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Resource Adequacy in the Pacific Northwest

Serving Load Reliably under a Changing Resource Mix

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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

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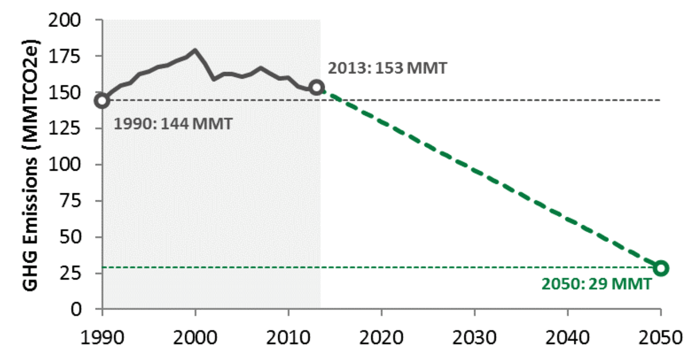
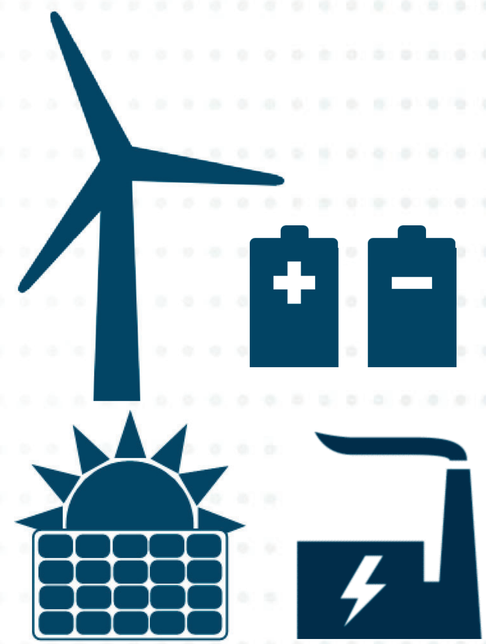
STUDY BACKGROUND & CONTEXT

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
- **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

Historical and Projected GHG Emissions for OR and WA





Study Sponsors

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

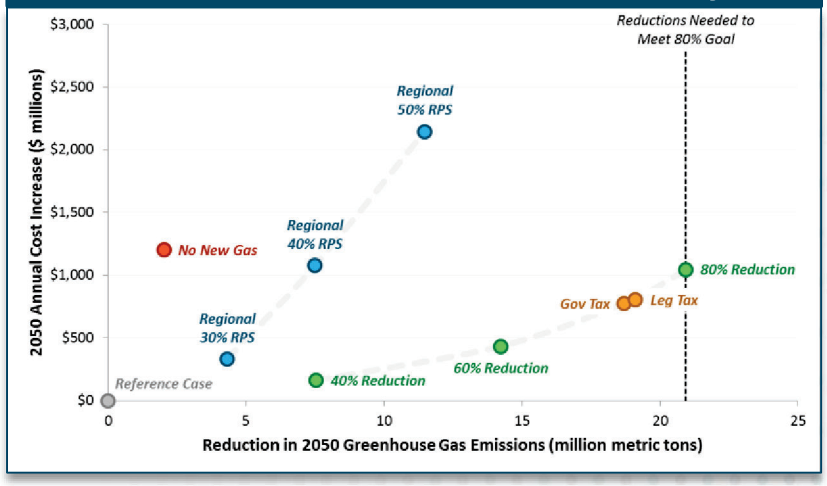
  - PGP is a trade association representing 10 consumer-owned utilities in Oregon and Washington.

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/

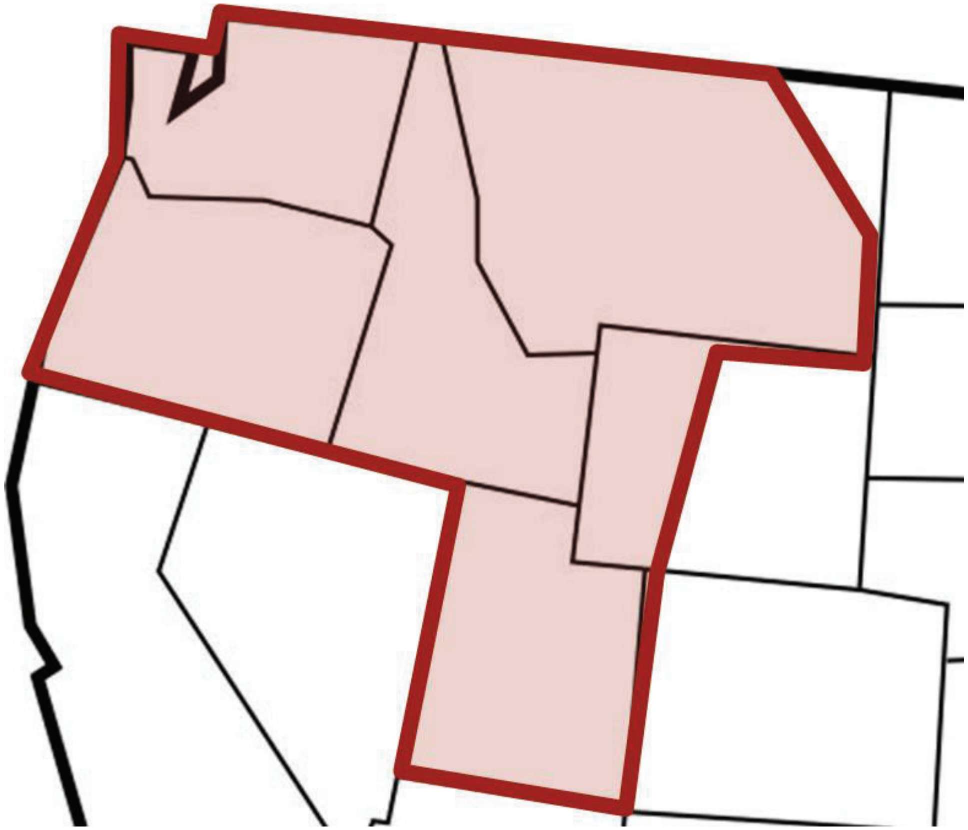
- **This study builds on the previous analysis by focusing on long-run reliability**
  - How much capacity is needed to serve peak load under a range of conditions in the NW?
  - How much capacity can be provided by wind, solar, storage and demand response?
  - What combination of resources would be 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

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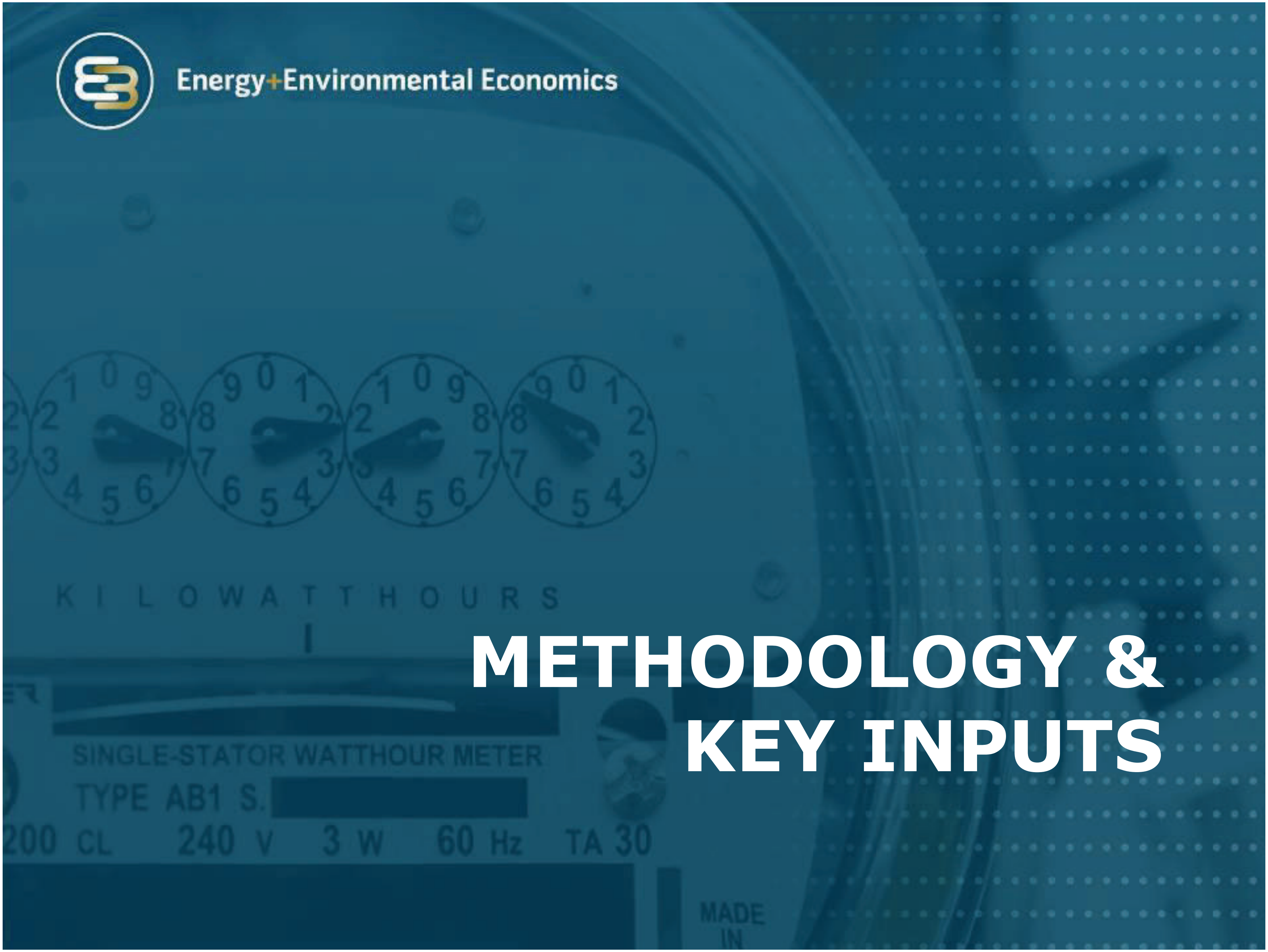


METHODOLOGY & KEY INPUTS

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

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

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

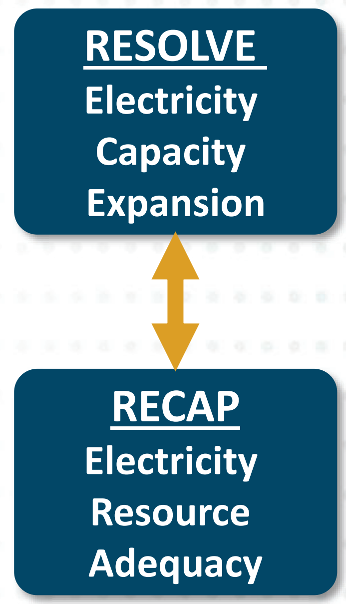
Additional metric definitions used for scenario development

- **<u>GHG Reduction %</u>** is the reduction below 1990 emission levels for the study region
  - The study region emitted 60 million metric electricity sector emissions in 1990
- **<u>CPS %</u>** 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
- **<u>GHG-Free Generation %</u>** 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
- **<u>Renewable Curtailment %</u>** 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



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

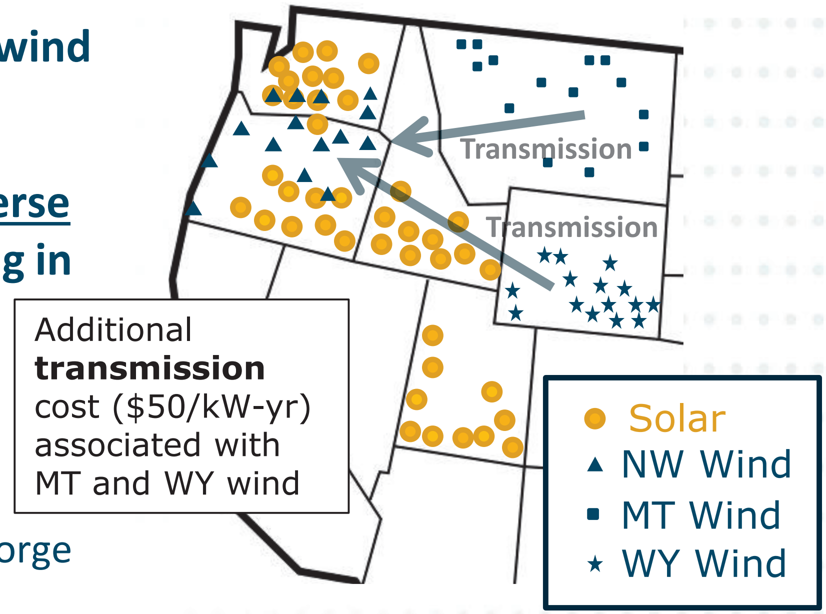
2018-2030 Scenarios	Carbon Reduction % Below 1990[1]	GHG-Free Generation %[2]	CPS %[3]	Carbon Emissions (MMT)
2018 Case[4]	-6%	71%	75%	63
2030 Reference Case[4]	-12%	61%	65%	67
2030 Coal Retirement	30%	61%	65%	42

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

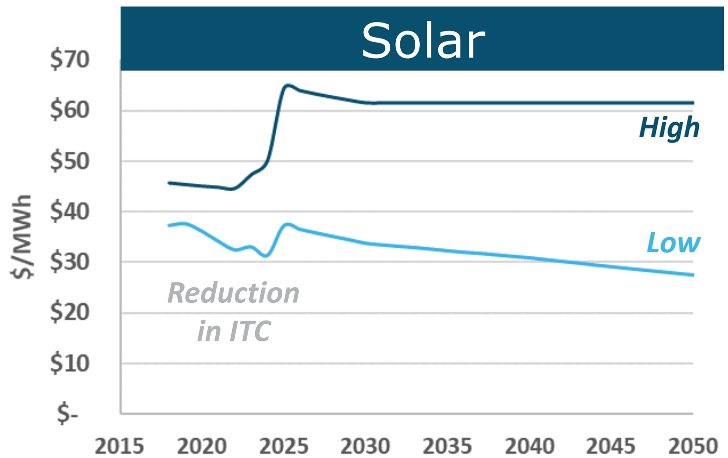
$2016

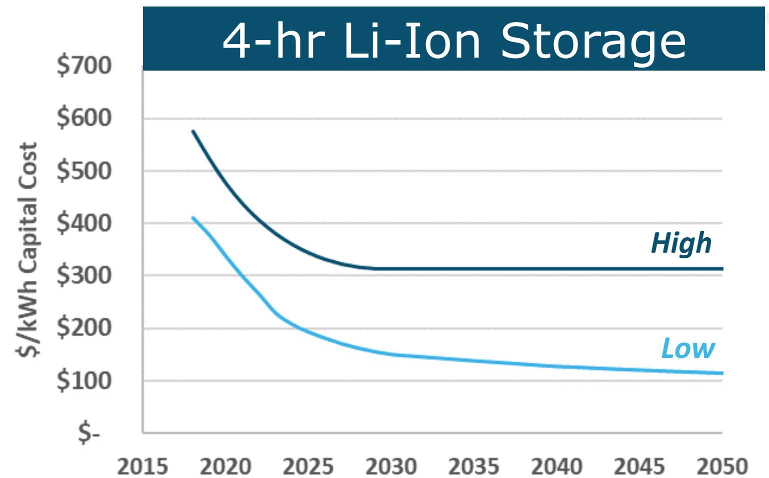
Technology	Unit	Resource Cost High	Resource Cost Low	Transmission	Notes
Solar PV	*$/MWh*	**$59**	**$32**	**$8**	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 27%
NW Wind	*$/MWh*	**$55**	**$43**	**$6**	High Source: PGP Study; Low Source: NREL 2018 ATB Mid Case; CF = 37%
MT/WY Wind	*$/MWh*	**$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**		

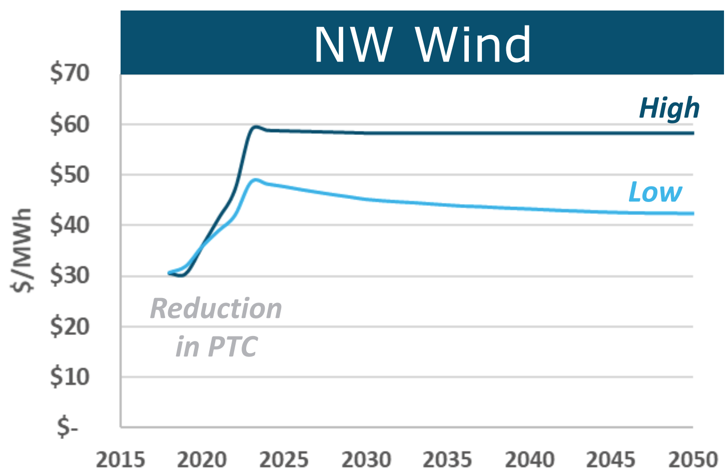
Costs shown are the average cost over the 2018-2050 timeframe; trajectories in following slide

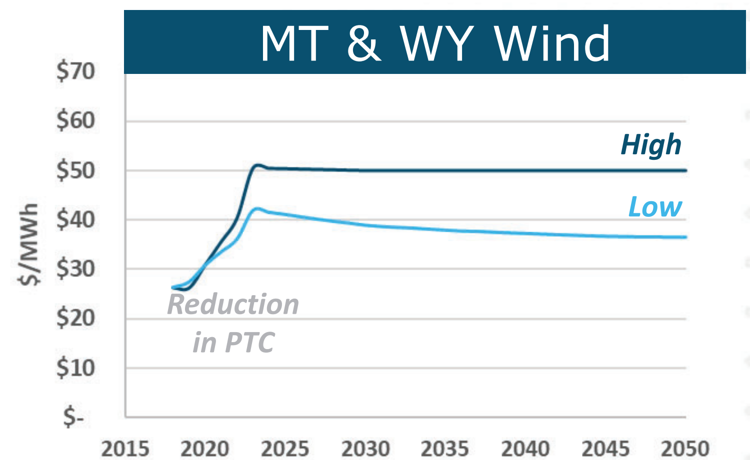
Note: RECAP is primarily a loss-of-load probability model that calculates resource *availability* over thousands of simulated years. RECAP does estimate least-cost *dispatch* and *capacity expansion* but this functionality does not involve optimization and is necessarily approximate

Resource Cost Assumptions





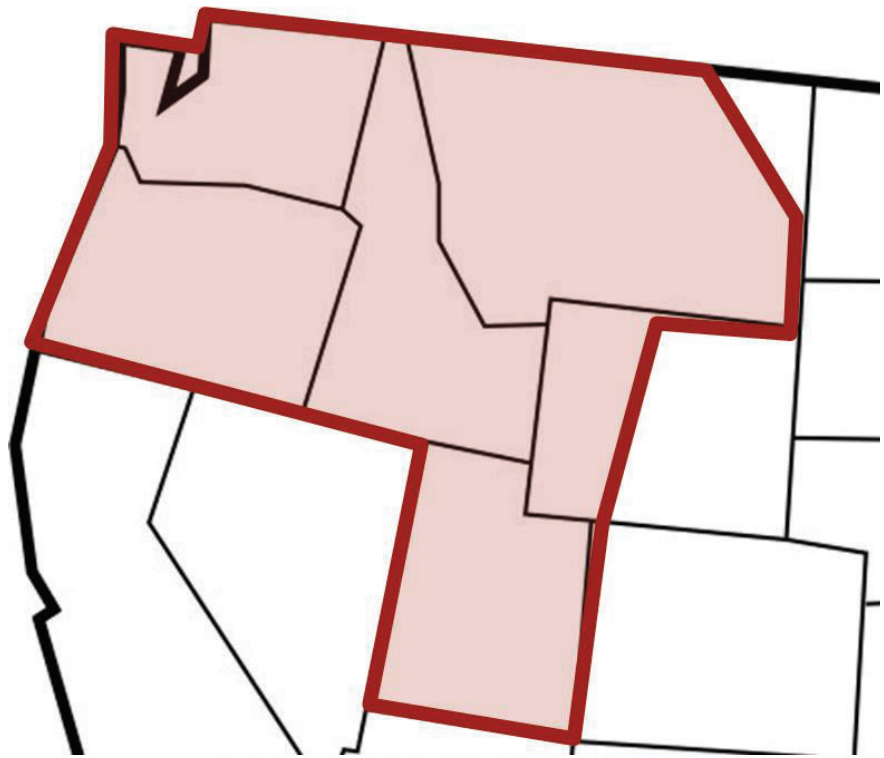




Shown in 2016 dollars

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.

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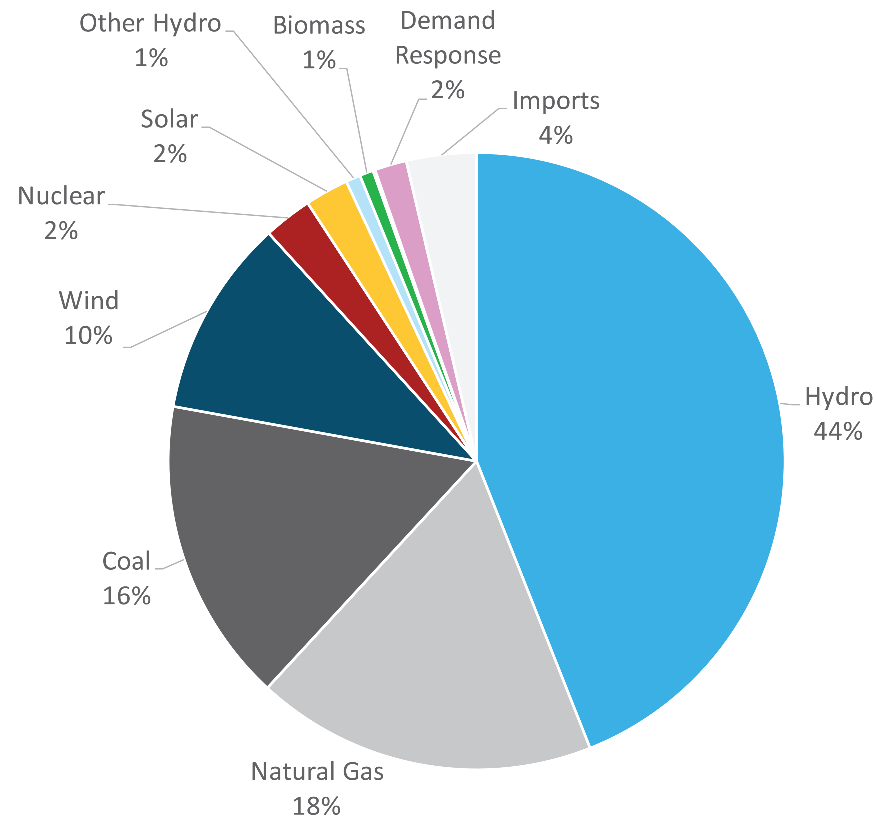
2018 RESULTS

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*

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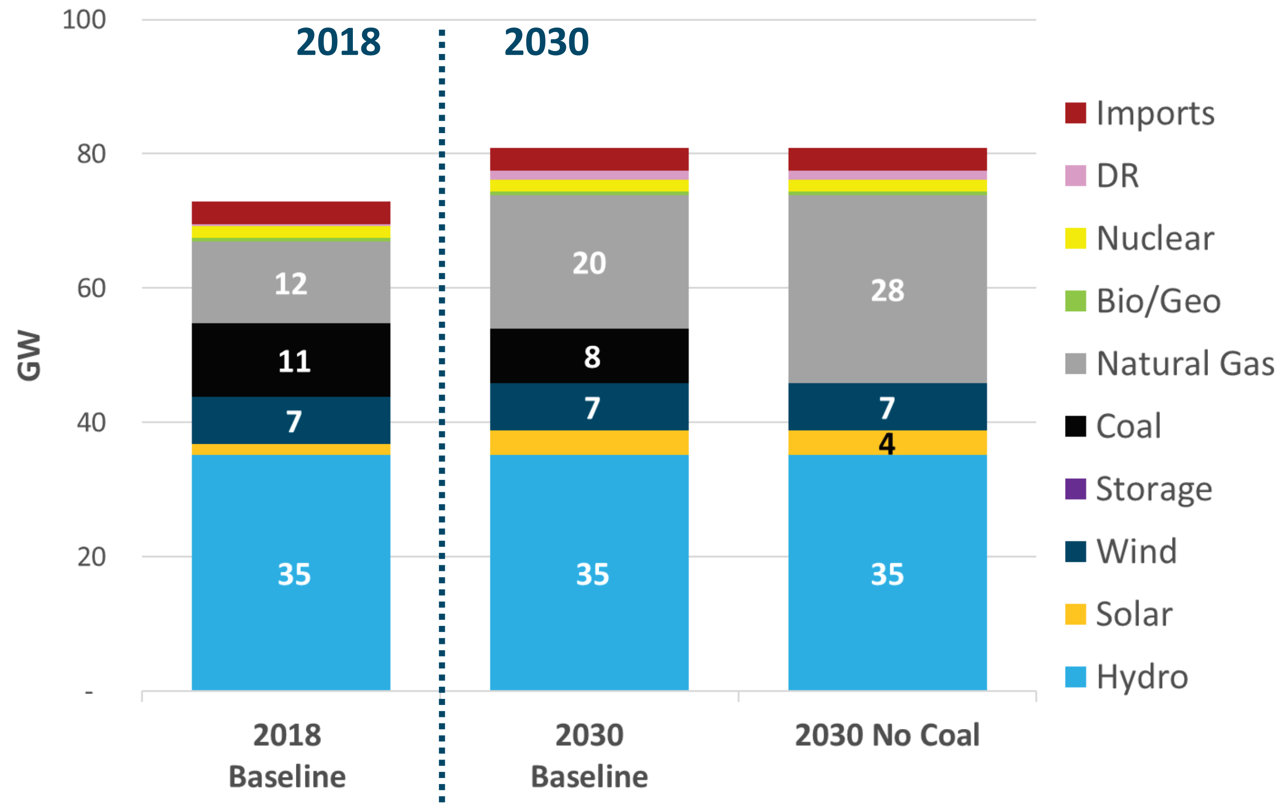
2030 RESULTS

2030 Portfolios



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

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

Resources / Effective Capacity (GW)	2030	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*

