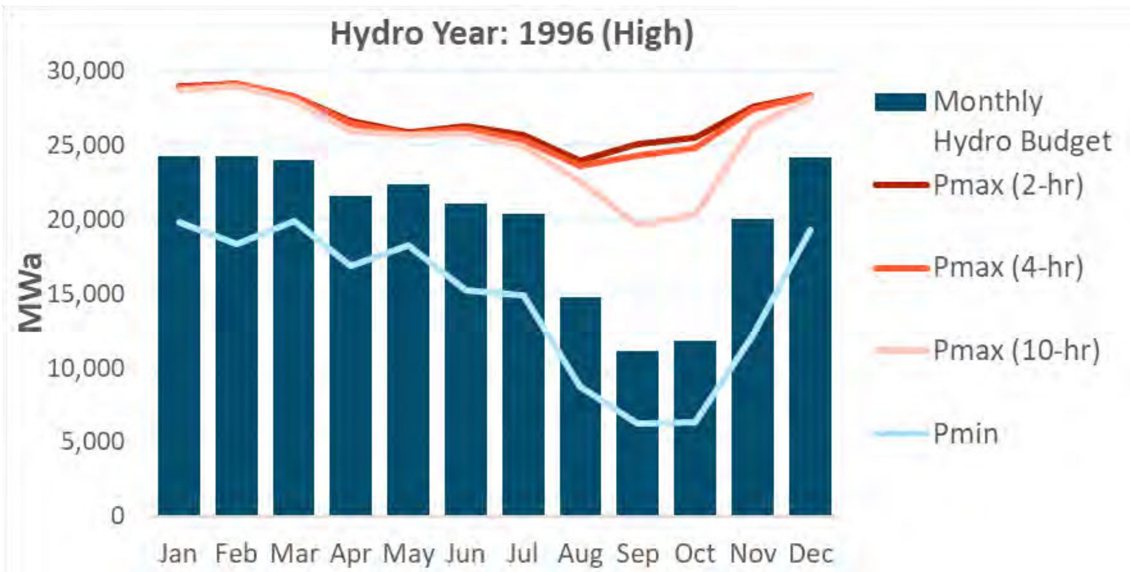
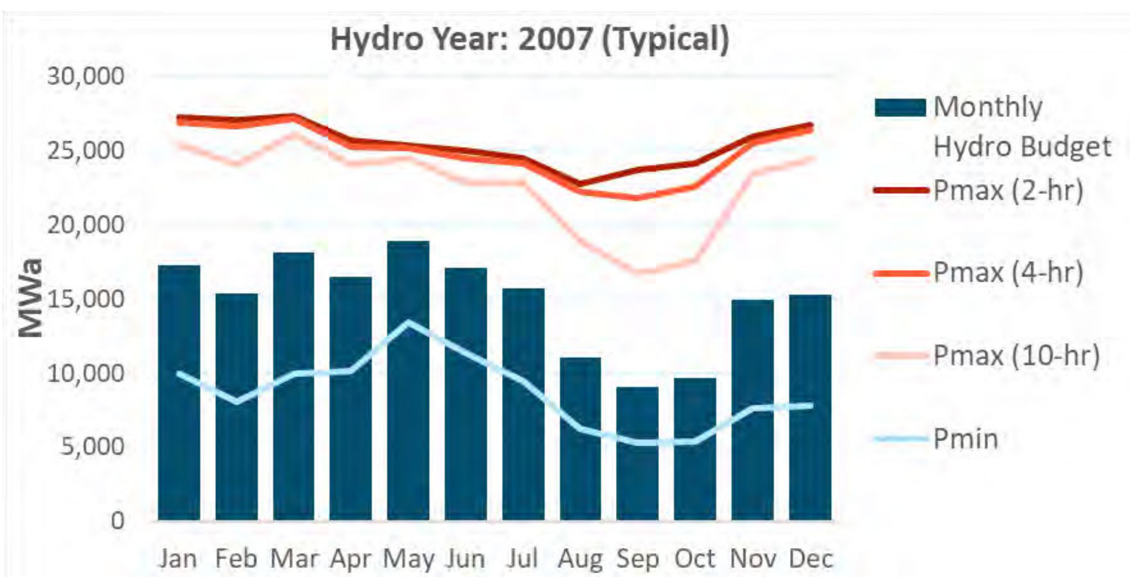


Figure 9: Monthly budgets, sustained peaking limits and minimum outputs levels for 2007 (typical hydro)



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**

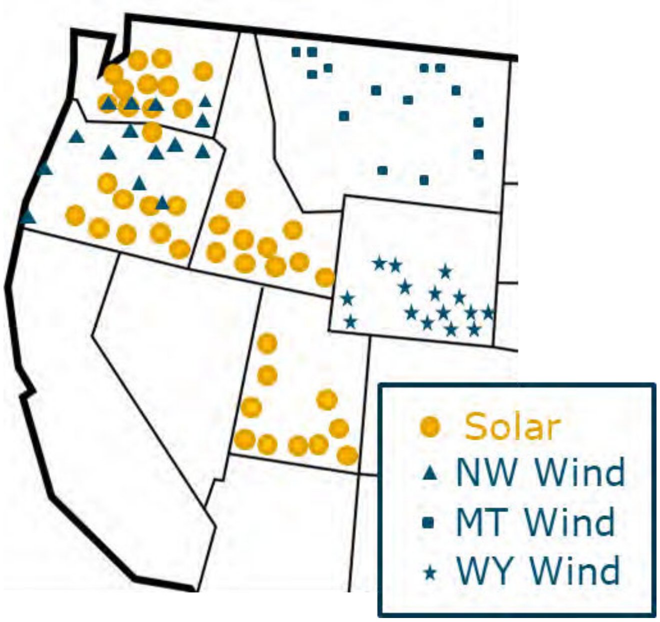
4.3 Candidate Resources

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.

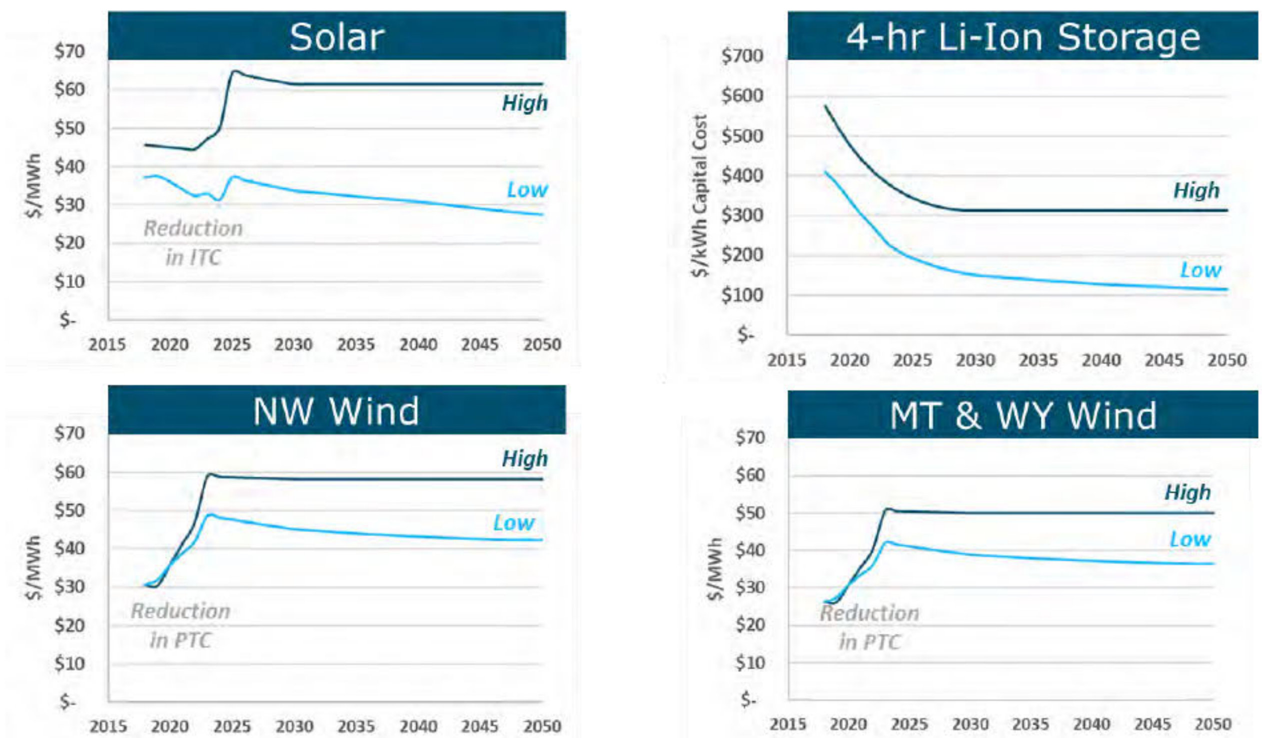
Table 12. Resource Cost Assumptions (2016 $)

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

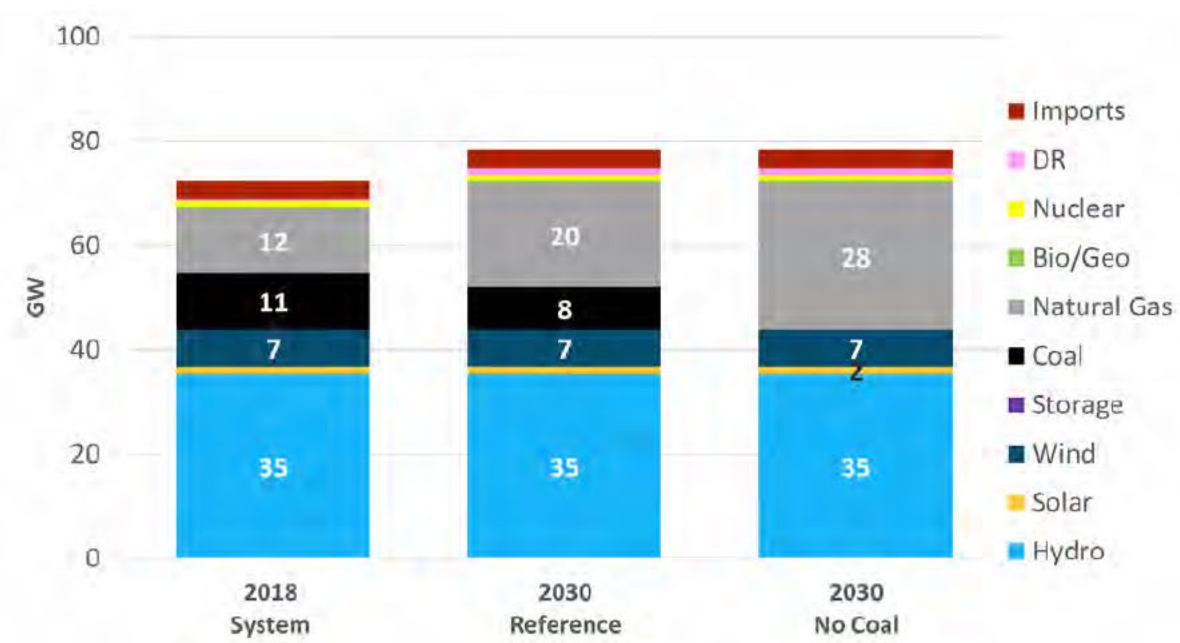


Table 15. 2030 Generation Portfolio: Key Metrics

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

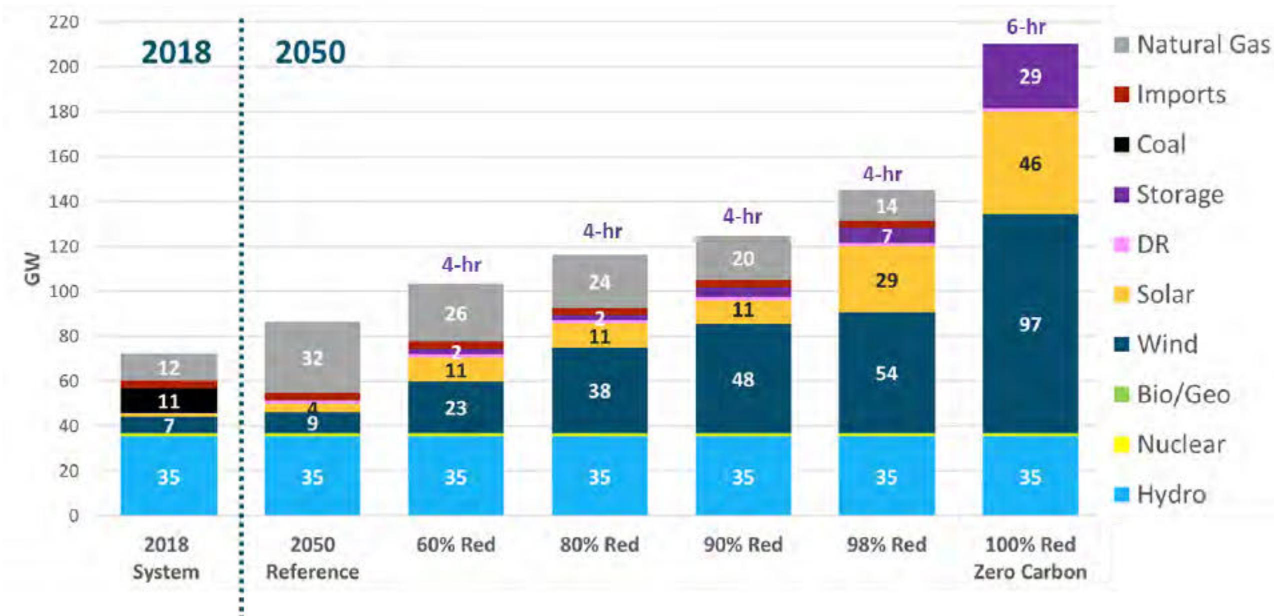


Table 17. 2050 Decarbonization Scenarios: Key Generation Metrics

Metric	Units	Reference Scenario	GHG Reduction Scenarios: 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.

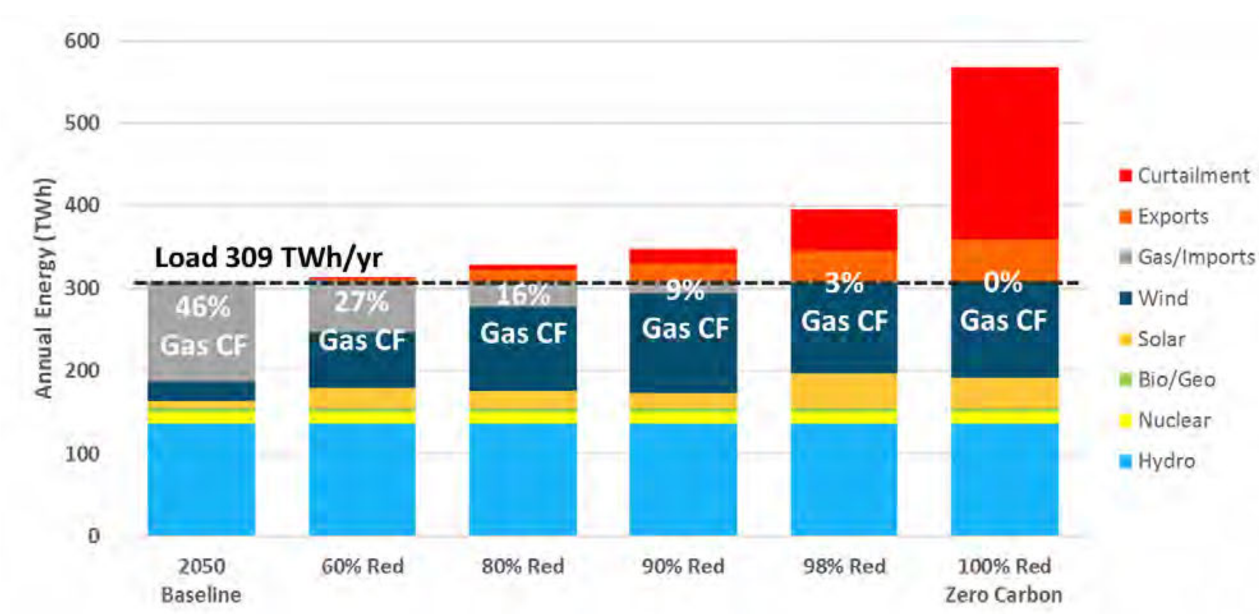
Analyzing the portfolio of each decarbonization scenario and resulting performance metrics yields several interesting observations.

+ 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 (*vs. Ref*)	—	$0	$1	$2	$3	$16
	Hi			$2	$4	$5	$9	$28
Unit Cost Increase	Lo	$/MWh (*vs. Ref*)	—	$0	$3	$5	$10	$52
	Hi			$7	$14	$18	$28	$89

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

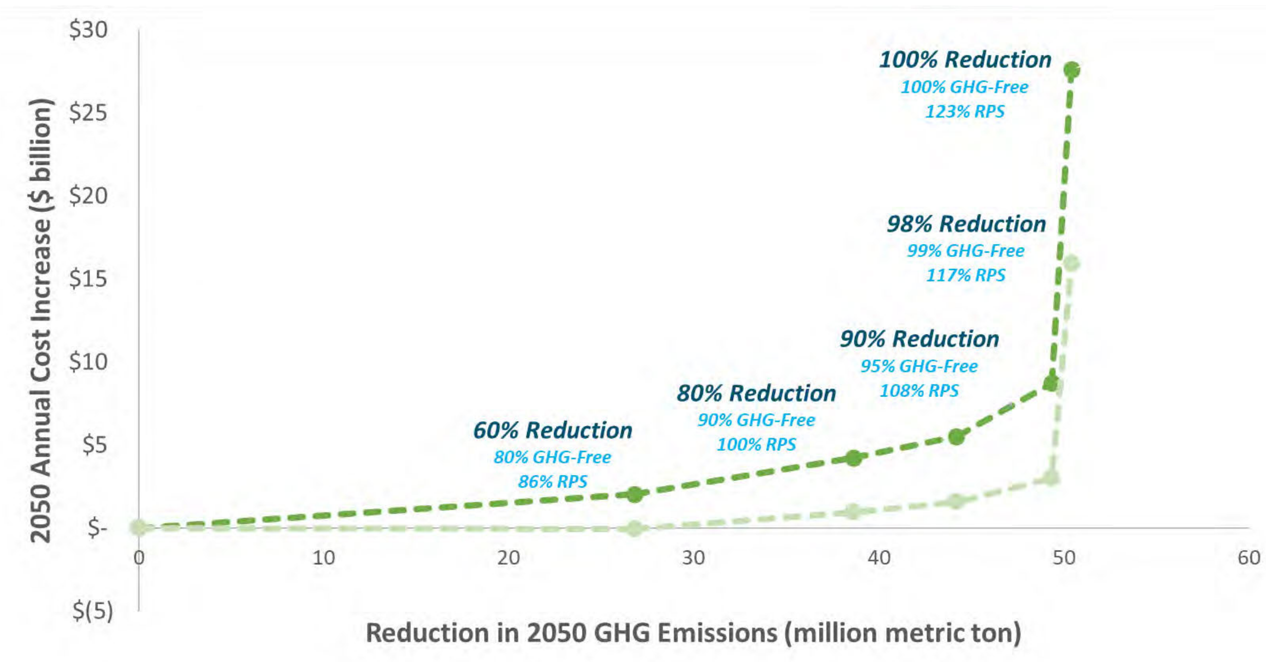
+ To reduce GHG emissions to 80% below 1990 levels, a portfolio of wind/solar/storage can be obtained at an additional annual cost of $1 to $4 billion ($3 to $14/MWh) after accounting for the avoided costs of new gas build and utilization. Assuming an existing average retail rate of $0.10/kWh, this implies 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

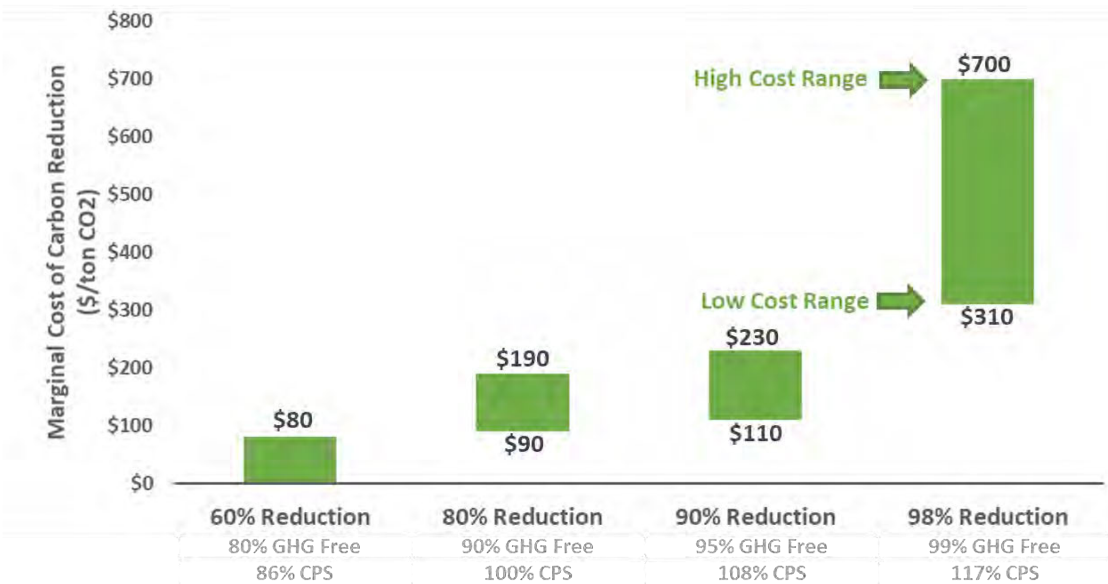
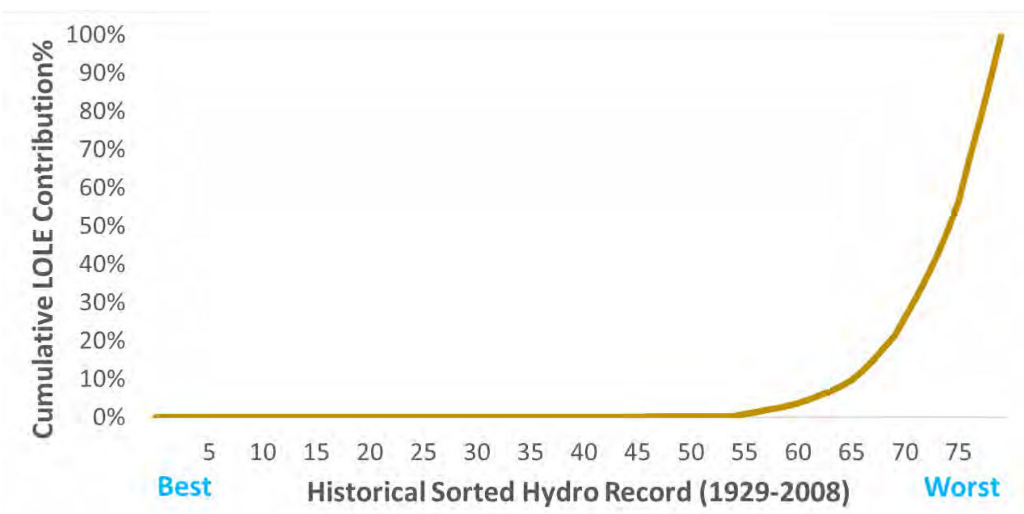


Figure 17: Marginal Cost of GHG Reduction: 60% Reduction to 100% Reduction

5.3.3 DRIVERS OF RELIABILITY CHALLENGES

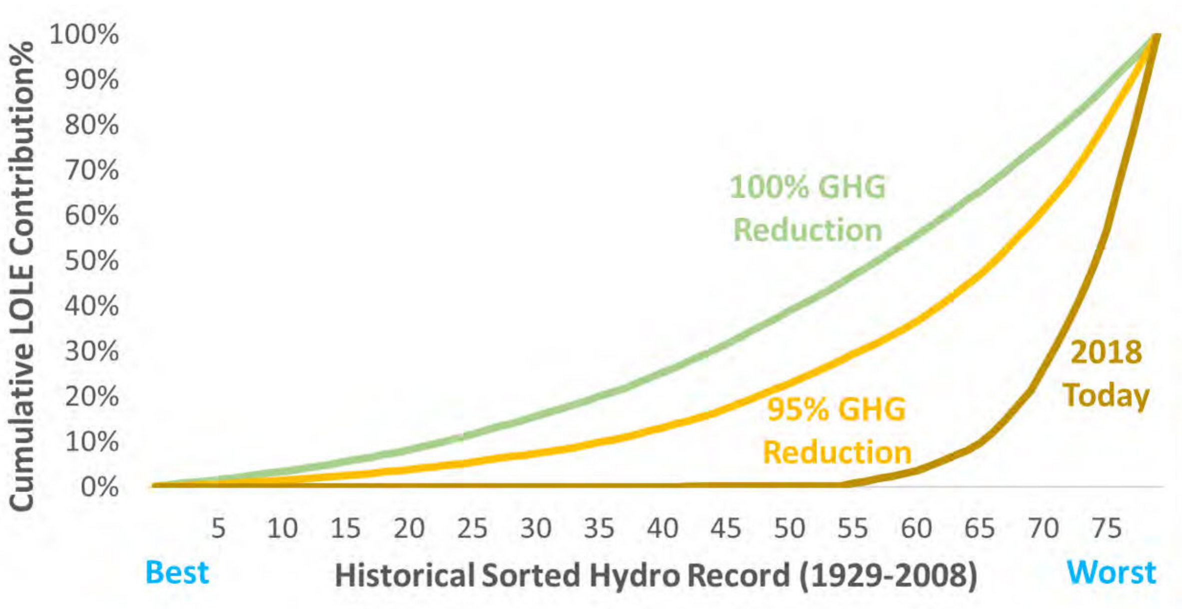
The major drivers of loss of load in the Greater Northwest system include high load events, prolonged low renewable generation events, and drought hydro conditions. In today's system where most generation is dispatchable, prolonged low renewable generation events do not constitute a large cause of loss-of-load 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