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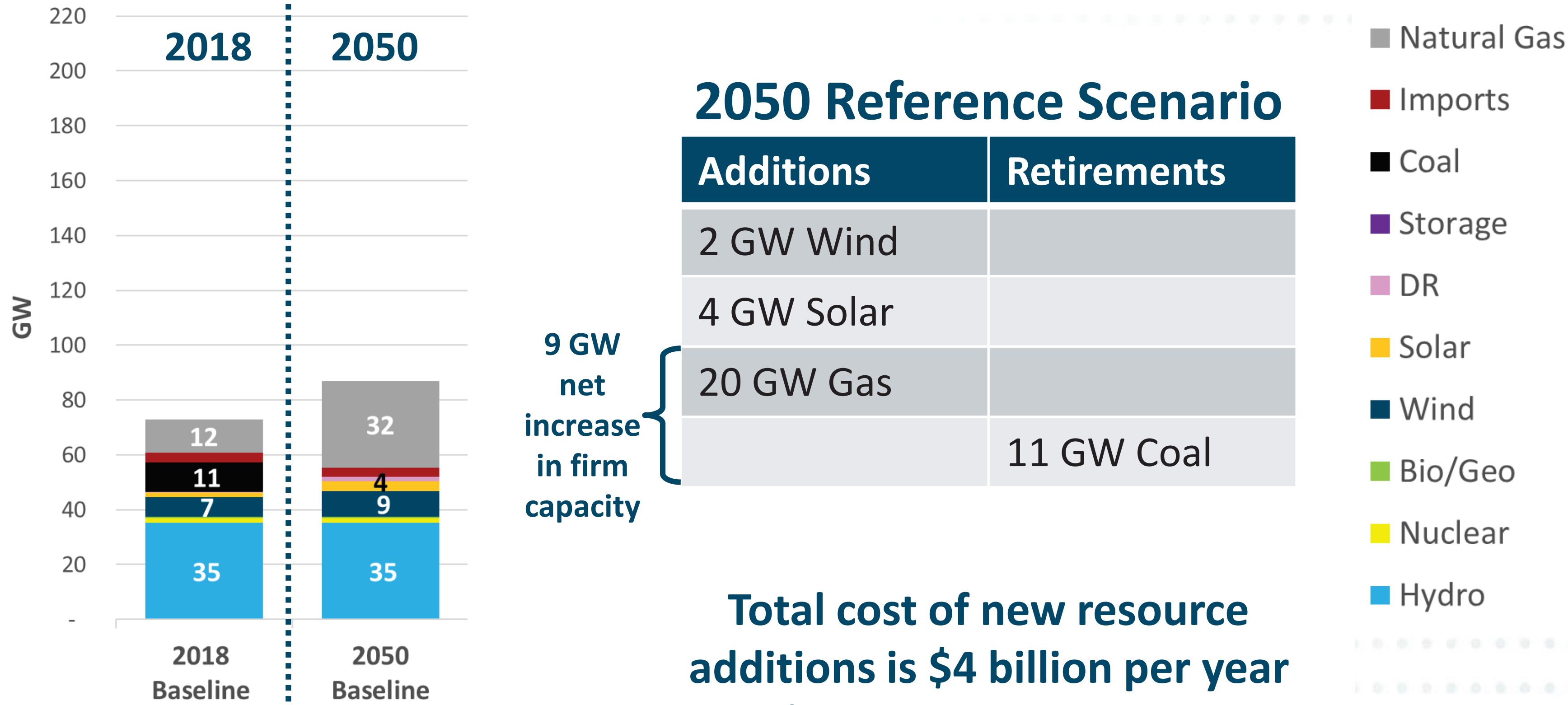
2050 RESULTS

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

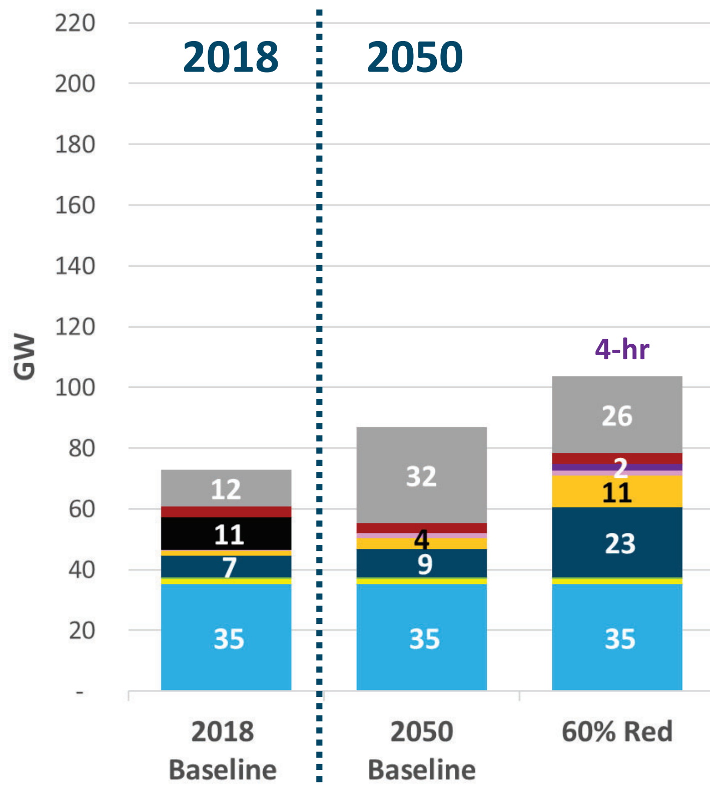
9 GW net increase in firm capacity (20 GW Gas, 11 GW Coal)

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



	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%

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

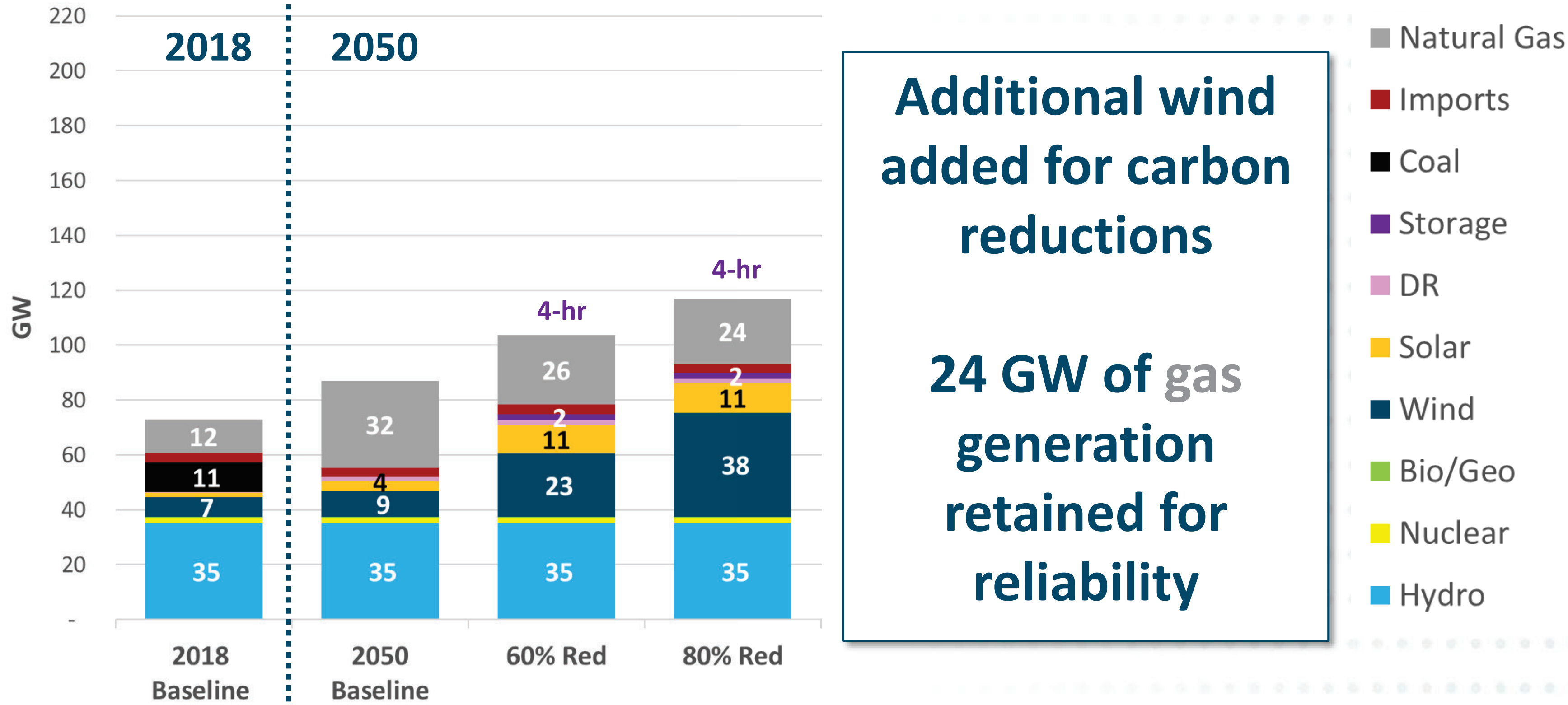
Gas generation retained for reliability

- Natural Gas
- Imports
- Coal
- Storage
- DR
- Solar
- Wind
- Bio/Geo
- Nuclear
- Hydro

[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

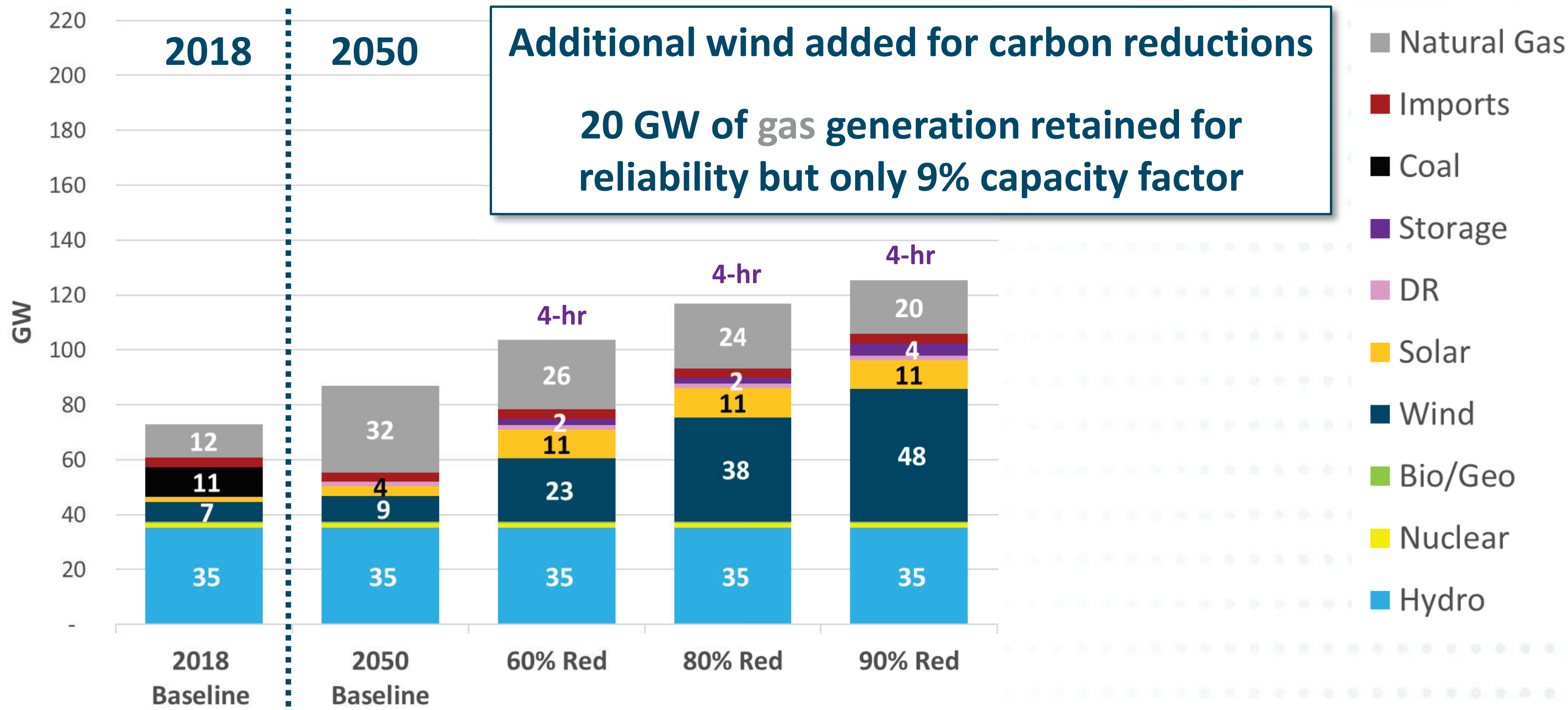
24 GW of gas generation retained for reliability

	2050 Baseline	60% Red	80% Red
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

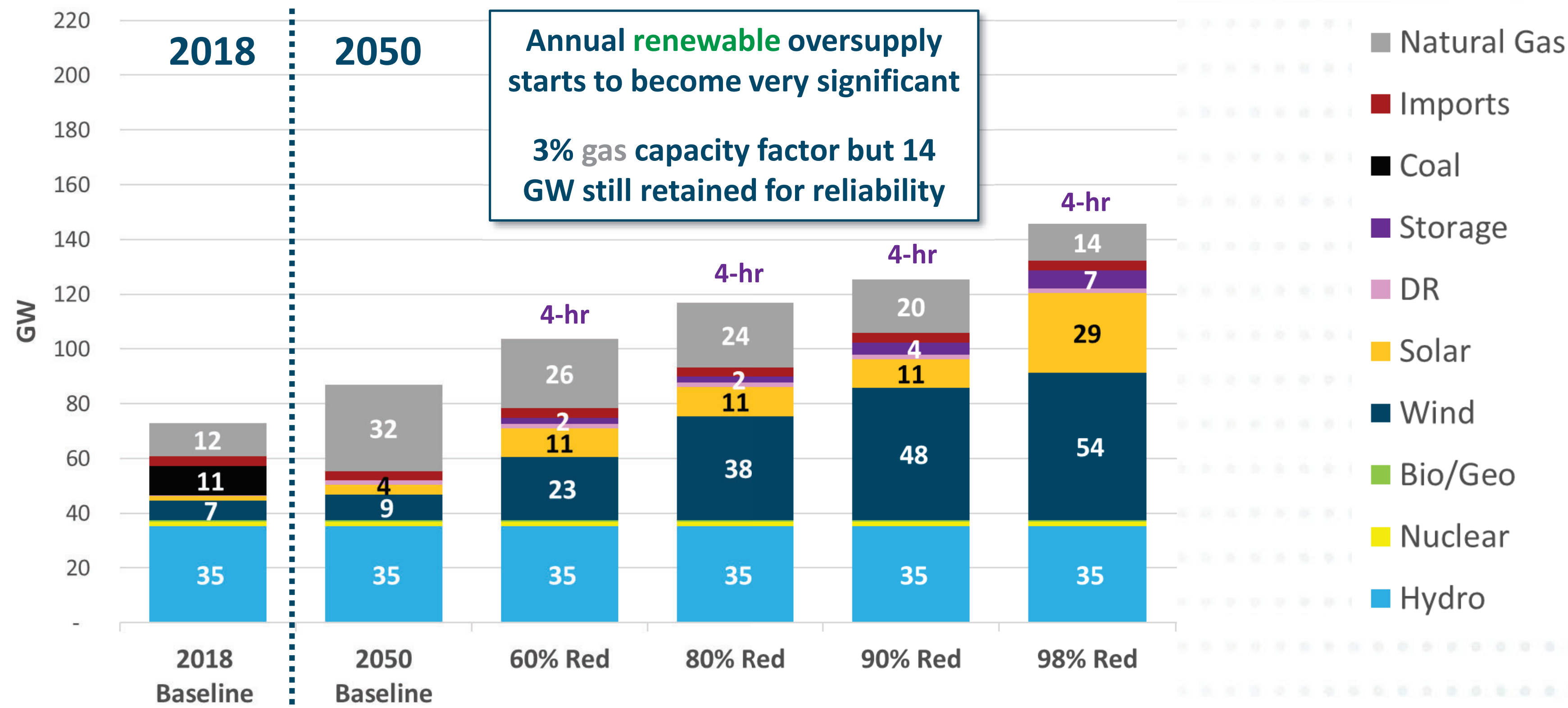


Carbon (MMT CO2)	50	25	12	6
CPS (%)[1]	63%	86%	100%	108%
GHG Free Generation (%)[2]	60%	80%	90%	95%
Annual Renewable Curtailment (%)	Low	Low	4%	10%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18
% GHG Reduction from 1990 level	16%	60%	80%	90%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

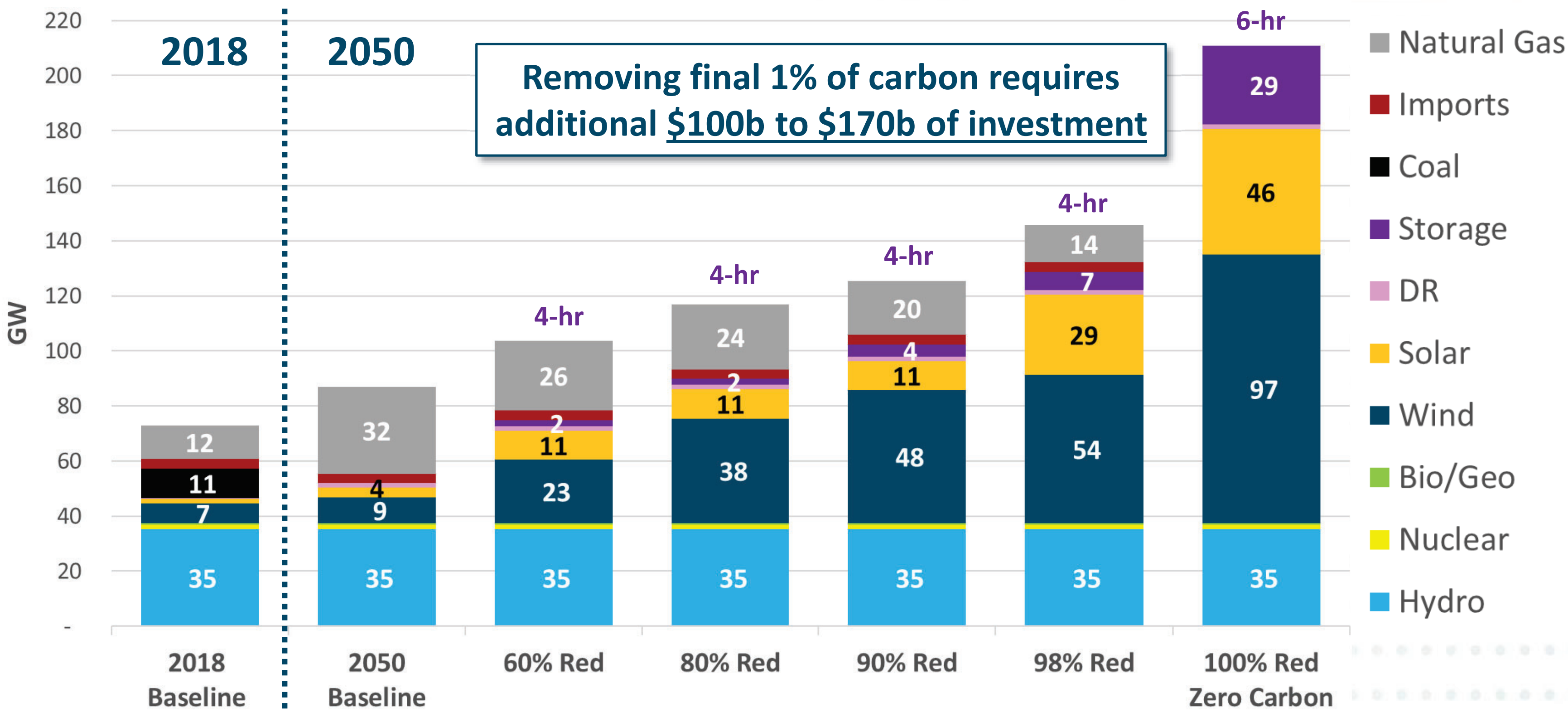


	2050 Baseline	60% Red	80% Red	90% Red	98% Red
Carbon (MMT CO2)	50	25	12	6	1
CPS (%)[1]	63%	86%	100%	108%	117%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9
Additional Cost ($/MWh)	Base	$0 - $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



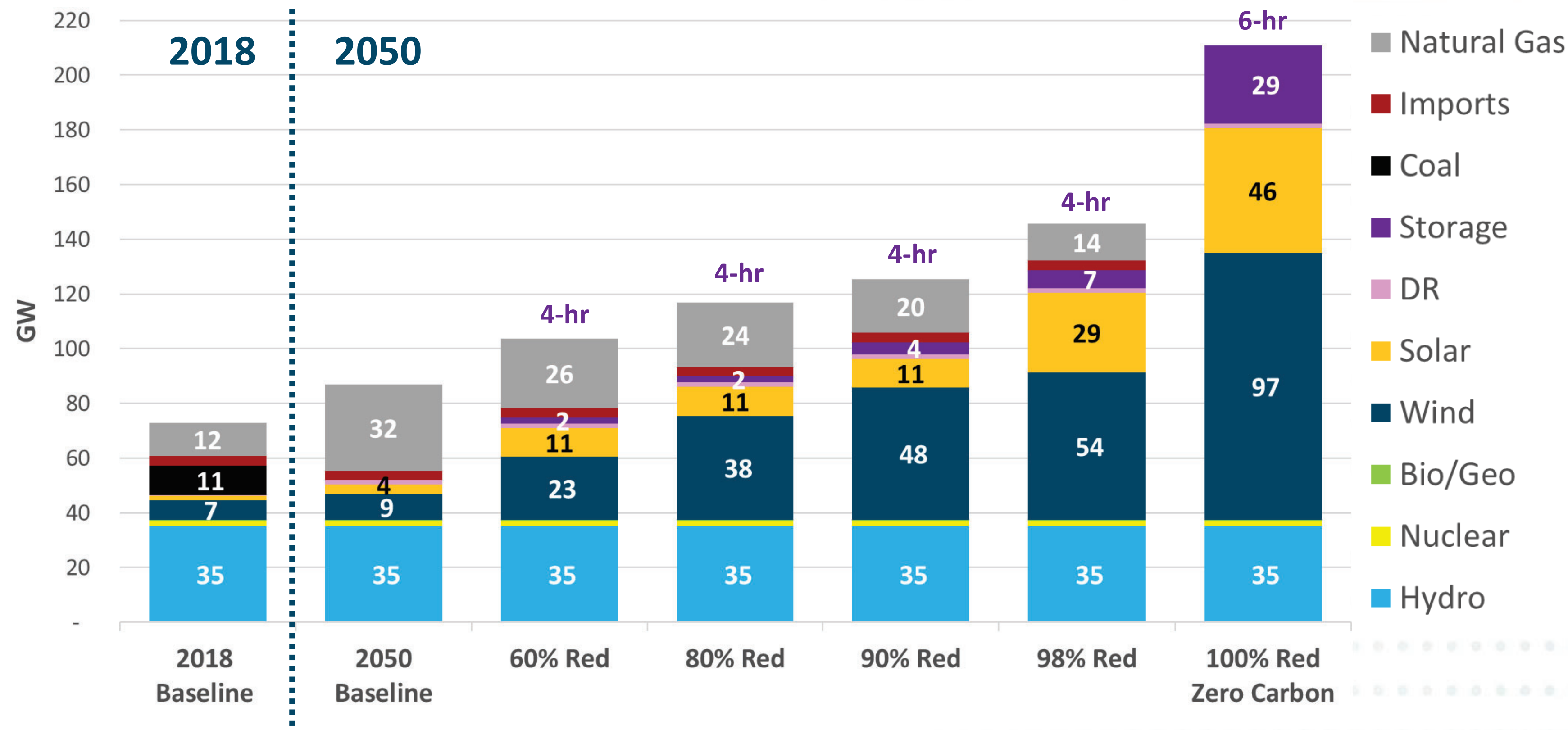
Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18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

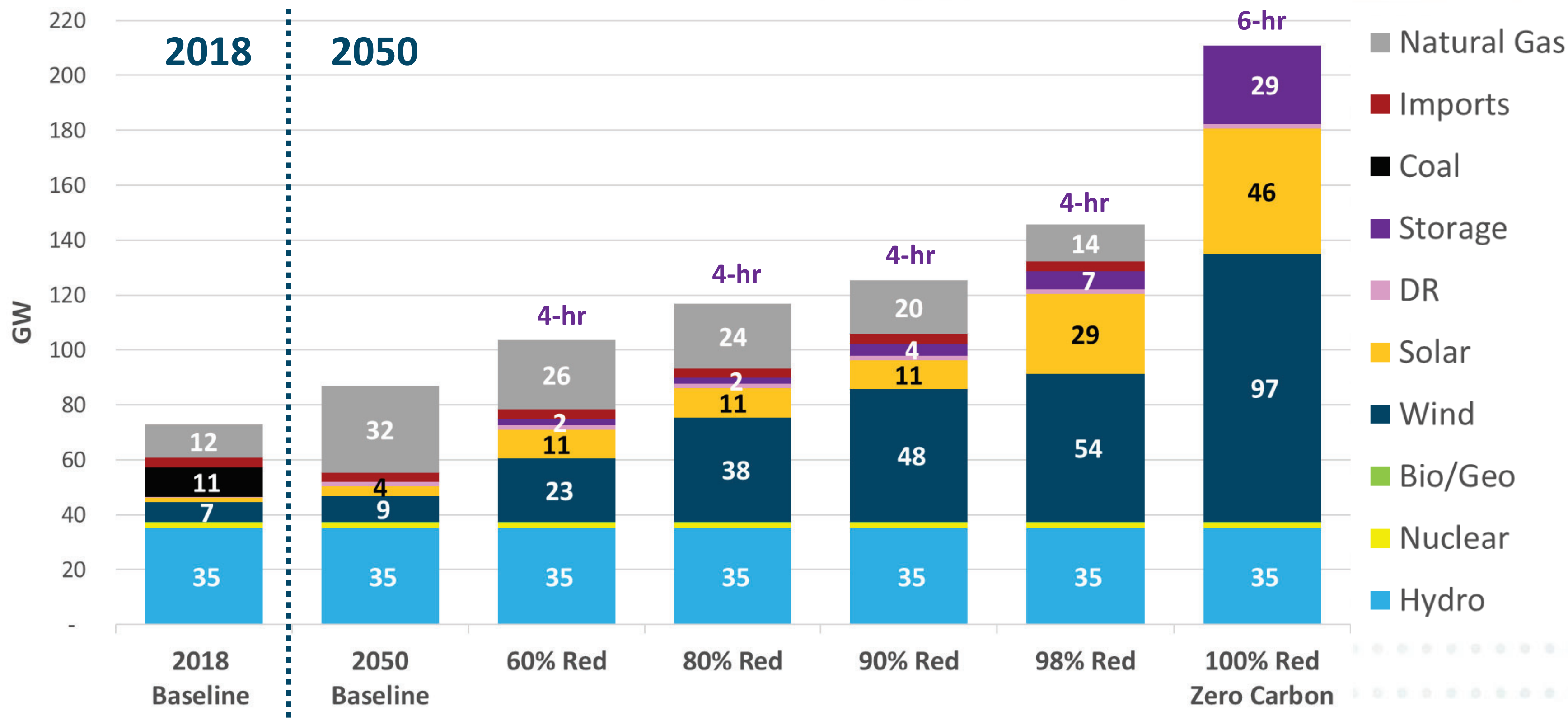


Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%

[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

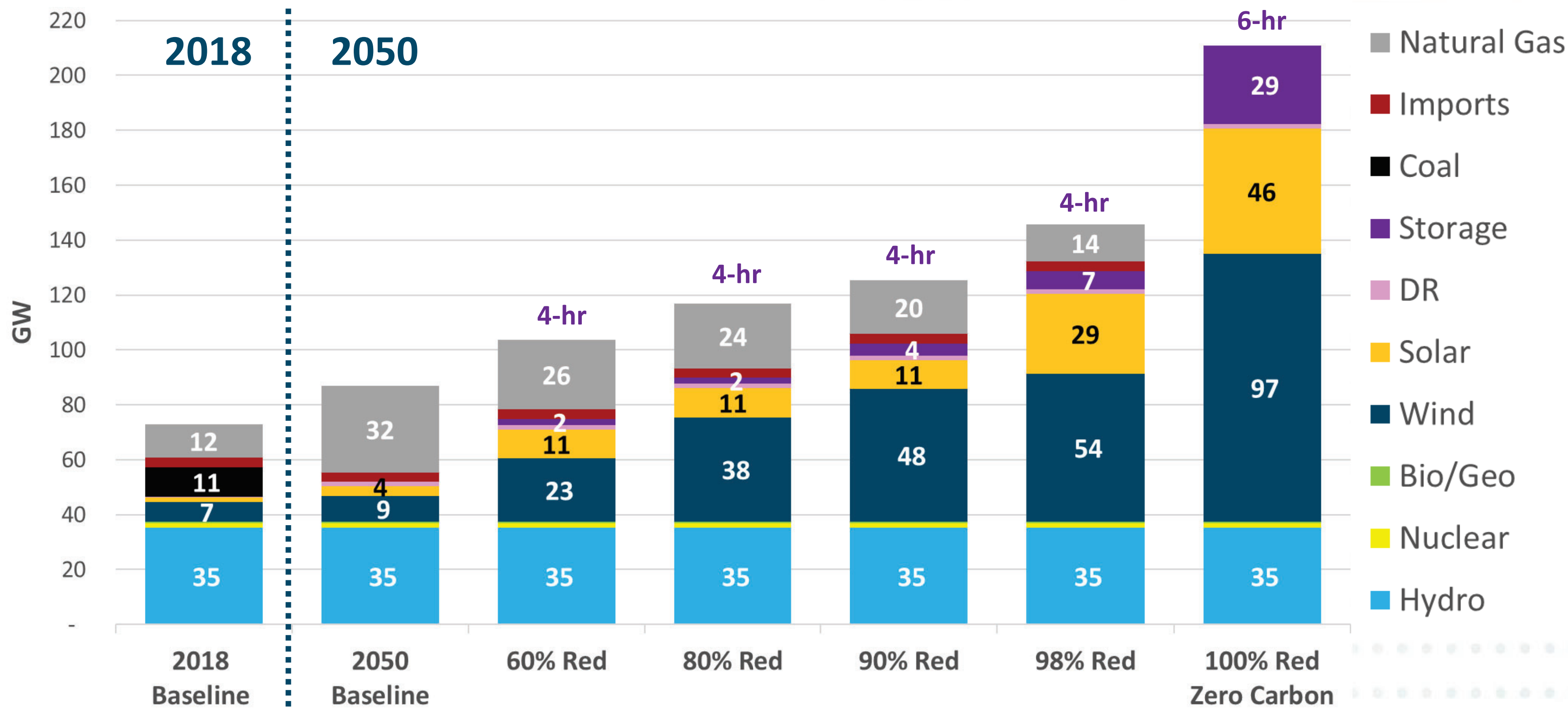


Renewable Capacity (GW)	13	34	49	59	83	143
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Gas Capacity (GW)	32	26	24	20	14	0
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[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

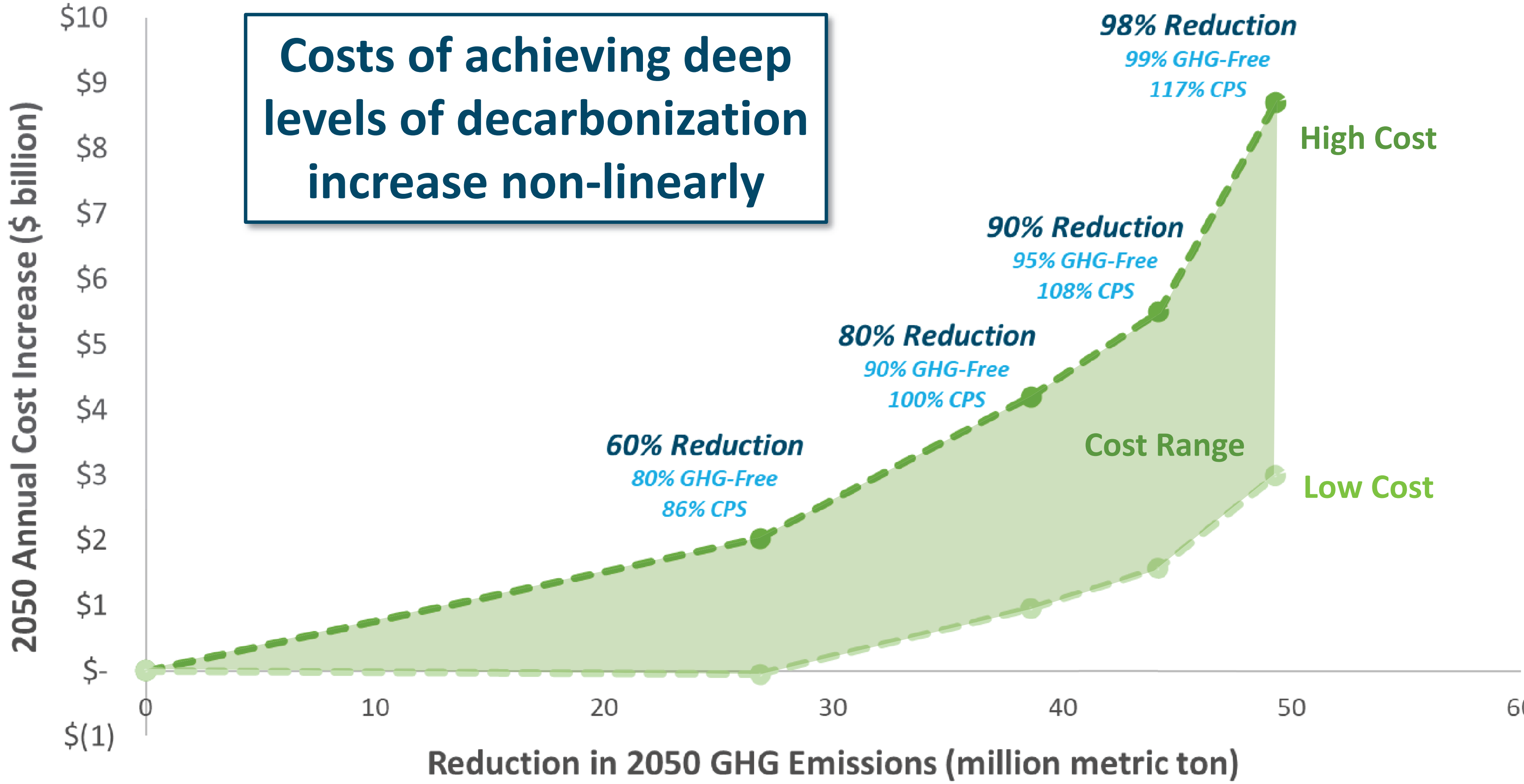
2050 Costs



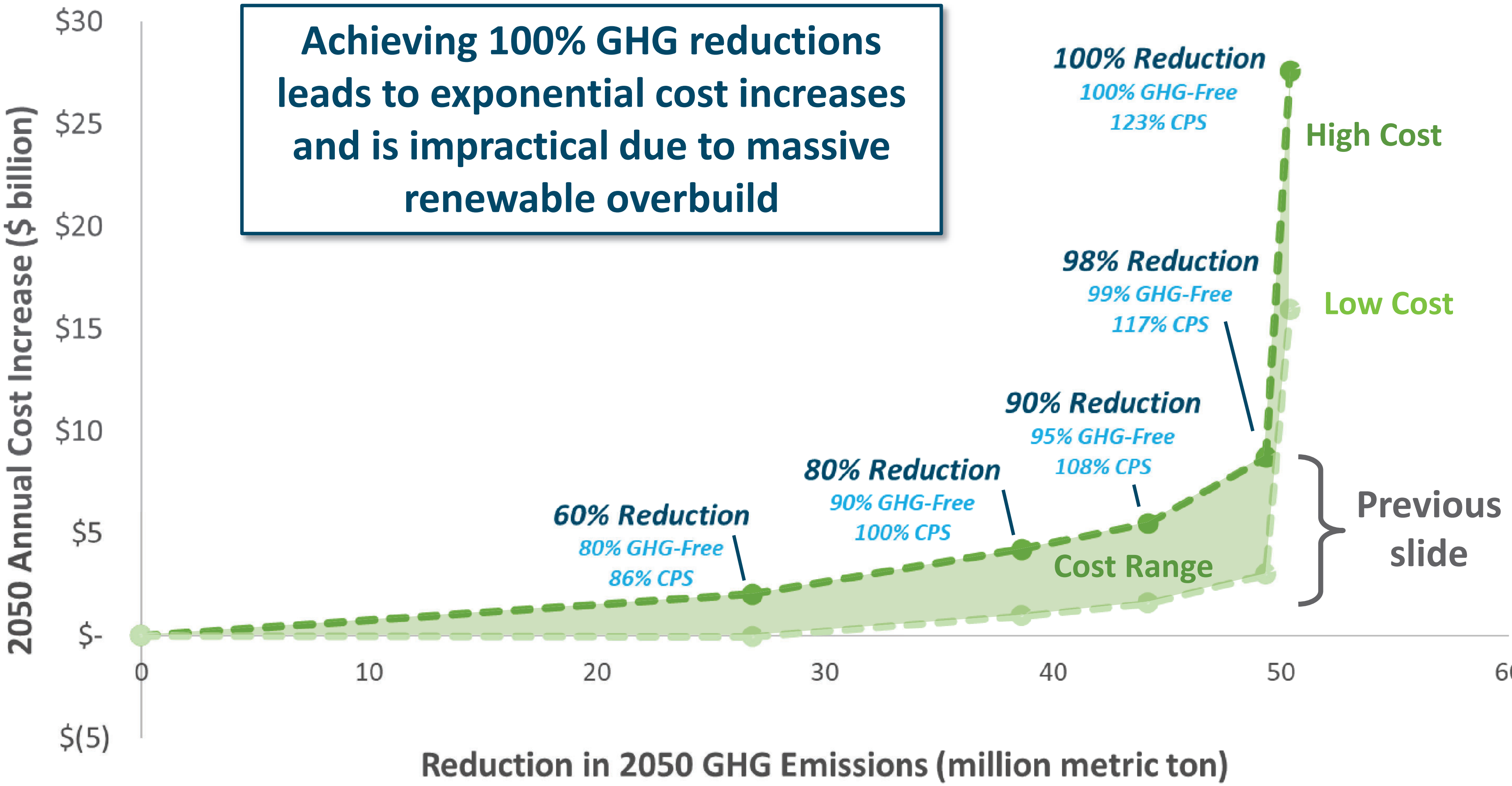
	2050 Baseline	60% Red	80% Red	90% Red	98% Red	100% Red Zero Carbon
Marginal Carbon Reduction Cost ($/Metric Ton)	Base	$0 - $80	$90 - $190	$110 - $230	$310 - $700	$11,000 – $16,000
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $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