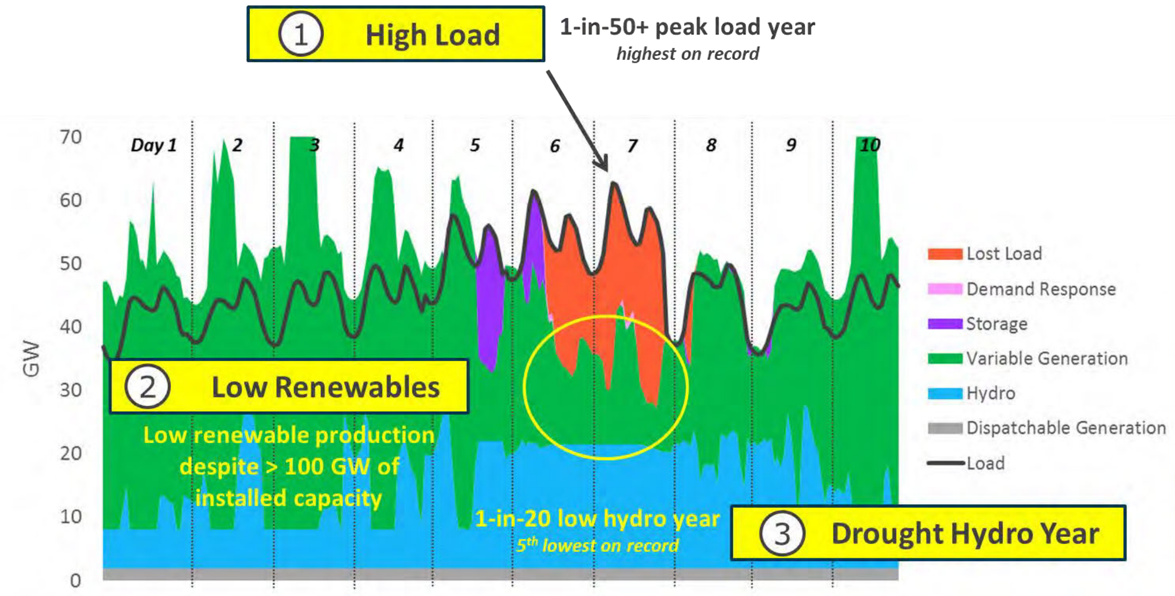
At very high renewable penetrations, in contrast, prolonged low renewable generation events usurp drought hydro conditions as the primary driver of reliability challenges. Figure 19 shows that at high levels of GHG reductions, loss-of-load is much less concentrated in the worst hydro years as prolonged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

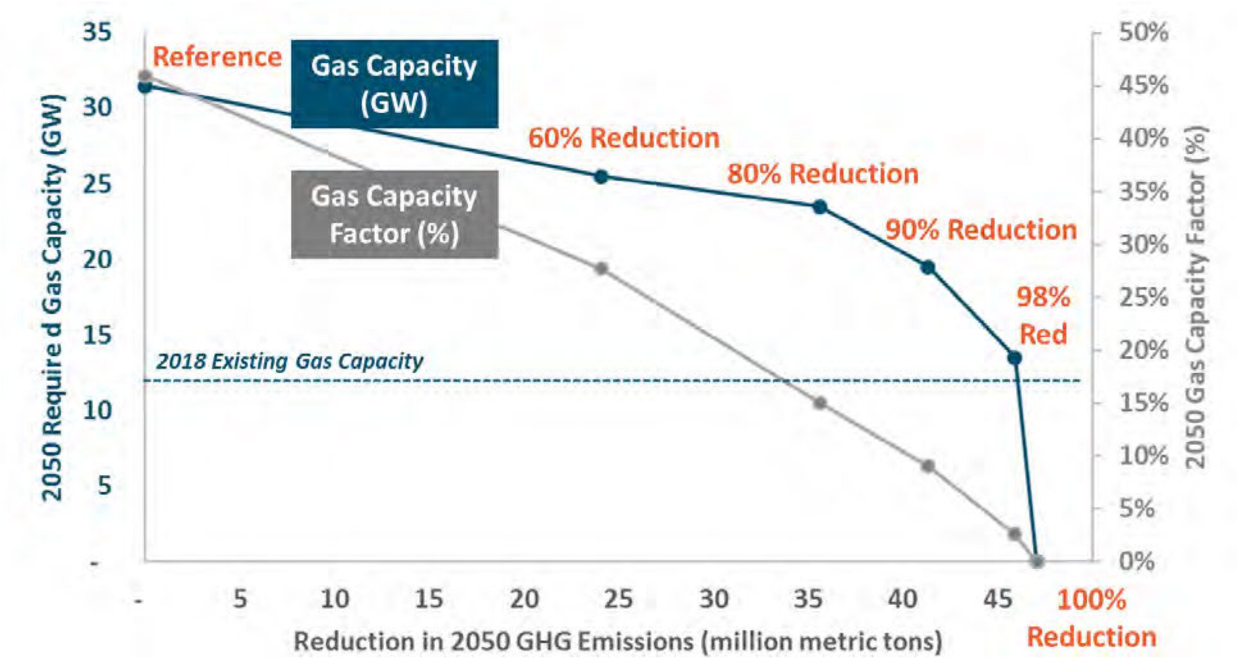
Figure 20: Loss-of-load Example in a Sample Week



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



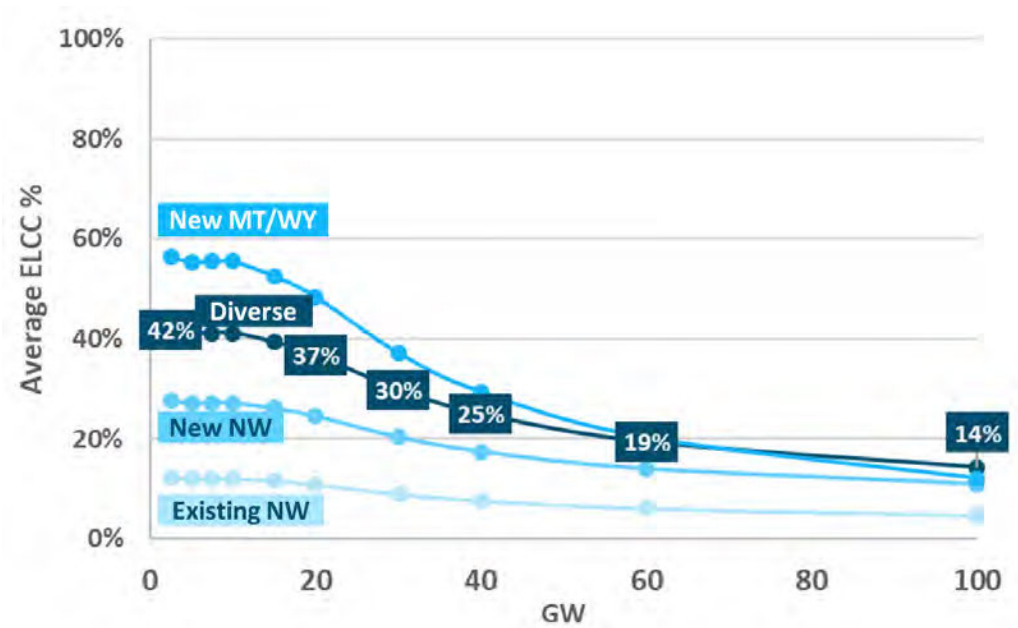
5.3.5 EFFECTIVE LOAD CARRYING CAPABILITY

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

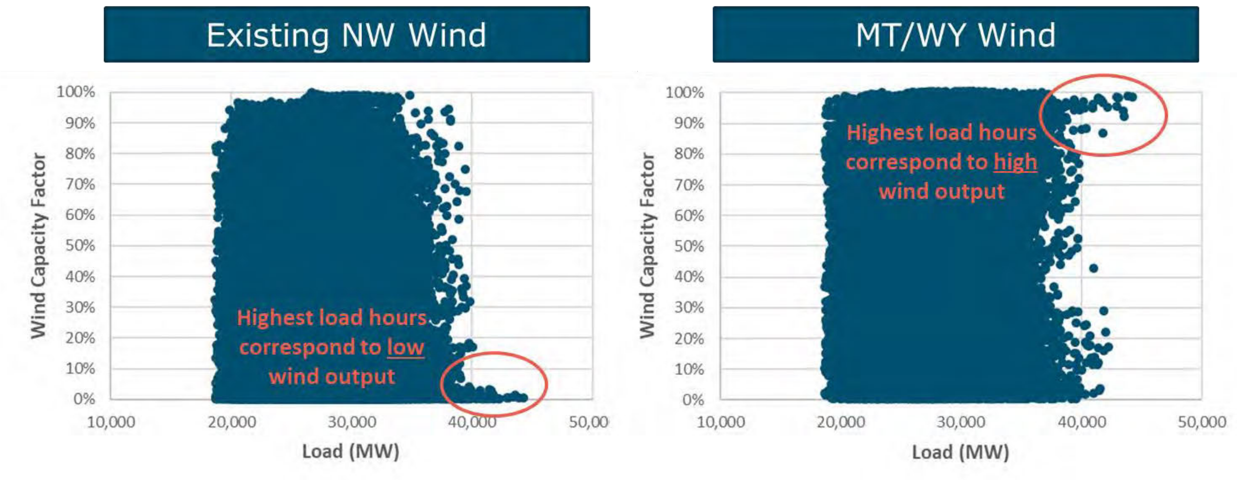
Wind resources in this study are grouped and represented as existing Northwest (Oregon and Washington) wind, new Northwest wind, and new Wyoming and Montana wind. The ELCC curves of each representative wind resource and as well as the combination of all three resources (i.e., "Diverse") are shown in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

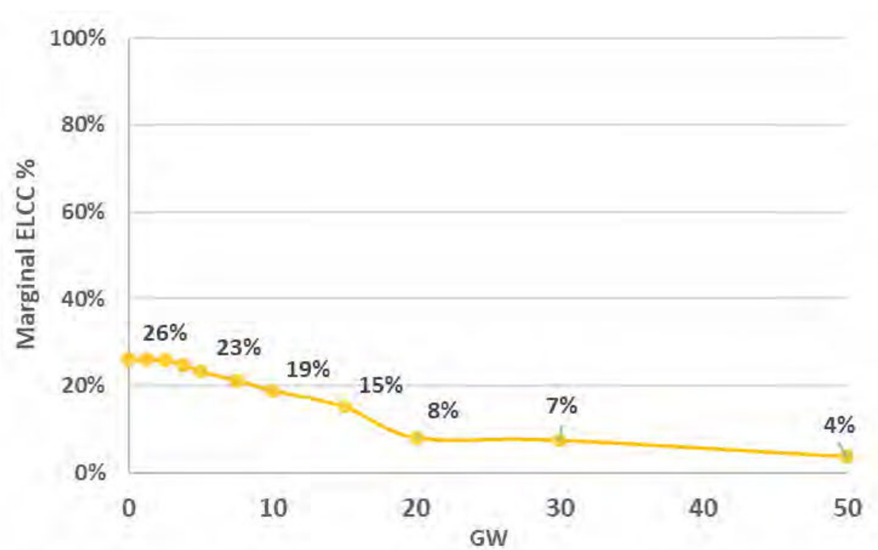
- The wide discrepancy between the "worst" wind resource (existing NW) and the "best" wind resource (new MT/WY) is primarily driven by the correlation of the wind production and peak load events in Washington and Oregon. Existing NW wind is almost entirely located within the Columbia River Gorge which 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.

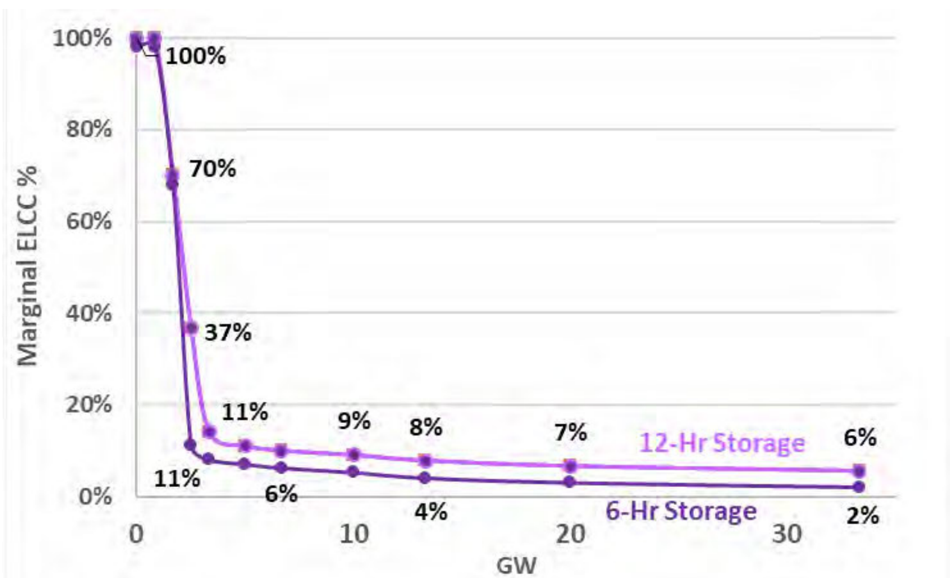
Figure 24: Solar ELCC at Various Penetrations



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

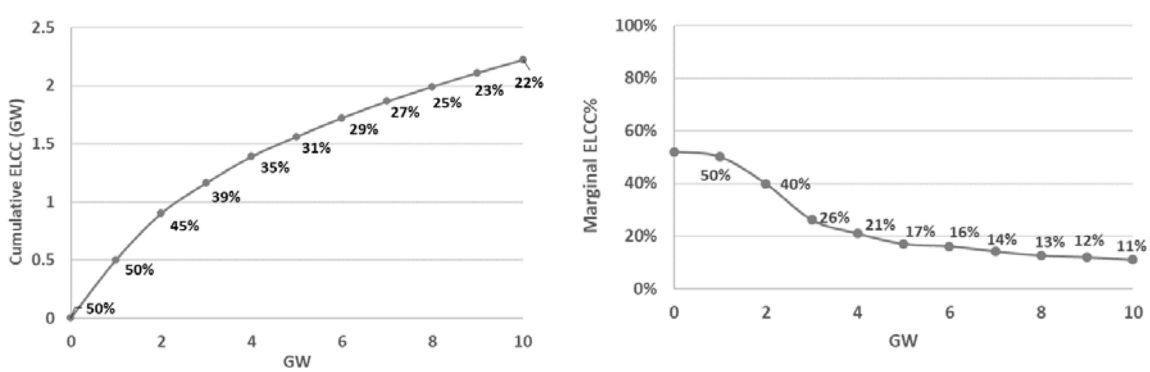


Figure 26 shows the cumulative and marginal ELCC of DR at increasing levels of penetration. Due to the limitations on the number of calls and duration of each call, DR has an initial ELCC of approximately 50%. Similar to energy storage, conventional 4-hour DR has less value in the Pacific Northwest than 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

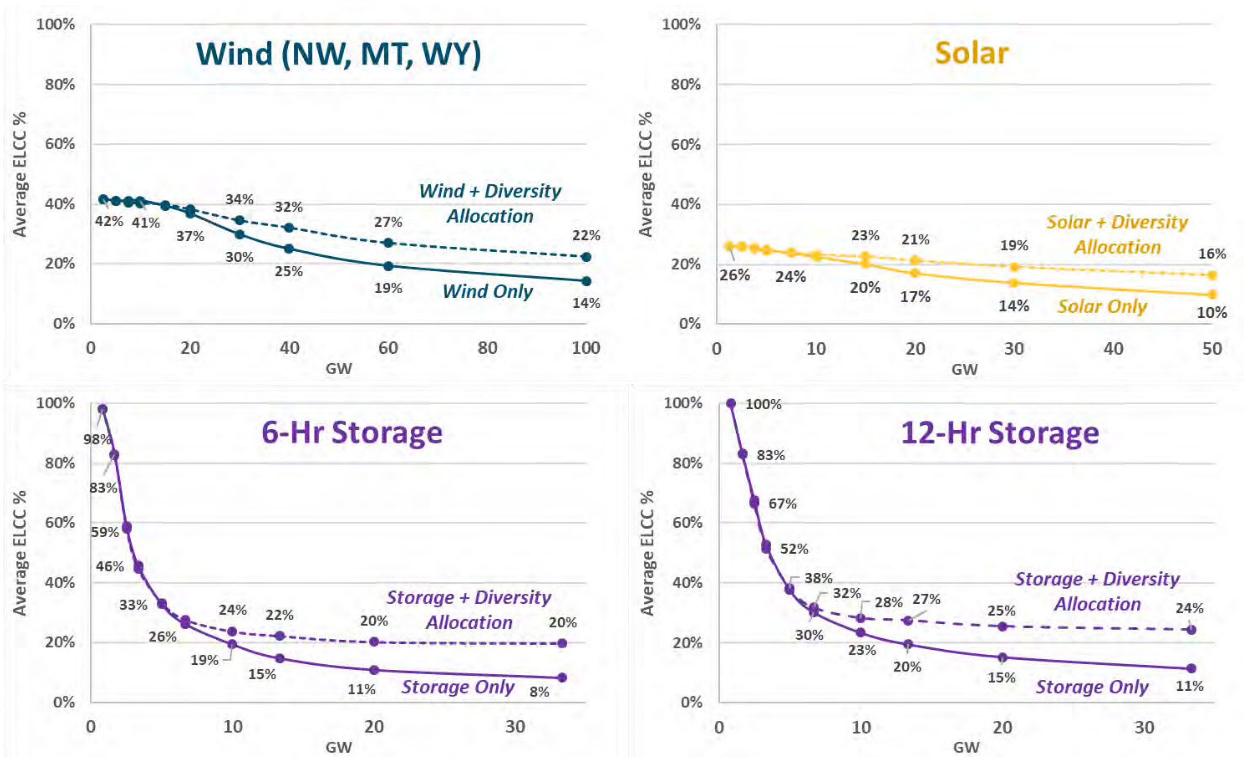
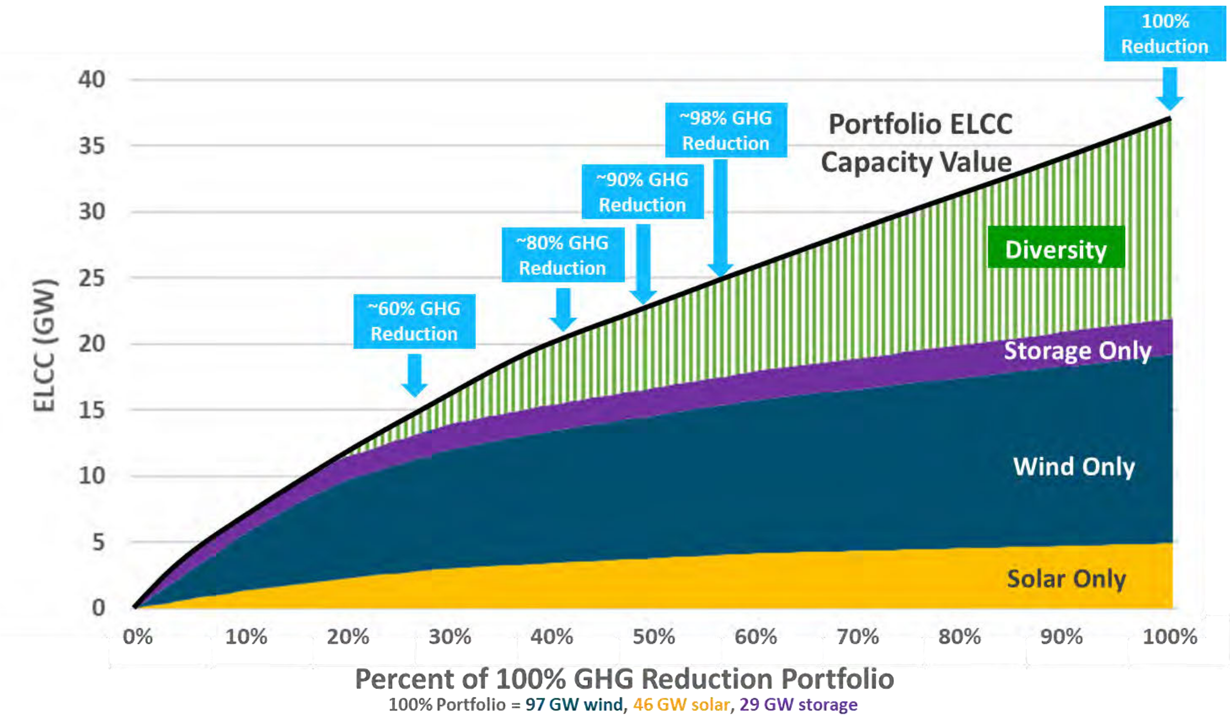


Figure 28 presents the cumulative portfolio ELCC of wind, solar, and storage up to the penetrations required to reliably serve load in a 100% GHG Reduction scenario. At high penetrations of renewables and storage, most of the ELCC is realized through diversity, although it still requires approximately 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

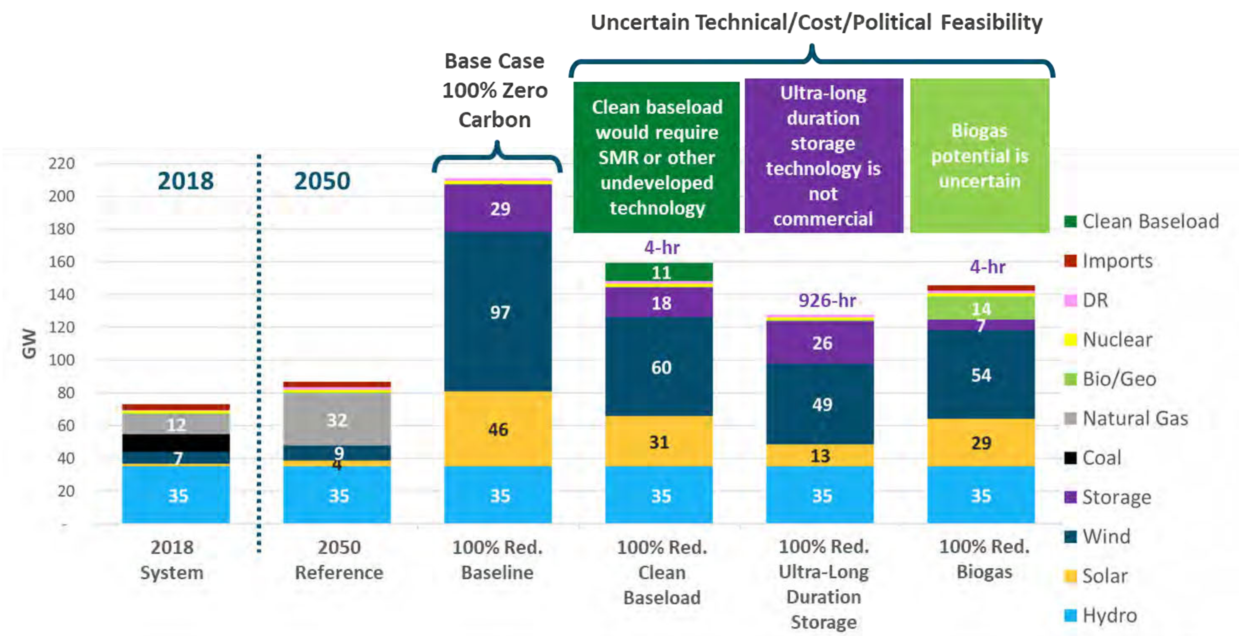
This study also explores the potential resource adequacy needs of a 100% GHG free electricity system recognizing that emerging technologies beyond wind, solar, and electric energy storage that are not yet available today may come to play a significant role in the region's energy future. Specifically, 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.

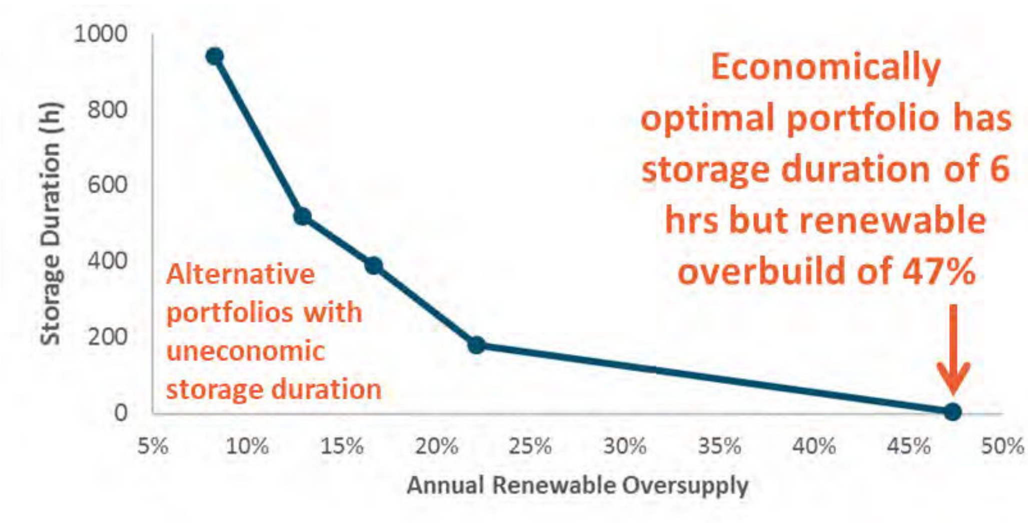
Table 22. 100% GHG Reduction Sensitivity Key Cost Metrics

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

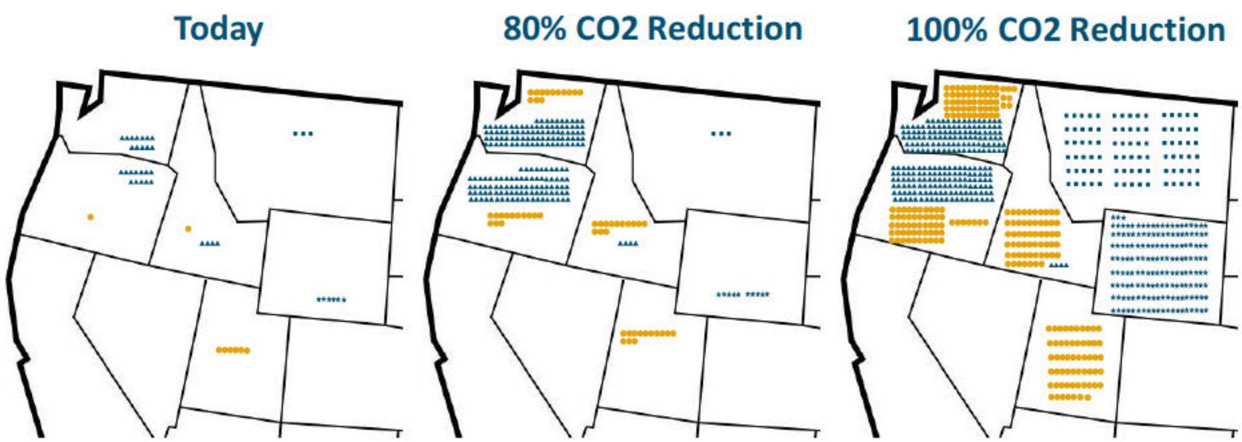
[20] Total land use is defined as the project footprint as a whole and is the more commonly cited land-use metric associated with wind plants. They vary with project and hence as presented as a range

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.

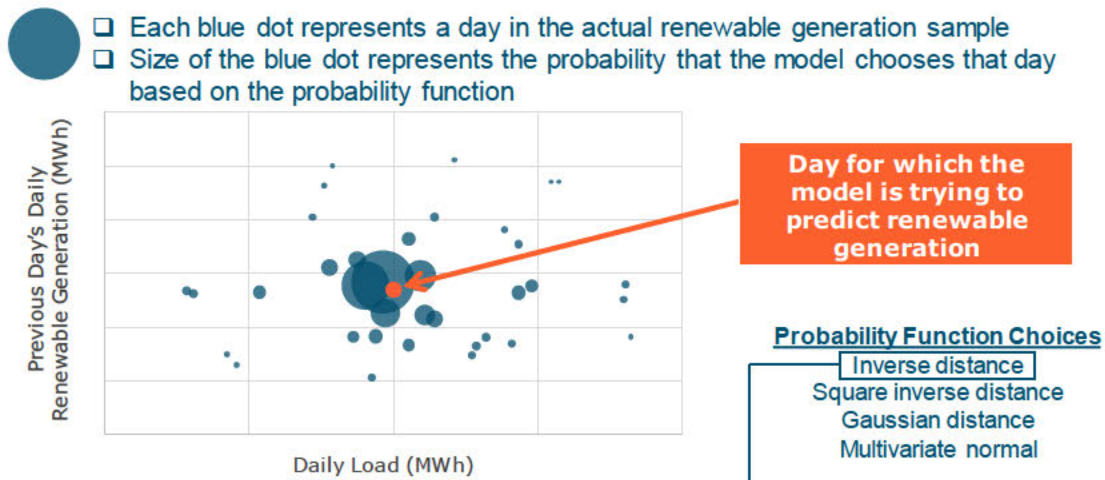
A stochastic process was used to match the available renewable profiles with historical weather years using the observed relationship for years with overlapping data i.e., years with available renewable data. For each day in the historical load profile (1948-2017), the model stochastically selects a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



Probability of sample i being selected $= \dfrac{\frac{1}{Distance_i}}{\sum_{j=1}^{n} \frac{1}{Distance_j}}$ Where $\text{distance}_i = \text{abs}[\text{load}_{\text{Aug 12}} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug 12}} - \text{renew}_i]/\text{stderr}_{\text{renew}}$

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.

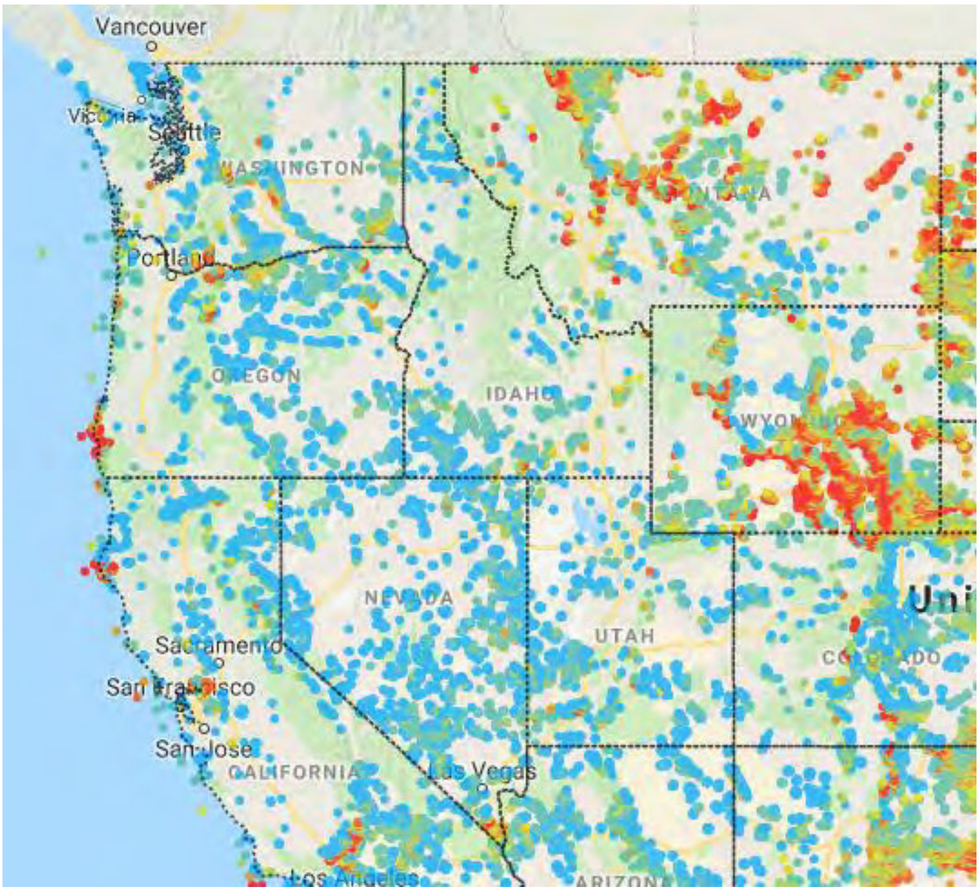
C.1 Wind Profiles

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).

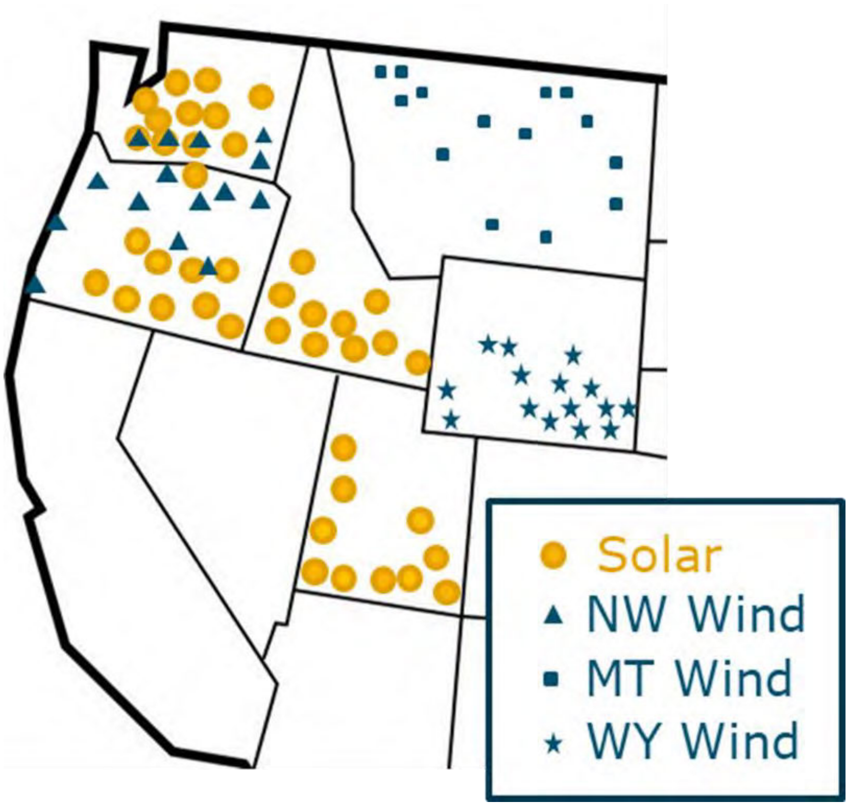
[24] https://maps.nrel.gov/wind-prospector/

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

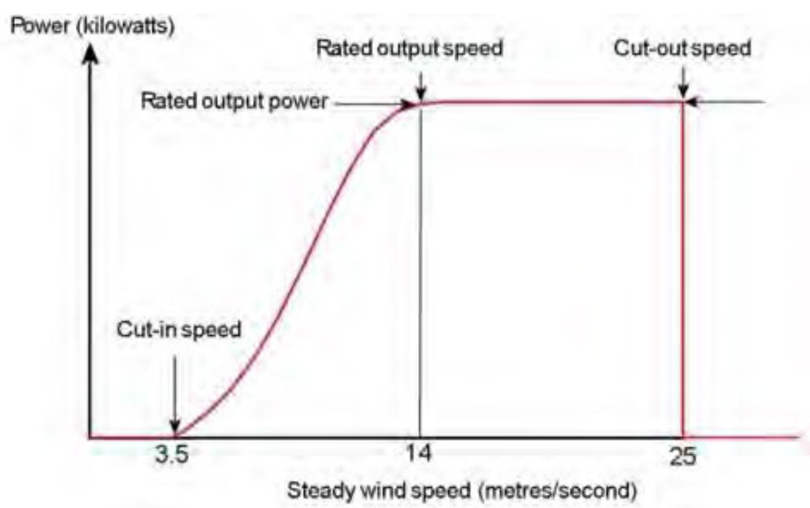
The amount of electricity generated from a wind turbine is a function of wind speed and turbine characteristics, such as the turbine hub height (height above the ground), and the turbine power curve (the mapping of the windspeed to the corresponding power output). Wind speeds increase with height above 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:

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

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

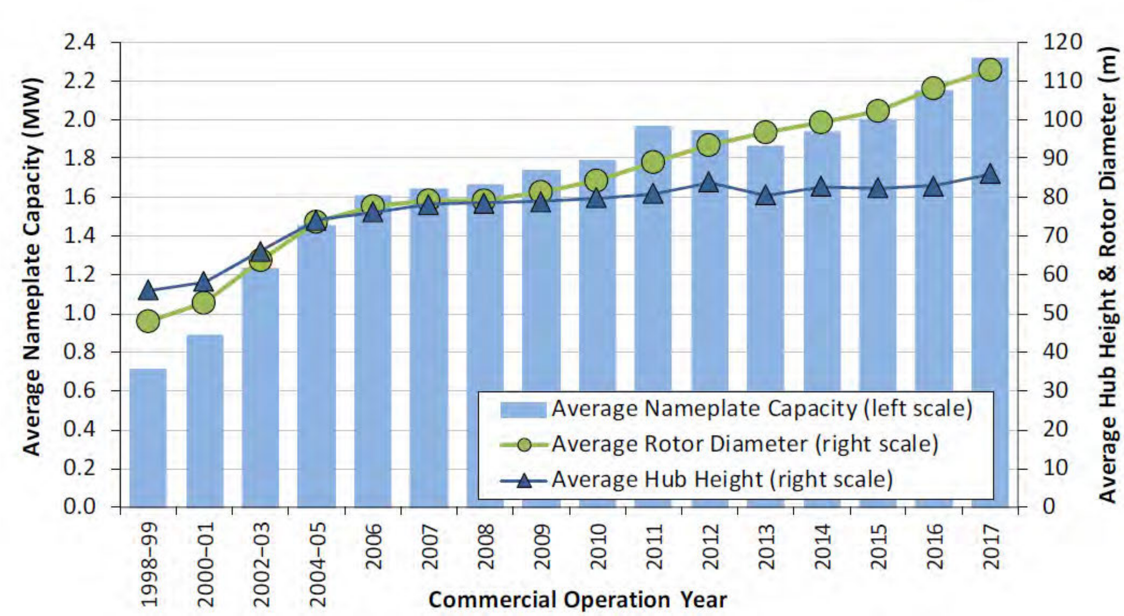
A typical power curve is shown in Figure 35. Turbine power curves define the cut-in speed (minimum windspeed for power generation), rated speed (minimum wind speed to achieve maximum turbine output), cut-out speed (maximum wind speed for power generation) and power generation between the cut-in speed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

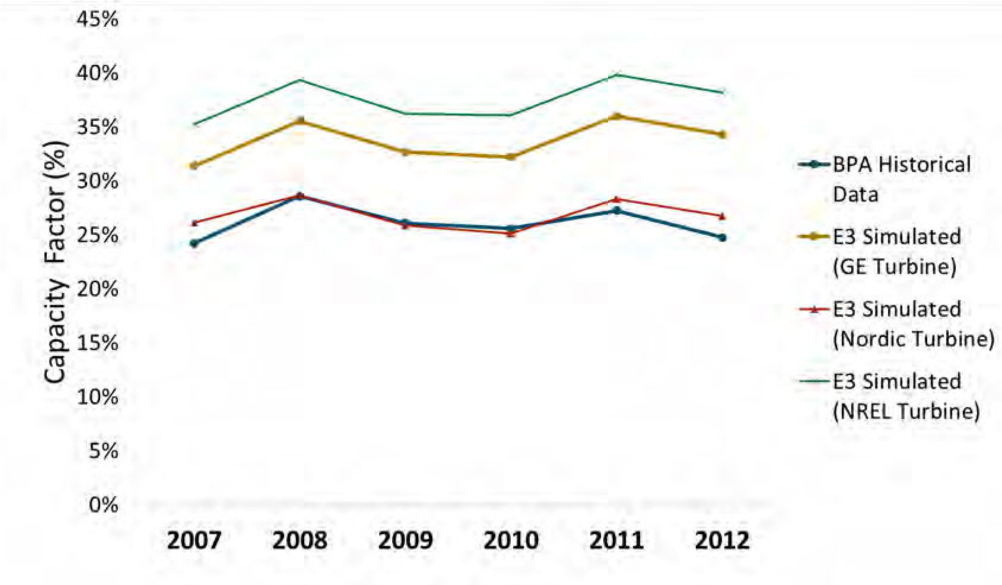
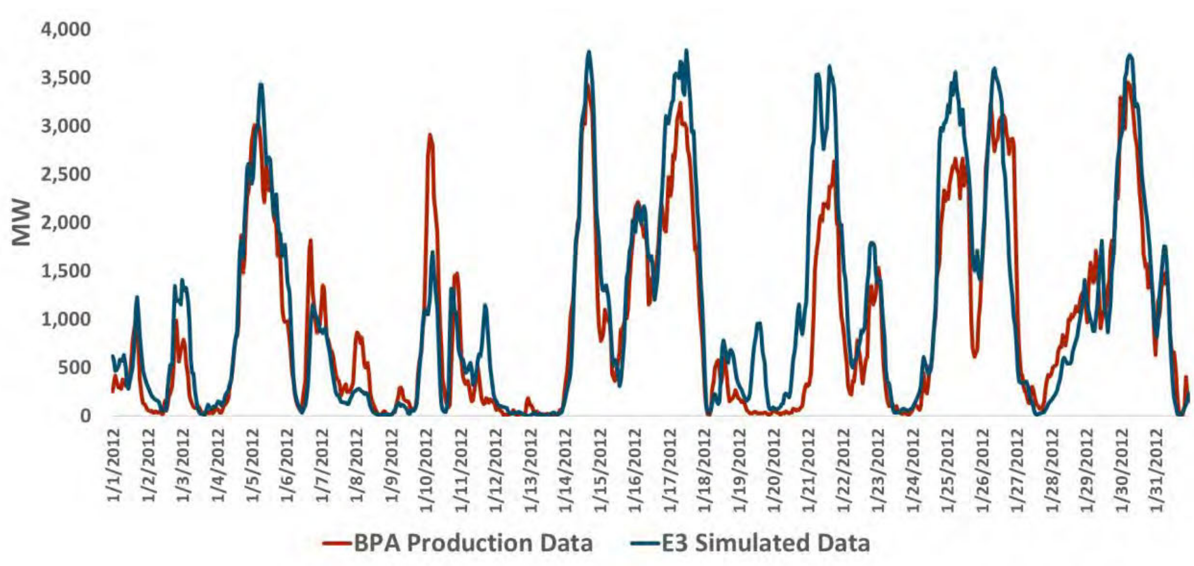


Figure 38: Comparison of Hourly Historical Wind Generation to Simulated Wind Generation for January 2012



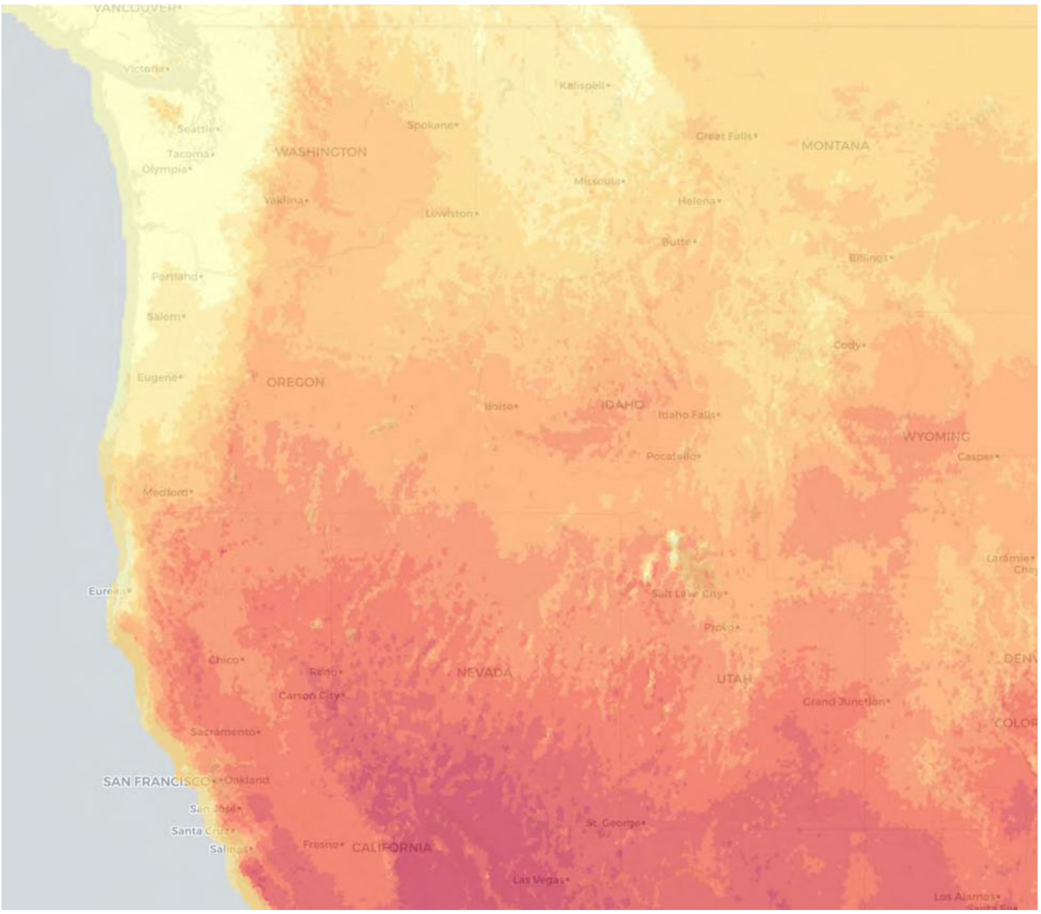
C.2 Solar Profiles

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).

[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.

UE 358

Attachment 026-C

Provided in Electronic Format

PNUCC Northwest Reginal Forecast

Northwest Regional Forecast

of Power Loads and Resources

2020 through 2029

PNUCC
April 2019

Special thanks to PNUCC System Planning Committee members and utility staff that provided us with this information.

Electronic copies of this report are available on the PNUCC website

www.PNUCC.org

101 SW Main Street, Suite 1605

Portland, OR 97204

503.294.1259

Table of Contents

2019 Northwest Regional Forecast Executive Summary

The One Certainty is Change

This annual analysis of Northwest utilities' data predicts the region's electric power need based on a look at supply and demand over the next 10 years, recognizing the unpredictability of weather and water conditions. This *Northwest Regional Forecast* has been a valuable tool to help inform utilities, decision-makers and others facing important decisions about the resource investments needed to ensure that the region has adequate supplies of electricity to meet the requirements of a growing region with a changing power supply picture.

This year's report, published on the heels of a recent record-setting wholesale energy price event in March, underscores the region's need for generating and demand-side resources that match up with characteristics of consumers' demand for electricity. It may also be a sign that traditional resource planning cannot fully capture the abilities and inabilities of our more dynamic, diverse power system.

This report largely shows a continuation of several compounding trends impacting the electric power industry's planning and operations. With the hydropower system as a backbone and a heavy reliance on future energy efficiency savings, utilities continue to operate – and make decisions about future power supply and demand – within a changing and sometimes chaotic economic, political, technological and social environment. The one certain thing is that the utility landscape continues to change and evolve.

Most notably, these are the key trends worth watching:

- Northwest utilities are achieving carbon-reduction goals and many are seeking opportunities to do more, while policymakers seem eager to enact more aggressive decarbonization legislation.
- Although the winter period shows improvement, serving winter peak demand remains a concern. And summertime peak demand continues to increase, focusing planners on peak capacity needs.
- The loss of several coal-fired power plants over the next decade will contribute to the challenges of maintaining an adequate, reliable power supply. In the Northwest, nearly 2,100 MW will be retired by 2022 with another 1,500 MW by 2029. Similarly, many more retirements are anticipated across the west, adding to regional adequacy concerns.
- Current planned construction of new wind and other renewable resources cannot be expected to fully offset the anticipated loss of generation from coal-fired power plant retirements.
- The use of new technologies, such as large-scale batteries, is being explored to confirm a greater role in utilities' resource plans.
- Growth in demand for electricity is not consistent across the region. On average, load growth is forecast under one percent annually. Some utilities are experiencing declining or flat loads, while a few expect well over three percent annual growth in demand through time.

These and other data-based perspectives are outlined in more detail on the following pages.

Decarbonization is Happening

Decarbonization of electric power supply is the conversion of fossil fuel-based energy to lower-carbon electricity sources. Utilities are taking action to transition their power supply, and states' legislatures are considering additional action aimed at reducing carbon emissions more aggressively, including both Oregon and Washington. California already has very aggressive carbon-reduction goals in place that will also impact the Northwest.

Utilities have taken the decarbonization goal to heart. To meet policy directives and consumers' desires, they are setting corporate carbon reduction goals to reduce greenhouse gasses that contribute to climate change. Customers are expecting that their utility will invest more in wind, solar and other renewables.

Programs to accommodate electric-powered vehicles with charging stations and incentives are also top-of-mind among electric utilities across the region as they move to decarbonize. In addition, utilities continue to encourage more homes and businesses to pursue efficient heat pumps while pursuing more non-carbon generation. The success of these electrification efforts will influence future power supply and demand forecasts, but just how much is yet to be determined.

Coal Retirements Underscore Reliability Challenges

Plans to retire eight coal-fired power units that serve the region will reduce the almost 6,800 megawatts of coal-fired generation available today to below 3,200 megawatts by 2028. This loss of more than 3,600 megawatts of dispatchable generation (both utility and non-utility owned) will be most notable during peak-demand periods in the winter and summer.

The committed and planned new generation facilities on the drawing board for the next five years are renewables projects. Then almost 950 MW of natural gas-fired generation are penciled in between 2025 and 2028. Utilities also continue to pursue aggressive energy-efficiency along with demand side-management programs designed to reduce energy use during peak periods. They are looking to capacity contracts and seeking to prove new technologies such as batteries, to also help fill the void created by the closure of the coal units.

Taken together, this is presenting the region with new challenges for reliably meeting demand under certain conditions. There is plenty of work ahead to identify and develop resources that meet the desire of customers and provide the supply attributes to ensure an adequate power system in the years ahead.

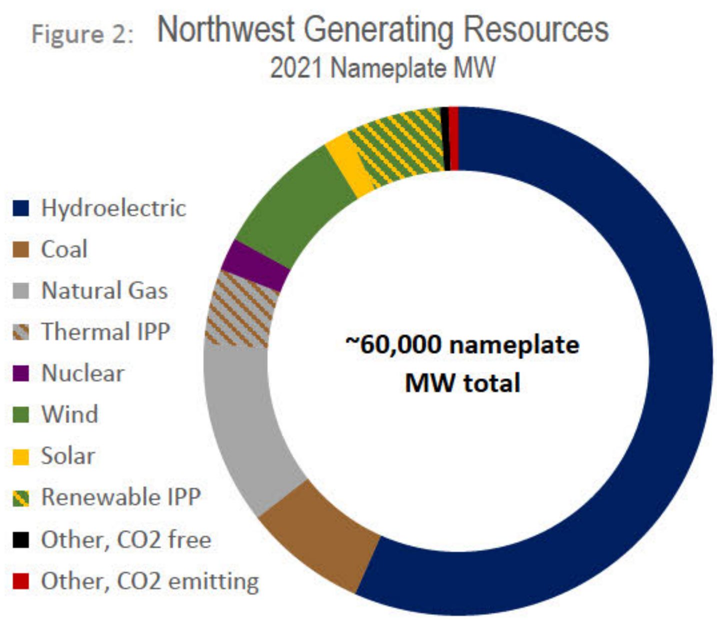
Figure 1: Northwest Planned Coal Unit Retirements

Project	Nameplate MW	Schedule
Valmy Unit 1	254	End of 2019
Centralia Unit 1	670	End of 2020
Boardman	585	End of 2020
Colstrip Unit 1 & 2	660	July 2022
Centralia Unit 2	670	End of 2025
Valmy Unit 2	267	End of 2025
Jim Bridger 2	540	End of 2028
Total	3,646 MW	

Hydropower Still Dominates

Utilities in the Northwest depend on a reliable, low-carbon fleet of resources to ensure that we meet the energy needs of customers. Since the 1930s, hydroelectric power has been the centerpiece of the Northwest's low-carbon energy portfolio, making up nearly 60 percent of the total electricity supply built in the region today. Even in low water conditions, hydropower makes up more than 60 percent of the region's winter peak capacity supply. Of course, the more abundant the water supply in a year, the greater the share of the Northwest's electric generation hydro provides.

Figure 2: Northwest Generating Resources

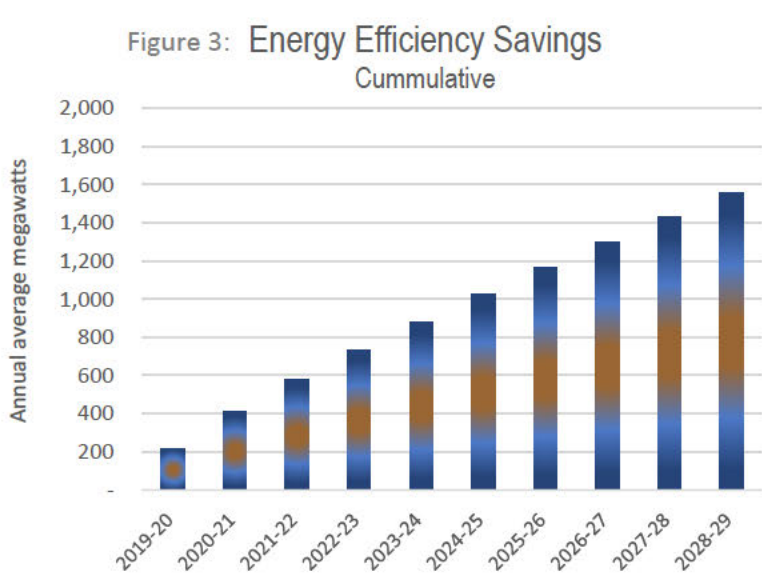


Our reliance on hydropower means the average carbon footprint of the Northwest's generating resources is less than half of the rest of the nation. It also means that the Northwest, in aggregate, has a head start in meeting national, regional, statewide and local goals that may be established for decarbonization.