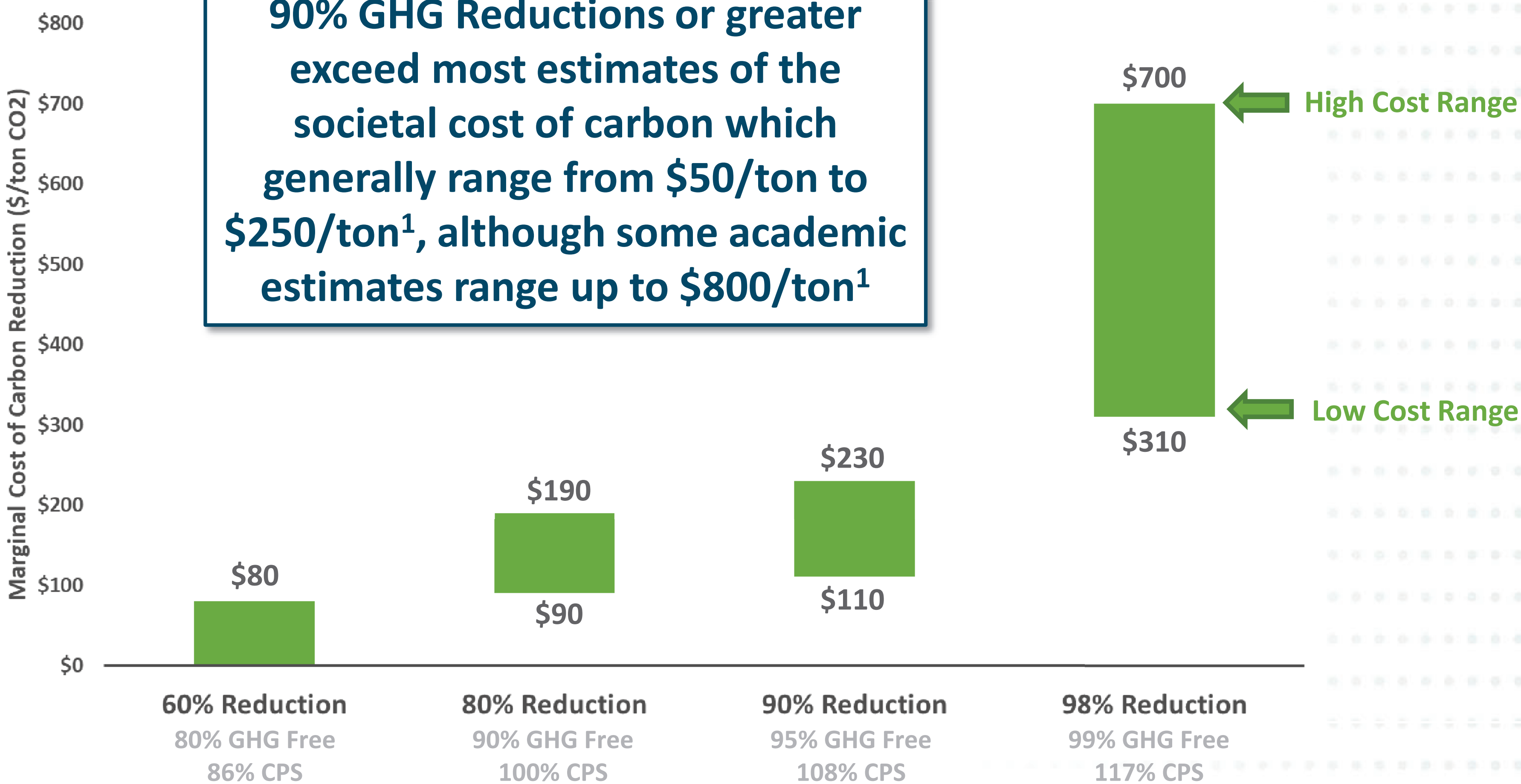


Cost of GHG Reduction



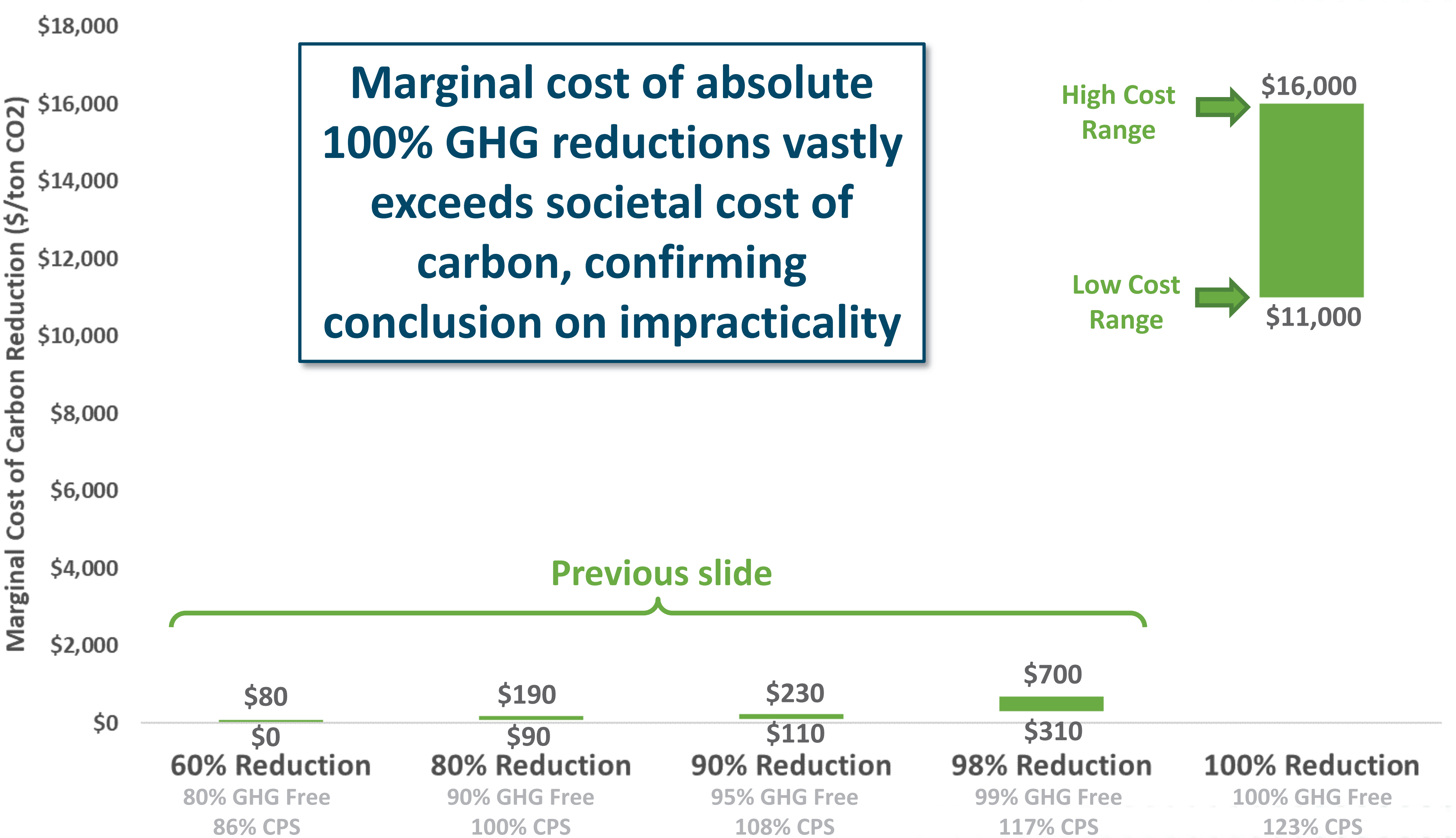
Marginal Cost of GHG Reduction

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

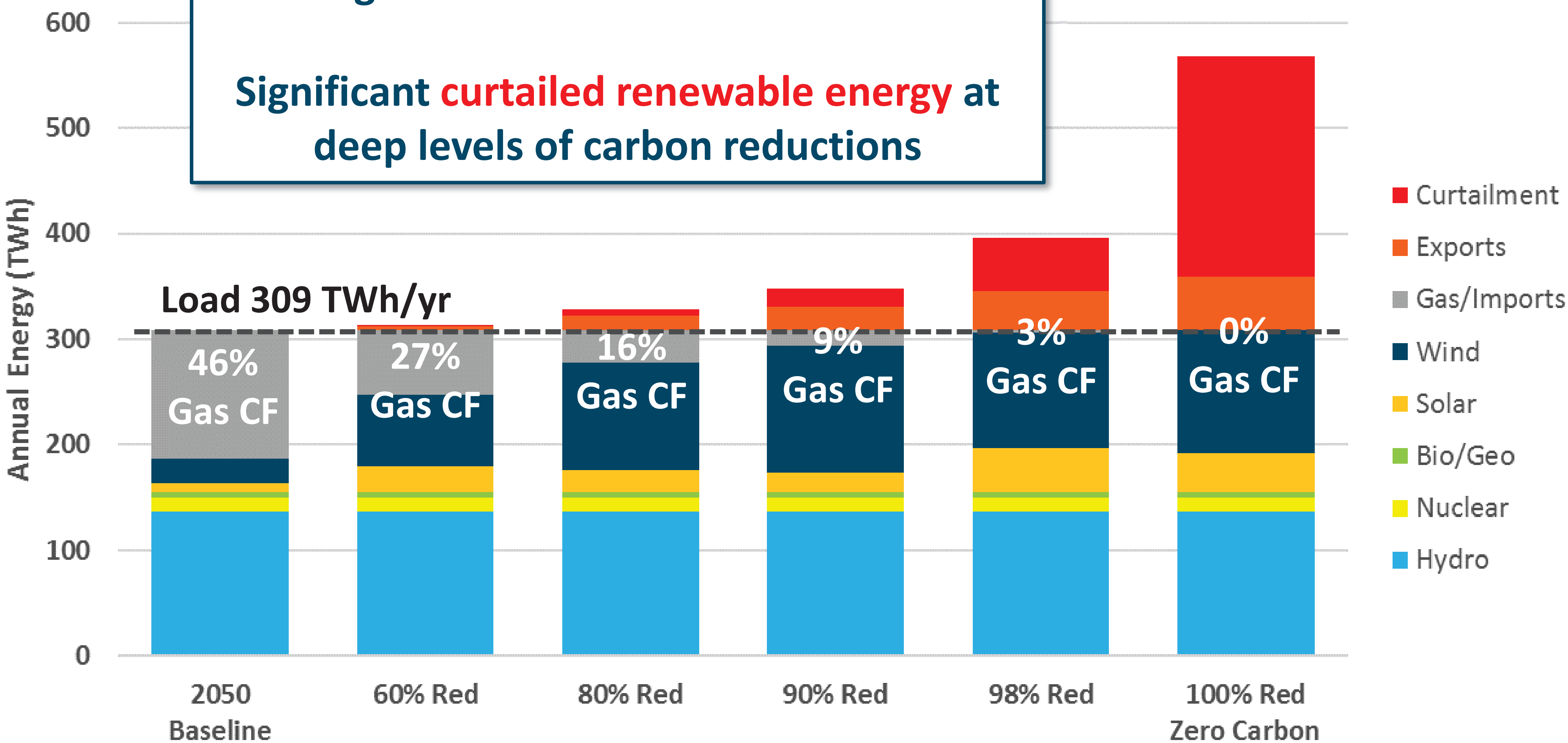
Marginal Cost of GHG Reduction



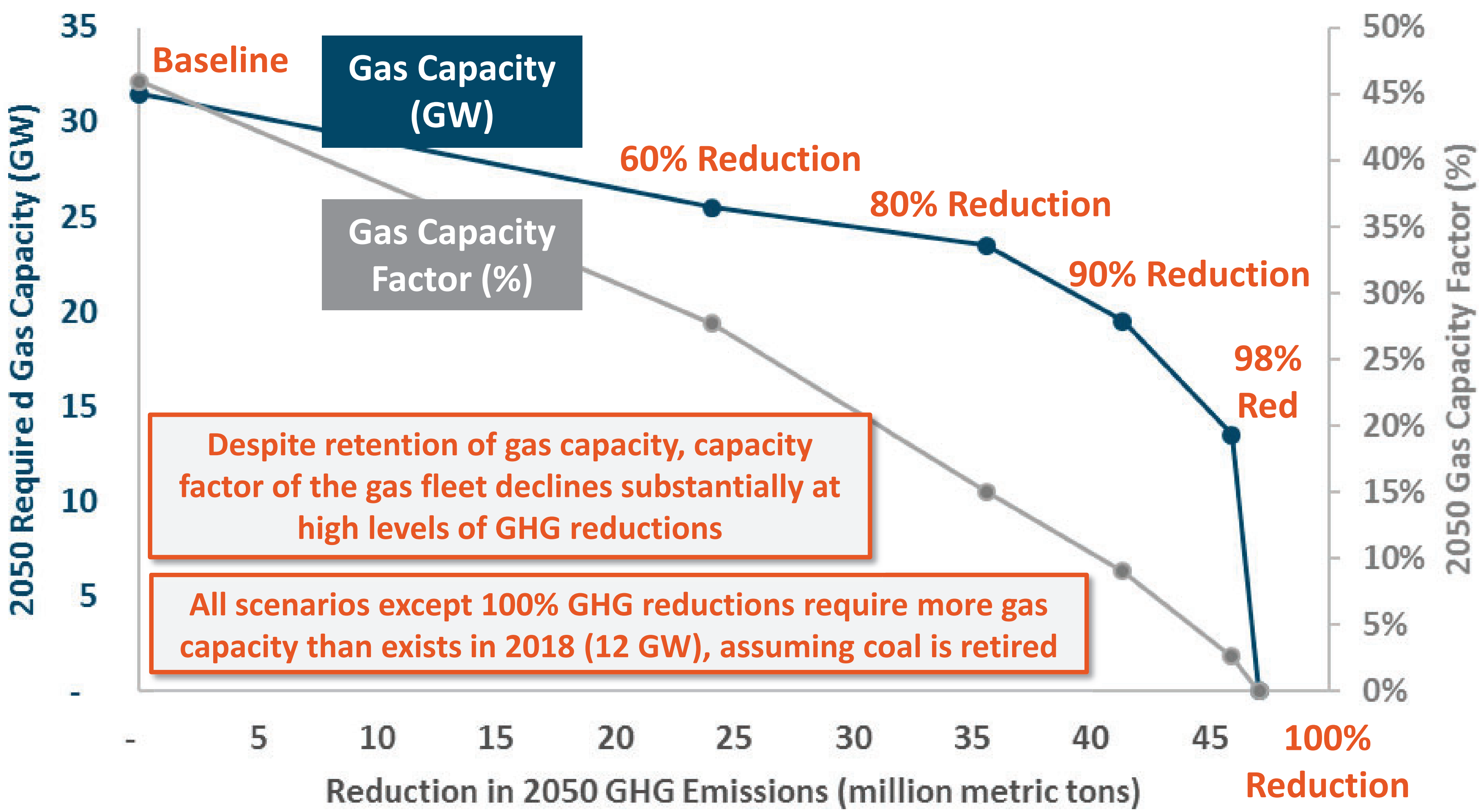
2050 Annual Energy Balance

Gas capacity factor declines significantly at higher levels of decarbonization

Significant curtailed renewable energy at deep levels of carbon reductions



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



2050 Load and Resource Balance

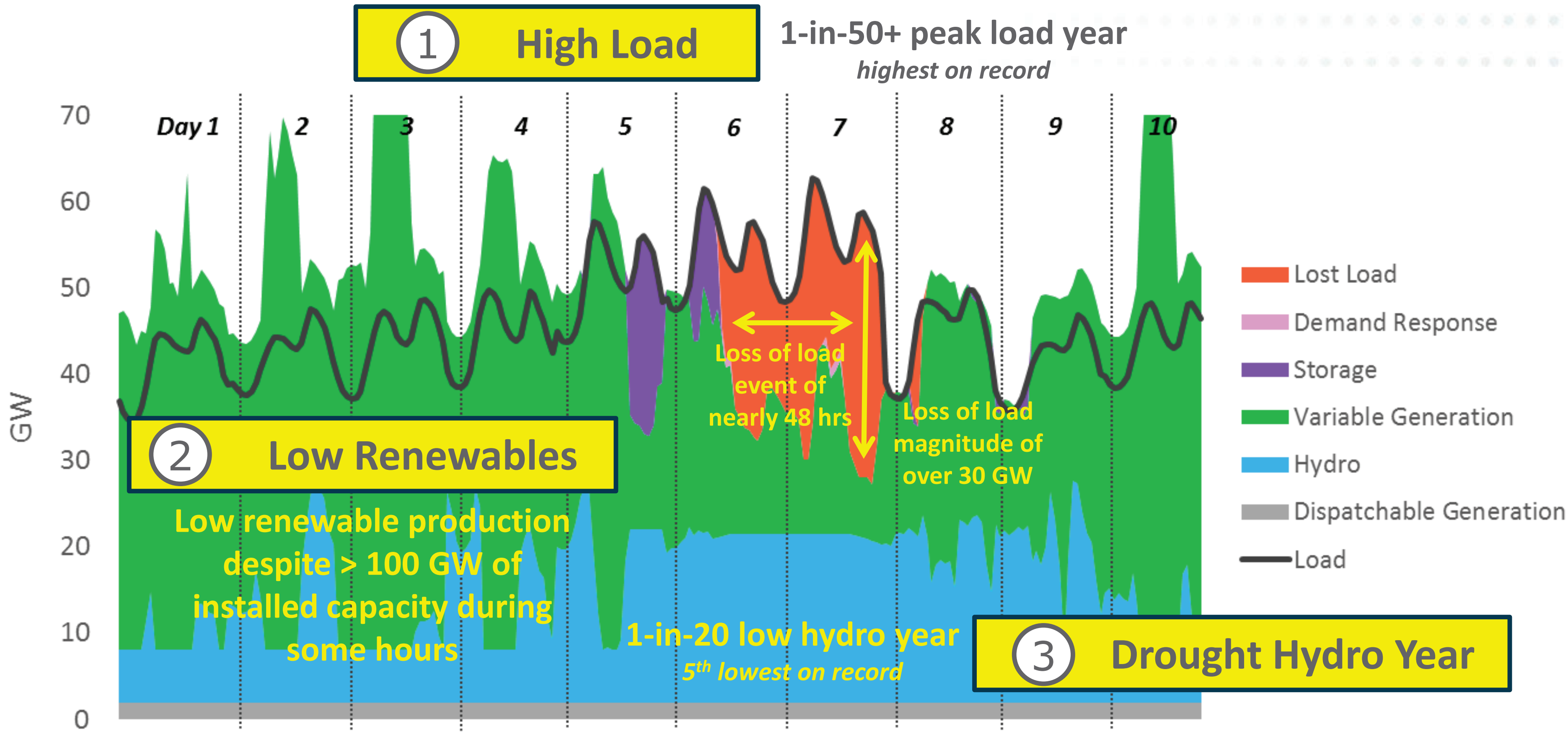
	2050		
	80% Reduction	90% Reduction	100% Reduction
Load (GW)			
Peak (Pre-EE)	65	65	65
Peak (Post-EE)	54	54	54
PRM (%)	*9%*	*9%*	*7%*
PRM	5	5	4
Total Load Requirement	59	59	57
Resources / Effective Capacity (GW)			
Coal	0	0	0
Gas	24	20	0
Bio/Geo	0.6	0.6	0.6
Imports	2	2	0
Nuclear	1	1	1
DR	1	1	1
Hydro	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

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

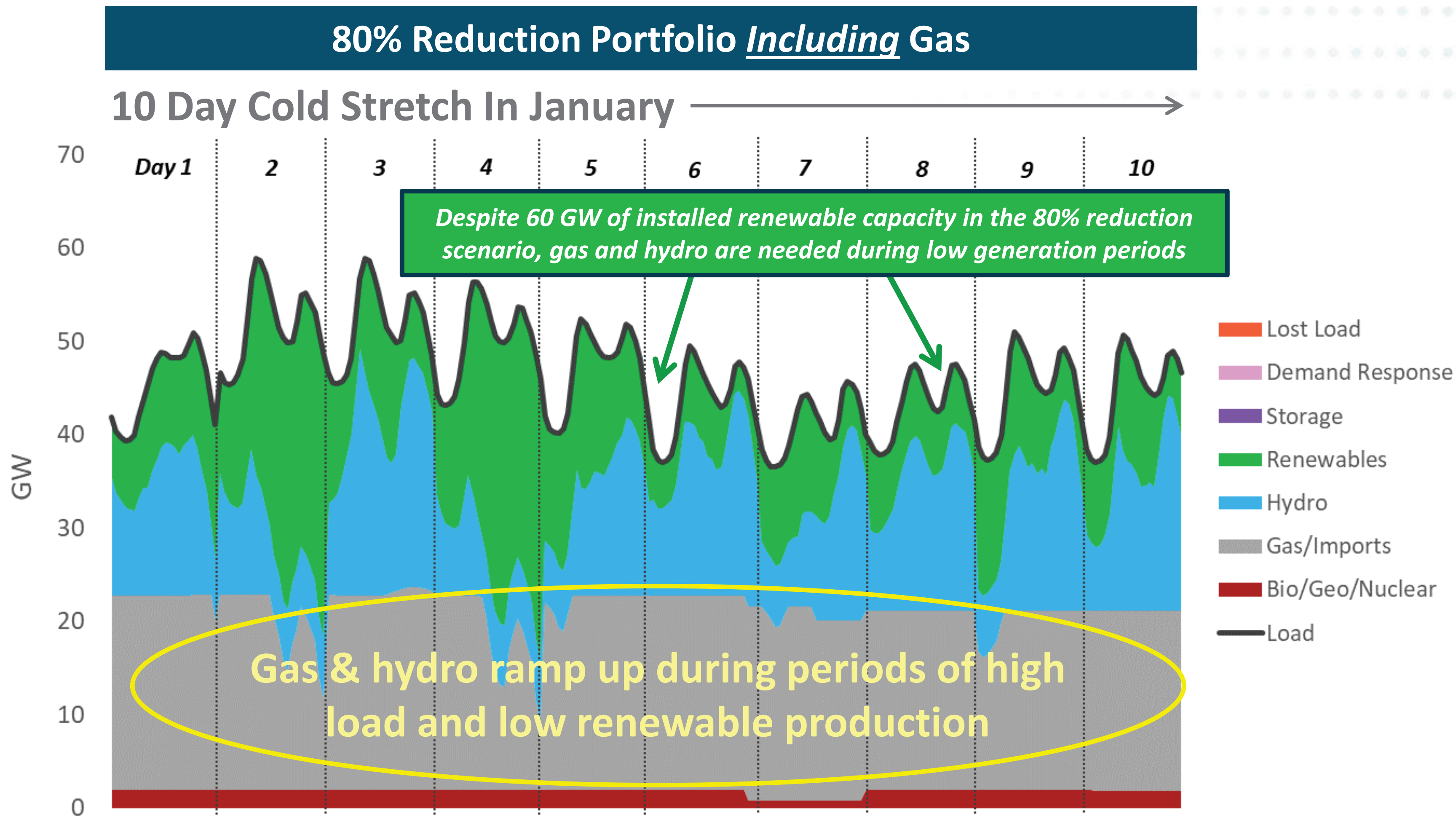
	Nameplate Capacity (GW)			ELCC (%)			Capacity Factor (%)		
	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.	80% Red.	90% Red.	100% Red.
Hydro	*35*	*35*	*35*	*58%*	*58%*	*57%*	*44%*	*44%*	*44%*
Wind	*38*	*48*	*96*	*19%*	*22%*	*22%*	*35%*	*36%*	*37%*
Solar	*11*	*11*	*46*	*19%*	*21%*	*16%*	*27%*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

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

The Stressful Tri-Fecta

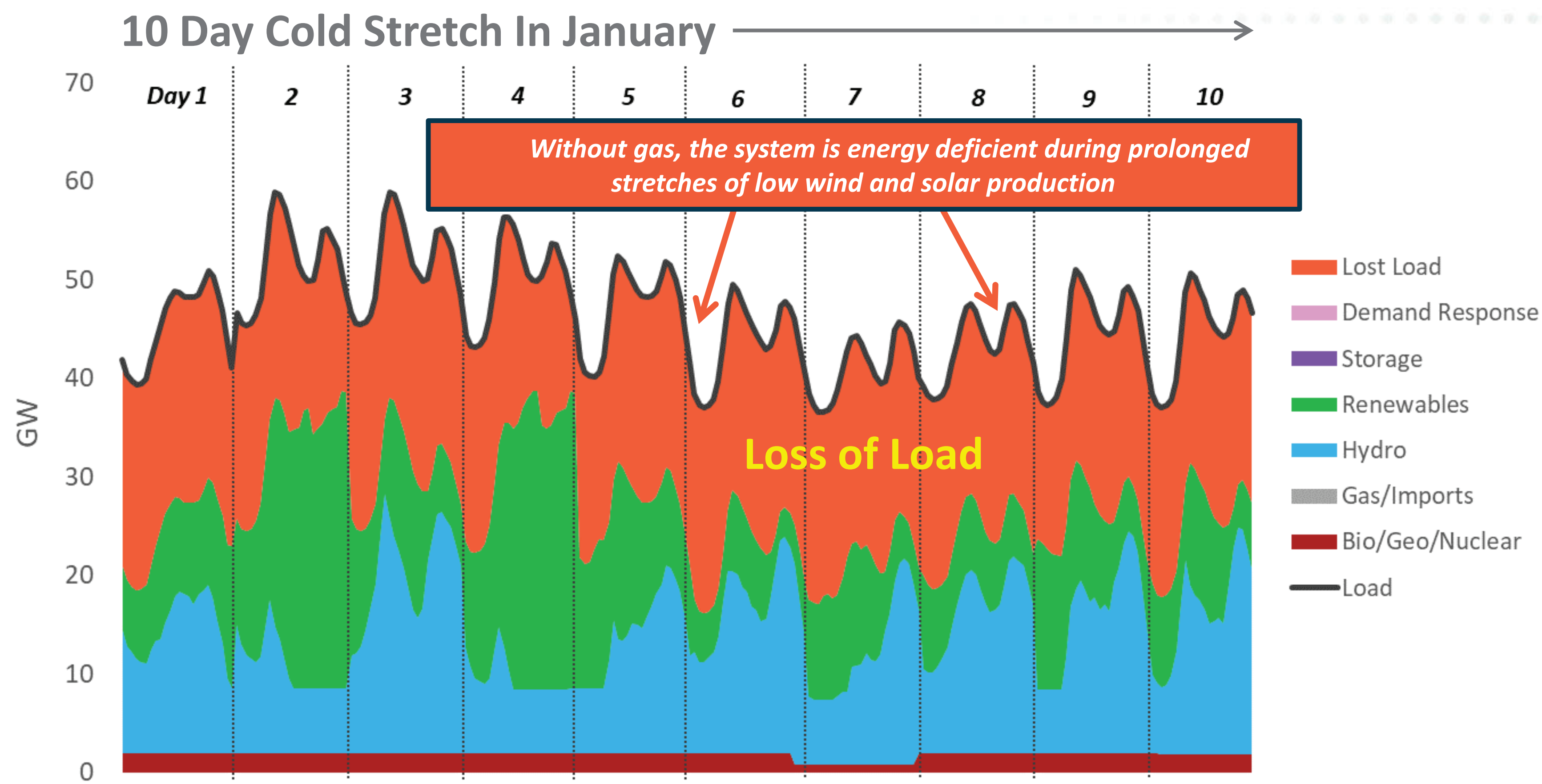


Illustrating the Need for Firm Capacity – January



Illustrating the Need for Firm Capacity – January

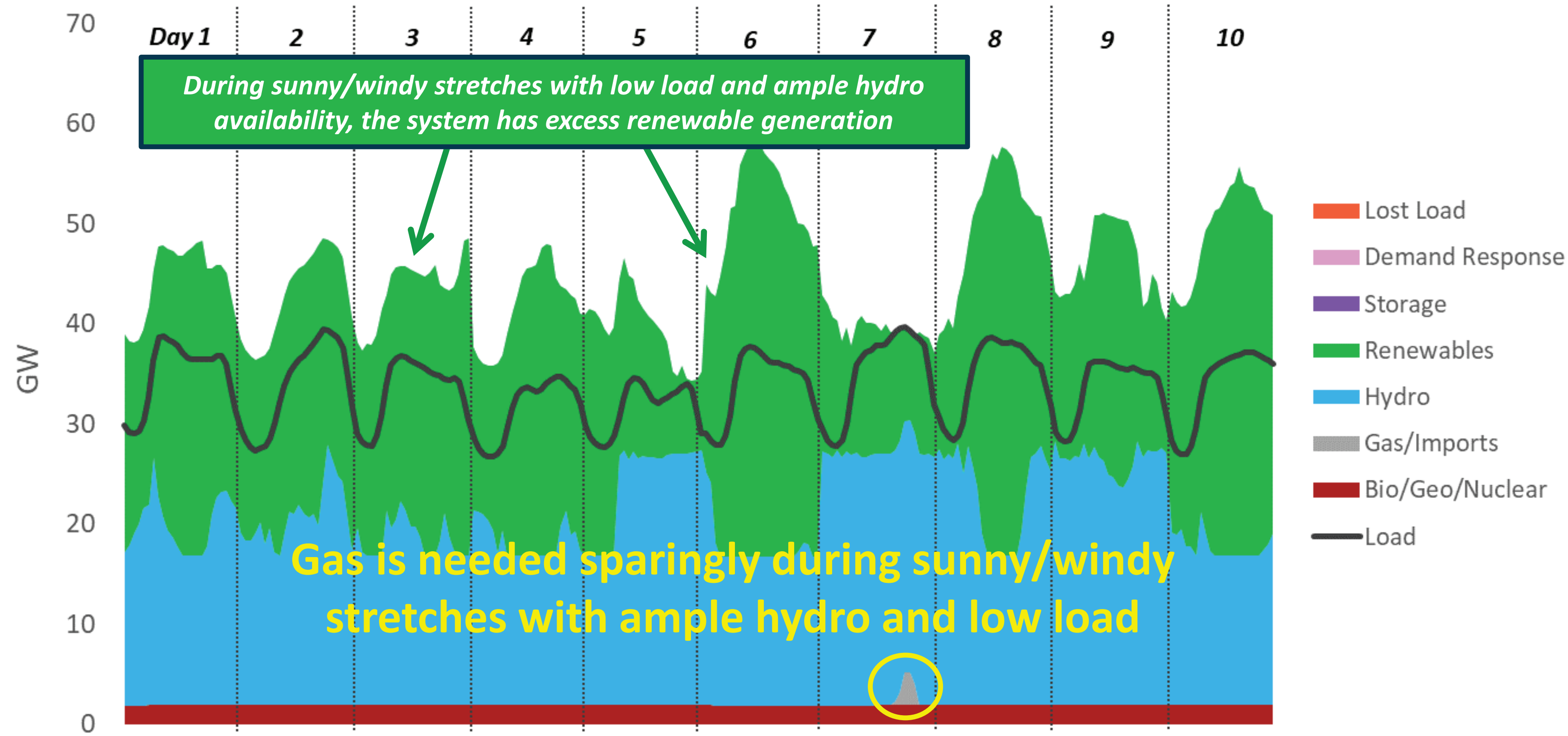
80% Reduction Case *Without* Gas



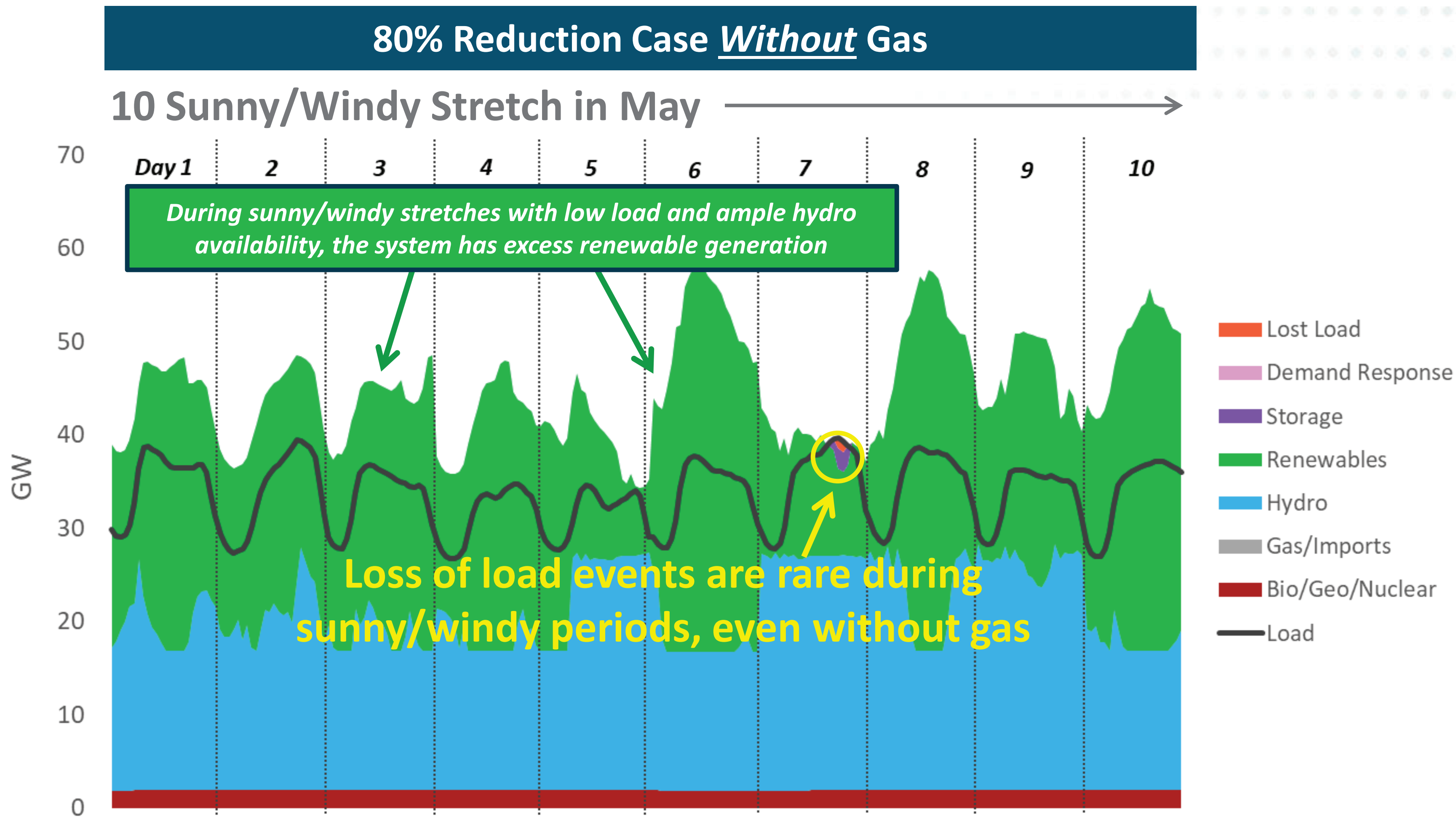
Illustrating the Need for Firm Capacity – May

80% Reduction Case *Including* Gas

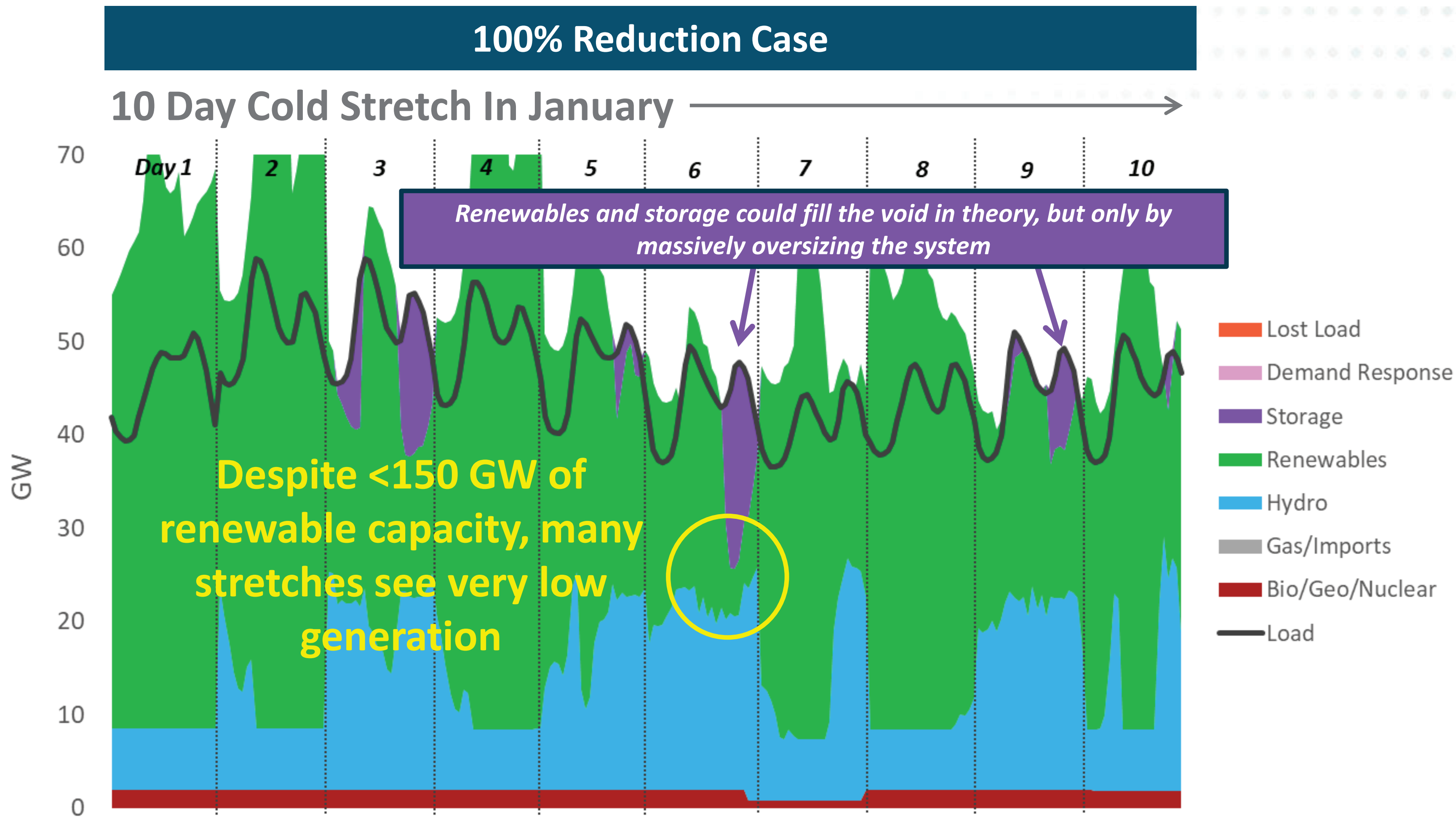
10 Sunny/Windy Stretch in May →



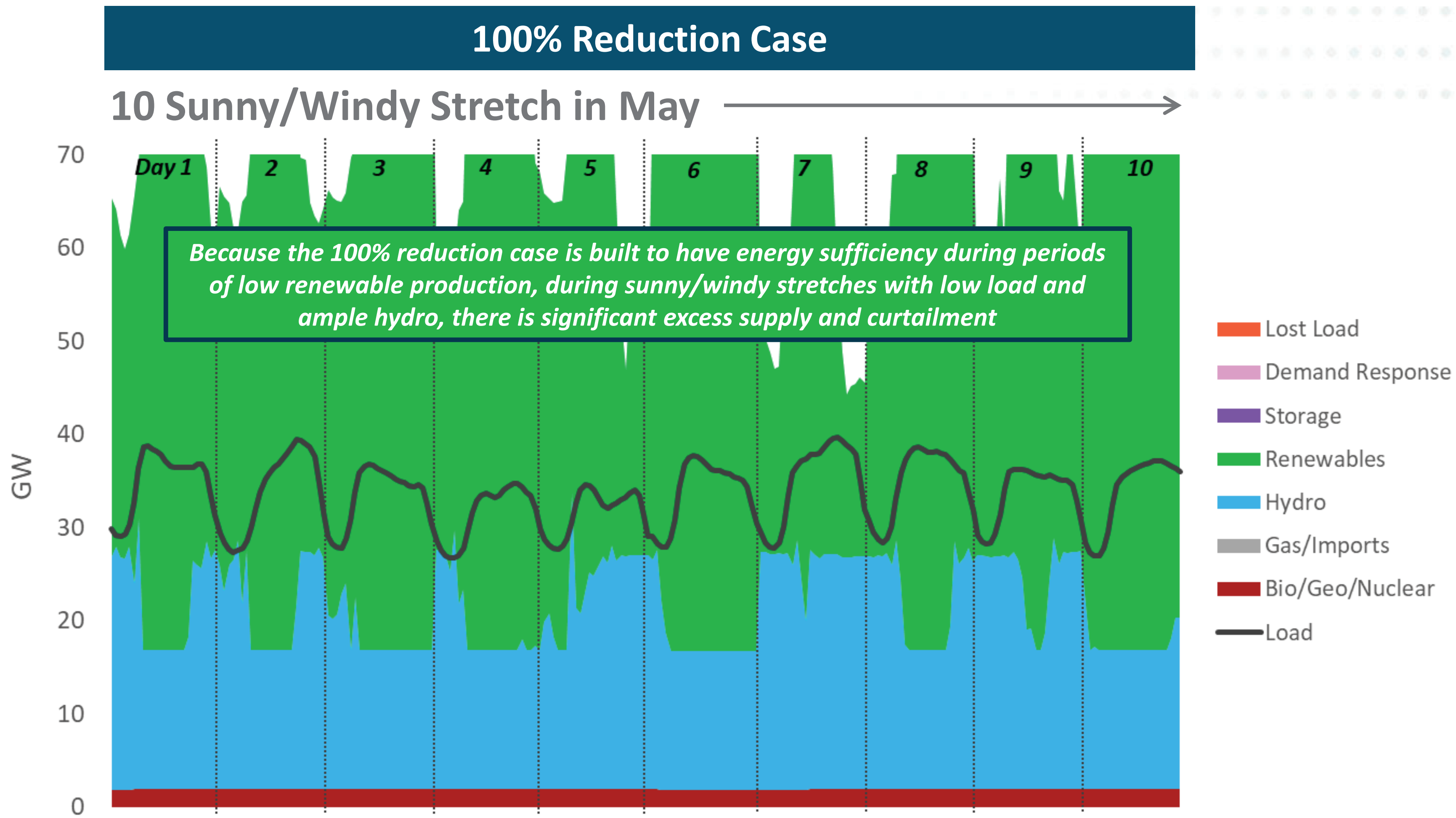
Illustrating the Need for Firm Capacity – May