One Constant: Energy Efficiency

Northwest utilities' steady and long-term commitment to offering energy-efficiency programs and incentives to customers has saved thousands of average megawatts, reducing the need to invest in new and expensive power plants. According to the Northwest Power & Conservation Council, a multi-state planning agency, the Northwest has saved more than 6,600 average annual megawatts since 1978 thanks to energy efficiency.

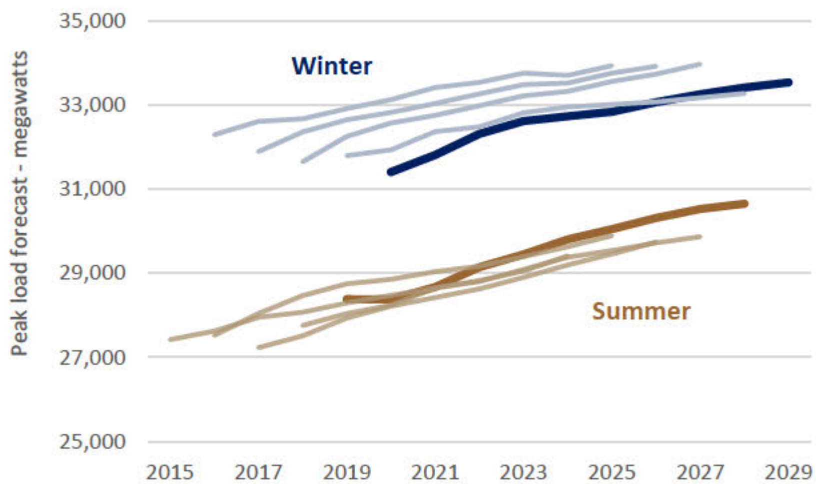
Figure 3: Energy Efficiency Savings



Based on utility data the Northwest has consistently exceeded its goals. The story remains constant. Utilities continue to invest heavily into energy efficiency, forecasting savings of almost 160 average megawatts per year. These numbers don't include the added savings from federal building and construction codes and standards, nor any market transformation efforts. The *Forecast* continues to predict significant energy efficiency acquisitions over the next decade.

Peak Demand Remains a Concern

Figure 4: Summer Growth Outpacing Winter

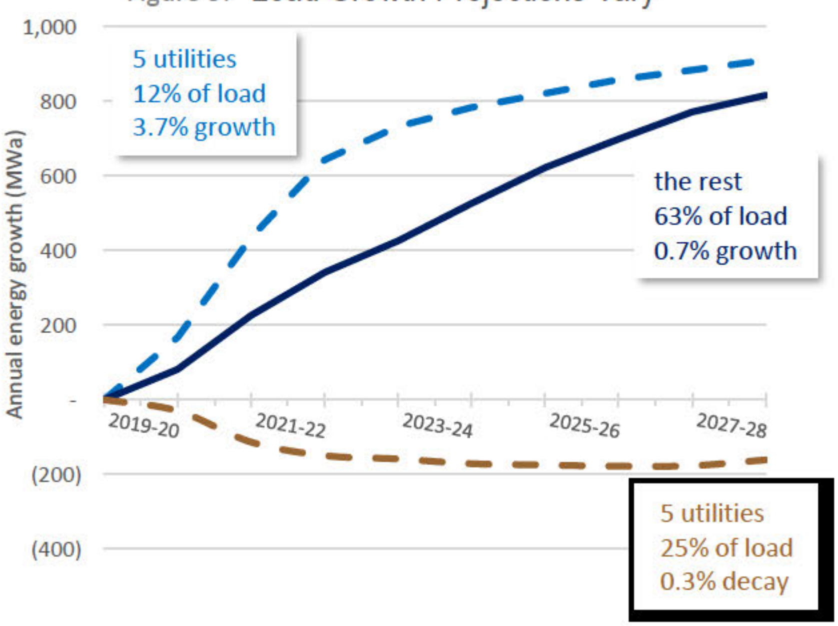


The trends for meeting the region's demand for power, especially during peak periods, might be as different as summer and winter – literally. Summer demand for electricity continues to stay on track. Multiple factors are likely contributing to this upward trend, including increased air conditioning. The projection for winter peak demand has slipped year over year. This is likely due to more energy efficiency, use of natural gas for heating, lost industrial load, among other drivers.

Growth Varies Across the Region

The overall growth in demand is not consistent across the Northwest. Some utilities are experiencing significant growth, due largely to anticipated new industrial customers. Many of these utilities are located east of the Cascades in Oregon and Washington, where lower electricity costs, cheaper land prices and other factors are attracting new, large customers – particularly high-tech companies that need large amounts of electricity for data centers.

Figure 5: Load Growth Projections Vary



The annual average load growth for the region is less than 1 percent – 0.8 percent over the ten-year horizon. Yet, demand for electricity for just five utilities is growing at an average rate of 3.7 percent per year, while five other utilities are anticipating decaying loads on average of 0.3 percent per year. The region's remaining utilities (over 60 percent of total demand) are expecting to grow on average at 0.7 percent annually.

Typically, the utilities with declining loads expect no new industrial customers to locate within their service territories. And while the number of residential customers is ticking up, energy use per customer is declining due to energy efficiency and federal codes and standards for new construction, use of natural gas for heating purposes or other factors.

Winter Need Remains, Summer Need Coming

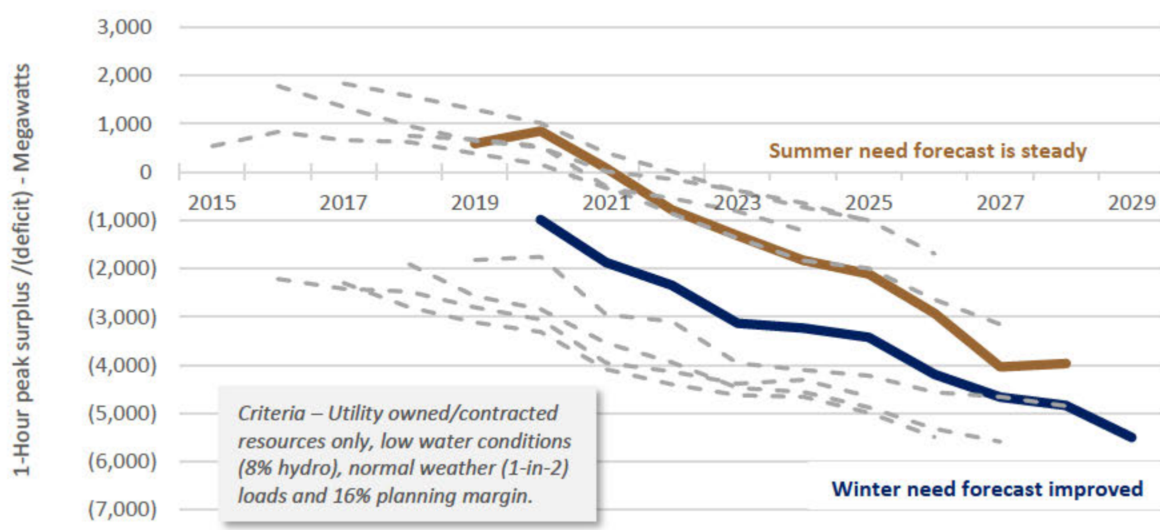
The Northwest has adequate generation to meet customer demand during most times of the year. However, the winter peak need still exists under this forecast's planning criteria. Although the picture has improved (in part due to the loss of large industrial load), the peak deficit grows through time if no future actions are taken.

The steady trend of a growing summer peak need is also drawing attention. Planning projections continue to indicate that within the *Forecast* horizon, summer peak requirements will outpace utilities' firm generation, challenging utility planners to consider actions to address both winter and summer peak capacity need. This is underscored with the planned coal unit retirements (See Figure 1 above) and periodic experiences of tighter power supply throughout the west in the last few years.

This increasing sense of concern regarding winter and summer resource adequacy seems counterintuitive to the *Need for Power* pictured here. Summer need is similar to past reports and the winter picture is improving. However, we cannot look at the Northwest utilities' load/resource balance picture in isolation.

Northwest utilities have leaned on better than low hydro generation, power from independent power producers, and imports from outside the region to ease adequacy concerns. Looking ahead, those same opportunities may not exist. Hydro generation, depending on water supply, varies and can continue to provide non-firm power. However, as large thermal resources are retired throughout the Western Interconnection, the availability of non-firm power (the market) is shrinking, especially during hours of low renewable production. The retirements, along with the growing uncertainty of a utility or developer's ability to build gas turbines to replace that lost generation, have triggered efforts to examine Northwest resource adequacy in a greater context.

Figure 6: Need for Power

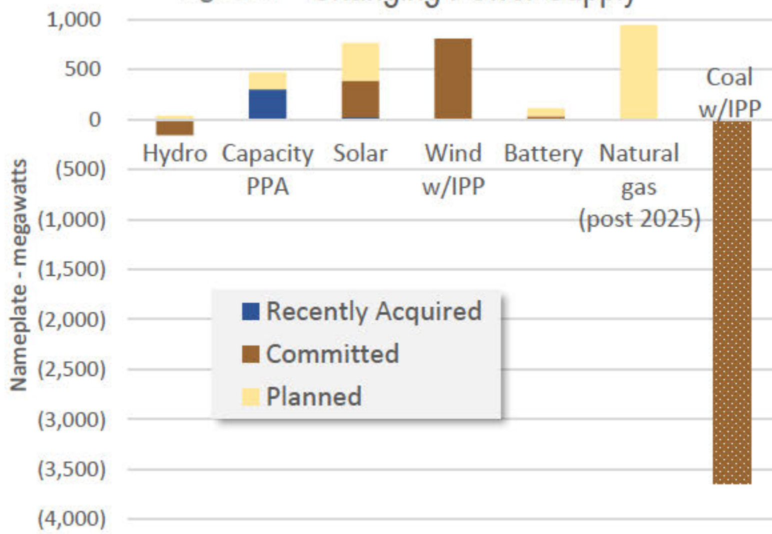


New Resource Plans Dynamic

This year's *Forecast* reflects a quickening pace-of-change for utilities' plans for acquiring new resources. New renewables are jumping in as committed, and planned new resources often show up one year and then fall away in another as utilities refine their plans to account for changing circumstances. Since last year's *Forecast*, another coal unit closure has shown up in our planning horizon and been added to our tally for a total of over 3,600 MW of dispatchable capacity leaving the picture. In addition, the first large-scale battery (30 MW) will be integrated with a combined 350 MW wind and solar project in Eastern Oregon that has been committed to the Northwest.

The changes are stacking up. We expect more in next year's report as utilities announce new goals for developing renewable generation and further decarbonizing their resource portfolios. Utilities have added 300 megawatts of contracts and 34 MW of new generation since last year. Nearly 900 megawatts of new generating resource, all wind and solar, are committed to be built in the next few years, as well as 200 MW of non-utility wind. Committed resources are included in the need for power assessment.

Figure 7: Changing Power Supply



Utilities reported nearly 1,600 megawatts of nameplate capacity in the planning stage – mostly wind, batteries and solar power from 2019 to 2025. Starting in 2025, planned natural gas plants begin to appear, totaling over 900 MW by 2027. On the outgoing side, as mentioned earlier, are almost 3,600 MW of coal (including coal units owned by Independent Power Producers).

The Future is Here

This year's *Northwest Regional Forecast* continues a trend that is relatively new in its 70-year history. Over the past two decades, the region has transformed into a more diverse mix of resources and customers. Stepping up to meet this challenge, utilities are carefully navigating a path for a reliable, adequate, affordable future.

Changes in customer desires have impacted energy usage and future supply. We have met the challenge to integrate new wind and solar resources into our existing hydropower dominate system. We are looking at how to achieve new, more aggressive carbon-reduction goals at the state and national level, in a region that already leads the country in a low carbon power supply. And we are paying careful attention to resolving the impact of the retiring dispatchable resources in this changing power supply landscape.

As always, we will keep our collective eyes on emerging trends and developments as new technologies for power supply evolve and the desires of consumers change.

Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The Forecast is a comprehensive look at the capability of existing and new electric generation resources, long-term firm contracts, expected savings from demand side management programs and other components of electric demand for the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the Northwest Region Requirements and Resources section. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

Northwest generating resources are shown by fuel type. Existing resources include those resources listed in Tables 5, 6, 10 and 11. Table 5, Recently Acquired Resources, highlights projects and supply that became available most recently. Table 6, Committed New Supply, lists those generating projects where construction has started, as well as contractual arrangements that have been made for providing power at a future time. Table 10, Northwest Utility Generating Resources, is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility contracted. Table 11, Independent Owned Generating Resources, lists generating projects owned by independent power producers and located in the Northwest.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. Table 7, Demand-Side Management Programs, provides a snapshot of expected savings from these programs for the next ten years. Table 8, Planned Resources, is a compilation of what utilities have reported in their individual integrated resource plans to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington, and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above, but served by BPA on the effective date of the *Act*.

Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Firm Requirements										
Load [1/]	20,472	20,691	21,026	21,314	21,482	21,623	21,755	21,867	21,969	22,051
Exports	476	465	467	467	467	467	467	467	467	467
Total	20,947	21,157	21,493	21,781	21,949	22,090	22,222	22,334	22,436	22,518
Firm Resources										
Hydro [2/]	11,117	11,117	11,097	11,079	11,080	11,080	11,080	11,080	11,080	11,080
Natural Gas3/	4,637	4,627	4,586	4,481	4,462	4,359	4,340	4,136	4,137	4,094
Renewables-Other	235	233	230	227	227	227	224	214	215	216
Solar	189	254	269	268	268	267	268	268	268	268
Wind	1,308	1,397	1,378	1,337	1,322	1,314	1,314	1,299	1,261	1,258
Cogeneration	45	45	27	8	8	8	8	8	8	8
Imports	706	709	711	713	716	671	640	338	339	339
Nuclear	1,100	937	1,100	937	1,100	937	1,100	937	1,100	937
Coal	3,621	3,664	3,111	3,108	2,912	2,847	2,741	2,796	2,732	2,248
Total	22,958	22,984	22,509	22,160	22,094	21,711	21,713	21,076	21,140	20,448
Surplus (Deficit)	**2,011**	**1,827**	**1,017**	**379**	**145**	**(379)**	**(509)**	**(1,258)**	**(1,296)**	**(2,070)**

[1/] Loads net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming 1936-37 water conditions
[3/] There is likely more energy available from thermal units whose data shows only planned generation

Table 2. Northwest Region Requirements and Resources – Monthly Energy shows the monthly energy values for the 2019-2020 operating year.

Average Megawatts	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Firm Requirements												
Load [1/]	20,346	18,609	18,709	20,767	23,536	23,213	21,649	20,459	19,129	18,848	19,737	20,977
Exports	613	521	521	521	521	491	491	491	491	491	491	506
Total	20,959	19,130	19,230	21,288	24,056	23,704	22,140	20,950	19,620	19,339	20,227	21,483
Firm Resources												
Hydro [2/]	11,715	9,136	9,526	10,863	11,595	11,202	9,144	9,581	9,412	11,341	14,633	13,512
Natural Gas [3/]	4,733	4,553	4,378	4,736	4,998	5,030	4,740	4,524	4,208	3,917	4,523	4,739
Renewables-Other	228	232	240	245	244	240	238	240	228	219	224	227
Solar	226	181	132	67	50	82	152	210	291	341	382	401
Wind	1,199	1,196	1,143	1,185	1,198	1,038	1,298	1,486	1,524	1,455	1,536	1,439
Cogeneration	43	45	47	47	55	55	51	54	46	40	28	43
Imports	701	659	671	705	744	762	729	736	674	677	697	721
Nuclear	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Coal	3,852	3,852	3,852	3,852	3,852	3,737	3,737	3,647	3,220	2,966	2,876	3,737
Total	23,798	20,953	21,088	22,799	23,835	23,247	21,190	21,577	20,703	22,056	25,998	25,918
Surplus (Deficit)	**2,839**	**1,823**	**1,858**	**1,511**	**(222)**	**(457)**	**(950)**	**627**	**1,083**	**2,717**	**5,771**	**4,435**

[1/] Loads net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming 1936-37 water conditions
[3/] There is likely more energy available from thermal units whose data shows only planned generation

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Firm Requirements										
Load [1/]	31,405	31,811	32,317	32,620	32,732	32,839	33,069	33,255	33,418	33,537
Exports	1,150	1,174	1,003	1,000	998	1,009	1,017	1,017	1,001	997
Planning Margin [2/]	5,025	5,090	5,171	5,219	5,237	5,254	5,291	5,321	5,347	5,366
Total	37,580	38,075	38,490	38,840	38,967	39,102	39,378	39,593	39,766	39,900
Firm Resources										
Hydro [3/]	22,549	22,549	22,549	22,546	22,546	22,546	22,546	22,546	22,546	22,546
Demand Response	42	86	92	120	146	169	206	224	228	228
Small Thermal & Misc.	167	167	167	167	167	167	167	167	165	165
Natural Gas	6,546	6,556	6,556	6,418	6,417	6,417	6,417	6,157	6,157	6,157
Renewables-Other	250	248	241	241	241	241	241	223	223	223
Solar	10	13	14	14	14	14	14	14	14	14
Wind	289	309	297	276	271	271	271	271	270	270
Cogeneration	59	59	9	9	9	9	9	9	9	9
Imports	1,367	1,471	1,475	1,479	1,483	1,407	1,010	1,013	1,016	1,016
Nuclear	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Coal	4,168	3,598	3,598	3,291	3,291	3,291	3,157	3,157	3,157	2,627
Total	36,592	36,200	36,143	35,706	35,730	35,676	35,183	34,926	34,931	34,400
Surplus (Need)	**(988)**	**(1,875)**	**(2,348)**	**(3,134)**	**(3,237)**	**(3,426)**	**(4,195)**	**(4,667)**	**(4,835)**	**(5,500)**

[1/] Expected (1-in-2) loads net of energy efficiency
[2/] Planning margin is 16% of load in every year (this is a change since 2018)
[3/] Firm hydro for capacity is the generation expected assuming critical (8%) water condition

Table 4. Northwest Region Requirements and Resources – Summer Peak

The sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Firm Requirements										
Load 1/	28,380	28,375	28,674	29,140	29,450	29,805	30,051	30,315	30,529	30,652
Exports	1,726	1,491	1,504	1,510	1,580	1,689	1,637	1,619	2,250	2,037
Planning Margin 2/	4,541	4,540	4,588	4,662	4,712	4,769	4,808	4,850	4,885	4,904
Total	34,647	34,405	34,766	35,312	35,742	36,263	36,496	36,785	37,664	37,594
Firm Resources										
Hydro 3/	21,267	21,267	21,267	21,264	21,264	21,264	21,264	21,264	21,264	21,264
Demand Response	381	415	425	451	471	486	506	536	542	542
Small Thermal & Misc.	165	167	167	167	167	167	167	167	165	165
Natural Gas	6,084	6,095	6,095	6,097	5,962	5,962	5,961	5,957	5,720	5,720
Renewables-Other	253	251	249	243	243	243	243	225	225	225
Solar	249	336	389	406	406	406	406	406	406	406
Wind	298	306	325	293	293	284	284	284	280	280
Cogeneration	50	50	26	9	9	9	9	9	9	9
Imports	1,066	1,072	1,178	1,184	1,189	1,194	1,120	725	730	730
Nuclear	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128
Coal	4,295	4,168	3,598	3,291	3,291	3,291	3,291	3,157	3,157	3,157
Total	35,235	35,254	34,846	34,532	34,423	34,435	34,379	33,859	33,625	33,625
Surplus (Need)	**588**	**849**	**81**	**(781)**	**(1,320)**	**(1,828)**	**(2,117)**	**(2,926)**	**(4,039)**	**(3,969)**

1/ Expected (1-in-2) loads net of energy efficiency
2/ Planning margin is 16% of load in every year (this is a change since 2018)
3/ Firm hydro for capacity is the generation expected assuming critical (8%) water condition

Northwest New and Existing Resources

Table 5. Recently Acquired Resources highlights projects that have recently become available.

Project	Fuel/Tech	Nameplate (MW)	Winter Peak (MW)	Summer Peak (MW)	Energy (MWa)	Utility/Owner
Calligan Creek	Hydro	6	6	2		Snohomish PUD
Hancock Creek	Hydro	6	6	3		Snohomish PUD
Adams Neilson PPA	Solar	22 (AC)				Avista/Strata Solar
BPA capacity PPA	PPA	200	200	200		PGE
AvanGrid capacity PPA	PPA	100	100	100		PGE
Total		**334**				

Table 6. Committed New Supply details contracts and generating projects where construction has started and that utilities are counting on to meet need. All supply listed in this table is included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Name plate (MW)	Winter Peak (MW)	Summer Peak (MW)	Energy (MWa)	Utility/Owner
Vale 1 Solar	2019	Solar	3		5	2	Idaho Power
Brush Solar	2019	Solar	3		1	1	Idaho Power
Morgan Solar	2019	Solar	3		2	2	Idaho Power
Baker Solar Center	2019	Solar	15		8		Idaho Power
PacifiCorp Wind Repower	2019	Wind	25				PacifiCorp
Rattlesnake Flat	2020	Wind	144			50	Avista/Clearway
Skookumchuck	2020	Wind	139				PSE
Montauge Wind (IPP)	2020	Wind	200				Avangrid
Wheatfield Wind	2020	Wind	300	49	49	100	PGE/NextEra
Wheatfield Battery	2021	Battery	30				PGE/NextEra
East. WA. Solar	2021	Solar	150				PSE/Avangrid
Wheatfield Solar	2021	Solar	50				PGE/NextEra
Idaho/Twin Falls Solar	2022	Solar	120				Idaho Power/Jackpot
Total			**1,182**				

Table 7. Demand-Side Management Programs is a snapshot of the regional utilities' efforts to manage demand. The majority of the energy efficiency savings are from utility programs and included in the regional analysis of power needs. This table also shows cumulative existing plus new demand response programs reported by utilities.

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Energy Efficiency (MWa)										
Incremental	218	194	166	152	150	143	141	135	130	128
Cumulative	218	413	579	731	881	1,023	1,165	1,299	1,429	1,558
Demand Response (MW)										
Winter (exist.+ forecast)	42	86	92	120	146	169	206	224	228	228
Summer (exist. + forecast)	381	415	425	451	471	486	506	536	542	542

Table 8. Planned Resources catalogues potential resources that utilities have identified to meet their own needs. These resources are not included in the regional analysis of power needs.

Project	Date	Fuel/Tech	Nameplate (MW)	Winter Peak (MW)	Summer Peak (MW)	Energy (MWa)	Utility
Generator Replacement	2019	Hydro	9	9	9		Grant County PUD
Generator Replacement	2019	Hydro	9	9	9		Grant County PUD
Generator Rebuild	2019	Hydro	9	9	9		Grant County PUD
Capacity PPA	2019	Unknown	50	50	-	5	Snohomish PUD
Hydro Upgrade	2020	Hydro	3	-	3		Idaho Power
Solar	2022	Solar	266	0			PSE
Battery	2023	Battery	50	38			PSE
Battery	2024	Battery	25	15			PSE
Solar	2024	Solar	112	0			PSE
Natural Gas Peaker	2025	Natural Gas	239	239			PSE
Natural Gas Peaker	2026	Natural Gas	192	204	177	178	Avista
Natural Gas Peaker	2026	Natural Gas	239	239			PSE
Thermal Upgrades	2026-2029	Natural Gas	34	34	35	31	Avista
Natural Gas Peaker	2027	Natural Gas	239	239			PSE
Capacity Resource	2028	Unknown	120	116	116	12	Snohomish PUD
Storage	2029	Unknown	5	5	5	0	Avista
Total			**1,599**				

Table 9. Committed and *Planned* Dispatchable Resources Timeline provides an expected schedule for new resource additions for both the committed resources already included in the load/resource picture, and planned resources that are not as far along in the acquisition/build process.

Nameplate MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Hydro	*26*	(160)										(134)
Capacity	*50*									*120*		170
Solar	24		200	*266*		*112*						741
Wind (inc. IPP)	25	783										808
Battery			30		*50*	*25*					*5*	110
Natural gas							*239*	*431*	*273*			943
Demand Response			44	6	28	26	23	37	17	5		186
Coal (inc. IPP)	(254)	(1,255)		(660)			(937)			(540)		(3,646)
Total incremental	**(129)**	**(632)**	**274**	**(248)**	**78**	**163**	**(675)**	**468**	**290**	**(416)**	**5**	
Total cumulative	**(129)**	**(761)**	**(487)**	**(735)**	**(657)**	**(494)**	**(1,169)**	**(701)**	**(411)**	**(827)**	**(823)**	

Table 10. Northwest Utility Generating Resources is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply.