Illustrating the Need for Firm Capacity – January

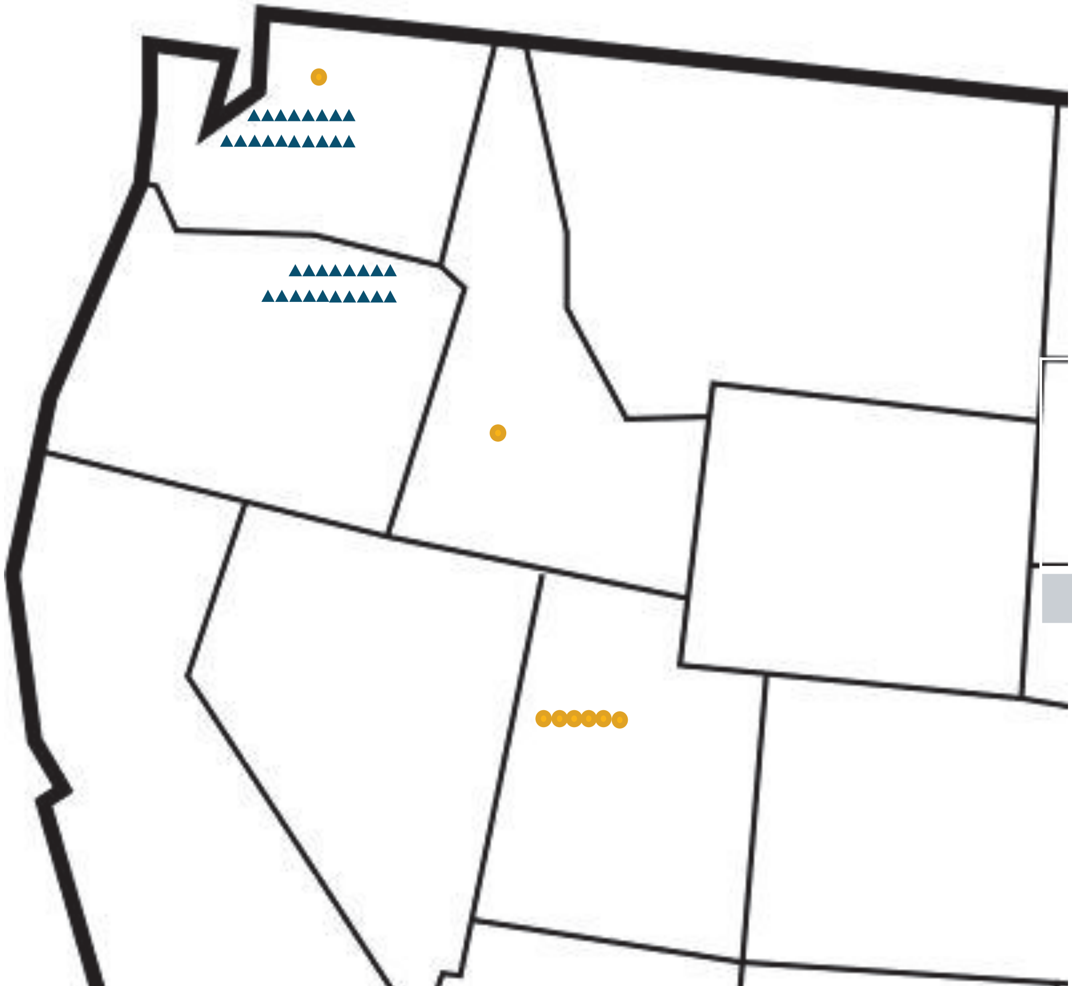


Illustrating the Need for Firm Capacity – May



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

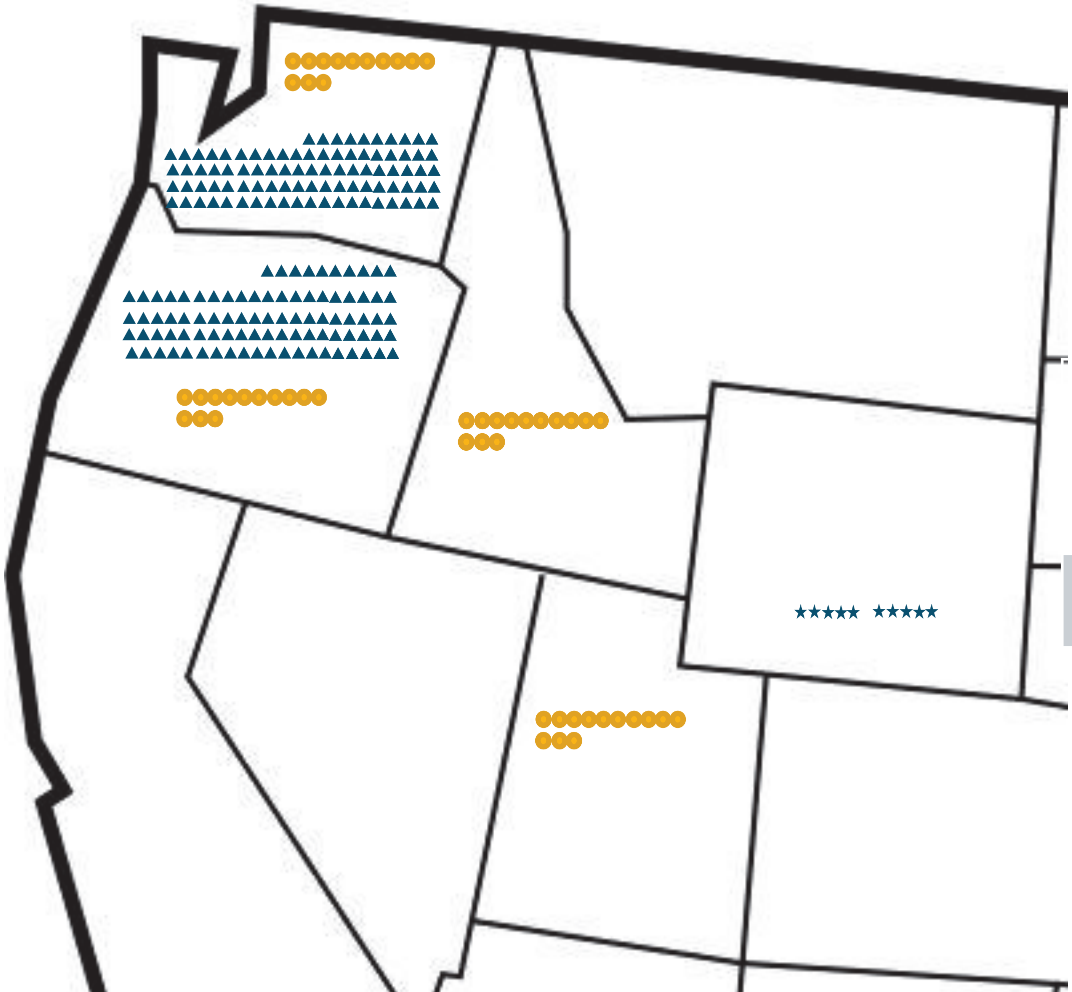
1.6 to 7.5x

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

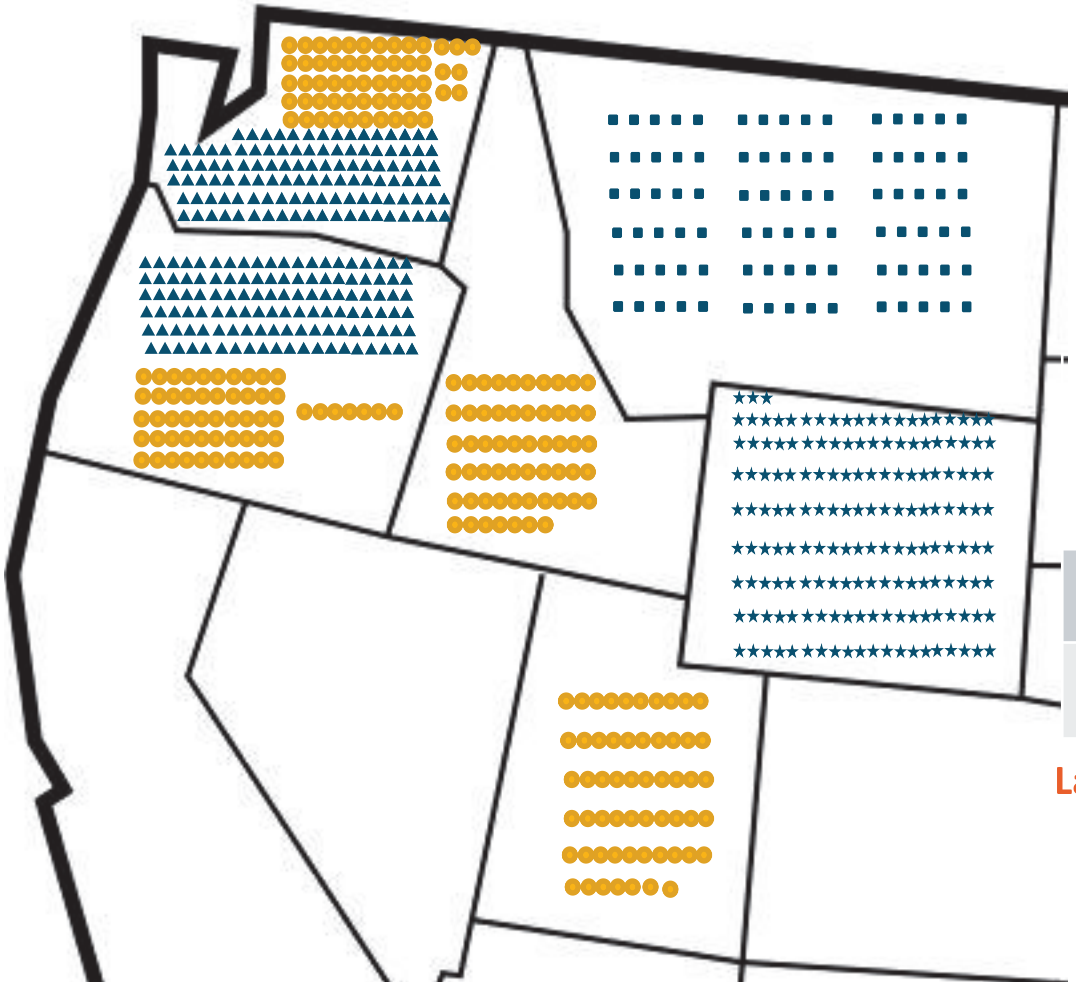
8 to 37x

the area of Portland and Seattle combined

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



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

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

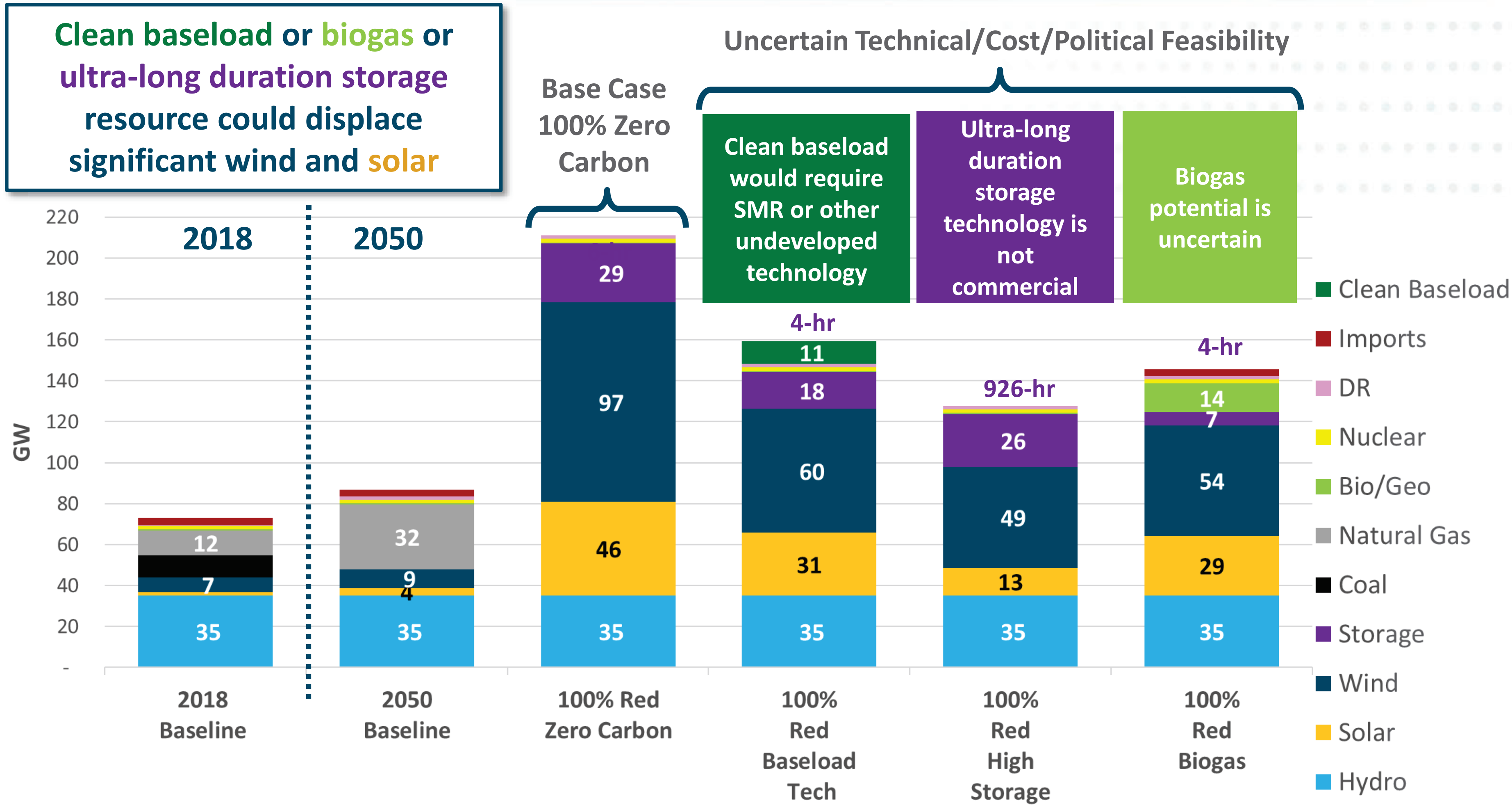
Land use in 100% Reduction case ranges from

20 to 100x

the area of Portland and Seattle combined

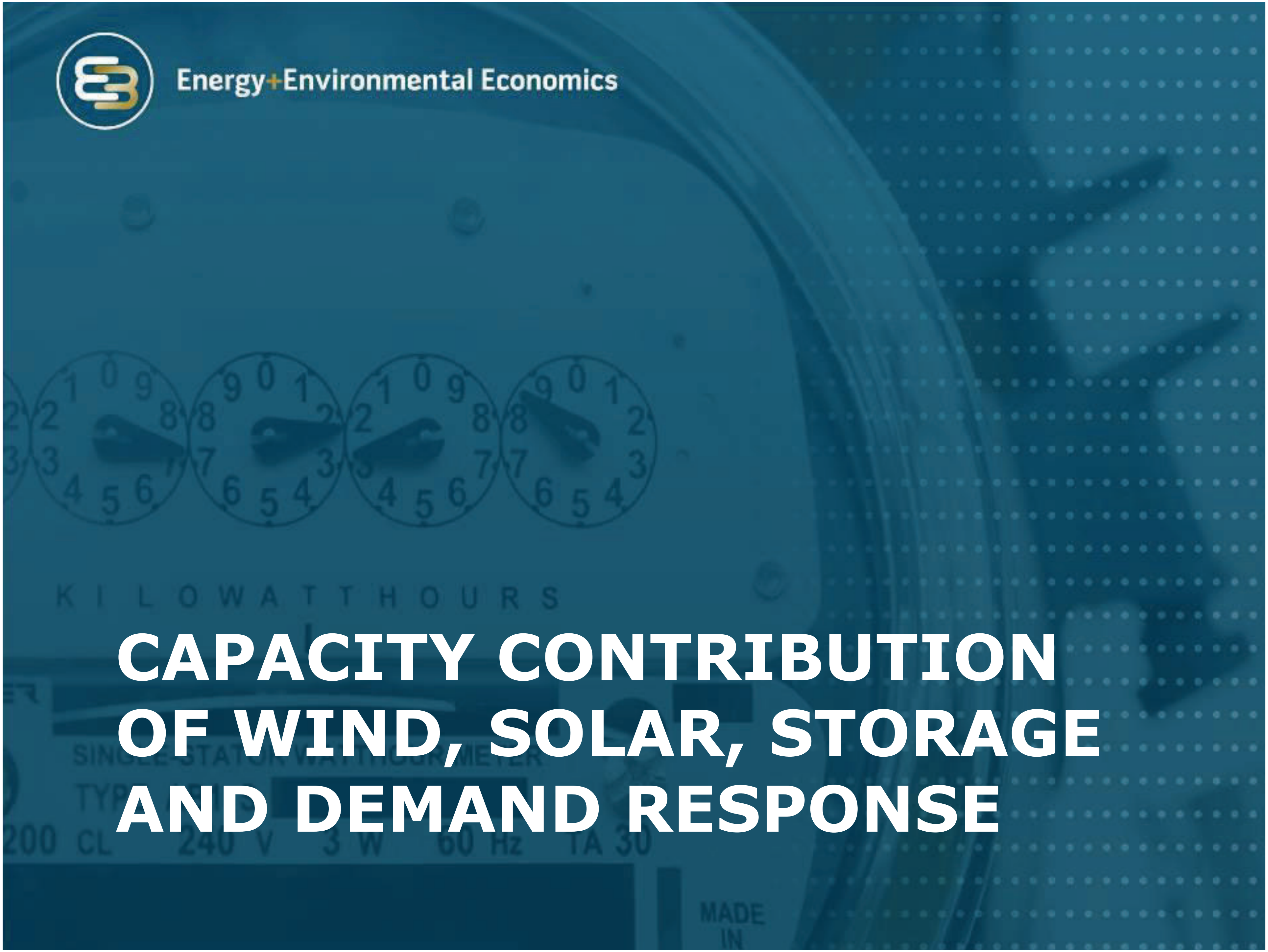
Portland land area is 85k acres
Seattle land area is 56k acres
Oregon land area is 61,704k acres

100% Reduction Portfolio Alternatives in 2050



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

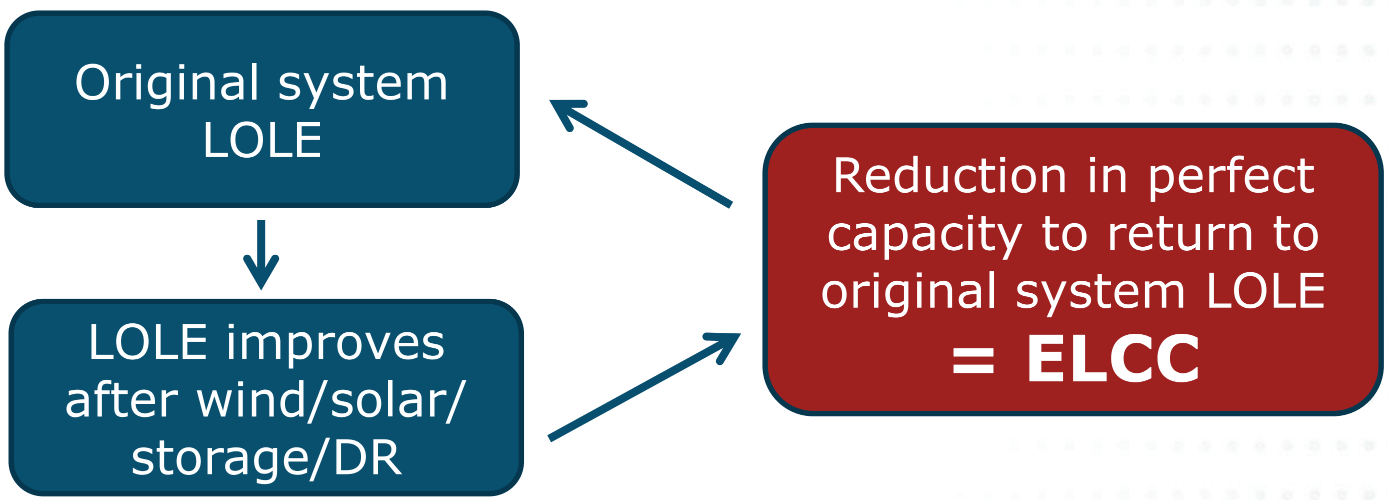
Energy+Environmental Economics



CAPACITY CONTRIBUTION OF WIND, SOLAR, STORAGE AND DEMAND RESPONSE

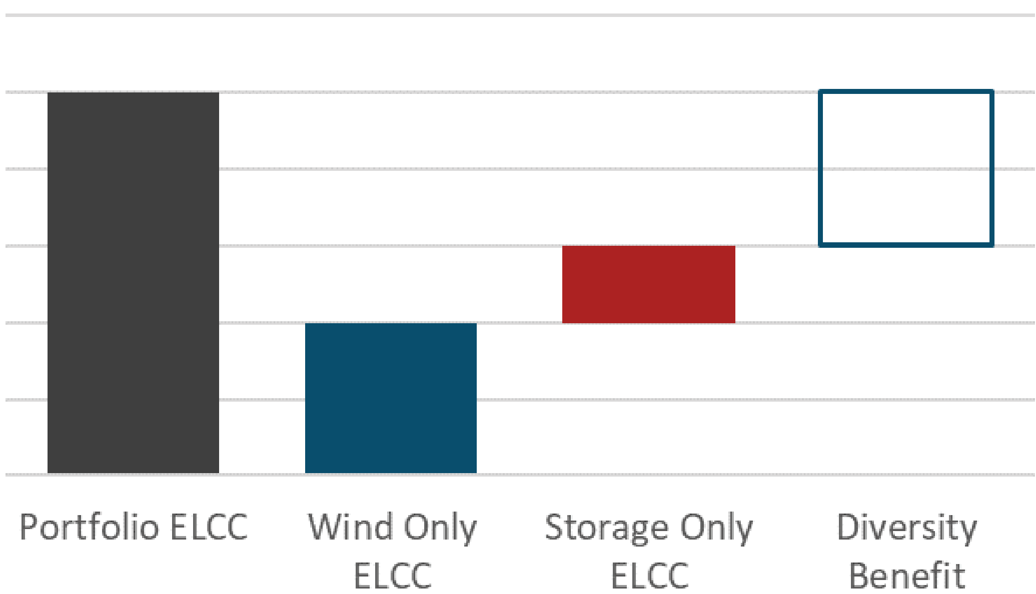
"ELCC" is used to determine effective capacity contribution from wind, solar, storage and demand response

- 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

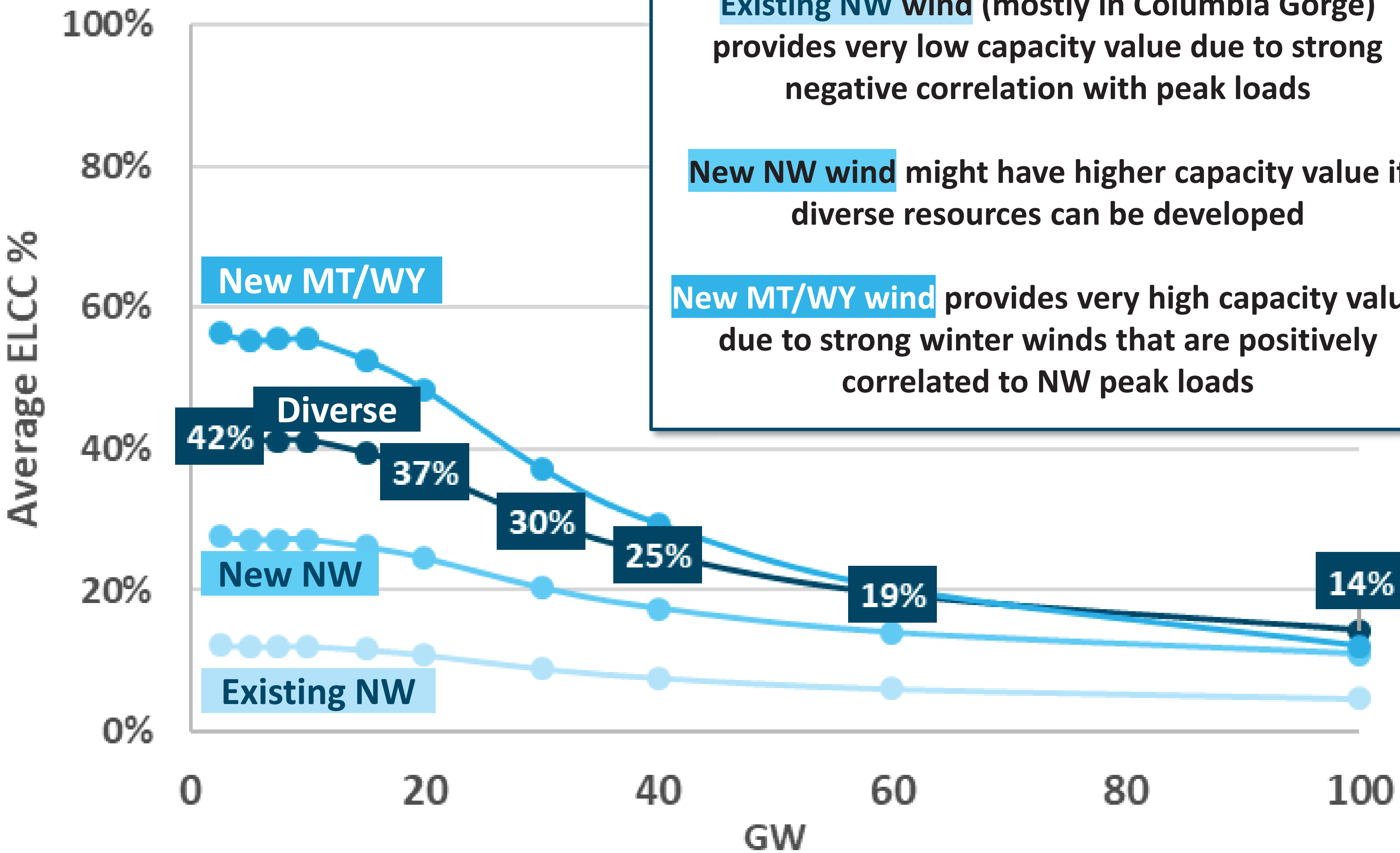


Portfolio ELCC & Diversity

- 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

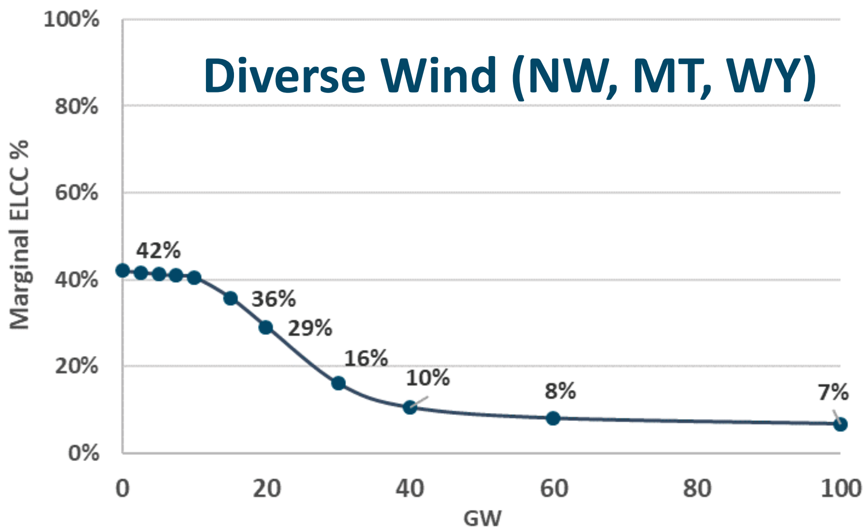


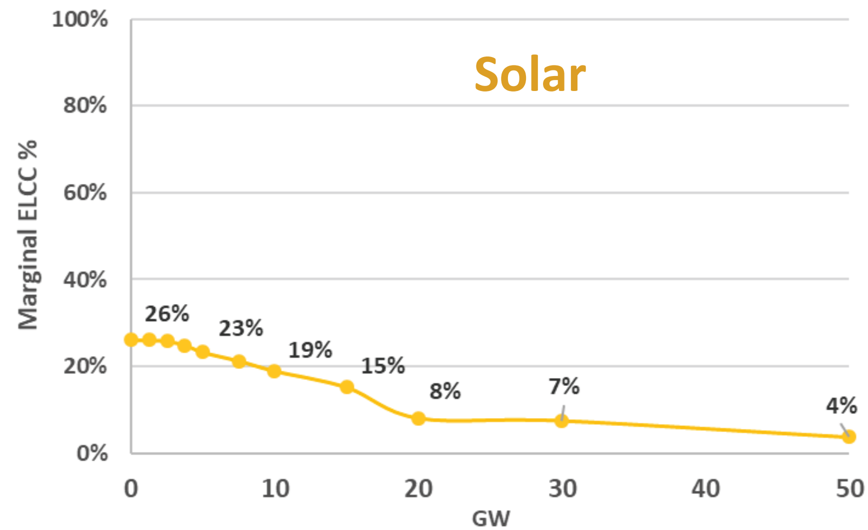
Existing NW wind (mostly in Columbia Gorge) provides very low capacity value due to strong negative correlation with peak loads

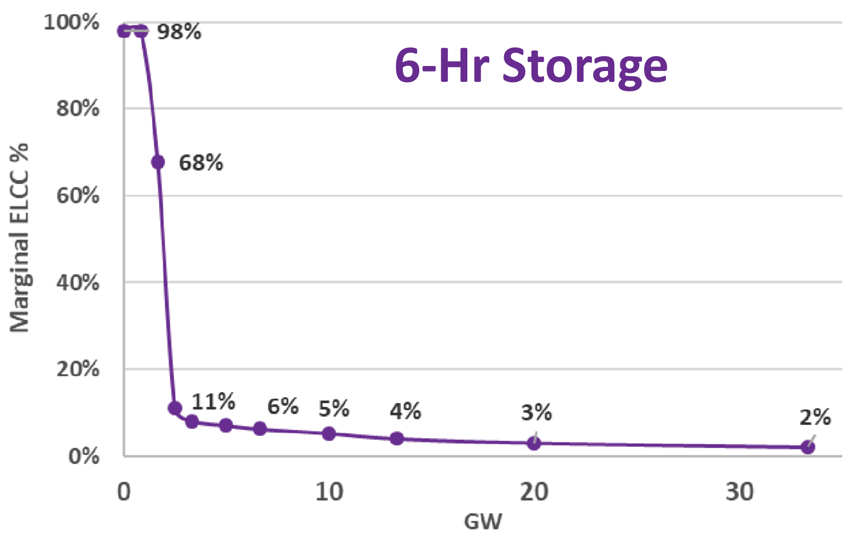
New NW wind might have higher capacity value if diverse resources can be developed

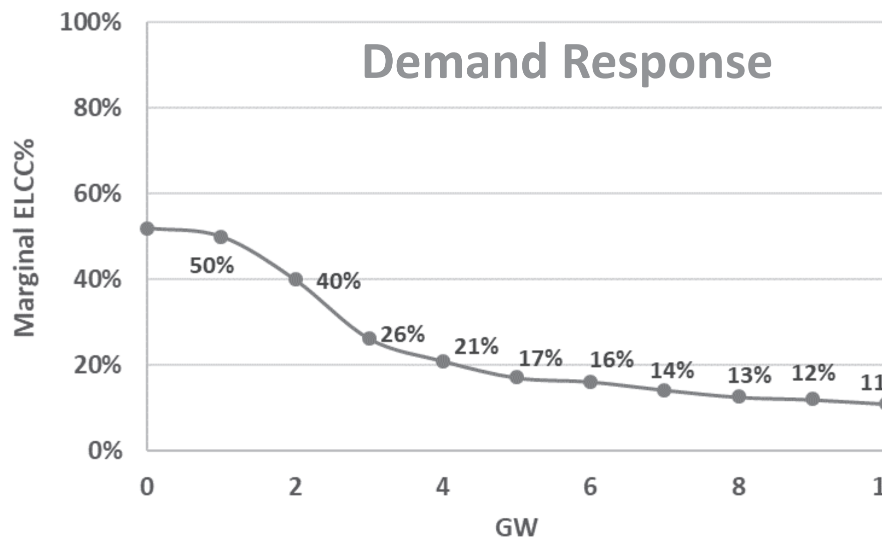
New MT/WY wind provides very high capacity value due to strong winter winds that are positively correlated to NW peak loads

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

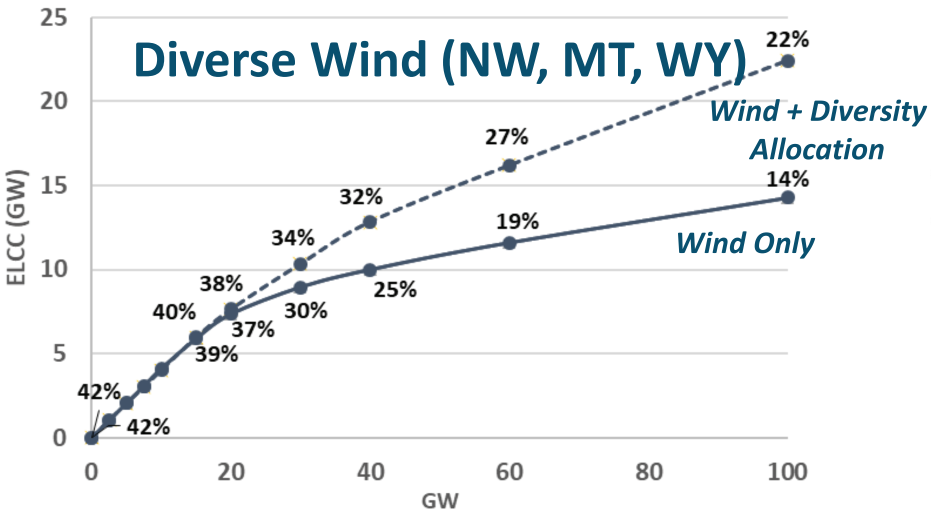


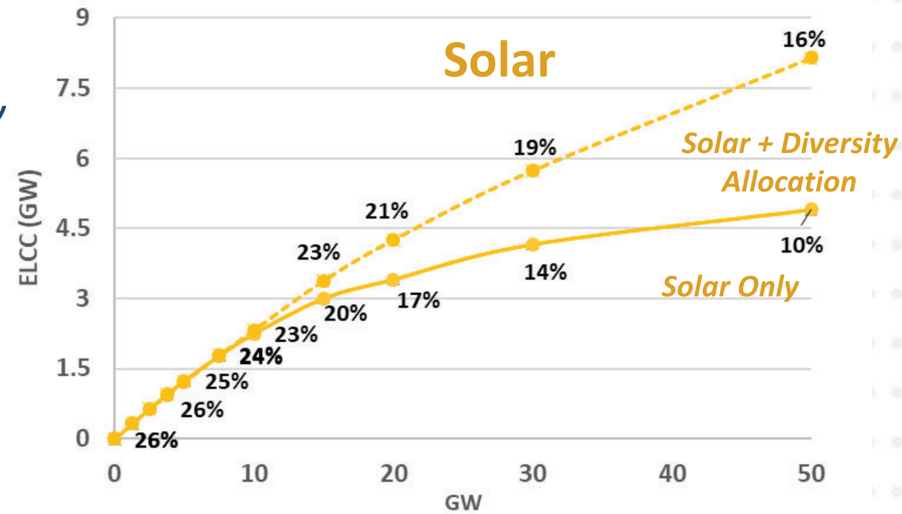


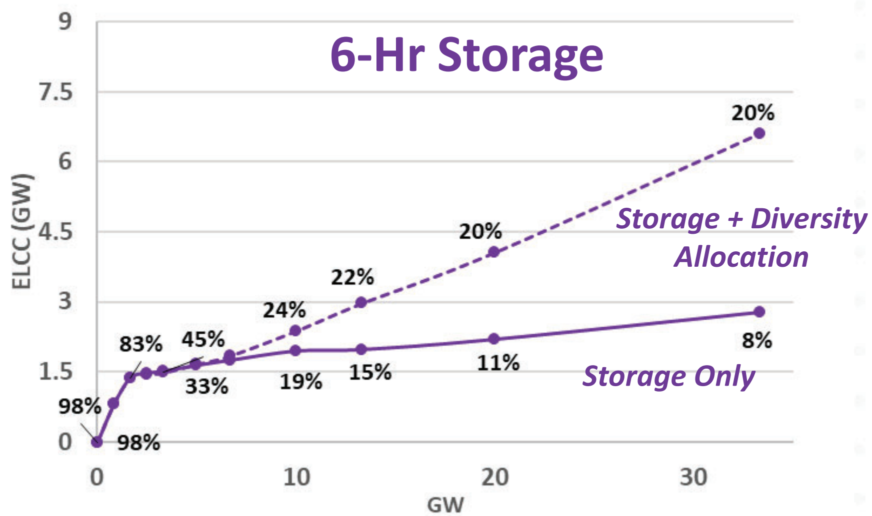




Cumulative ELCC Potential for Wind/Solar/Storage

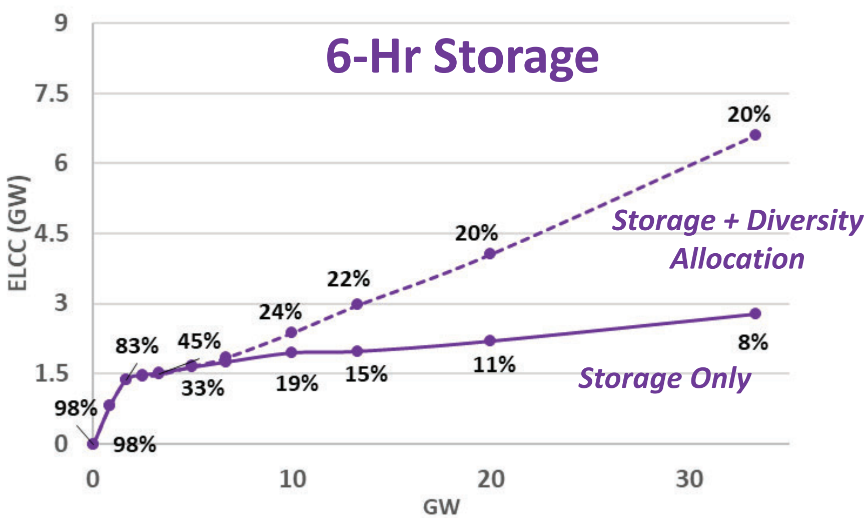


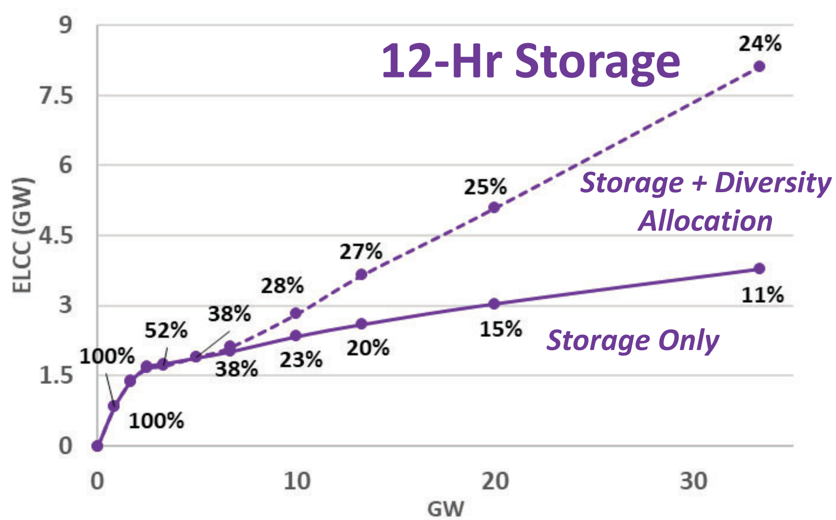




Value of Storage Duration

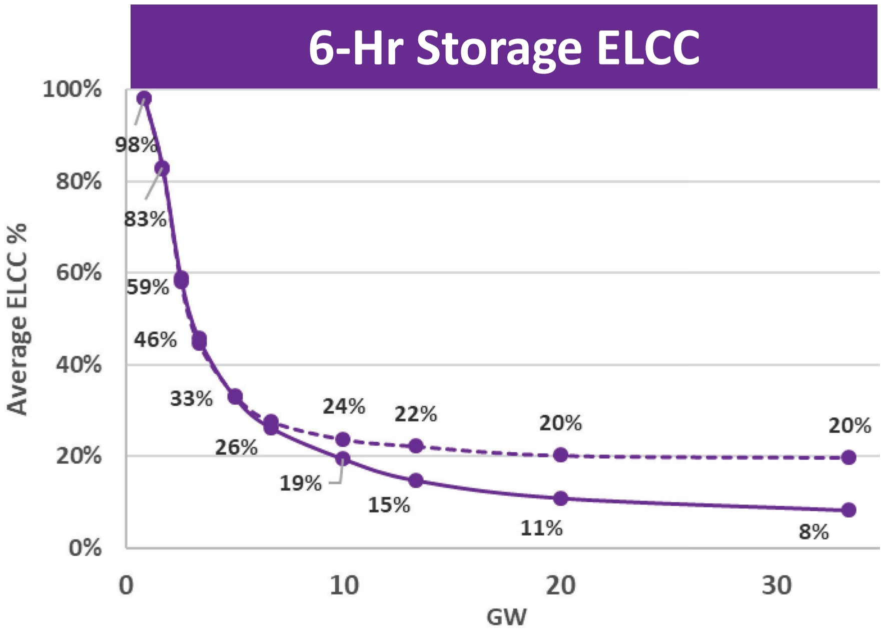
+ **Increasing the duration of storage provides additional ELCC capacity value, but there are still strong diminishing returns even for storage up to a duration of 12-hours**

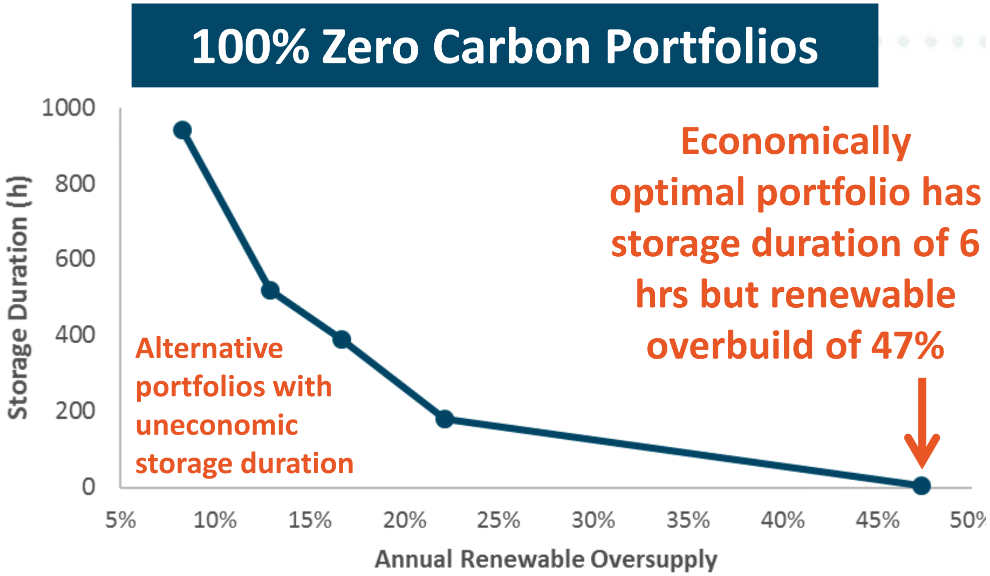




Energy storage is limited in its ability to provide firm generation

+ **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**



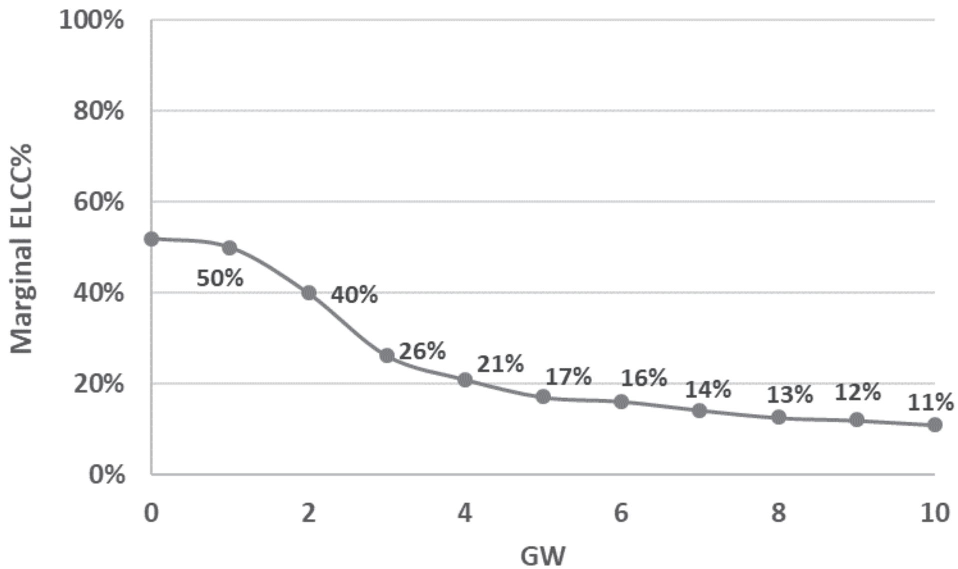


Demand response is limited in its ability to provide firm generation

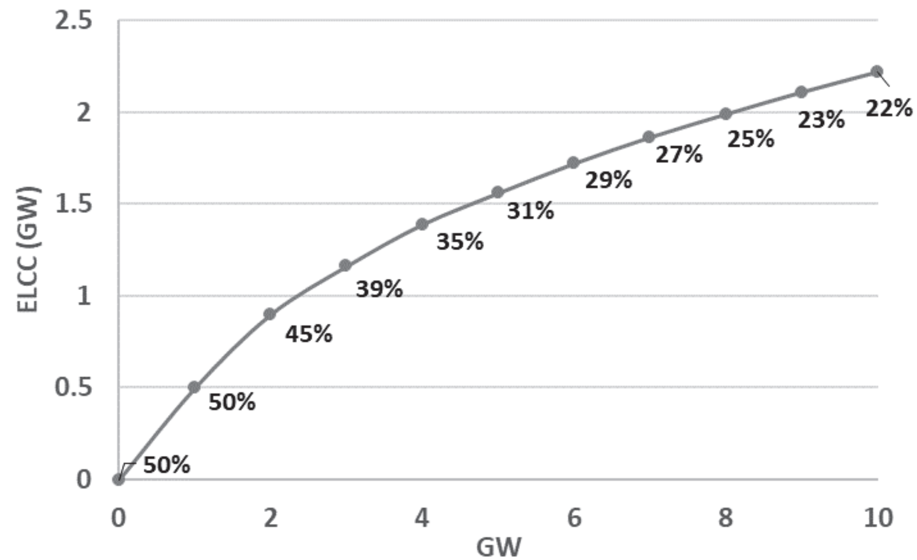
- Demand response is capable of providing capacity for limited periods of time, making it difficult to substitute for firm generation when energy is needed for prolonged periods of time
- DR assumption: 10 calls per year, 4 hours per call
- Results shown for the 2050 system