Project	Owner	NW Utility	Nameplate (MW)
HYDRO			**33,344**
Albeni Falls	US Corps of Engineers	Federal System (BPA)	43
Alder	Tacoma Power	Tacoma Power	50
American Falls	Idaho Power	Idaho Power	92
Anderson Ranch	US Bureau of Reclamation	Federal System (BPA)	40
Arena Drop	PURPA	Idaho Power	0
Arrowrock Dam	Clatskanie PUD/Irrigation Dist.	Clatskanie PUD	18
B. Smith	PacifiCorp	PacifiCorp	0
Baker City Hydro		Idaho Power	
Barber Dam		Idaho Power	4
Bell Mountain	PacifiCorp	PacifiCorp	1
Big Sheep Creek	Everand Jensen	Avista Corp.	0
Big Cliff	US Corps of Engineers	Federal System (BPA)	18
Birch Creek	PURPA	Idaho Power	0
Birch Creek	PacifiCorp	PacifiCorp	3
Black Canyon # 3	PURPA	Idaho Power	0
Black Canyon	US Bureau of Reclamation	Federal System (BPA)	10
Black Canyon Bliss Dam	PURPA	Idaho Power	-
Black Creek Hydro	Black Creek Hydro, Inc.	Puget Sound Energy	4
Blind Canyon	PURPA	Idaho Power	2
Boston Power		PacifiCorp	
Bliss	Idaho Power	Idaho Power	75
Boise River Diversion	US Bureau of Reclamation	Federal System (BPA)	2
Bonneville	US Corps of Engineers	Federal System (BPA)	1,102
Box Canyon-Idaho	PURPA	Idaho Power	0
Boundary	Seattle City Light	Seattle City Light	1,119
Box Canyon	Pend Oreille County PUD	Pend Oreille County PUD	70
Briggs Creek	PURPA	Idaho Power	1
Brownlee	Idaho Power	Idaho Power	585
Bypass	PURPA	Idaho Power	10
Cabinet Gorge	Avista Corp.	Avista Corp.	265
Calligan Creek	Snohomish County PUD	Snohomish County PUD	6
Calispel Creek	Pend Oreille County PUD	Pend Oreille County PUD	1
Canyon Springs	PURPA	Idaho Power	0
Carmen-Smith	Eugene Water & Electric Board	Eugene Water & Electric Board	105
Cascade	US Bureau of Reclamation	Idaho Power	12
CDM Hydro	PacifiCorp	PacifiCorp	6
Cedar Falls, Newhalem	PURPA	Seattle City Light	33
Central Oregon Siphon		PacifiCorp	5
Chandler	US Bureau of Reclamation	Federal System (BPA)	12

Project	Owner	NW Utility	Nameplate (MW)
Chelan	Chelan County PUD	Chelan County PUD	59
Chief Joseph	US Corps of Engineers	Federal System (BPA)	2,457
C. J. Strike	Idaho Power	Idaho Power	83
Clark Canyon Dam	PURPA	Idaho Power	8
Clear Lake	Idaho Power	Idaho Power	3
Clear Springs Trout	PURPA	Idaho Power	1
Clearwater #1	PacifiCorp	PacifiCorp	15
Clearwater #2	PacifiCorp	PacifiCorp	26
Cline Falls	COID	PacifiCorp	1
COID	PacifiCorp	PacifiCorp	7
Copco #1	PacifiCorp	PacifiCorp	20
Copco #2	PacifiCorp	PacifiCorp	27
Cougar	US Corps of Engineers	Federal System (BPA)	25
Cowlitz Falls	Lewis County PUD	Federal System (BPA)	70
Crystal Springs	PURPA	Idaho Power	2
Curry Cattle Company	PURPA	Idaho Power	0
Curtis Livestock	PacifiCorp	PacifiCorp	0
Cushman 1	Tacoma Power	Tacoma Power	43
Cushman 2	Tacoma Power	Tacoma Power	81
Deep Creek	Gordon Foster	Avista Corp.	0
Derr Creek	Jim White	Avista Corp.	0
Detroit	US Corps of Engineers	Federal System (BPA)	100
Dexter	US Corps of Engineers	Federal System (BPA)	15
Diablo Canyon	Seattle City Light	Seattle City Light	182
Dietrich Drop	PURPA	Idaho Power	5
Dry Creek		PacifiCorp	4
D. Wiggins		PacifiCorp	
Dworshak	US Corps of Engineers	Federal System (BPA)	400
Dworshak/ Clearwater		Federal System (BPA)	
Eagle Point	PacifiCorp	PacifiCorp	3
East Side	PacifiCorp	PacifiCorp	3
Eight Mile Hydro	PURPA	Idaho Power	0
Electron	Electron Hydro, LLC	Puget Sound Energy	23
Elk Creek	PURPA	Idaho Power	2
Eltopia Branch Canal	SEQCBID	Seattle City Light	2
Esquatzel Small Hydro	Green Energy Today, LLC	Franklin County PUD	1
Fall Creek	PacifiCorp	PacifiCorp	3
Falls Creek	Clallam PUD	Other Public (BPA)	0
Falls River	PURPA	Idaho Power	9
Faraday	Portland General Electric	Portland General Electric	37
Fargo Drop Hydro	PURPA	Idaho Power	1
Farmers Irrigation	PacifiCorp	PacifiCorp	3

Project	Owner	NW Utility	Nameplate (MW)
Faulkner Ranch	PURPA	Idaho Power	1
Fish Creek	PacifiCorp	PacifiCorp	11
Fisheries Development Co.	PURPA	Idaho Power	0
Foster	US Corps of Engineers	Federal System (BPA)	20
Frontier Technologies	PacifiCorp	PacifiCorp	4
Galesville Dam	PacifiCorp	PacifiCorp	2
Gem State Hydro		Other Publics (BPA)	23
Geo-Bon No 2	PURPA	Idaho Power	1
Georgetown Power	PacifiCorp	PacifiCorp	0
Gorge	Seattle City Light	Seattle City Light	207
Grand Coulee	US Bureau of Reclamation	Federal System (BPA)	6,494
Green Peter	US Corps of Engineers	Federal System (BPA)	80
Green Springs	US Bureau of Reclamation	Federal System (BPA)	16
Hailey CSPP	PURPA	Idaho Power	0
Hancock Creek	Snohomish County PUD	Snohomish County PUD	6
Hazelton A	PURPA	Idaho Power	8
Hazelton B	PURPA	Idaho Power	8
Head of U Canal	PURPA	Idaho Power	1
Hells Canyon	Idaho Power	Idaho Power	392
Hills Creek	US Corps of Engineers	Federal System (BPA)	30
Hood Street Reservoir	Tacoma Power	Tacoma Power	1
Horseshoe Bend	PURPA	Idaho Power	10
Hungry Horse	US Bureau of Reclamation	Federal System (BPA)	428
Hutchinson Creek	STS Hydro	Puget Sound Energy	1
Ice Harbor	US Corps of Engineers	Federal System (BPA)	603
Idaho Falls - City Plant		Federal System (BPA)	8
Idaho Falls - Lower Plant		Federal System (BPA)	8
Idaho Falls - Upper Plant		Federal System (BPA)	8
Ingram Warm Springs	PacifiCorp	PacifiCorp	1
Iron Gate	PacifiCorp	PacifiCorp	18
Island Park		Fall River Rural Electric Cooperative	5
Jackson (Sultan)	Snohomish County PUD	Snohomish County PUD	112
James Boyd		PacifiCorp	
Jim Ford Creek	Ford Hydro	Avista Corp.	2
Jim Knight	PURPA	Idaho Power	0
John C. Boyle	PacifiCorp	PacifiCorp	90
John Day	US Corps of Engineers	Federal System (BPA)	2,160
John Day Creek	Dave Cereghino	Avista Corp.	1
John H Koyle	PURPA	Idaho Power	1
Joseph Hydro		PacifiCorp	
Kasel-Witherspoon	PURPA	Idaho Power	1
Kerr	NorthWestern Corporation	NorthWestern Energy	194

Project	Owner	NW Utility	Nameplate (MW)
Koma Kulshan	Koma Kulshan Associates	Puget Sound Energy	11
La Grande	Tacoma Power	Tacoma Power	64
Lacomb Irrigation	PacifiCorp	PacifiCorp	1
Lake Creek		Other Publics (BPA)	
Lake Oswego Corp.		Portland General Electric	1
Lateral No. 10	PURPA	Idaho Power	2
Leaburg	Eugene Water & Electric Board	Eugene Water & Electric Board	16
Lemolo #1	PacifiCorp	PacifiCorp	32
Lemolo #2	PacifiCorp	PacifiCorp	33
Lemoyne	PURPA	Idaho Power	0
Libby	US Corps of Engineers	Federal System (BPA)	525
Lilliwaup Falls		Other Public (BPA)	1
Little Falls	Avista Corp.	Avista Corp.	32
Little Goose	US Corps of Engineers	Federal System (BPA)	810
Little Wood	PURPA	Idaho Power	3
Little Wood/Arkoosh	PURPA	Idaho Power	1
Little Wood River Ranch II	PURPA	Idaho Power	1
Lloyd Fery	PacifiCorp	PacifiCorp	0
Long Lake	Avista Corp.	Avista Corp.	70
Lookout Point	US Corps of Engineers	Federal System (BPA)	120
Lost Creek	US Corps of Engineers	Federal System (BPA)	49
Lower Baker	Puget Sound Energy	Puget Sound Energy	115
Lower Granite	US Corps of Engineers	Federal System (BPA)	810
Lower Malad	Idaho Power	Idaho Power	14
Lower Monumental	US Corps of Engineers	Federal System (BPA)	810
Lower Salmon	Idaho Power	Idaho Power	60
Lowline #2	PURPA	Idaho Power	3
Lowline Canal	PURPA	Idaho Power	3
Lowline Midway	Idaho Power	Idaho Power	8
Lucky Peak	US Corps of Engineers	Seattle City Light	113
Magic Reservoir	PURPA	Idaho Power	9
Main Canal Headworks	SEQCBID	Seattle City Light	26
Malad River	PURPA	Idaho Power	1
Mayfield	Tacoma Power	Tacoma Power	162
McNary	US Corps of Engineers	Federal System (BPA)	980
McNary Fishway	US Corps of Engineers	Other Publics (BPA)	10
Merwin	PacifiCorp	PacifiCorp	136
Meyers Falls	Hydro Technology Systems	Avista Corp.	1
Middlefork Irrigation	PacifiCorp	PacifiCorp	3
Mile 28	PURPA	Idaho Power	2
Mill Creek (Cove)		Idaho Power	1
Mill Creek		Other Publics (BPA)	1

Project	Owner	NW Utility	Nameplate (MW)
Milner	Idaho Power	Idaho Power	59
Minidoka	US Bureau of Reclamation	Federal System (BPA)	28
Mink Creek	PacifiCorp	PacifiCorp	3
Mitchell Butte	PURPA	Idaho Power	2
Monroe Street	Avista	Avista Corp.	15
Mora Drop	PURPA	Idaho Power	2
Morse Creek		Port Angeles	1
Mossyrock	Tacoma Power	Tacoma Power	300
Mountain Energy	PacifiCorp	PacifiCorp	0
Mount Tabor	City of Portland	Portland General Electric	0
Moyie Springs	City of Bonners Ferry	Other Publics (BPA)	4
Mud Creek/S&S	PURPA	Idaho Power	1
Mud Creek/White	Mud Creek Hydro	Idaho Power	0
N-32 Canal (Marco Ranches)	Ranchers Irrigation Inc.	Idaho Power	1
Nicols Gap	PacifiCorp	PacifiCorp	1
Nicolson SunnyBar	PacifiCorp	PacifiCorp	0
Nine Mile	Avista Corp.	Avista Corp.	26
Nooksack	Puget Sound Hydro, LLC	Puget Sound Energy	2
North Gooding		Idaho Power	
North Fork	Portland General Electric	Portland General Electric	41
North Fork Sprague	PacifiCorp	PacifiCorp	1
N.R. Rousch	PacifiCorp	PacifiCorp	0
Noxon Rapids	Avista Corp.	Avista Corp.	466
Odell Creek	PacifiCorp	PacifiCorp	0
Oak Grove	Portland General Electric	Portland General Electric	51
O.J. Power	PacifiCorp	PacifiCorp	0
Opal Springs	PacifiCorp	PacifiCorp	5
Ormsby		PacifiCorp	
Owyhee Dam	PURPA	Idaho Power	5
Oxbow	Idaho Power Company	Idaho Power	190
Packwood	Energy Northwest	Multiple Utilities	26
Palisades	US Bureau of Reclamation	Federal System (BPA)	177
PEC Headworks	SEQCBID	Grant County PUD	7
Pelton Reregulation	Warm Springs Tribe	Portland General Electric	19
Pelton	Portland General Electric	Multiple Utilities	110
Phillips Ranch	Glen Phillips	Avista Corp.	0
Pigeon Cove	PURPA	Idaho Power	2
Portland Hydro-Project	City of Portland	Portland General Electric	36
Portneuf River		PacifiCorp	1
Potholes East Canal 66 Headworks	SEQCBID	Seattle City Light	2
Post Falls	Avista Corp.	Avista Corp.	15

Project	Owner	NW Utility	Nameplate (MW)
Preston City	PacifiCorp	PacifiCorp	0
Powerdale	PacifiCorp	PacifiCorp	6
Pristine Springs	PURPA	Idaho Power	0
Priest Rapids	Grant County PUD	Multiple Utilities	956
Pristine Springs #3	PURPA	Idaho Power	0
Prospect projects	PacifiCorp	PacifiCorp	44
Quincy Chute	SEQCBID	Grant County PUD	9
R.D. Smith	SEQCBID	Seattle City Light	6
Reynolds Irrigation	PURPA	Idaho Power	0
Reeder Gulch	City of Ashland	Other Publics (BPA)	0
Rock Creek No. 1	PURPA	Idaho Power	2
River Mill	Portland General Electric	Portland General Electric	19
Rock Creek No. 2	PURPA	Idaho Power	2
Rocky Brook	Mason County PUD #3	Other Public (BPA)	2
Sagebrush	PURPA	Idaho Power	0
Rock Island	Chelan County PUD	Multiple Utilities	629
Rocky Reach	Chelan County PUD	Multiple Utilities	1,300
Ross	Seattle City Light	Seattle City Light	450
Round Butte	Portland General Electric	Multiple Utilities	247
Roza	US Bureau of Reclamation	Federal System (BPA)	13
Sahko	PURPA	Idaho Power	1
Santiam	PacifiCorp	PacifiCorp	0
Schaffner	PURPA	Idaho Power	1
Sheep Creek	Glen Phillips	Avista Corp.	2
Shingle Creek	PURPA	Idaho Power	0
Shoshone II	PURPA	Idaho Power	1
Shoshone CSPP	PURPA	Idaho Power	0
Slide Creek	PacifiCorp	PacifiCorp	18
Shoshone Falls	Idaho Power	Idaho Power	13
Soda Springs	PacifiCorp	PacifiCorp	11
Smith Creek	Smith Creek Hydro, LLC	Eugene Water & Electric Board	38
Snedigar Ranch	PURPA	Idaho Power	1
Snoqualmie Falls	Puget Sound Energy	Puget Sound Energy	54
Spokane Upriver	City of Spokane	Avista Corp.	16
Soda Creek	City of Soda Springs	Other Publics (BPA)	1
Snake River Pottery	PURPA	Idaho Power	
South Fork Tolt	Seattle City Light	Seattle City Light	17
Stauffer Dry Creek		PacifiCorp	
Summer Falls	SEQCBID	Seattle City Light	92
Stone Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	12
Strawberry Creek	South Idaho Public Agency	Other Publics (BPA)	
Sygitowicz	Cascade Clean Energy	Puget Sound Energy	0

Project	Owner	NW Utility	Nameplate (MW)
Swan Falls	Idaho Power	Idaho Power	25
Swift 1	PacifiCorp	Multiple Utilities	219
Swift 2	Cowlitz County PUD	Multiple Utilities	-
TGS/Briggs		PacifiCorp	
Tiber Dam	PURPA	Idaho Power	8
The Dalles	US Corps of Engineers	Federal System (BPA)	1,807
The Dalles Fishway	Northern Wasco Co. PUD	Northern Wasco Co. PUD	5
Thompson Falls	NorthWestern Corporation	NorthWestern Energy	94
Thousand Springs	Idaho Power	Idaho Power	9
Toketee	PacifiCorp	PacifiCorp	43
Trout Company	PURPA	Idaho Power	0
Trail Bridge	Eugene Water & Electric Board	Eugene Water & Electric Board	10
Tunnel #1	PURPA	Idaho Power	7
Twin Falls	PURPA	Puget Sound Energy	20
Twin Falls	Idaho Power	Idaho Power	53
Walla Walla	PacifiCorp	PacifiCorp	2
TW Sullivan	Portland General Electric	Portland General Electric	15
Upper Baker	Puget Sound Energy	Puget Sound Energy	105
Upper Falls	Avista Corp.	Avista Corp.	10
Upper Malad	Idaho Power	Idaho Power	8
Upper Salmon 1 & 2	Idaho Power	Idaho Power	18
Upper Salmon 3 & 4	Idaho Power	Idaho Power	17
Weeks Falls	So. Fork II Assoc. LP	Puget Sound Energy	5
Wallowa Falls	PacifiCorp	PacifiCorp	1
Walterville	Eugene Water & Electric Board	Eugene Water & Electric Board	8
Wanapum	Grant County PUD	Multiple Utilities	934
West Side	PacifiCorp	PacifiCorp	1
Wells	Douglas County PUD	Multiple Utilities	774
White Water Ranch	PURPA	Idaho Power	0
Wilson Lake Hydro	PURPA	Idaho Power	8
Woods Creek	Snohomish County PUD	Snohomish County PUD	1
Yakima-Tieton	PacifiCorp	PacifiCorp	3
Wynoochee	Tacoma Power	Tacoma Power	13
Yale	PacifiCorp	PacifiCorp	134
Yelm		Other Publics (BPA)	12
Young's Creek	Snohomish County PUD	Snohomish County PUD	8

Project	Owner	NW Utility	Nameplate (MW)
COAL			**5,429**
Boardman	Portland General Electric	Multiple Utilities	575
Colstrip #1	PP&L Montana, LLC	Multiple Utilities	330
Colstrip #2	PP&L Montana, LLC	Multiple Utilities	330
Colstrip #3	PP&L Montana, LLC	Multiple Utilities	740
Colstrip #4	NorthWestern Energy	Multiple Utilities	805
Jim Bridger #1	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #2	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #3	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #4	PacifiCorp / Idaho Power	Multiple Utilities	508
Valmy #1	NV Energy / Idaho Power	Multiple Utilities	254
Valmy #2	NV Energy / Idaho Power	Multiple Utilities	267
NUCLEAR			**1,230**
Columbia Generating Station	Energy Northwest	Federal System (BPA)	1,230
NATURAL GAS			**6,878**
Alden Bailey	Clatskanie PUD	Clatskanie PUD	11
Beaver	Portland General Electric	Portland General Electric	516
Beaver 8	Portland General Electric	Portland General Electric	25
Bennett Mountain	Idaho Power	Idaho Power	173
Boulder Park	Avista Corp.	Avista Corp.	25
Carty	Portland General Electric	Portland General Electric	440
Chehalis Generating Facility	PacifiCorp	PacifiCorp	517
Coyote Springs I	Portland General Electric	Portland General Electric	266
Coyote Springs II	Avista Corp.	Avista Corp.	287
Danskin	Idaho Power	Idaho Power	92
Danskin 1	Idaho Power	Idaho Power	179
Dave Gates	NorthWestern Energy	NorthWestern Energy	150
Encogen	Puget Sound Energy	Puget Sound Energy	159
Ferndale Cogen Station	Puget Sound Energy	Puget Sound Energy	245
Frederickson	EPCOR Power L.P./PSE	Multiple Utilities	258
Fredonia 1 & 2	Puget Sound Energy	Puget Sound Energy	208
Fredonia 3 & 4	Puget Sound Energy	Puget Sound Energy	108
Fredrickson 1 & 2	Puget Sound Energy	Puget Sound Energy	149
Goldendale	Puget Sound Energy	Puget Sound Energy	298
Hermiston Generating P.	PacifiCorp/Hermiston Gen. Comp.	PacifiCorp	469
Kettle Falls CT	Avista Corp.	Avista Corp.	7
Lancaster Power Project	Avista Corp.	Avista Corp.	270
Langley Gulch	Idaho Power	Idaho Power	319
Mint Farm Energy Center	Puget Sound Energy	Puget Sound Energy	312
Northeast A&B	Avista Corp.	Avista Corp.	62

Project	Owner	NW Utility	Nameplate (MW)
Port Westward	Portland General Electric	Portland General Electric	415
Port Westward Unit 2	Portland General Electric	Portland General Electric	220
Rathdrum 1 & 2	Avista Corp.	Avista Corp.	167
River Road	Clark Public Utilities	Clark Public Utilities	248
Rupert (Magic Valley)	Rupert Illinois Holdings	Idaho Power	10
Sumas Energy	Puget Sound Energy	Puget Sound Energy	127
Whitehorn #2 & 3	Puget Sound Energy	Puget Sound Energy	149
COGENERATION			**147**
Billings Cogeneration	Billings Generation, Inc.	NorthWestern Energy	64
Hampton Lumber		Snohomish County PUD	5
International Paper Energy	Eugene Water & Electric Board	Eugene Water & Electric Board	26
Simplot-Pocatello	PURPA	Idaho Power	12
Tasco-Nampa	Tasco	Idaho Power	2
Tasco-Twin Falls	Tasco	Idaho Power	3
Wauna (James River)	Western Generation Agency	Multiple Utilities	36
RENEWABLES-OTHER			**307**
Bannock County Landfill	PURPA	Idaho Power	3
Bettencourt B6	PURPA	Idaho Power	2
Bettencourt Dry Creek	PURPA	Idaho Power	2
Big Sky West Dairy	PURPA	Idaho Power	2
Bio Energy		Puget Sound Energy	1
Bio Fuels, WA		Puget Sound Energy	5
Biomass One	PacifiCorp	PacifiCorp	25
City of Spokane Waste to E.	City of Spokane	Avista Corp.	26
Coffin Butte Resource	Power Resources Cooperative		6
Cogen Company	Prairie Wood Products Co-Gen Co.	Oregon Trail Coop	8
Co-Gen II - DR Johnson	PacifiCorp	PacifiCorp	8
Columbia Ridge Landfill Gas	Waste Management	Seattle City Light	13
Convanta Marion	Portland General Electric	Portland General Electric	16
Double A Digestor	PURPA	Idaho Power	5
Dry Creek Landfill	Dry Creek Landfill Inc.	PacifiCorp	3
Edaleen Dairy		Puget Sound Energy	1
Farm Power Tillamook	Tillamook	Tillamook	1
Fighting Creek	PURPA	Idaho Power	3
Flathead County Landfill	Flathead Electric Cooperative	Flathead Electric Cooperative	2
Hidden Hollow Landfill	PURPA	Idaho Power	3
Hooley Digester	Tillamook PUD	Tillamook PUD	1
H. W. Hill Landfill	Allied Waste Companies	Multiple Utilities	10.5
Interfor Pacific-Gilchrist	Midstate Electric Co-op	Midstate Electric Co-op	2
Kettle Falls	Avista Corp.	Avista Corp.	51

Project	Owner	NW Utility	Nameplate (MW)
Lynden	Farm Power	Puget Sound Energy	1
Mill Creek (Cove)		Idaho Power	1
Neal Hot Springs	U.S Geothermal	Idaho Power	23
Olympic View 1&2	Mason County PUD #3	Mason County PUD #3	5
Pine Products	PacifiCorp	PacifiCorp	6
Plum Creek NLSL	Plum Creek MDF	Flathead Electric Cooperative	6
Pocatello Wastewater	PURPA	Idaho Power	0
Portland Wastewater	City of Portland	Portland General Electric	1.7
Qualco Dairy Digester		Snohomish PUD	1
Raft River 1	US Geothermal	Idaho Power	16
Rainier Biogas		Puget Sound Energy	1
Rexville	Farm Power	Puget Sound Energy	1
River Bend Landfill	McMinnville Water & Light	McMinnville Water & Light	5
Rock Creek Dairy	PURPA	Idaho Power	4
Seneca	Seneca Sustainable Energy, LLC	Eugene Water & Electric Board	20
Short Mountain		Emerald PUD	3
Skookumchuck		Puget Sound Energy	1
Smith Creek		Puget Sound Energy	0
Stimson Lumber	Stimson Lumber	Avista Corp.	7
Stoltze Biomass	F.H. Stoltze Land & Lumber	Flathead Electric Coop	3
Tamarack	PURPA	Idaho Power	5
Van Dyk		Puget Sound Energy	0
VanderHaak Dairy	VanderHaak Dairy, LLC	Puget Sound Energy	1
Whitefish Hydro	City of Whitefish	Flatthead Electric Cooperative	0
SOLAR			**956**
Ashland Solar Project		BPA	0
American Falls Solar	PURPA	Idaho Power	20
American Falls Solar II	PURPA	Idaho Power	20
Baker Solar	PURPA	Idaho Power	10
Bellevue Solar	EDF Renewable Energy	Portland General Electric	2
Boise City Solar (ID Solar 1)	PURPA	Idaho Power	40
Brush Solar	PURPA	Idaho Power	3
Finn Hill Solar		Puget Sound Energy	0
Grand View Solar	PURPA	Idaho Power	80
Grove Solar	PURPA	Idaho Power	10
Hyline Solar Center	PURPA	Idaho Power	10
Island Solar		Puget Sound Energy	0
King Estate Solar	Lane County Electric Coop	Lane County Electric Coop	-
Morgan Solar	PURPA	Idaho Power	3
Mountain Home Solar	PURPA	Idaho Power	20
Moyer-Tolles Solar	Umatilla Electric Coop		1

Project	Owner	NW Utility	Nameplate (MW)
Murphy Flat Power	PURPA	Idaho Power	20
Neilson Solar		Avista	19
Open Range Solar Center	PURPA	Idaho Power	10
Orchard Ranch Solar	PURPA	Idaho Power	10
PacifiCorp Solar Bundle		PacifiCorp	193
PGE QF Solar		Portland General Electric	230
Puget Eastern WA		Puget Sound Energy	150
Railroad Solar Center	PURPA	Idaho Power	10
Simco Solar	PURPA	Idaho Power	20
Thunderegg Solar Center	PURPA	Idaho Power	10
Vale I Solar	PURPA	Idaho Power	3
Vale Air Solar	PURPA	Idaho Power	10
Wheatridge Solar	NextEra	PGE	50
Wild Horse Solar Project	Puget Sound Energy	Puget Sound Energy	1
Yamhill Solar	EDF Renewable Energy	Portland General Electric	1
WIND			**4,992**
3Bar-G Wind		Puget Sound Energy	0
Bennett Creek	PURPA	Idaho Power	21
Benson Creek Wind	PURPA	Idaho Power	10
Big Top	Big Top LLC (QF)	PacifiCorp	2
Biglow Canyon - 1	Portland General Electric	Portland General Electric	125
Biglow Canyon - 2	Portland General Electric	Portland General Electric	150
Biglow Canyon - 3	Portland General Electric	Portland General Electric	174
Burley Butte Wind Farm	PURPA	Idaho Power	21
Butter Creek Power	Butter Creek Power LLC	PacifiCorp	5
Camp Reed Wind Park	PURPA	Idaho Power	23
Cassia Wind Farm	PURPA	Idaho Power	11
Coastal Energy	CCAP	Grays Harbor PUD	6
Cold Springs	PURPA	Idaho Power	23
Combine Hills I	Eurus Energy of America	PacifiCorp	41
Combine Hills II	Eurus Energy of America	Clark Public Utilities	63
Condon Wind	Goldman Sachs /SeaWest NW	Federal System (BPA)	25
Desert Meadow Windfarm	PURPA	Idaho Power	23
Durbin Creek	PURPA	Idaho Power	10
Elkhorn Wind	Telocaset Wind Power Partners	Idaho Power	101
Foote Creek Rim 1	PacifiCorp & EWEB	Multiple Utilities	41
Foote Creek Rim 2	PPM Energy	Federal System (BPA)	2
Foote Creek Rim 4	PPM Energy	Federal System (BPA)	17
Fossil Gulch Wind	PURPA	Idaho Power	11
Four Corners Windfarm	Four Corners Windfarm LLC	PacifiCorp	10
Four Mile Canyon Windfarm	Four Mile Canyon Windfarm LLC	PacifiCorp	10