72°

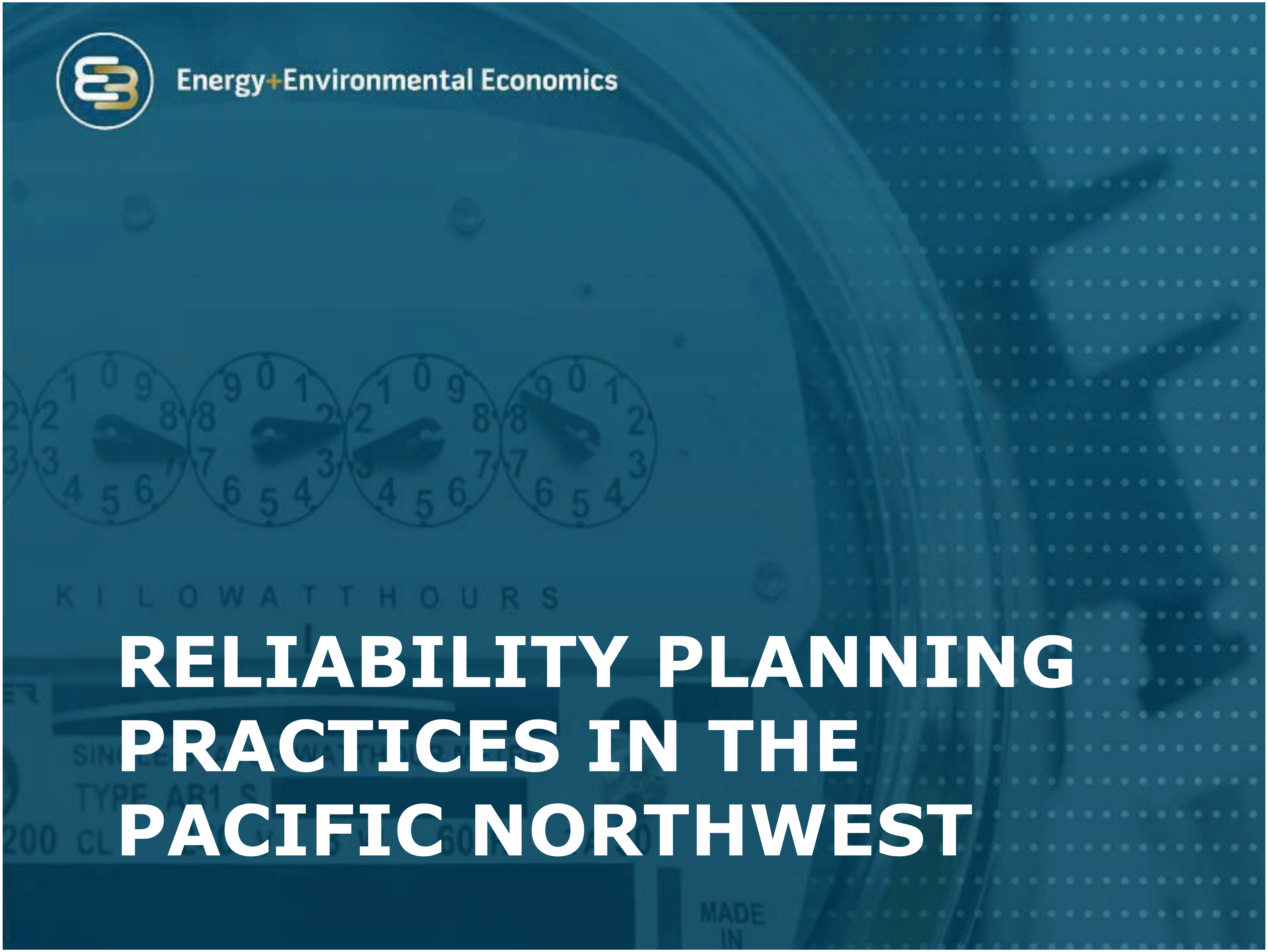
DR Marginal ELCC %



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

Energy+Environmental Economics

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

Energy+Environmental Economics

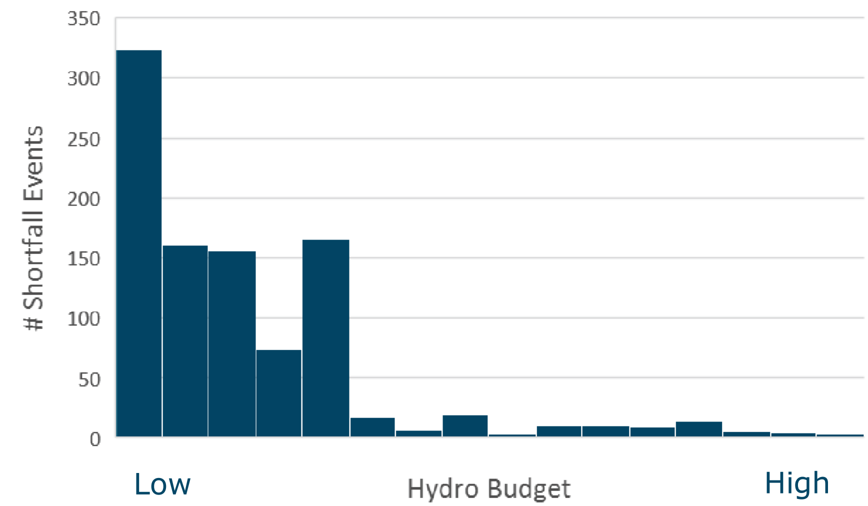
APPENDIX

Energy+Environmental Economics

ROLE OF HYDRO IN MEETING RESOURCE ADEQUACY NEEDS

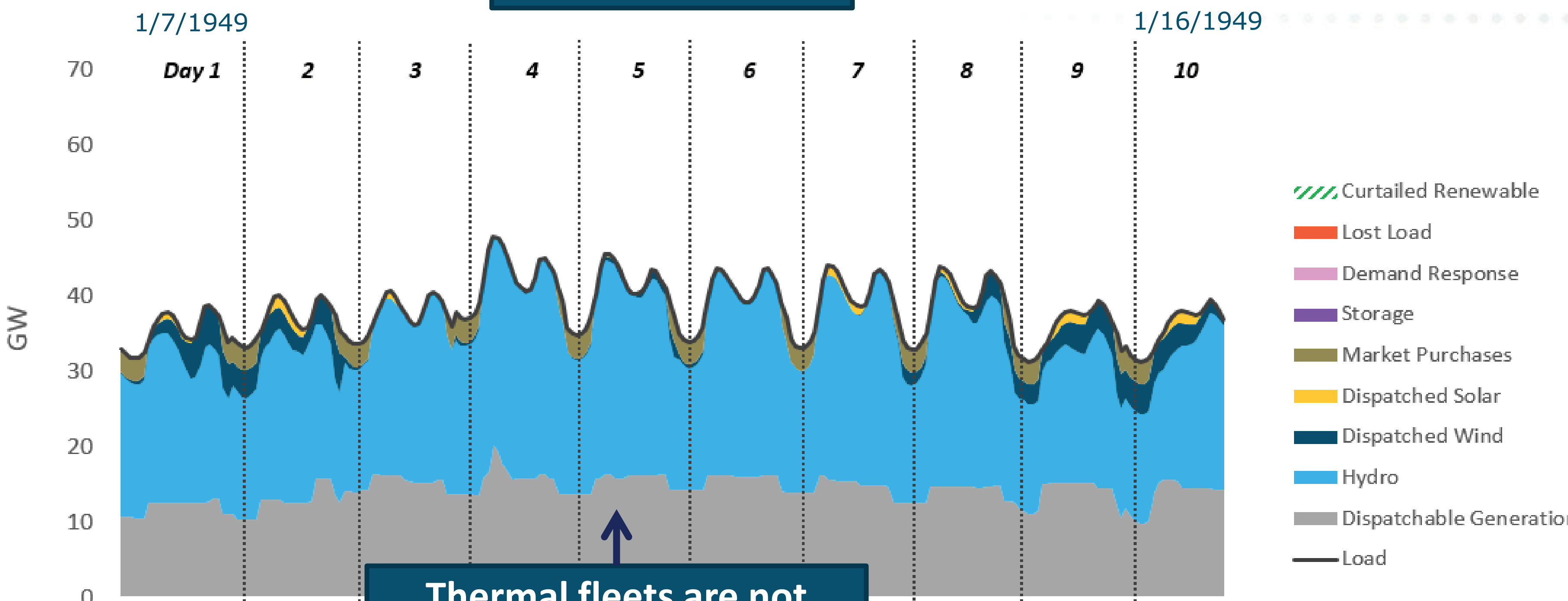
Low Hydro Years: Low Reliability

- **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**



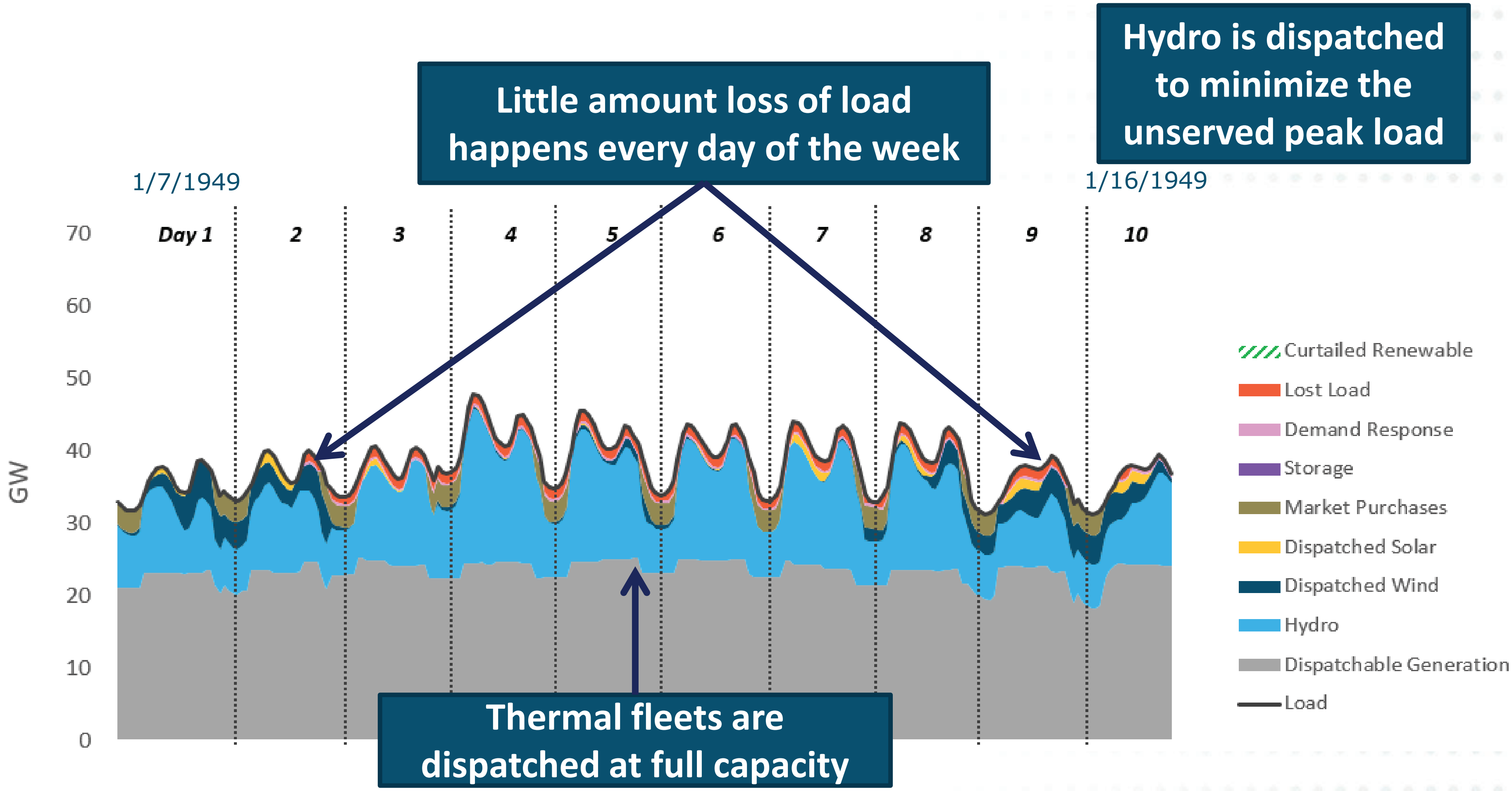
Today's System with Median Hydro

No loss of load event in this week

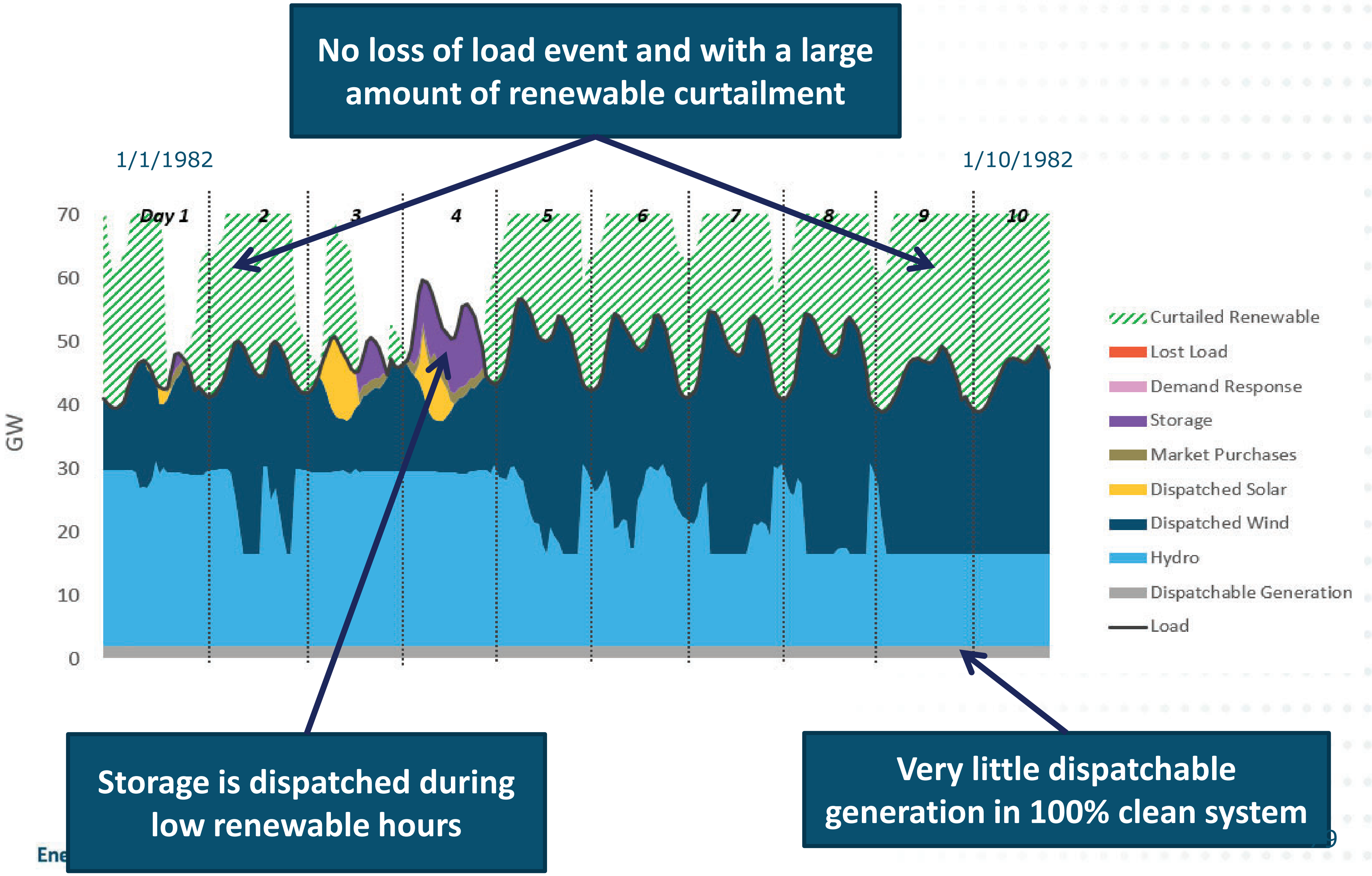


Thermal fleets are not dispatched at full capacity

Today's System with Low Hydro



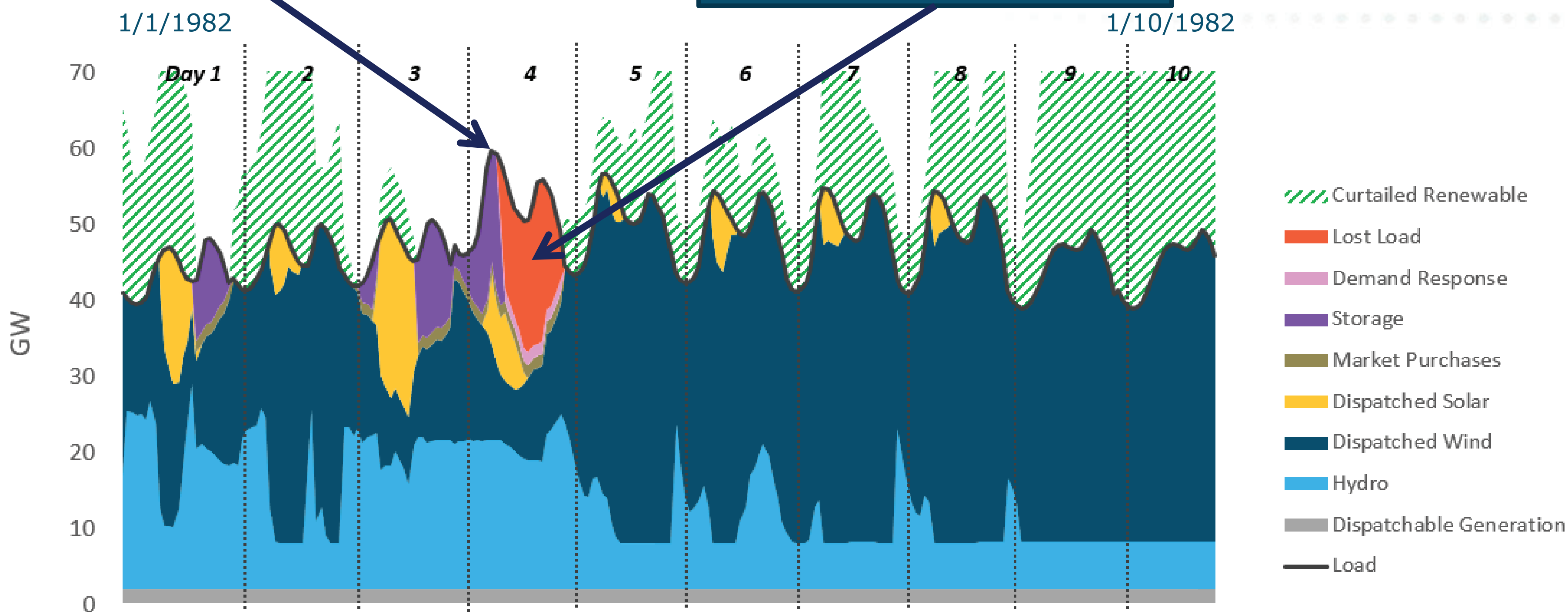
2050 System with Median Hydro



2050 System with Low Hydro

Storage depletes at this moment

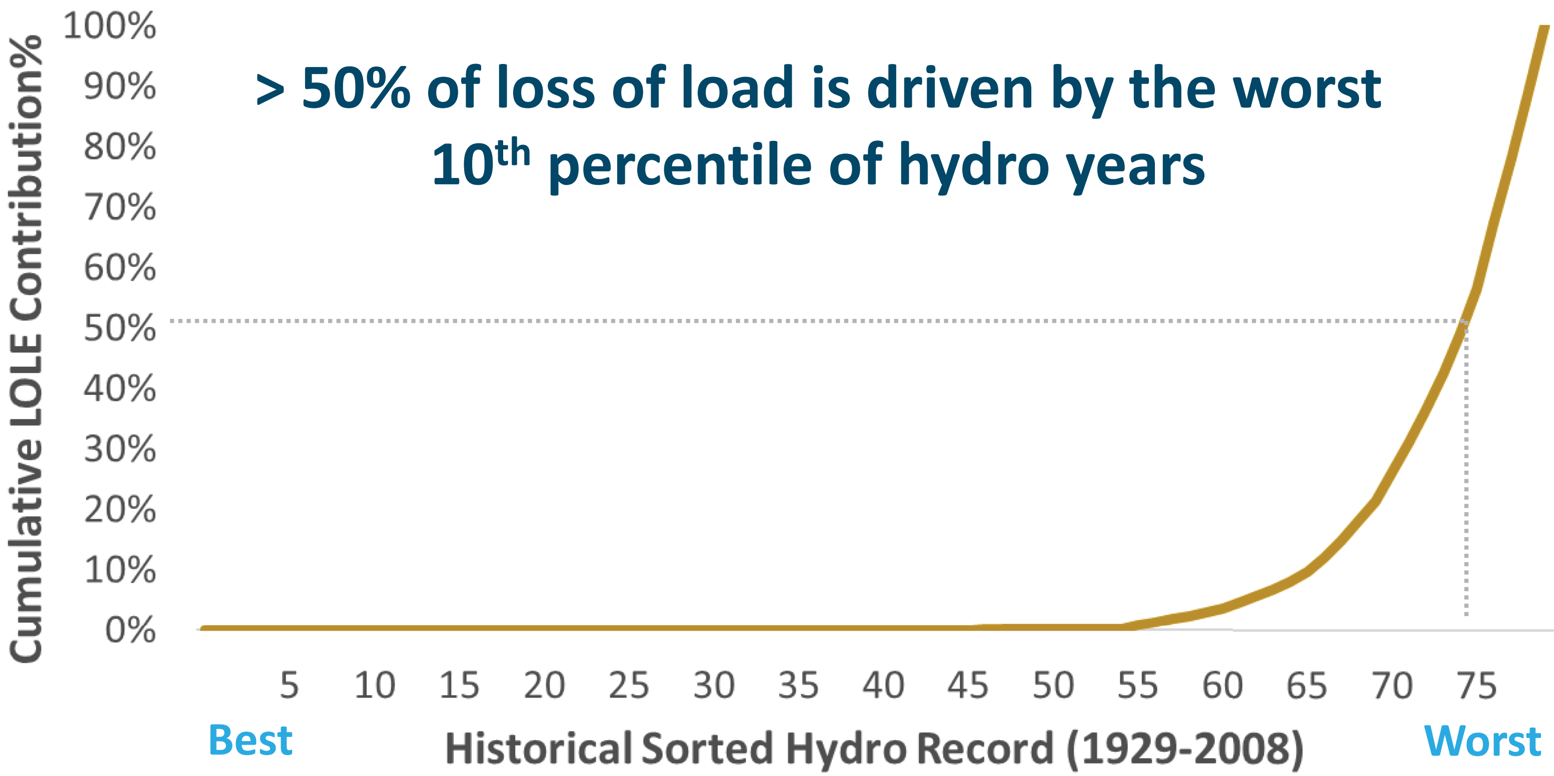
Large amount loss of load happens on one day



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

2018 Hydro Analysis

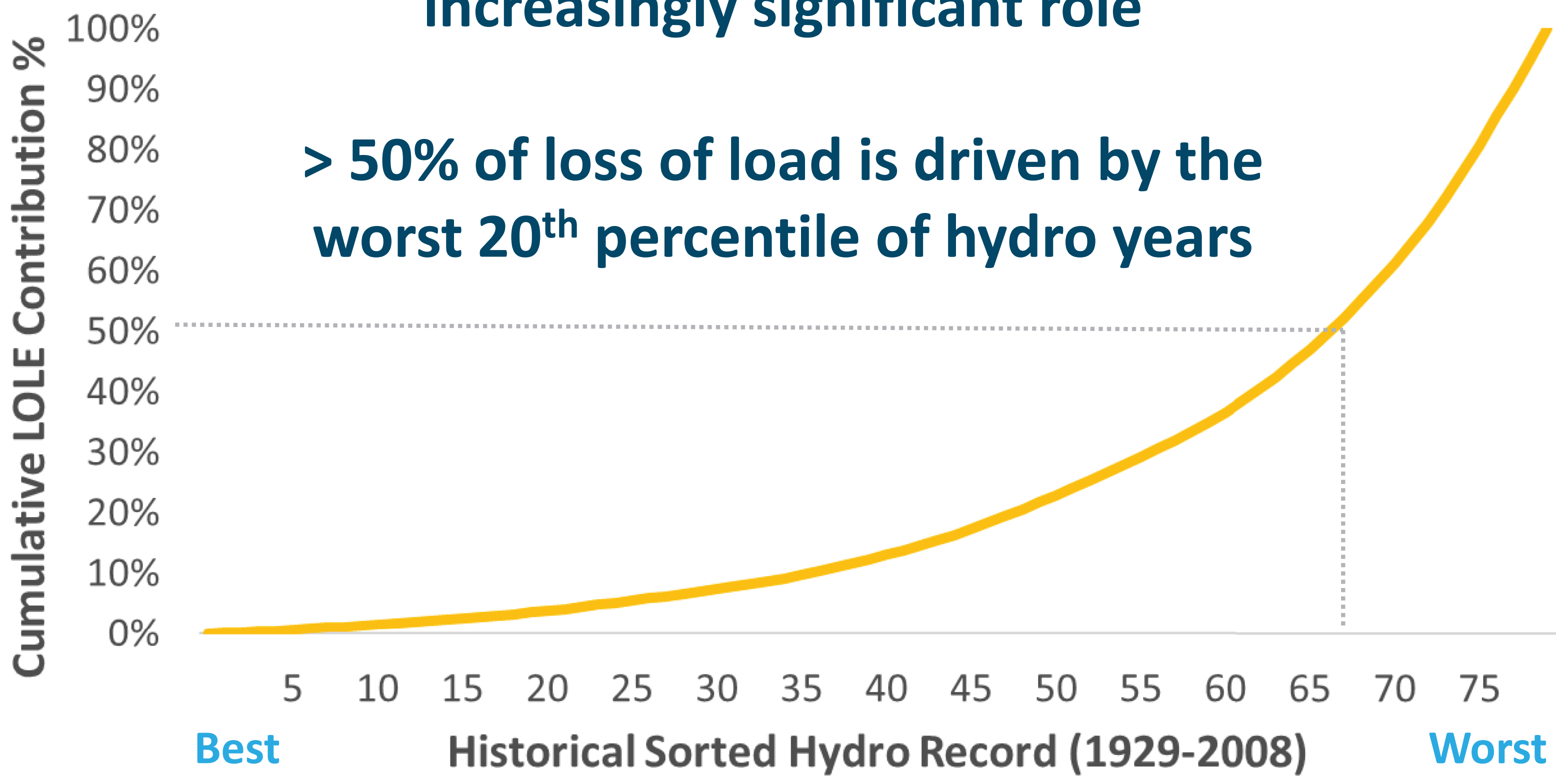
In today's system, nearly all loss of load is driven by low hydro years which is the single most variable factor in the system



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

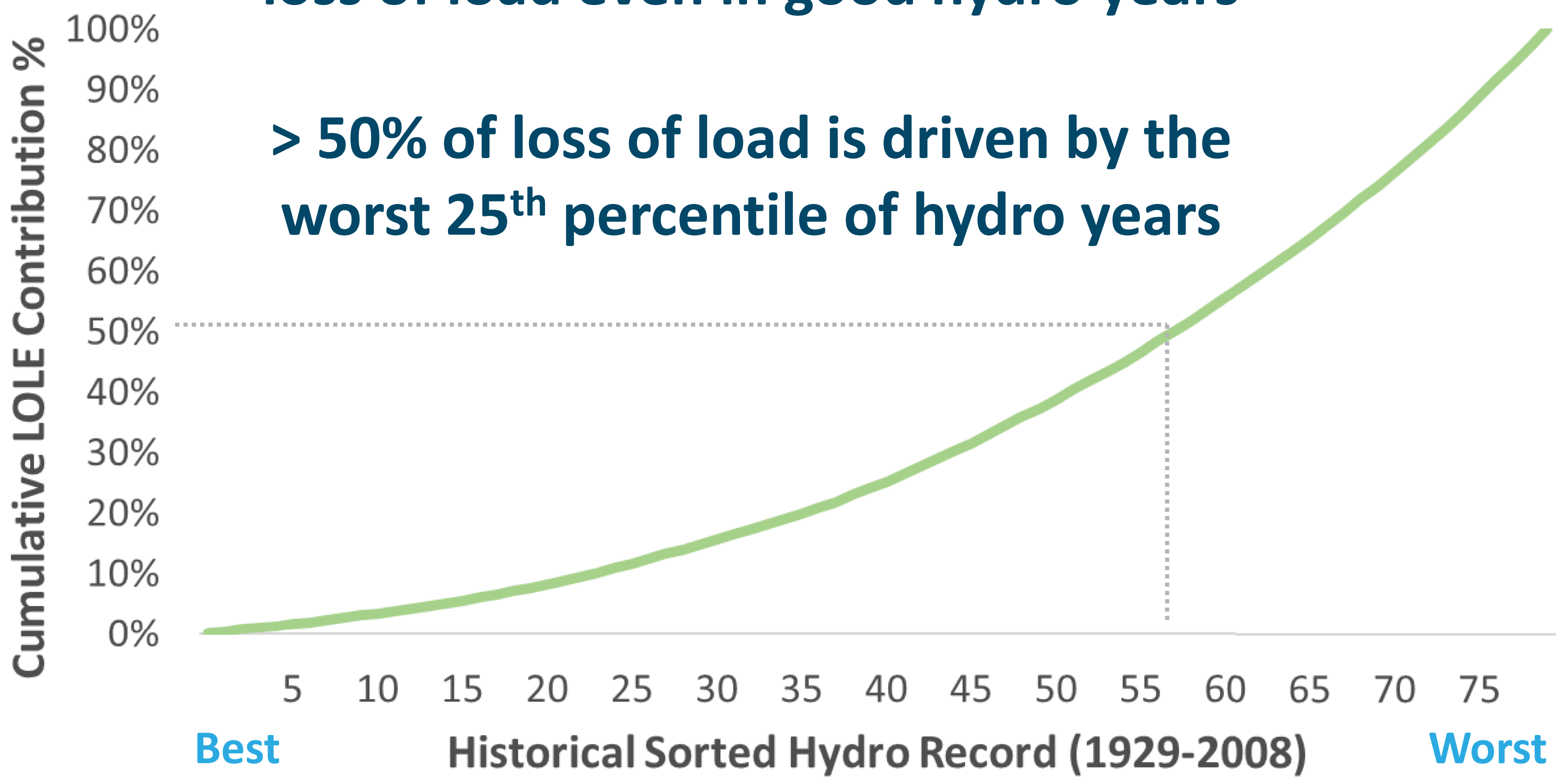
> 50% of loss of load is driven by the worst 20th percentile of hydro years