Project	Owner	NW Utility	Nameplate (MW)
Golden Valley Wind Farm	PURPA	Idaho Power	12
Goodnoe Hills	PacifiCorp	PacifiCorp	94
Hammett Hill Windfarm	PURPA	Idaho Power	23
Harvest Wind	Summit Power	Multiple Utilities	99
Hay Canyon Wind	Hay Canyon Wind Project LLC	Snohomish County PUD	101
High Mesa Wind	PURPA	Idaho Power	40
Hopkins Ridge	Puget Sound Energy	Puget Sound Energy	157
Horseshoe Bend	PURPA	Idaho Power	9
Horseshoe Bend	PURPA	Idaho Power	9
Jett Creek	PURPA	Idaho Power	10
Judith Gap	Invenergy Wind, LLC	NorthWestern Energy	135
Klondike I	PPM Energy	Federal System (BPA)	24
Klondike II	PPM Energy	Portland General Electric	75
Klondike III	PPM Energy	Multiple Utilities	221
Knudson Wind		Puget Sound Energy	0
Leaning Juniper 1	PPM Energy	PacifiCorp	101
Lime Wind Energy	PURPA	Idaho Power	3
Lower Snake River 1	Puget Sound Energy	Puget Sound Energy	342
Lime Wind Energy	PURPA	Idaho Power	3
Marengo	Renewable Energy America	PacifiCorp	140
Marengo II	PacifiCorp	PacifiCorp	70
Milner Dam Wind Farm	PURPA	Idaho Power	20
Moe Wind	Two Dot Wind	NorthWestern Energy	1
Nine Canyon	Energy Northwest	Multiple Utilities	96
Oregon Trail Windfarm	Oregon Trail Windfarm LLC	PacifiCorp	10
Oregon Trails Wind Farm	PURPA	Idaho Power	14
Pa Tu Wind Farm	Pa Tu Wind Farm, LLC	Portland General Electric	9
Pacific Canyon Windfarm	Pacific Canyon Windfarm LLC	PacifiCorp	8
Palouse Wind	Palouse Wind, LLC	Avista Corp.	105
Paynes Ferry Wind Park	PURPA	Idaho Power	21
Pilgrim Stage Station Wind	PURPA	Idaho Power	11
Prospector Wind	PURPA	Idaho Power	10
Rattlesnake Flats		Avista Corp.	144
Rockland Wind	PURPA	Idaho Power	80
Ryegrass Windfarm	PURPA	Idaho Power	23
Salmon Falls Wind Farm	PURPA	Idaho Power	22
Sand Ranch Windfarm	Sand Ranch Windfarm LLC	PacifiCorp	10
Sawtooth Wind	PURPA	Idaho Power	21
Sheep Valley Ranch	Two Dot Wind	NorthWestern Energy	1
Skookumchuck		Puget Sound Energy	131
Stateline Wind	NextEra	Multiple Utilities	300
Swauk Wind		Puget Sound Energy	4

Project	Owner	NW Utility	Nameplate (MW)
Thousand Springs Wind	PURPA	Idaho Power	12
Three Mile Canyon	Momentum RE	PacifiCorp	10
Tuana Gulch Wind Farm	PURPA	Idaho Power	11
Tuana Springs Expansion	PURPA	Idaho Power	36
Tucannon	Portland General Electric	Portland General Electric	267
Two Ponds Windfarm	PURPA	Idaho Power	23
Vansycle Ridge	ESI Vansycle Partners	Portland General Electric	25
Wagon Trail Windfarm	Wagon Trail Windfarm LLC	PacifiCorp	3
Ward Butte Windfarm	Ward Butte Windfarm LLC	PacifiCorp	7
Wheat Field Wind Project	Wheat Field Wind LLC	Snohomish County PUD	97
Wheatridge	PGE/NextEra	PGE/NextEra	300
White Creek	White Creek Wind I LLC	Multiple Utilities	205
Wild Horse	Puget Sound Energy	Puget Sound Energy	273
Willow Spring Windfarm	PURPA	Idaho Power	10
Wolverine Creek	Invenergy	PacifiCorp	65
Yahoo Creek Wind Park	PURPA	Idaho Power	21
SMALL THERMAL AND MISCELLANEOUS			**130**
Crystal Mountain	Puget Sound Energy	Puget Sound Energy	3
PGE DSG		Portland General Electric	127
Wheatridge battery	PGE/NextEra	PGE/NextEra	30
	Total		**53,502**

Table 11. Independent Owned Generating Resources is a comprehensive list of independently owned electric power supply located in the region. The nameplate values listed below show full availability. Some of these units have partial contracts (reflected in the load/resource tables) with Northwest utilities.

Project	Owner	Nameplate (MW)
HYDRO		**15**
Big Creek (Hellroaring)		-
PEC Headworks	SEQCBID	7
Soda Point Project		-
Sygitowicz	Cascade Clean Energy	0
Owyhee Tunnel No.1	Owyhee Irrigation District	8
COAL		**1,340**
Centralia #1	TransAlta	670
Centralia #2	TransAlta	670
NATURAL GAS		**2,081**
Grays Harbor (Satsop)	Invenergy	650
Hermiston Power Project	Hermiston Power Partners (Calpine)	689
Klamath Cogen Plant	Iberdrola Renewables	502
Klamath Peaking Units 1-4	Iberdrola Renewables	100
March Point 1	March Point Cogen	80
March Point 2	March Point Cogen	60
COGENERATION		**28**
Boise Cascade		9
Freres Lumber	Evergreen BioPower	10
Rough & Ready Lumber	Rough & Ready	1
Warm Springs Forest		8
RENEWABLES-OTHER		**26**
Spokane MSW	City of Spokane	23
Treasure Valley		3
Solar		**56**
Gala Solar Farm		**56**

Project	Owner	Nameplate (MW)
WIND		**3,447**
Big Horn	Iberdrola Renewables	199
Big Horn-Phase 2	Iberdrola Renewables	50
Cassia Gulch	John Deere	21
Glacier Wind - Phase 1	Naturener	107
Glacier Wind - Phase 2	Naturener	104
Goshen North	Ridgeline Energy	125
Juniper Canyon - Phase 1	Iberdrola Renewables	151
Kittitas Valley	Horizon	101
Klondike IIIa	Iberdrola Renewables	77
Lava Beds Wind		18
Leaning Juniper II-North	Iberdrola Renewables	90
Leaning Juniper II-South	Iberdrola Renewables	109
Linden Ranch	NW Wind Partners	50
Magic Wind Park		20
Martinsdale Colony North	Two Dot Wind	1
Martinsdale Colony South	Two Dot Wind	2
Montague Wind	AvanGrid	200
Notch Butte Wind		18
Pebble Springs Wind	Iberdrola Renewables	99
Rattlesnake Rd Wind (aka Arlington)	Horizon Wind	103
Shepards Flat Central	Caithness Energy	290
Shepards Flat North	Caithness Energy	265
Shepards Flat South	Caithness Energy	290
Stateline Wind	NextEra	300
Vancycle II (Stateline III)	NextEra	99
Vantage Wind	Invenergy	90
Willow Creek	Invenergy	72
Windy Flats	Cannon Power Group	262
Windy Point	Tuolumne Wind Project Authority	137
SMALL THERMAL AND MISCELLANEOUS		**44**
Colstrip Energy LP Coal	Colstrip Energy Limited Partnership	44
Total		**7,038**

Report Description

This report provides a regional firm needs assessment (Tables 1 - 4) using annual energy (August through July), monthly energy, winter peak-hour and summer peak-hour metrics. The monthly energy picture is provided to underscore the variability of the power need within an average year. A seasonal or weekly snapshot would tell a similar story. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This information reflects the summation of individual utilities' load forecasts and generating resources expected to meet their load, as well as the presents the total of utilities' planned resource acquisitions to meet future needs. The larger utilities, in most cases, prepared their own projections for their integrated resource plans. BPA provides much of the information for its smaller customers. This section includes procedures used in preparing the load resource comparisons, a list of definitions, and a list of the utilities summarized by this report (Table 12).

Load Estimate

Regional loads are the sum of demand estimated by the Northwest utilities and BPA for its federal agency customers, certain non-generating public utilities, and direct service industrial customers (DSI – currently not a significant part of regional load). Load projections reflect network transmission and distribution losses, reductions in demand due to rising electricity prices, and the effects of appliance efficiency standards and energy building codes. Savings from demand-side management programs, such as energy efficiency, are also reflected in the regional load forecasts.

Energy Loads

A ten-year forecast of monthly firm energy loads is provided. This forecast reflects normal (1-in-2) weather conditions. The tabulated information includes the annual average load for the year forecast period as well as the monthly load for the first year of the report.

Peak Loads

Northwest regional peak loads are provided for each month of the ten-year forecast period. The tabulated loads for winter and summer peak are the highest estimated 60-minute clock-hour average demand for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utility peak loads, and does not account for the fact that each utility may experience its peak load at a different hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional peak requirements, a planning margin is added to the load. Like the *2018 Forecast*, this year's planning margin is different from past reports. The planning margin is set to 16 percent of the total peak load for every year of the planning horizon. In many *Forecast's* before 2018 the planning margin started at 12 percent for the first year and grew a percent a year until it reached 20 percent and remained at 20 percent thereafter. The justification for this change is three-fold.

- The purpose for the growing planning margin was in part to address uncertainty of planning for generating resources with long planning and construction lead times (coal and nuclear power plants). Utilities are not currently planning for these types of resources.
- The growing planning margin as a percent of load overstated the growing regional requirements and resulting need for power.
- A flat planning margin simplifies comparison analyzes of reports from different years.

This planning margin is intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance and project construction delays.

Demand-Side Management Programs

Savings from demand-side management efforts are reported in *Table 7. Demand-Side Management Programs*. These estimates are the savings for the ten-year study period and include expected future energy savings from existing and new programs in the areas of energy efficiency, distribution efficiency, some market transformation, fuel conversion, fuel switching, energy storage and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response activity is reported in *Table 7* as well. The total load reduction reported is the cumulative sum of different utilities' agreements with their customers. Each program has its own characteristics and limitations.

Generating Resources

This report catalogues existing resources, committed new supply (including resources under construction), as well as planned resources. For the assessment of need only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using a computer model that simulates reservoir operation of past hydrologic conditions with today's operating constraints and requirements. The historical stream flow record used covers the 80-year period from August 1928 through July 2008. The bulk of the hydro modeling used in this report is provided by BPA, the US Army Corps of Engineers, and/or project owners.

Energy

The firm energy capability of hydro plants is the amount of energy produced during the operating year with the lowest 12-month average generation. The lowest generation occurred in 1936-37 given today's river operating criteria. The firm energy capability is the average of 12 months, August 1936 to July 1937. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment.

Peak Capability

For this report the peak capability of the hydro system represents the maximum sustained hourly generation available to meet peak demand during the period of heavy load. Historically, a 50-hour sustained peak (10 hours/day for 5 days) has been reported.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves (including wind reserves).

Computer models are used to estimate the operational hydro peaking capability of the major projects, based on their monthly average energy for 70 or 80 water conditions, depending on the source of information. The peaking capability used for this report is the 8th percentile of the resulting hourly peak capabilities for January and August to indicate winter and summer peak capability respectively. These models shape the monthly hydro energy to maximize generation in the heavy load hours.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoirs and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis.

Downstream Fish Migration

Another requirement incorporated in the computer simulations is modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal and Other Renewable Resources

Thermal resources are reported in a variety of categories. Coal, cogeneration, nuclear, and natural gas projects are each totaled and reported as individual categories.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables include energy from biomass, geothermal, municipal solid waste projects and other miscellaneous projects.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy and peaking capabilities of plants are submitted by the sponsors of the projects and take into consideration scheduled maintenance (including refueling), forced outages and other expected operating constraints. Some small fossil-fuel plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy may be available from these peaking resources but is not included in the regional load/resource balance.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management, are tabulated in this report. These resources are reported as *Recently Acquired Resources, Committed New Supply* and *Planned Resources* to reflect the different stages of development.

Recently Acquired Resources

The Recently Acquired Resources reported in *Table 5* have been acquired in the past year and are serving Northwest utility loads as of December 31, 2018. They are reflected as part of the regional firm needs assessment.

Committed New Supply

Committed New Supply reported in *Table 6* includes those projects under construction or committed resources and supply to meet Northwest load that are not delivering power as of December 31, 2018. In this report, resources being built by utilities or resources where their output is firmly committed to utilities are included in the regional load-resource analysis. Future savings from committed demand-side management programs are reported in Table 7.

Planned Resources

Planned Resources presented in *Table 8* include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. Projects specifically named in *Planned Resources* are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

Contracts

Imports and exports include firm arrangements for interchanges with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, the Pacific Southwest and Canada. Contracts to and from these areas are amounts delivered at the area border and include any transmission losses associated with deliveries.

Short term purchases from Northwest independent power producers and other spot market purchases are not reflected in the tables that present the firm load resource comparisons.

Non-Firm Resources

The *Forecast* omits from the load/resource comparisons non-firm power supply that may be available to utilities to meet needs. These non-firm sources include generation from uncommitted Northwest independent power producers, imports from power plants located outside the region, and hydro generation likely available when water supply is greater than the assumed critical water.

Independent Owned Generating Resources, presented in *Table 11*, include thermal independent power producers (IPP) located in the region. The table below shows the nameplate amount of dispatchable non-firm generation over the next five years. Due to maintenance, unplanned outages, fuel availability, unit commitments to out-of-region buyers, and other factors, the actual amount of resource available from these sources may be less. Note the decrease from 2020 to 2021 as Centralia Unit 1 retires.

Thermal Northwest IPP Nameplate MW				
2019	**2020**	**2021**	**2022**	**2023**
3,095	3,095	2,425	2,425	2,425

Non-firm imports depend on several factors including availability of out-of-region resources, availability of transmission interties, and market friction. In their *2018 Resource Adequacy* study for year 2023, the Northwest Power and Conservation Council assumed 2,500 MW of available spot imports from California in the winter, and zero for summer (3,000 MW of generation was assumed to be available off-peak year-round in a day-ahead market). However, as noted earlier a trend of large thermal resource retirements in the Western Interconnection could impact power available for import into the Northwest in the coming years.

Looking at hydropower, the Forecast assumes critical water (8%) during peak hours. Most years the water supply for the hydro system is not at critical levels. During an average, the region could expect an additional 4,100 MW of sustained peaking generation in January and 2,200 MW in August.

Table 12. Utilities included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec. Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

Definitions

Annual Energy

Energy value in megawatts that represents the average output over the period of one year. Expressed in average megawatts.

Average Megawatts

(MWa) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal

This category of generating resources includes the region's coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

These projects are under construction and/or committed resources and supply to meet Northwest load but not delivering power as of December 31, 2018.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Direct Service Industries (DSI)

Large electricity-intensive industries such as aluminum smelters and metals-reduction plants that purchase power directly from the Bonneville Power Administration for their own use. Very few of these customers exist in the region today.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

Historical Streamflow Record

A database of unregulated streamflows for 80 years (July 1928 to June 2008). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose percent of ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) or non-qualified facilities of independent power producers (IPPs).

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2017 is August 1, 2016 through July 31, 2017.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planned Resources

These resources include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. These projects are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties. In the 2018 *Forecast* the planning margin changed to a flat 16% of the regional load for each year of the study. Earlier reports included a growing planning margin that started at 12% of load, increasing 1% per year until it reached 20%.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

Requirements

For each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems and other utility scale solar projects. This category does not include customer side distributed solar generation.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Wind Resources

This category of resources includes the region’s wind powered projects.

UE 358

Attachment 026-D

Provided in Electronic Format

September 2019 Briefing on Post 2020 Grid Operational Outlook

California ISO

Briefing on post 2020 grid operational outlook

Mark Rothleder, Vice President – Market Quality and State Regulatory Affairs

Board of Governors Meeting

General Session

September 18, 2019

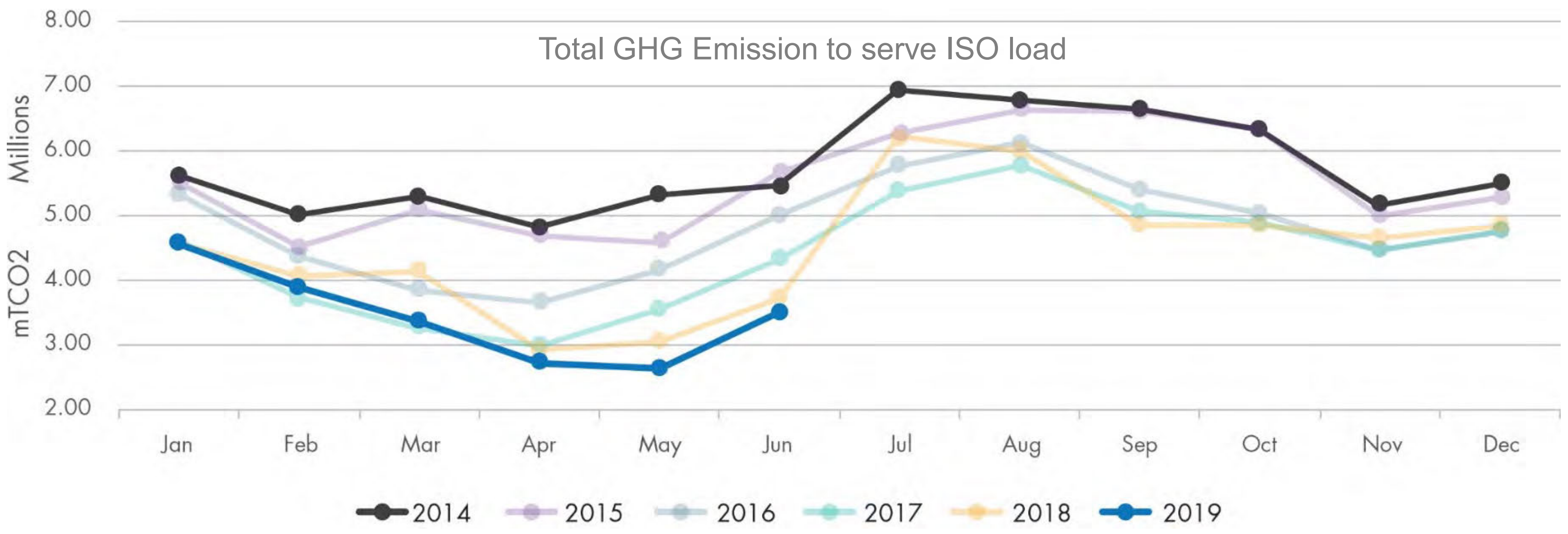
ISO supports California's clean energy goals

33% RPS

78%
highest load level served by renewable energy

98.7%
highest load level served by carbon-free resources

34% Reduction in GHG Emission associated with serving ISO since 2014



California ISO

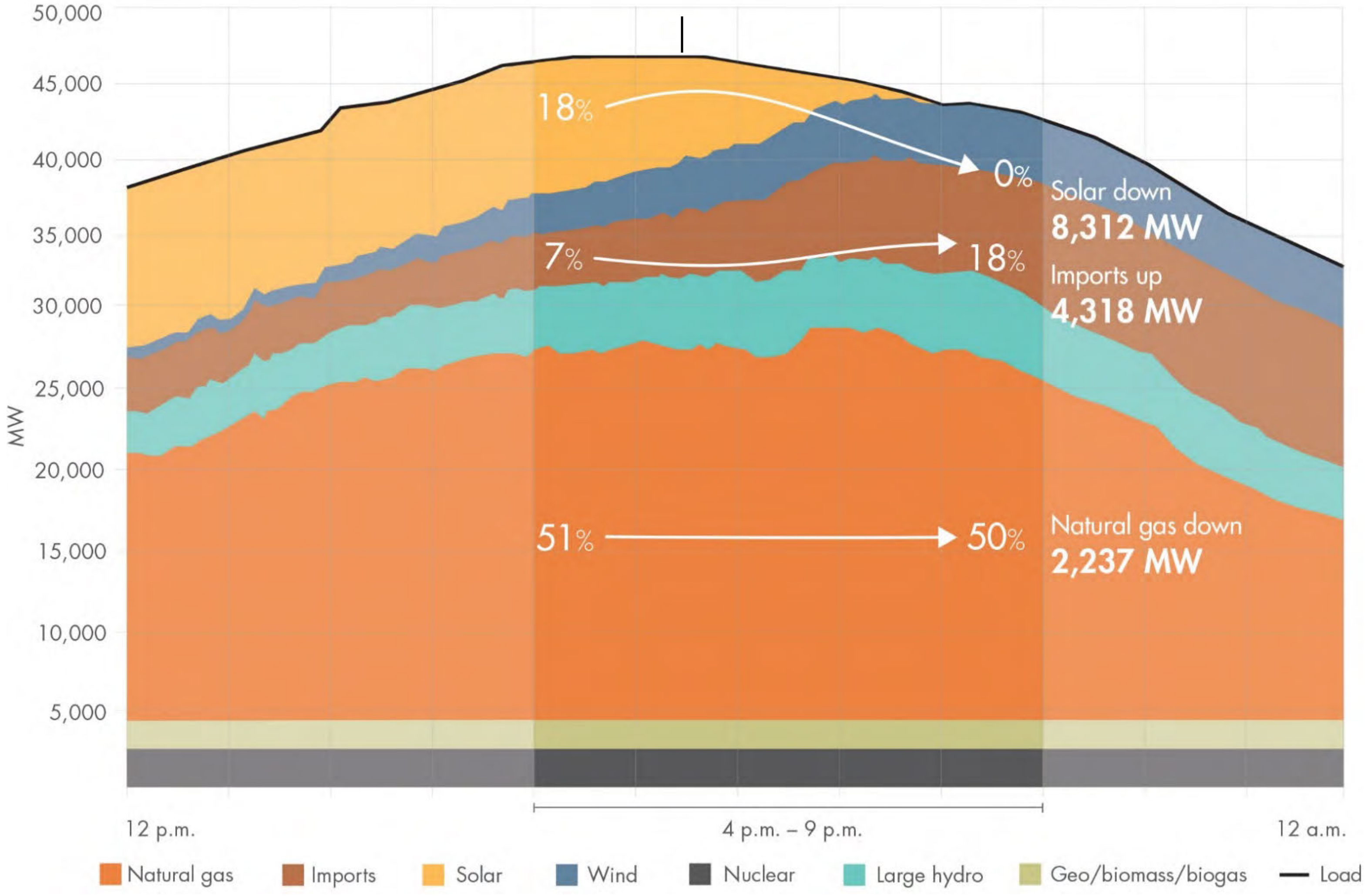
Challenges

- **Challenge 1: Capacity shortfall in 2020 and meeting summer evening peak load**
- Challenge 2: Increased ramping needs
- Challenge 3: Low renewable energy production from multi-day weather events

Challenge 1: Capacity shortfall in 2020 and meeting summer evening peak load

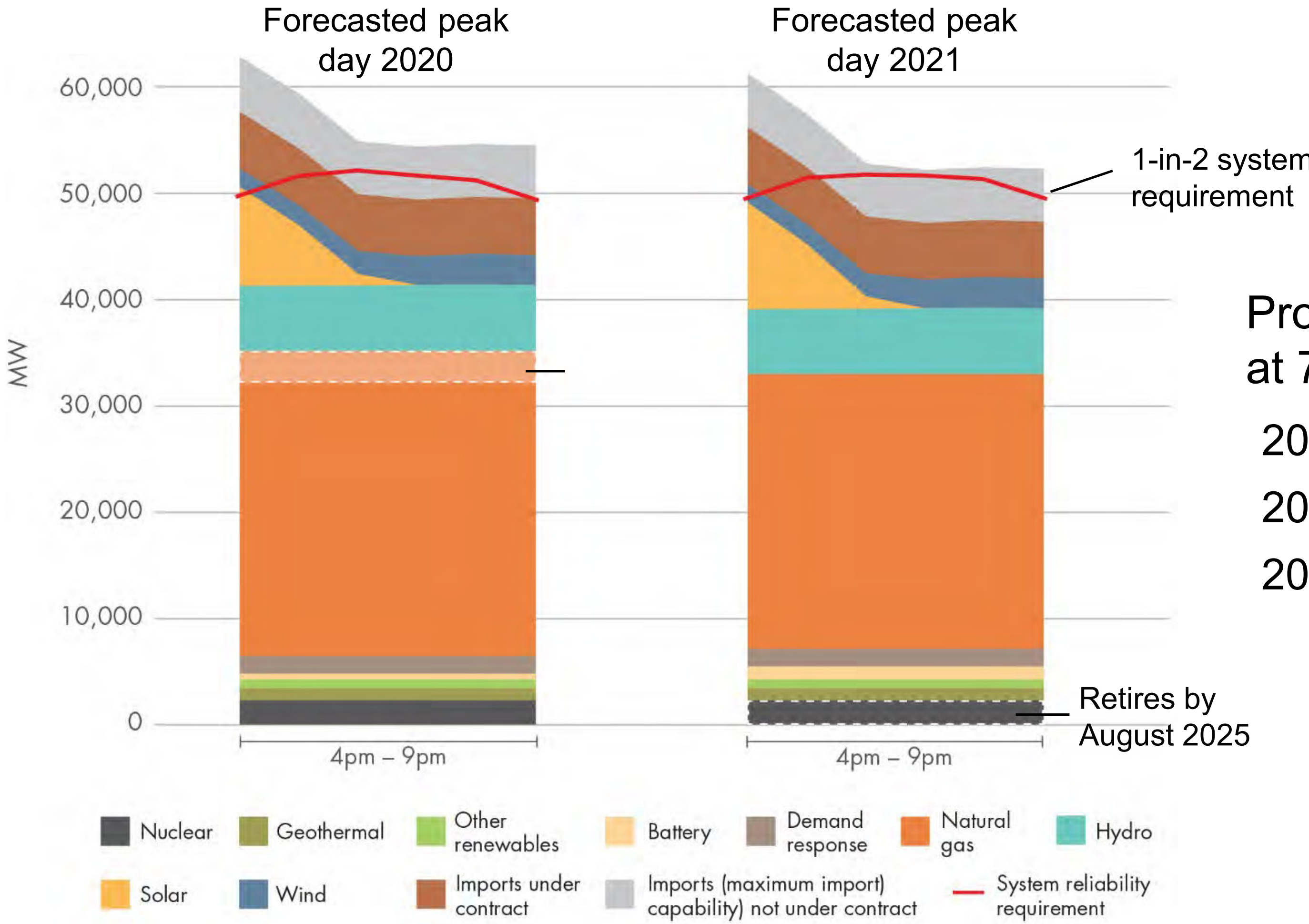
- The peak demand the ISO serves is shifting from the afternoon to the early evening
- Solar production is significantly reduced or not available during these new, later peak demand hours
- Instead, we now rely on energy from natural gas resources and imports
- However, energy capacity is decreasing due to:
  - Net retirement of 4,000 MW of once-through cooling steam generation
  - Reduced imports due to increasing load, thermal resource retirement, and increasing renewable integration needs outside of California
  - Potential changes in hydro conditions and availability in CA and west

Gas and imports support high loads after sun sets



California ISO

Potential resource shortage[1] starting in 2020



Projected shortfalls at 7 p.m.:

2020 = **2,300 MW**

2021 = **4,400 MW**

2022 = **4,700 MW**

[1] *Assumes no transmission outages or other significant events affecting availability of generation*

California ISO

Challenge 1: Capacity shortfall in 2020 and meeting summer evening peak load – ***Recommended actions***

- Increase resource adequacy contracting from operational, mothballed and new resources
- Secure available import capacity
- Consider extension of once-through cooling compliance date on critical units until CPUC identifies alternatives

- Diversify fleet for evening peaks, include preferred resources that align with needs; e.g. geothermal and wind
- Add both short- and long-duration storage focused on evening peak
- Strategically maintain gas fleet

Other actions to consider:

- **Add automated demand response**
- **Increase energy efficiency**

UE 358

Attachment 026-E

Provided in Electronic Format

External Study E. Market Capacity Study

External Study E. Market Capacity Study

Northwest Loads and Resources Assessment

Prepared for Portland General Electric

January 2019

Energy+Environmental Economics

Northwest Loads and Resources Assessment

Prepared for Portland General Electric

January 2019

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Project team:
Kiran Chawla
Manohar Mogadali
Nick Schlag
Arne Olson

Table of Contents

1 Study Scope & Overview

In 2017, the Oregon Public Utilities Commission (OPUC) acknowledged Portland General Electric's (PGE) request to conduct a study related to the treatment of existing surplus capacity available in the market for PGE's 2019 Integrated Resource Plan. The specific questions PGE was seeking to answer were:

+ How future changes in resources and loads in the Pacific Northwest might affect the region's overall capacity position; and
+ The implications of these factors have for PGE's long-term planning assumptions of market purchases of available surplus capacity

The Pacific Northwest has historically been in a surplus condition for capacity. As a result, some utilities in the region have relied on the purchase of surplus capacity from the markets to cost-effectively meet their resource adequacy targets and peak demand needs. However, a number of recent studies of the capacity availability in the region have shown that the region is expected to be short on capacity in the near-term. This study examines the expected changes in loads and resources for the region and its implications for PGE's long-term resource planning assumptions with regards to the availability of market purchases of surplus capacity.

A number of existing studies conducted by entities within the region have examined similar questions. These studies generally point to several emerging trends that will impact the load-resource balance of the Northwest in the future:

+ Increasing peak loads, especially in the summer;
+ Anticipated coal plant retirements;
+ Limited anticipated additions of thermal power plants in the coming years;
+ Addition of new renewables to meet regional policy goals; and
+ A continued high level of energy efficiency achievement by utilities.

These trends are expected to reshape the regional load-resource balance in the next few years.

PGE hired Energy & Environmental Economics (E3) to conduct a study to inform its integrated resource planning process by examining these trends and their implications for the region's load-resource balance. To understand the variability in expected surplus capacity in the region and its relationship to some of the key assumptions, E3 reviewed existing studies examining the forecasted regional balance of loads and resources and developed a simple, flexible Excel spreadsheet tool ('E3 model' or 'the model') to investigate a range of scenarios for the region. E3 used the model to create 3 scenarios – a 'Base Case', reflecting expected trends within the industry, as well as 'High Need' and 'Low Need' scenarios that provide upper and lower bounds on the availability of surplus capacity. The key inputs, assumptions and results for the different scenarios are described in the following sections.

The remainder of this report is organized as follows:

+ Section 2 begins with a summary of the existing studies looking at the capacity position for the region;
+ Section 3 describes the approach used by E3 to develop its heuristics-based model;
+ Section 4 describes the scenarios and input assumptions used in the model to create recommendations for capacity position; and
+ Section 5 concludes with a range of scenario-based recommendations for market capacity purchases available for PGE.

2 Review of Findings in Existing Studies

2.1 Overview of Studies

To understand the ranges for plausible forecasts for load and resource buildout and retirements, as well as regional imports and exports for the region, E3 reviewed existing studies published by key regional entities such as the Northwest Power and Conservation Council (NWPCC, or 'the Council'), Bonneville Power Administration (BPA) and Pacific Northwest Utilities Conference Committee (PNUCC).

The Council publishes two key documents that look at expected changes to loads and resources for the region:

+ The Pacific Northwest Power Supply Adequacy Assessment ('2023 Adequacy Assessment') is a short-term outlook that assesses the loss of load probability in a snapshot operating year, typically 5 years out, and,
+ The Northwest Conservation and Electric Power Plan ('7th Power Plan') takes a longer-term approach of looking at load and resource changes expected through a longer time horizon. The most recent document has provided an outlook through 2035

BPA publishes an annual study called the 'White Book' reviewing the loads and resources expected for both the Federal hydro system and the Northwest region footprint (which uses the same geography used by the Council). For this analysis, E3 reviewed the 2017 Pacific Northwest Loads and Resources Study ('2017 White Book') published by BPA.

The Pacific Northwest Utilities Conference Committee (PNUCC) is another regional entity that publishes the expected trends in loads and resources for the Pacific Northwest. E3 reviewed the 2018 PNUCC Northwest Regional Forecast of Power Loads and Resources ('2018 PNUCC study') for this analysis.

Across all of the studies, the key assumptions that are varied are:

+ Expected load growth in the region, and levels of achievable energy efficiency (EE) and demand response (DR) resources
+ Resources available to meet peak loads in the region, which include assumptions on thermal retirements, expected renewables build, as well as the uncontracted independent power producer (IPP) resources that can sell power into the Pacific Northwest as well as to regions outside of the Pacific Northwest footprint such as California
+ Analytical approach used in evaluating system energy and capacity needs (deterministic versus stochastic, or probability based), and the metrics used to reflect the needs (whether it's a planning reserve margin or a loss of load probability metric).
+ Treatment of different types of variable and use-limited resources (e.g. wind, solar, hydro, storage) in their contribution to meeting system resource adequacy needs.

The descriptions for each of the studies and the key assumptions and conclusions from the studies reviewed are detailed below.

2.1.1 NWPCC 2023 ADEQUACY ASSESSMENT

The Council publishes an annual outlook for a future operating year, typically 5 years out, to assess resource adequacy with a probabilistic approach. The Council, in collaboration with the Resource Adequacy Advisory Committee (RAAC), uses its probability-based resource adequacy model GENESYS to provide loss of load probability (LOLP) statistics as well as other adequacy metrics such as the size of potential shortages, their frequency, and their duration. For the system to be deemed adequate in terms of power supply, the Council targets an annual LOLP of less than 5%—meaning that, on average, loss of load events will occur in fewer than one in twenty years. The adequacy analysis uses an aggregate regional approach to assess power supply, and the individual utilities may have different results from those examined by the Council at a regional level. The Council tests the impacts of differing peak loads and availability of market imports from California in its assessment to provide a range of LOLP results.

2.1.2 NWPCC 7TH POWER PLAN

The Council also develops and publishes a power plan for an adequate, efficient, economic and reliable power supply for the region every five years; the most recent of these, the 7th Power Plan (the 'Power Plan'), was released in 2016. In the process of developing its plan, the Council incorporates feedback from a variety of technical and policy advisory stakeholder groups that represent interests of utilities, state energy offices, and public interest groups. The purpose of the plan is to address different sources of uncertainties facing the electric system in the Northwest and to provide guidance on the resources that could be used to achieve a reliable and economic power system over a 20-year period.

The Power Plan provides a resource strategy based on differing assumptions on load growth, energy efficiency, demand response and procurement of other resources. As a part of this evaluation, the Power Plan inherently examines the balance of loads and resources within the region, identifying the potential long-term need for new capacity as well as resource strategies to meet it.

2.1.3 2017 BPA WHITE BOOK

Every year, BPA publishes the "White Book," which is an outlook on the Federal System and Pacific Northwest region's loads and resources for the upcoming 10-year period. BPA uses the White Book for long-term planning purposes for its service territory, as well as to make information and data available for interested regional entities. For the purpose of this study, E3 focused on the Pacific Northwest regional analysis provided in the White Book.

In its regional analysis, BPA estimated the future loads and export obligations and compared those to forecasts for generation and contractual purchases to estimate regional energy and capacity surpluses or deficits. The White Book results are provided for both winter energy and capacity needs, at a monthly as well as annual time step. However, the BPA White Book does not provide a capacity and energy surplus or deficit analysis for the summer.

2.1.4 2018 PNUCC NORTHWEST REGIONAL FORECAST OF POWER LOADS AND RESOURCES

Similar to BPA, the PNUCC publishes its annual outlook for the region's demand and power supply. In order to develop its forecasts for regional loads and resources, the PNUCC document uses information gathered from utilities and provides an outlook on the Northwest power system accessible to key stakeholders.

2.2 Literature Review Takeaways

There are differences in some of the key assumptions and analytical approaches used by the regional entities to provide estimates of the region's net capacity position. The key assumptions and how they are treated across the studies are described in Table 1.

Despite these differences in assumptions, the results from the studies are broadly consistent. The BPA White Book, the NWPCC 2023 Adequacy Assessment as well as PNUCC study show a net winter capacity need for the region by 2021. The NWPCC 7th Power Plan provides a range of net capacity positions for 2021 from a surplus of approximately 700 MW to a deficit of approximately 1 GW. If IPPs that are not contracted to specific regional entities are not available as dependable resources to meet peak needs, the winter capacity need would be realized as early as 2019. Because the PNUCC study does not include in-region IPPs among its dependable resources for the region, it shows a winter capacity need of 1.8 GW by 2019 and a summer capacity need of 0.3 GW starting in 2021.

Table 1 Key assumptions for different existing studies included in the literature review.

Assumption	NWPCC 2023 Adequacy Assessment	NWPCC 7th Power Plan	2017 BPA White Book	2018 PNUCC Study
Analytical Approach	Stochastic	Deterministic	Deterministic	Deterministic
Peak Load Forecast	Distribution of peak loads for 80 temperature year	Ranges of weather-normalized load forecasts	BPA load forecasts	Non-coincident peak (NCP) of all participating utilities
Resources	Existing and planned, IPPs included	Existing, IPPs included	As per utility IRPs, IPPs included	Existing and committed; IPPs not included
Adequacy Metric	LOLP standard of 5%	Adequacy Reserve Margin (ARM) instead of PRM	Reserve margin requirement based on operating reserves and transmission losses	Planning Reserve Margin (PRM) of 16%
Hydro Capacity	A wide range of hydro conditions modeled stochastically in GENESYS	P2.5% 10-hour sustained peaking ability	BPA internal Hourly Operating and Scheduling Simulator (HOSS) model	8th percentile based on average water
Wind Capacity	ELCC endogenously calculated in GENESYS	5% assumed contribution to ARM	Wind capacity not counted as firm	5% assumed contribution to peak

3 Modeling Approach

3.1 Modeling Methodology

To inform input assumptions for PGE's IRP, E3 developed a model to determine the future trajectory of loads and resources under different assumptions for the Northwest region to estimate the net capacity position expected for the region in future. The model was informed by existing studies, and can be used to vary key assumptions to test their impact on the expected regional capacity surplus or deficit.

The model created to inform this study uses a "planning reserve margin" (PRM) approach to examine the balance of loads and resources within the region. The concept of a PRM—a common convention used to estimate the amount of dependable capacity needed by a utility or region to serve load based on a margin needed above average conditions to account for weather excursions, unplanned plant outage, as well as contingency reserves —is used by individual utilities both within the Northwest and throughout the country. While the Northwest region does not have a formal PRM requirement as a reliability standard, the concept remains a useful approach to evaluate the balance of loads and resources within the region.

3.2 Model Calibration Approach

The PRM approach used herein is not intended to supplant the more detailed loss-of-load-probability modeling conducted by the Council in its studies. Rather, E3 calibrated its model to provide results consistent with the Council's 2023 Adequacy Assessment. The Council's adequacy assessment uses a sophisticated stochastic modeling approach to estimate the loss of load probability metrics for the region and is arguably the most robust study of reliability needs in the region. The purpose of calibrating the model is twofold: 1) calibrating the model to the Council's adequacy assessment helps benchmark to the best available information for the region, and 2) the model can then be used to test additional scenarios and sensitivities not provided in existing regional studies.

In order to calibrate the E3 model to the Council's adequacy assessment, E3 used a three-step process:

1) Align input assumptions for regional load and available generation resources with the 2023 Adequacy Assessment;

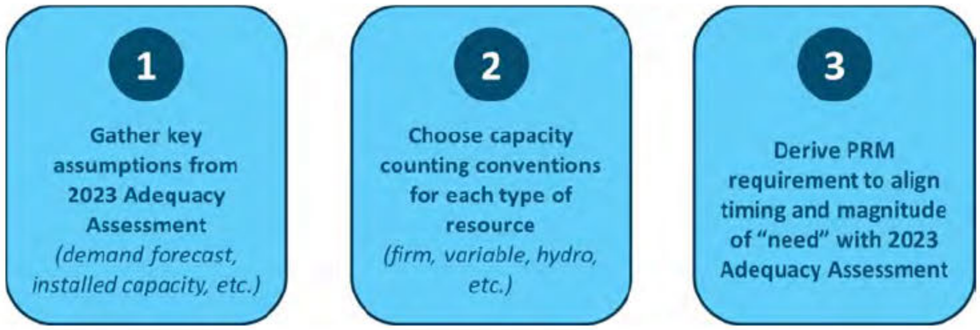
2) Select conventions used in the model to translate nameplate capacity to dependable capacity[1] for each resource; and

3) Adjust the PRM requirement (% of regional peak demand) to align regional surplus/deficit with the 2023 study.

This approach is illustrated in Figure 1 below.

[1] These conventions are informed by the 7th Power Plan where applicable, as discussed in Section 3.3.2.

Figure 1 Calibration approach and the derivation of the PRM used in the model.



Through this process, E3 was able to translate the probability based stochastic modeling used by the Council in its adequacy assessment into a simple heuristic-based planning metric. Some of the key differences between the Council's GENESYS model used for estimating regional capacity position and the spreadsheet based E3 model with the simplified PRM treatment are highlighted in Table 2.

Table 2. Key differences between the NWPCC 2023 Adequacy Assessment GENESYS model and the spreadsheet based E3 model.

Category	GENESYS	E3 Model
Approach	Stochastic	Deterministic
Adequacy Metric	LOLP	PRM
Analysis Horizon	One year snapshot	15-year outlook
Hydro	Stochastic simulation of 80+ years	Assumed contribution (%) to winter & summer peak
Renewables	Stochastic simulation of hourly renewable output	Assumed static ELCC (%)

3.3 Assumptions Used in Calibration

3.3.1 LOADS AND RESOURCES

As discussed in section 3.1, E3 used the NWPCC 2023 Adequacy Assessment to align key inputs including summer and winter peak loads net of expected energy efficiency, levels of demand response in the summer and winter, contracted as well as market imports and exports from outside of the Northwest footprint, capacity of thermal resources, and availability of in-region IPP resources.

Table 3 Summary of 2023 seasonal loads and nameplate resources in the Northwest.

Loads	2023 Load MW (Winter)	2023 Load MW (Summer)
1-in-2 Peak Demand (including cost-effective EE)	34,070	27,176
Firm Exports	462	477
Total Load	34,532	27,653
Resources	**Nameplate Capacity MW (Winter)**	**Nameplate Capacity MW (Summer)**
Thermal (includes IPPs)	14,679	12,973
Hydro	34,697	
Solar	448	

Wind	6,264	
Other	1,200	
DR	740	1056

3.3.2 DEPENDABLE CAPACITY CONVENTIONS

For each resource type included in the model, E3 chose a convention to translate the region's nameplate capacity to an estimate of dependable capacity. The conventions generally used are:

+ The contributions of thermal and demand response resources are assumed to be 100% of nameplate capacity;
+ The contribution of hydro resources, due to energy limits related to hydro conditions, are based on their 10-hr sustained peaking capability; and
+ The contribution of variable renewable resources, including wind and solar, are based on assumed "Effective Load Carrying Capability"—a measure of the equivalent firm capacity for variable resources.

The resulting quantities of dependable capacity available to the region in the summer and winter seasons are shown in Table 4 and Table 5 below; additional detail and justification for the conventions used to attribute dependable capacity to hydro and renewable resources is subsequently discussed.

Table 4 Summary of 2023 winter nameplate and dependable capacities of resources in the Northwest.

Resources	Nameplate Capacity MW (Winter)	Dependable Capacity % (Winter)	Dependable Capacity MW (Winter)
Thermal (includes IPPs)	14,679	100%	14,679
Hydro	34,697	51%	17,790
Solar	448	26%	116
Wind	6,264	5%	313
Other	1,200	65%	784
DR	740	100%	740
Total	**58,028**		**34,422**

Table 5 Summary of 2023 summer nameplate and dependable capacities of resources in the Northwest.

Resources	Nameplate Capacity MW (Summer)	Dependable Capacity % (Summer)	Dependable Capacity MW (Summer)
Thermal (includes IPPs)	12,973	100%	14,679

Hydro	34,697	44%	15,404
Solar	448	81%	363
Wind	6,264	5%	313
Other	1,200	65%	784
DR	1056	100%	1056
Total	**56,638**		**32,599**

3.3.2.1 Thermal Resources

In this study, the contribution of thermal resources towards the regional reserve margin requirement is assumed to be equal to their nameplate capacity. This convention is commonly used by utilities who rely on a planning reserve margin requirement.

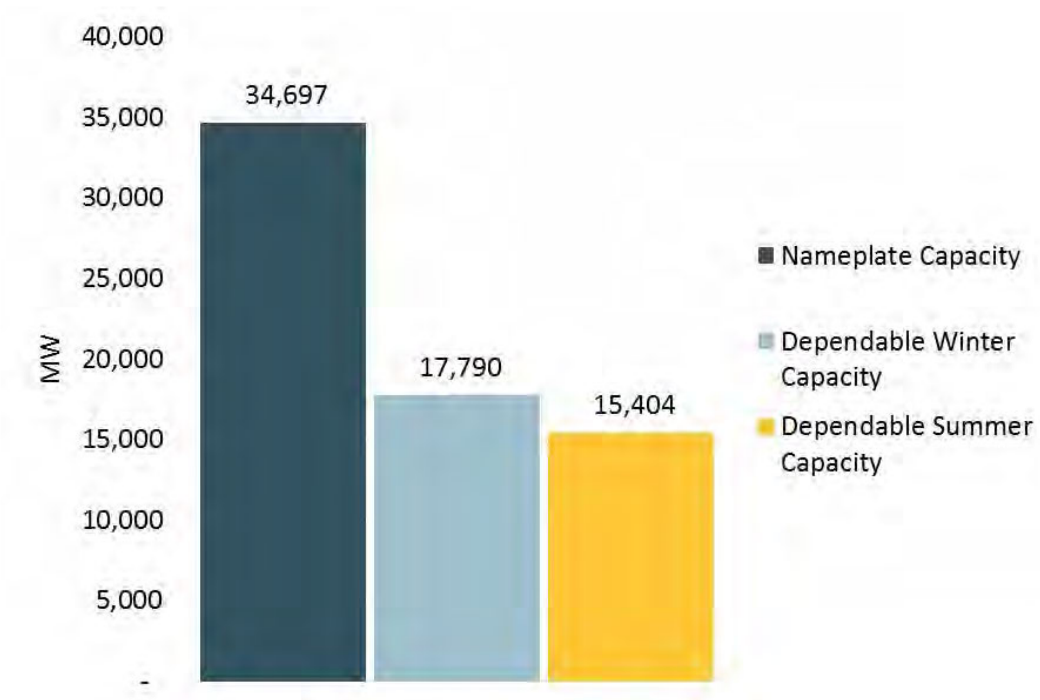
3.3.2.2 Demand Response Resources

The treatment of demand response (DR) resources in this study is simplified and their full capacity is assumed to contribute towards the regional reserve margin requirement. This may overstate the dependable capacity of DR resources because in reality they are energy limited, and have limits on the number of times they can be called as well as the duration of those calls.

3.3.2.3 Hydro Resources

The Pacific Northwest region has more than 34 GW of nameplate hydro capacity and extensive hydro reservoirs. However, the full capacity of these resources is typically not counted towards meeting the region's peak loads due to their energy limited nature as well as other non-power constraints on the hydro system. For the E3 model, a simplified static view of the hydro system was needed. E3 selected the sustained dependable capacity values provided in the 7th Power Plan. The values are higher for the winter than for the summer. The nameplate capacity, the dependable winter capacity and the dependable summer capacity for the hydro fleet is shown in Figure 2.

Figure 2. Seasonal dependable capacity of hydro resource fleet in the Northwest.



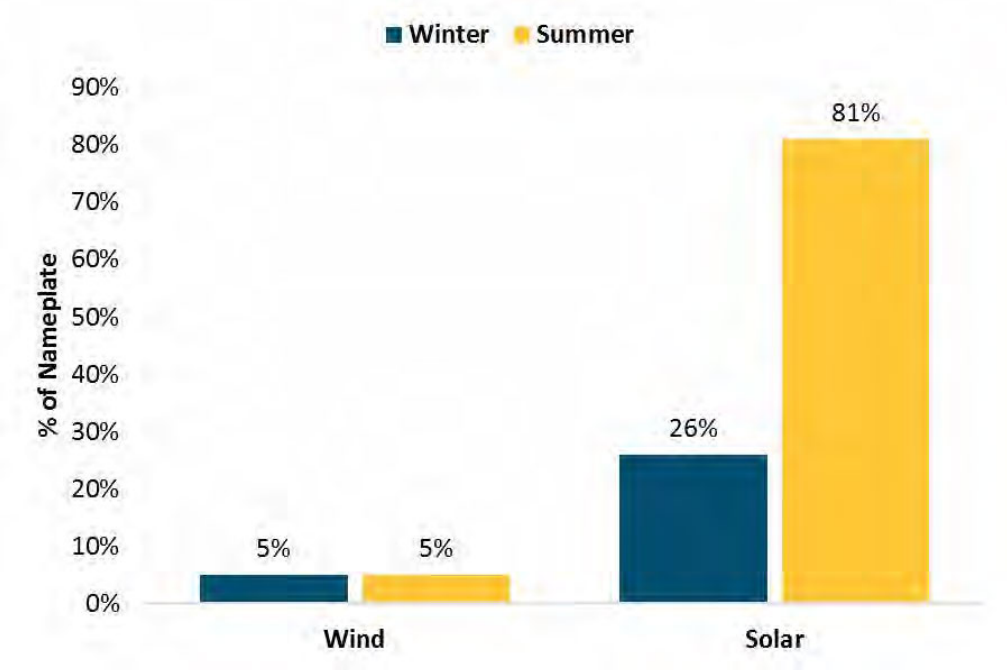
Even though this convention used for PRM purposes, it does not mean that the planning horizon assumes critical water conditions for the study period. With a different convention used for hydro dependable capacity, a different PRM would be calculated, but the identified capacity need would still be the same.

3.3.2.4 Renewable ELCC

Variable renewable resources do not usually contribute their full nameplate capacity towards meeting system peak needs. Due to their intermittent generation, to estimate the contribution of renewables to system peak, effective load carrying capacity (ELCC) of renewables is used. The ELCC metric helps translate the renewable production as a fraction of nameplate capacity during a peak load event.

For developing estimates for wind and solar ELCC, E3 used the Council's 7th Power Plan. In Chapter 11 of the 7th Power Plan, the Council provides a system adequacy assessment. In this assessment, the 7th Power Plan provides assumptions related to dependable capacity of wind and solar resources. For wind resources, E3 used the Power Plan's assumption of 5% ELCC for wind resources for both winter and summer. For solar resources E3 used the 'Associated System Capacity Contribution' (ASCC) metric of 26% in the winter and 81% in the summer, which is the closest to an ELCC metric provided in the Power Plan. The variable renewables ELCC assumptions by season are provided in Figure 3.

Figure 3 Seasonal ELCC for wind and solar resources as a fraction of their nameplate capacity.



3.3.3 PLANNING RESERVE MARGIN REQUIREMENT

After aligning the input assumptions with the Council's adequacy assessment and 7th Power Plan, E3 derived a planning reserve margin in a simplified manner that yielded approximately the capacity need for winter 2023 published by the Council. The planning reserve margin therefore is directly tied to the input assumptions used in deriving it. The metric is treated as a calibration parameter and would change if the underlying assumptions, such as the dependable capacity of hydro resources or renewables ELCC, are changed.

Table 6 below summarizes these assumptions and how they are used to derive the PRM metric in the E3 model for the winter. The same PRM metric is then used for the summer analysis as well.

Table 6 Summary of winter assumptions used in model calibration and derivation of the planning reserve margin.

Resource	Dependable MW	Additional Detail
Total Dependable Capacity	34,422	
Imports	2,565	2,500 MW from CA + 65 MW firm imports
Generic Need identified in 2023 RA Assessment	700	
Total Resources	**37,687**	
Loads	**Load MW**	
1-in-2 Peak Demand	34,070	
Firm Exports	462	
Total Load	**34,532**	
Reserve Margin Need	**~10%**	**Ratio between Total Resources & Total Load**

4 Scenario Inputs and Assumptions

In order to create a reasonable range of expected capacity surplus or deficit for the region, E3 developed three scenarios using the model. The base scenario uses the assumptions aligned with the Council's 2023 Adequacy Assessment, extended through 2035. For the Low Need and High Need scenario, E3 varied key drivers such as loads, energy efficiency, demand response (DR) and availability of market imports from California. The scenario-specific loads, EE and DR assumptions were derived using a combination of inputs from the Council's 2023 Adequacy Assessment and the 7th Power Plan.

The resource assumptions were obtained from the Council's Power Plant database[2] and updated to reflect new information where applicable. The Power Plant database was published in 2015, so the coal retirement announcements since then have been reflected in the database by E3. The hydro and renewables dependable capacity are held constant across scenarios to maintain consistency with the derived planning reserve margin.

For the assumption of market imports available for the Northwest from California, E3 used a combination of the Council's 2023 Adequacy Assessment

[2] Can be accessed at https://www.nwcouncil.org/energy/energy-topics/power-supply

assumptions and internal analyses related to expected capacity position for California in the summer and winter.

A summary of the assumptions used in the three scenarios is provided in Table 7.

Table 7. Key assumptions across the Low Need, Base Case, and High Need scenarios.

Assumption	Low Need	Base Case	High Need
Load Forecast *(pre-EE)*	1.46%/yr (W); 1.73%/yr (S)	1.74%/yr (W); 1.92%/yr (S)	1.94%/yr (W); 2.21%/yr (S)
Energy Efficiency *(treated as a resource)*	**100%** of cost-effective EE	**100%** of cost-effective EE	**75%** of cost-effective EE
Demand Response	NWPCC Low	NWPCC Med	NWPCC High
Thermal Generation	Announced retirements		
Hydro Generation	Constant at today's levels		
Renewable Generation	Current plans		
Market Imports	3400 MW through 2023, 2100 MW by 2030 (W); 1400 MW in the near term, 0 in the long term (S)	2500 MW (W); 0 (S)	3400 MW through 2021, 0 after 2023 (W); 0 (S)

The detailed assumptions for each category are described in sections 4.1 to 4.6 below.

4.1 Load Forecast

E3 relied on a combination of the Council's adequacy assessment and 7th Power Plan to develop a reasonable range of low, mid and high load forecast trajectories. The 2023 Adequacy Assessment document is a near-term reliability outlook for a single snapshot year and is a more appropriate reference source for near-term peak load forecasts. The 7th Power Plan, by contrast, is a long-term planning document with less of a focus on near-term peak load forecasting. The 7th Power Plan is a more appropriate source for reasonable ratios between low, mid and high future load trajectories that incorporate uncertainty in drivers of loads. As a result, E3 used the 2023 Adequacy Assessment study to determine the mid scenario loads, but supplemented it with the ratios between low to mid and mid to high scenarios from the 7th Power Plan to create a range of load forecast assumptions. The mid scenario gross-load forecast (i.e. before the impact of energy efficiency or DR) was developed using a 3 step-approach as shown in Figure 4:

1) Begin with Council's 2023 Adequacy Assessment peak load forecast (which includes cost-effective energy efficiency)
2) Add back in the embedded cost-effective energy efficiency (treated explicitly as a resource in the E3 model)
3) Extrapolate the gross loads using the compound average growth rate for the 2020-23 period

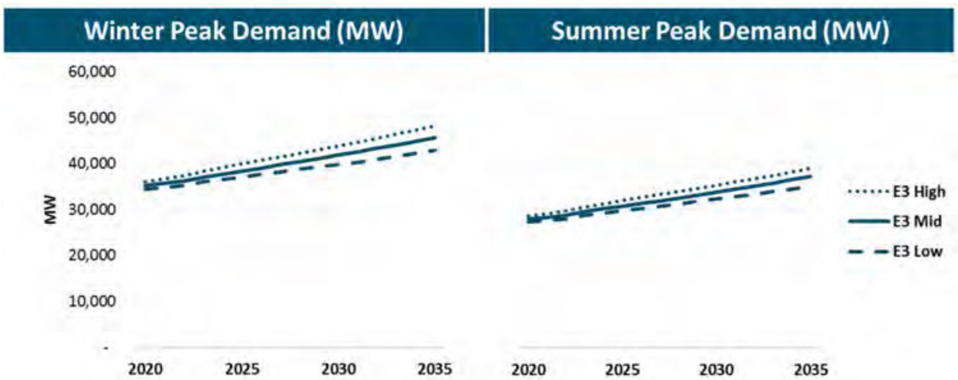
The derivation of the Base Case forecast consistent with the 2023 Adequacy Assessment and the resulting forecast is shown in Figure 4.

Figure 4. Development of mid scenario gross load forecast.

To develop a range of forecasts, E3 applied the ratios of mid to low loads and mid to high loads obtained from the 7th Power Plan to incorporate the expected ranges in pre-EE loads.

The resulting pre-EE load growth rates for peak loads in the winter are in the 1.5% - 1.9% range, whereas for summer they are higher, in the 1.7% - 2.1% range. The scenario specific peak load assumptions for winter and summer are shown in the figure below. Even though the summer peak grows at a rate higher than the winter peak, as seen in the figure below, it stays lower than the winter peak levels.

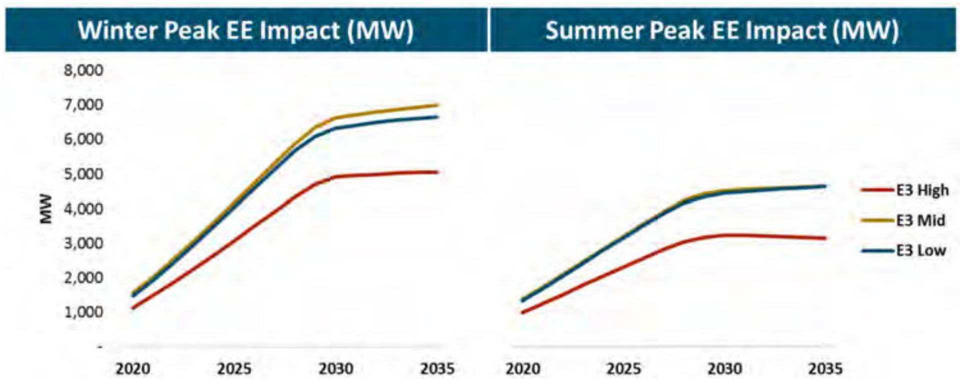
Figure 5. Seasonal peak load forecasts for the Low Need, Base Case, and High Need scenarios.



4.2 Energy Efficiency

In the E3 model, future achievement of energy efficiency is treated as an incremental supply resource (rather than embedding its effect in the demand forecast). This study relies on the estimated deployment of cost-effective energy efficiency identified by the Council in its 7th Power Plan; the Council's forecast achievement of efficiency is used directly in the Base and Low Need scenarios and derated by 25% in the High Need scenario. The assumed contribution of energy efficiency towards meeting peak loads is shown in Figure 6. Due to the achieved energy efficiency assumed to be 75% of the levels identified in the 7th Power Plan, the High Need scenario energy efficiency values are lower than the Base Case scenario assumptions.

Figure 6. Seasonal impact of energy efficiency on regional peak loads by scenario.



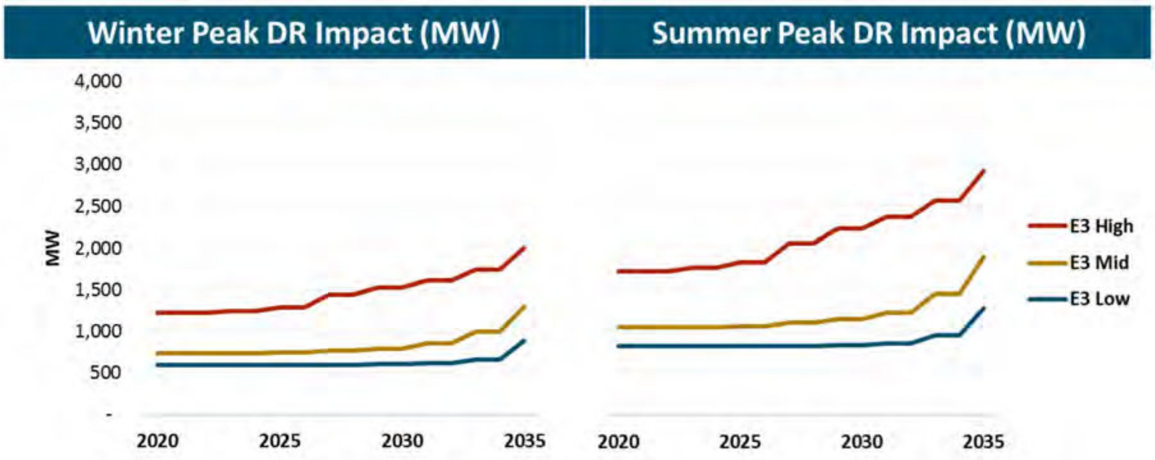
4.3 Demand Response

Similar to energy efficiency, E3 modeled demand response as a resource in the E3 model. To maintain consistency with loads and energy efficiency, the low, medium, and high DR assumptions from 7th Power Plan were used for the Low Need, Base Case, and High Need scenarios. The winter values from the 7th Power Plan were reduced by approximately one third, consistent with the Council's approach in the 2023 Adequacy Assessment, which adjusted the winter DR values due to "ongoing concerns about barriers to its acquisition."[3] The resulting

[3] The DR contribution to peak is not further adjusted to account for reduced capacity contribution due to impacts of call limited, time limited and snap back behavior.

assumptions for DR contribution to peak loads by season for the different scenarios are shown in Figure 7 below.

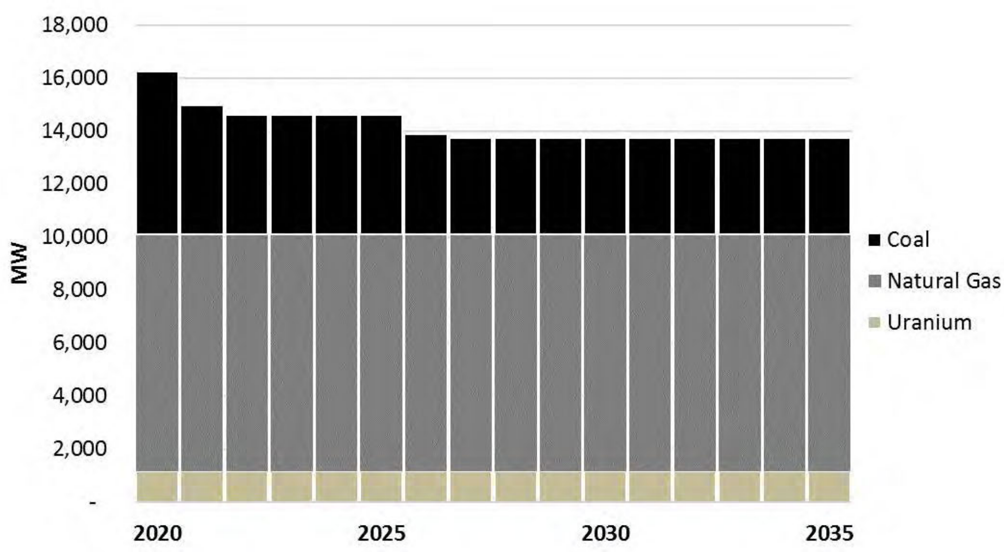
Figure 7 Seasonal impact of demand response on regional peak loads by scenario.



4.4 Thermal Resources

E3 used the Council's Power Plant database as a starting point to determine the available nameplate capacities of all the generators in the region. The total dependable capacity levels by thermal technology types were benchmarked to the Council's 2023 Adequacy Assessment. The coal retirement dates were updated to reflect the latest planned retirement schedules. The nuclear and gas resources were assumed to stay online for the study horizon.

Figure 8 Dependable capacities for coal, natural gas and nuclear resources in the Northwest over time.

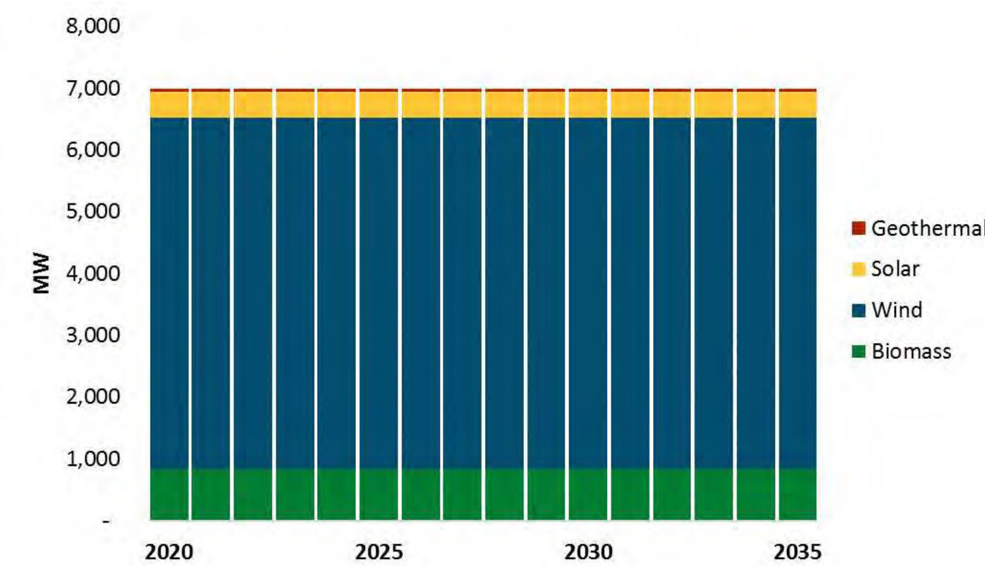


Among thermal resources, there are resources in the Northwest that fall under the category of 'independent power producers' or IPPs. These resources are physically located in the Northwest, but if not contracted to a particular in-region entity, may sell power to out of region markets. For IPPs, E3 assumed their full dependable capacity (~2.3 GW in 2023) was available for in-region demand needs in the winter, consistent with the assumption made by the Council in its modeling. For the summer, the IPPs availability is derated (1000 MW in 2023) to account for the likelihood of these resources selling into California, which is a summer peaking system, again consistent with the Council's 2023 Adequacy Assessment.

4.5 Renewables Resources

Nameplate capacities for renewables resources, both existing as well as planned, were obtained from the Council's power plants database. The planned renewables resources in different stages of development are provided in the power plants database. Consistent with the Council's adequacy assessment assumptions, E3 included the renewables resources that were under construction or were in advanced stages of development as demonstrated by a site certificate, engineering procurement and construction contract, and/or an announced construction schedule. As described in section 3.2.2, the nameplate capacities were translated to ELCC metrics using static assumptions for both wind and solar.

Figure 9. Nameplate capacities for existing renewable resources in the Northwest.

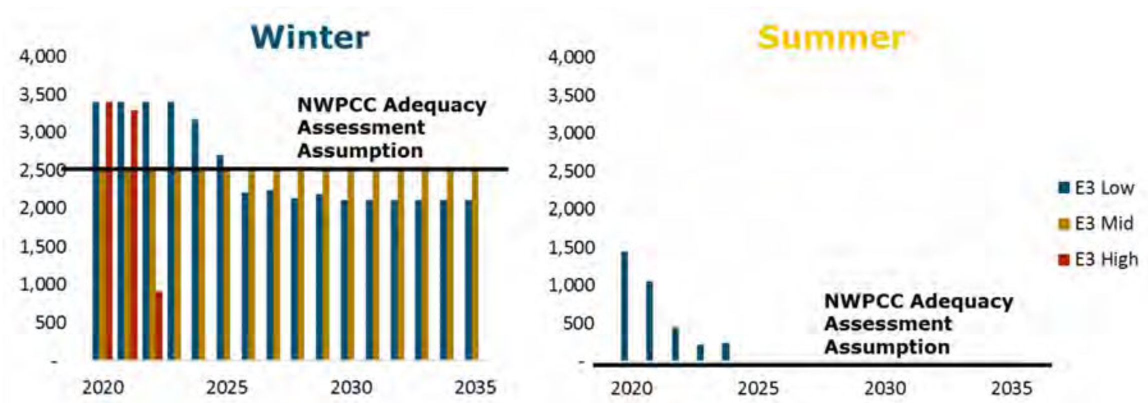


4.6 Availability of California Imports

The availability of imports from California into the NW was varied by scenario. For the mid scenario, the assumptions were aligned with the Council's adequacy assessment. For the Low Need and High Need scenarios, E3 estimated the available surplus for the NW through an analysis of CAISO load-resource balance for the winter and summer. For its CAISO calculations, E3 relied on the California Energy Commission's (CEC) load forecasts and California Public Utilities Commission's (CPUC) integrated resource planning model's resource availability assumptions.

The maximum import availability is capped at 3400 MW, which is the 95th percentile transfer capability on the transmission system from California to the Northwest.

Figure 10. Annual availability of imports into the Northwest from California by season for the three modeled scenarios.



As seen in Figure 10, in the near-term, the winter surplus is higher than the Council’s adequacy assessment assumption for the low need and high need scenarios. This is because in the near-term, E3 calculations for the CAISO loads and resources balance show a surplus in the winter. In the longer-term, E3 calculations used for the low as well as high scenario show imports from California into the Northwest being less than those assumed by the Council’s adequacy assessment due to a combination of increasing winter loads in California as well as once-through cooling thermal plant retirements. For the summer, the low scenario calculations by E3 assume low load growth in the summer resulting in a surplus of capacity in the near term. For the mid and high scenarios, California does not have surplus power to export to the Northwest in the summer.

5 Results and Conclusions

Using the assumptions described in Sections 3 and 4 for the different scenarios, E3 developed:

+ A range of capacity position estimates for the NW region as a whole
+ A range of available market surplus capacity for PGE

To allocate the available regional surplus to PGE, if any, E3 used PGE's peak load share of the regional peak for summer and winter. Using data on peak load forecasts obtained from PGE, E3 calculated the winter share for PGE to be ~10% and the summer share to be ~12%.

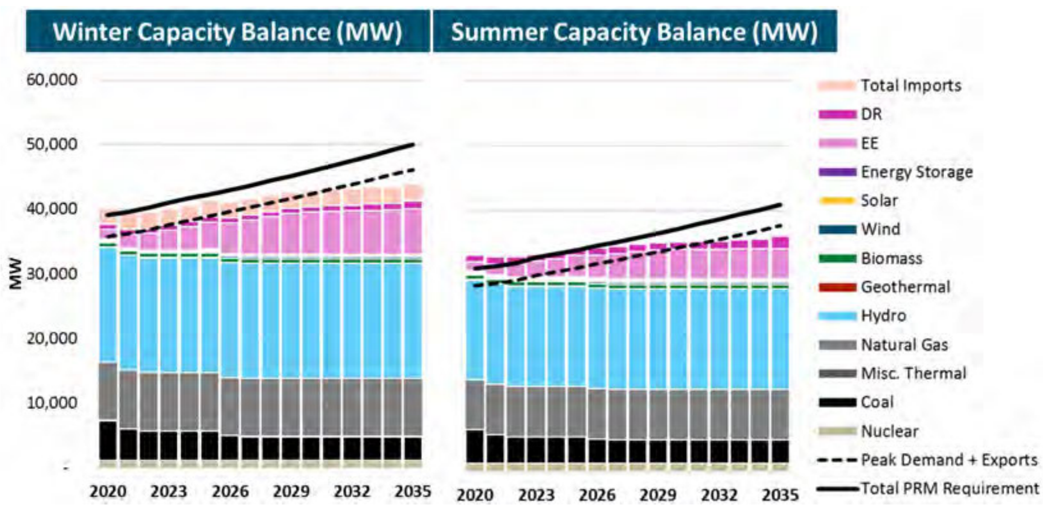
It should be noted that this study does not impose additional constraints, such as transmission system constraints, which may impact the ability of PGE to utilize regional capacity to serve customer loads.

5.1 Regional Results Summary

Across the three scenarios, winter load-resource balance is reached between 2021 and 2026 for the winter, and 2023 to 2029 for the summer.

Figures below shows the seasonal capacity position results for the three scenarios annually.

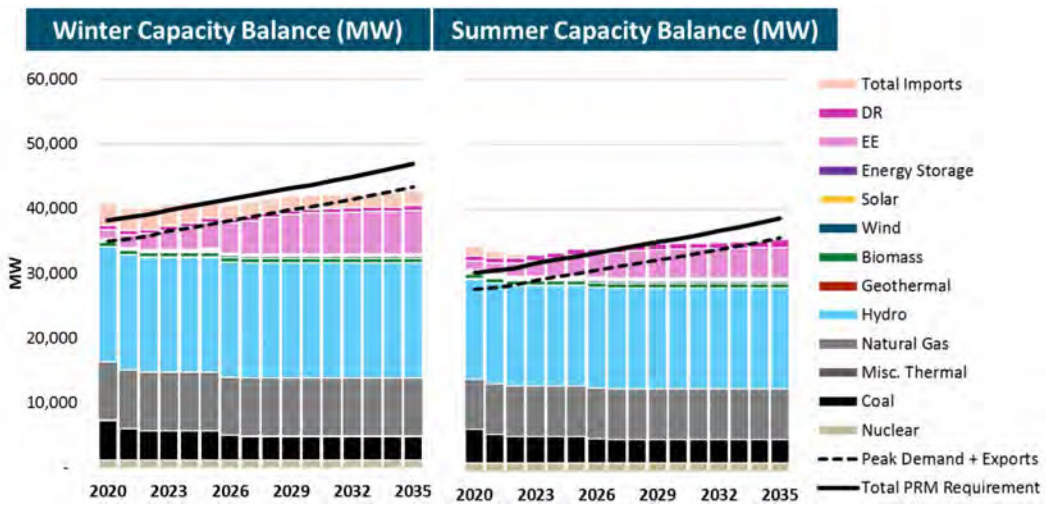
Figure 11. Base Case scenario annual capacity position results for the Northwest by season.



For the Base Case, the region maintains a capacity surplus until 2020 in the winter and 2025 in the summer. The winter capacity deficit seen starting in 2021 is consistent with the Council's adequacy assessment outlook as well as the BPA White Book.

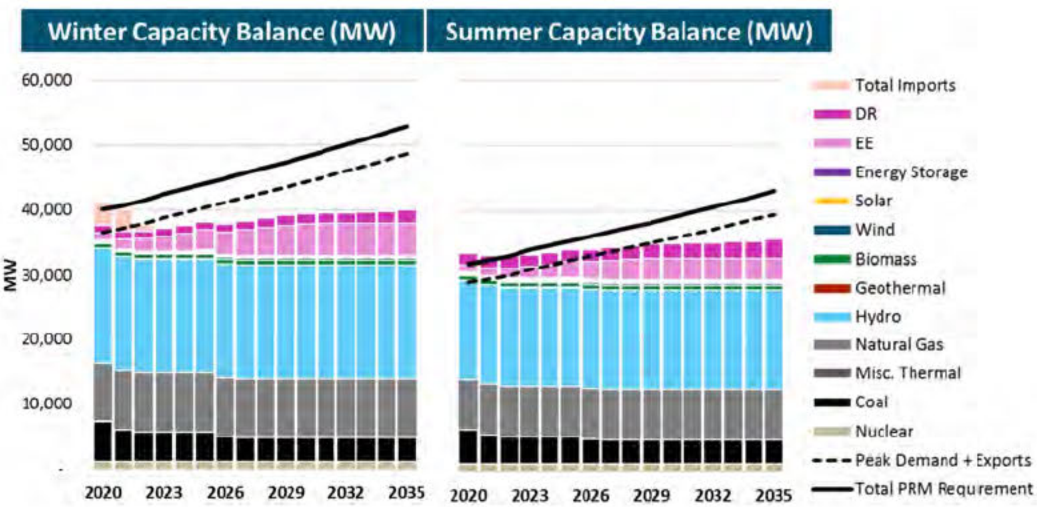
For the Low Need scenario, a combination of lower loads and higher imports available from California pushes out the capacity deficit year to 2026 for the winter and 2029 for the summer as shown in Figure 12.

Figure 12. Low scenario annual capacity position results for the Northwest by season.



Lastly, for the High Need scenario, the assumption of higher loads and lower availability of imports from California results in a winter capacity deficit for the region in 2021 which is greater in magnitude than the Base Case, and a summer capacity deficit in 2023 as shown in Figure 13.

Figure 13. High scenario annual capacity position results for the Northwest by season.



The summary for the year in which the region has a net capacity short position for the different scenarios is provided in Table 8 below.

Table 8. Year in which the region experiences a capacity deficit for the three different scenarios.

	First Year of Capacity Deficit	
Scenario	**Winter**	**Summer**
Low Need Scenario	2026	2029
Base Case	**2021**	**2026**
High Need Scenario	2021	2023

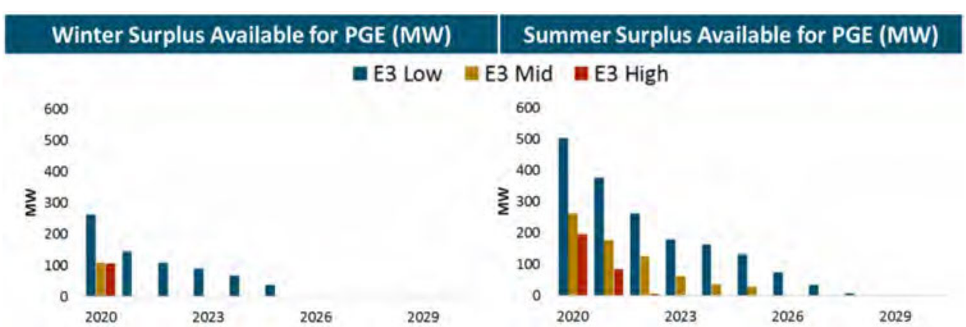
5.2 PGE Market Surplus Results Summary

To derive recommended input assumptions for PGE's IRP analysis, this study assumes the share of regional surplus capacity available to PGE is roughly equal to its load-ratio share within the broader region. In years of capacity surplus for the region, PGE is allocated its peak share of the available surplus by season. This approach results in the following seasonal results across scenarios:

- In the winter, the Low Need scenario shows a capacity surplus available for PGE through 2025. In the Base Case and High Need scenarios, there is no winter market surplus starting in 2021.
- In the summer, the market surplus is available through 2022 for all scenarios, which is later than the winter estimates. Even though summer peaks are growing at a higher rate than the winter, the winter in the region is more constrained in its ability to meet peak loads.

Figure 14 shows the resulting market surplus capacity PGE can rely on for its planning purposes.

Figure 14. Net annual surplus market capacity available for PGE by scenario.



5.3 Key Takeaways and Additional Considerations

As seen in section 5.2, PGE can rely on 100 MW – 250 MW of winter market surplus in 2020 depending on load growth in the region and availability of market imports from California. For the summer, PGE can rely on 100 MW – 500 MW of market surplus through 2021 and a smaller amount thereafter depending on load growth and imports availability.

The E3 model primarily examined the effect of loads, EE, DR and imports available from California to create its recommendations for seasonal market surplus. However, thermal plant retirements not captured in this modeling exercise could result in a net short position for the region sooner. Similarly, the development of new resources could push out the need for new capacity and enable a higher level of market purchases of surplus capacity for PGE.

Lastly, the IPP resources located in the region, if contracted to entities outside of the Northwest, could result in a net capacity deficit sooner.