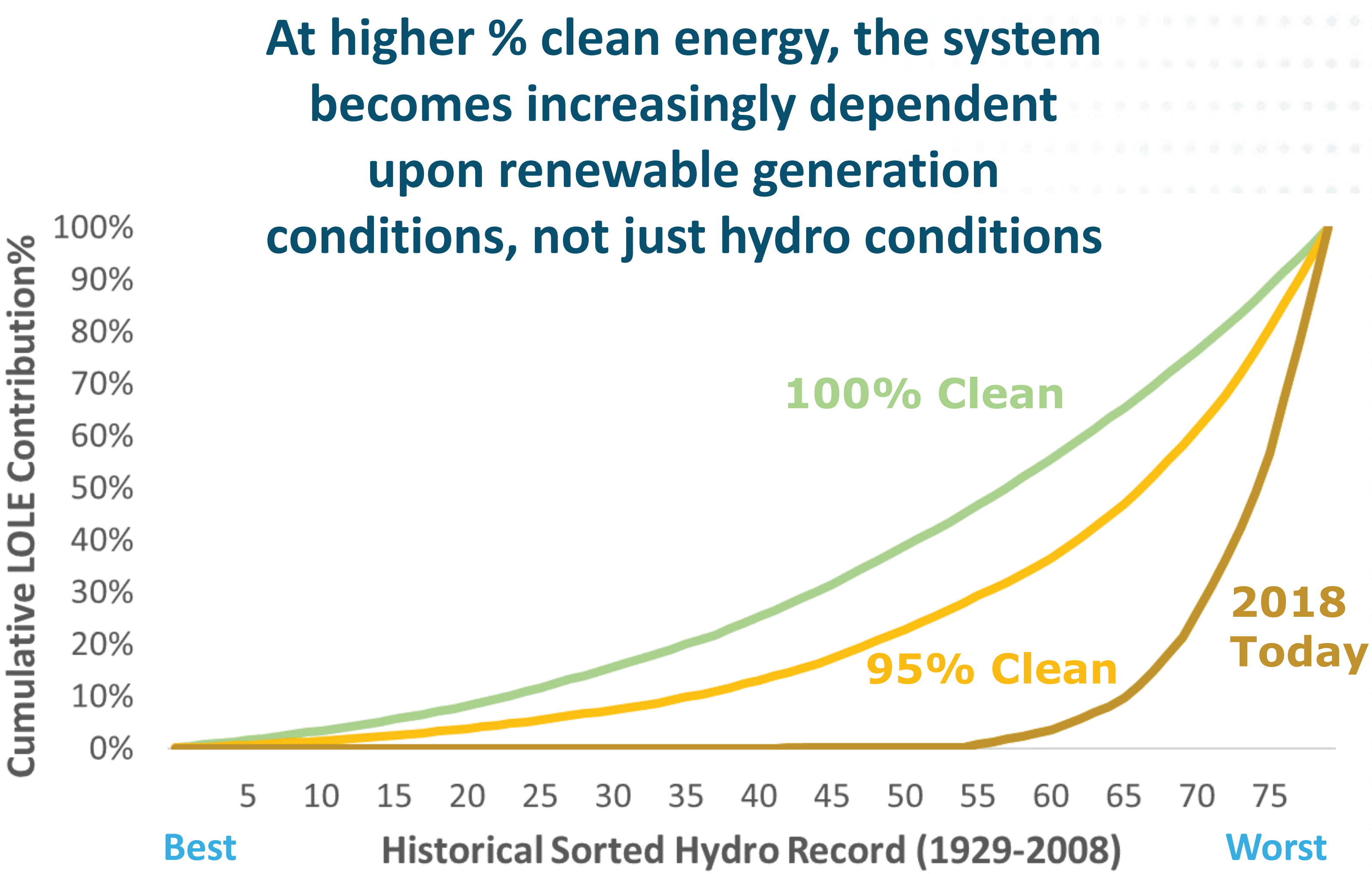
2050 - 100% Clean Hydro Analysis

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

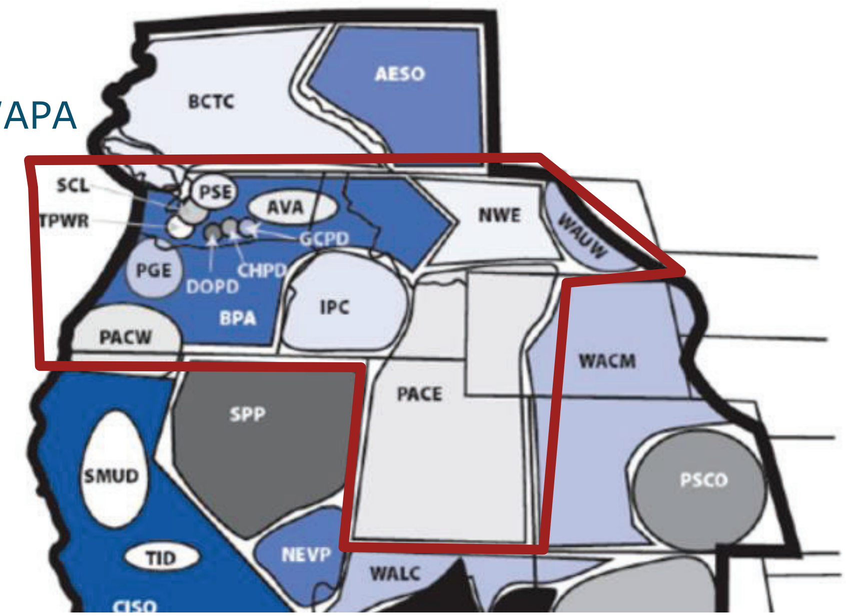


Energy+Environmental Economics

RECAP TECHNICAL DETAILS

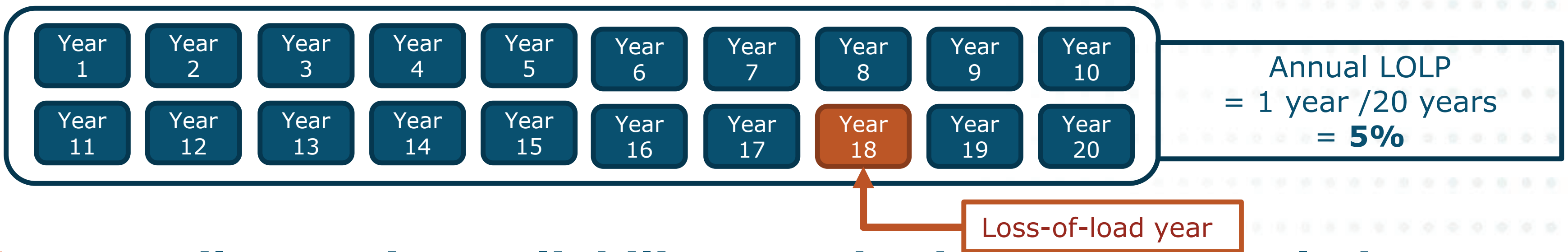
Modeling Region

- 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

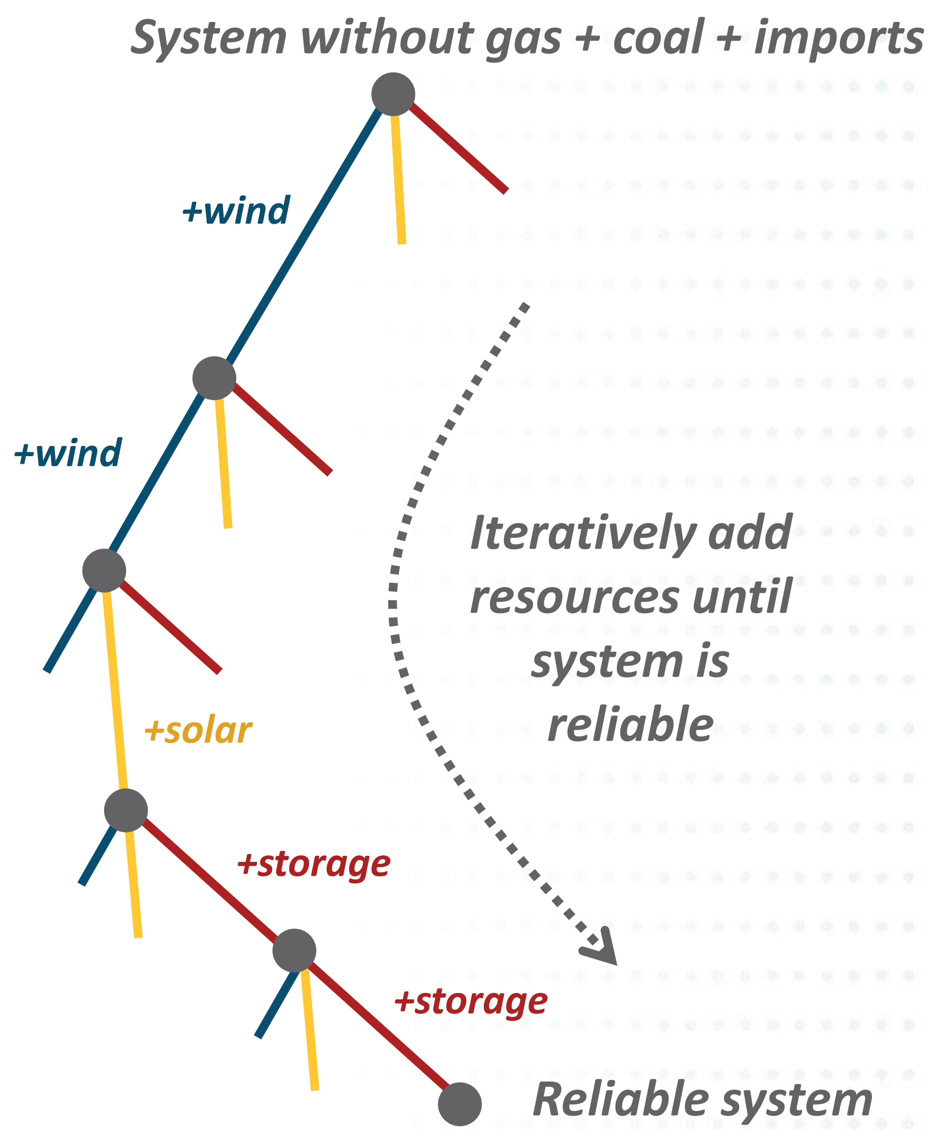
- **NWPCC has adopted a 5% annual loss of load probability (aLOLP)**
  - Every 1 in 20 years can result in a shortfall



- **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

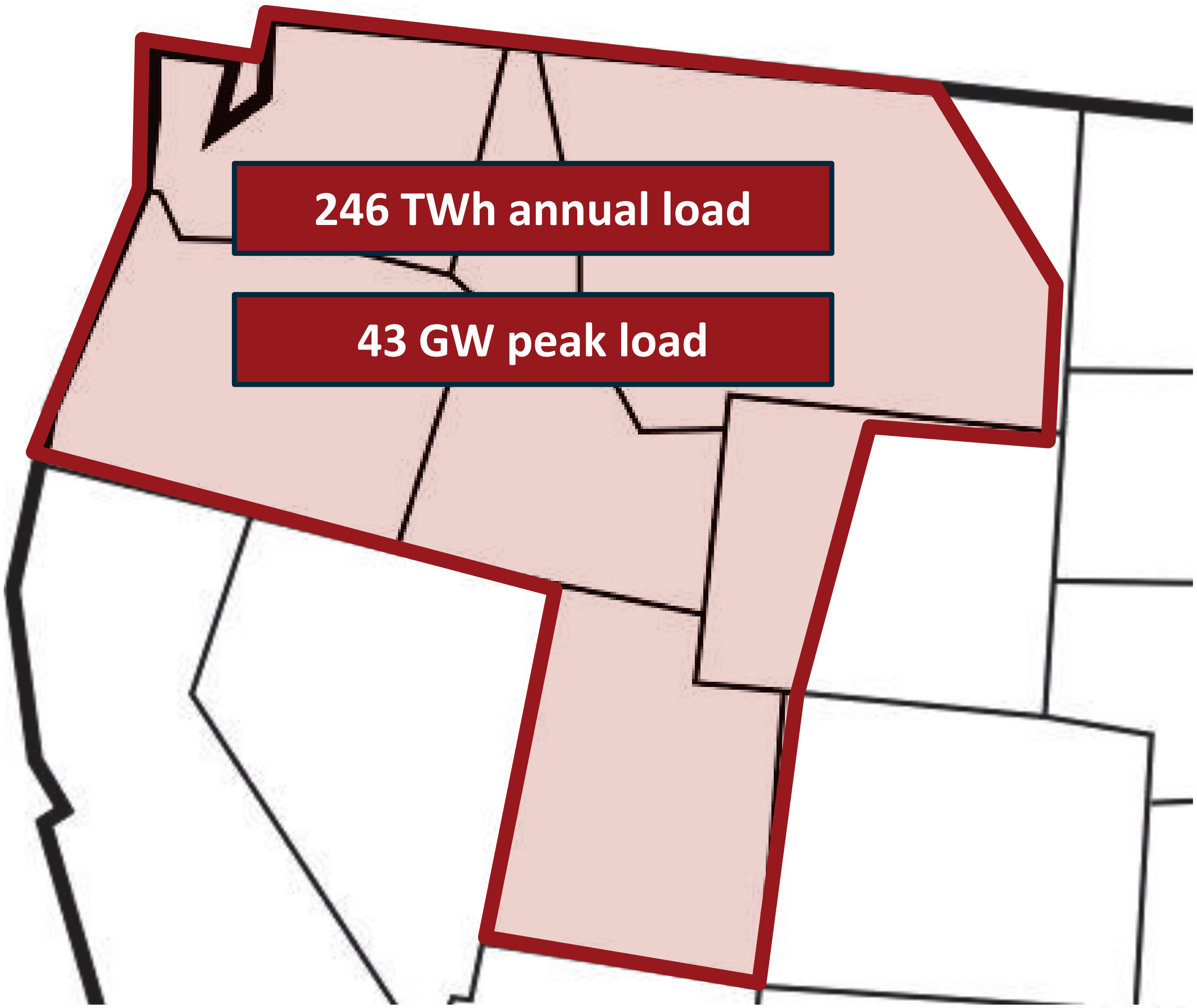
- Smart search functionality iteratively evaluates the reliability contribution of adding quantities of equal cost carbon free resources and selecting the resource with the highest contribution
- This allows the model to select a cost optimal portfolio of resources that provides adequate reliability



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
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
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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

Wind

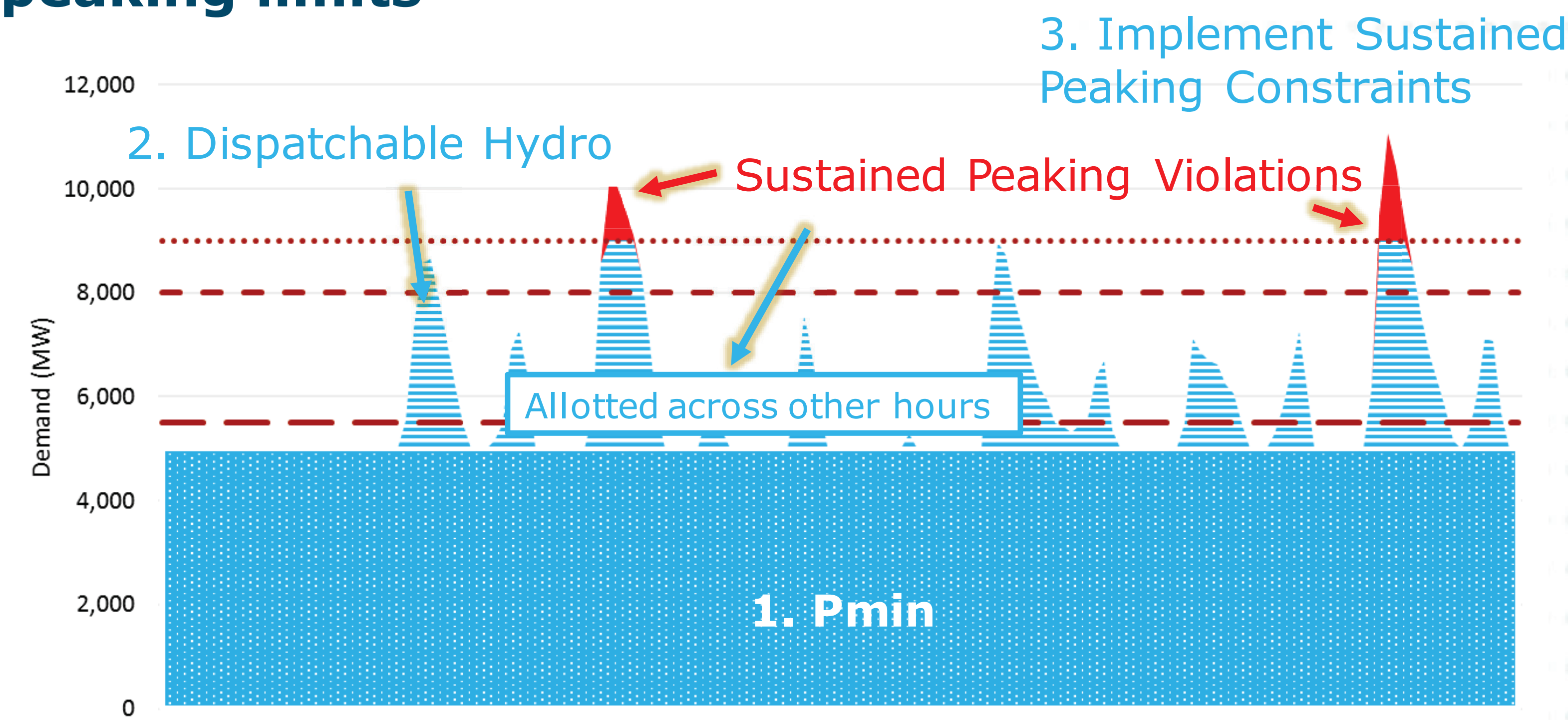
+ **Wind profiles are simulated output from existing and new sites based on NREL's mesoscale meteorological modeling from historical years 2007-2012**

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

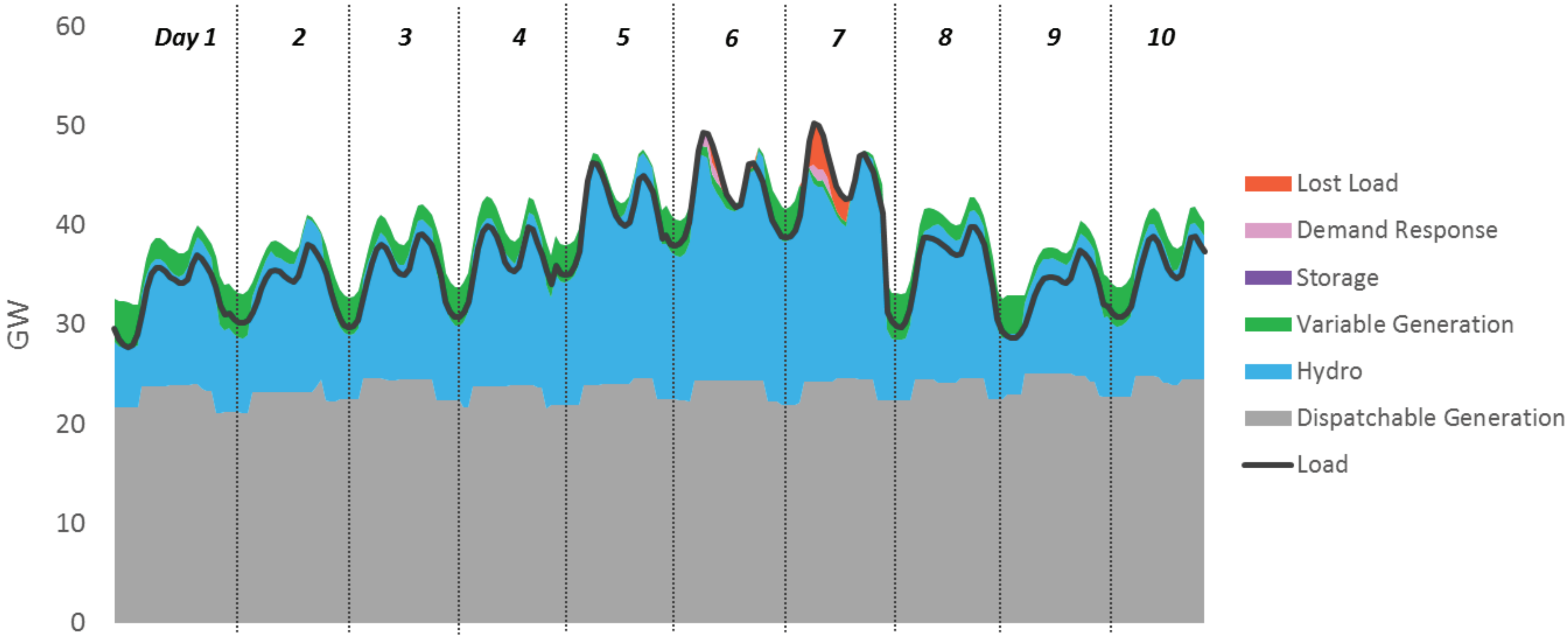
Hydro

- 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)

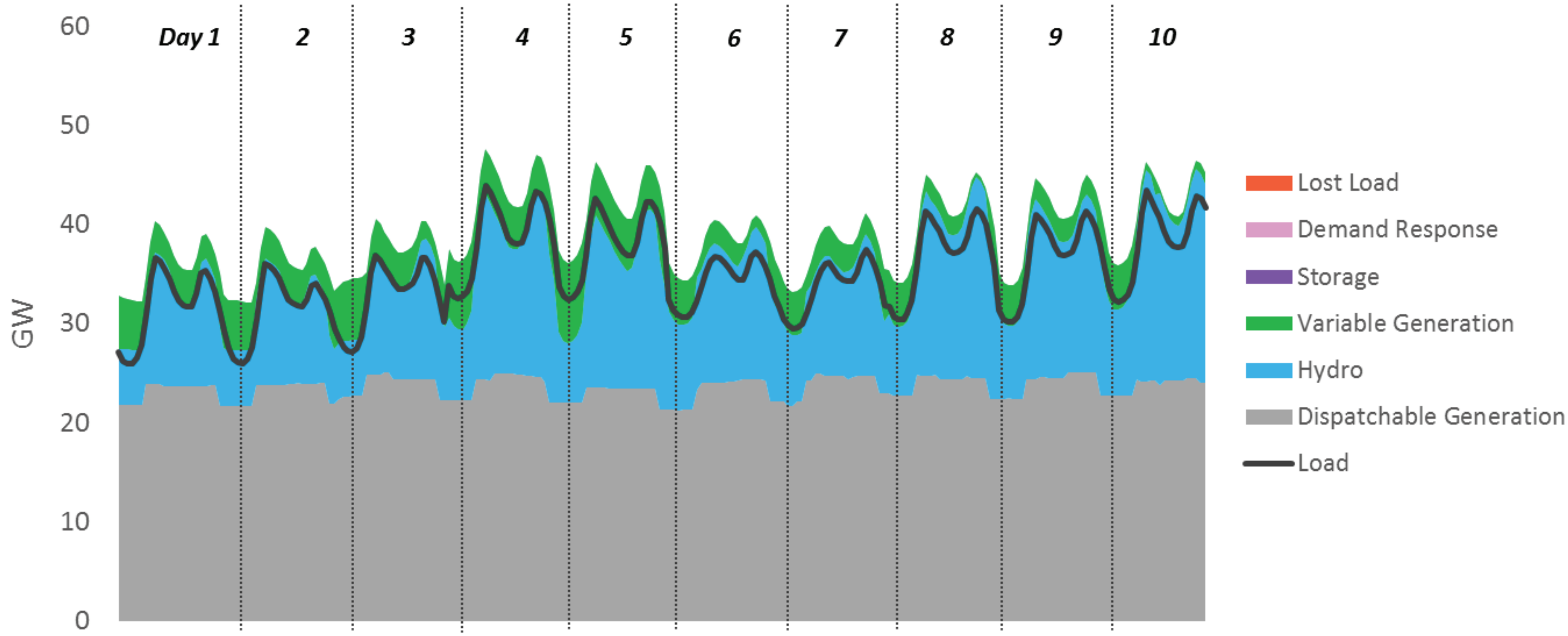


Note:

- 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

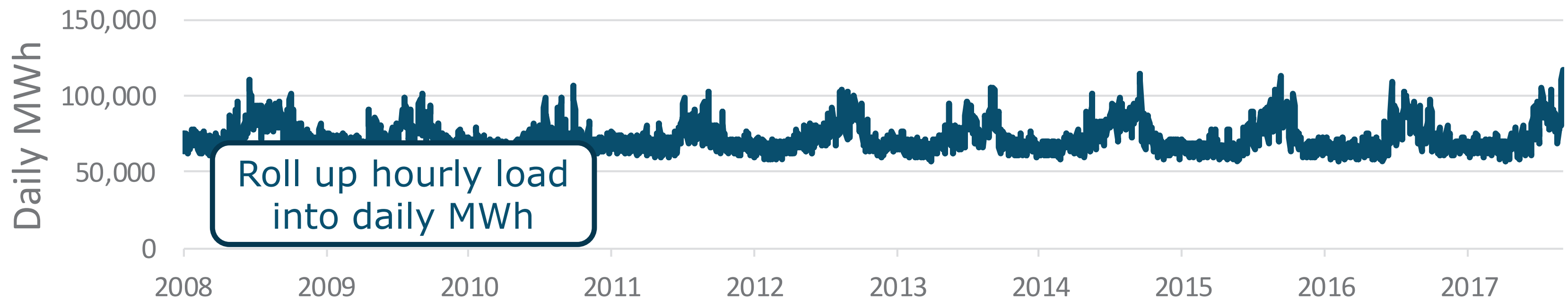
No load shortfall: (Feb 1 – Feb 10, Temp Year: 1982)



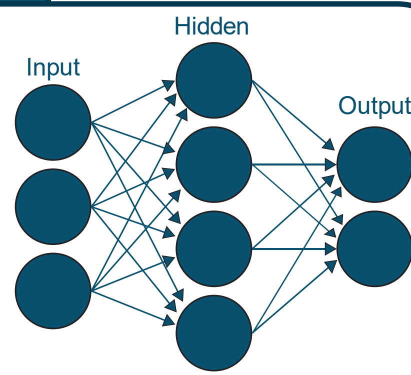
<u>Note</u>:

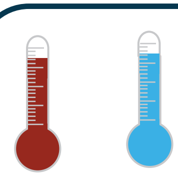
- Dispatchable Generation - includes thermal, geothermal, nuclear, run-of-river hydro, and imports
- Variable Generation – includes wind, solar and spot market purchases (in low-load hours)
- Hydro – includes all non-ROR hydro
- DR – 80 calls of 4 hour duration and 142.5 MW

Running Neural Network Model



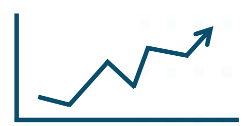
Run neural network model to establish relationship between daily gross load and the following factors





Max & Min Daily Temp

Month & Day-Type



Day Index for Economic Growth

Training the Model

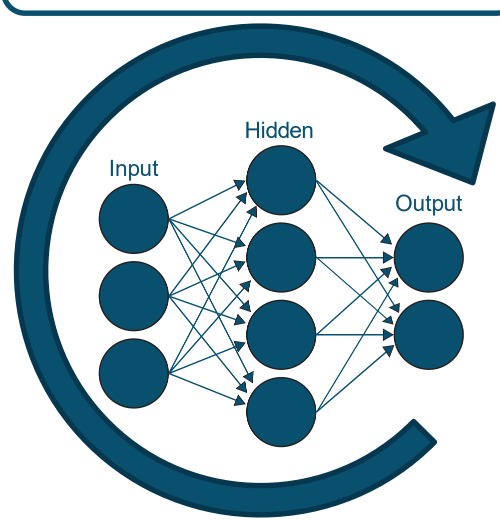
Use historical temperatures and calendar to 'train' NN model

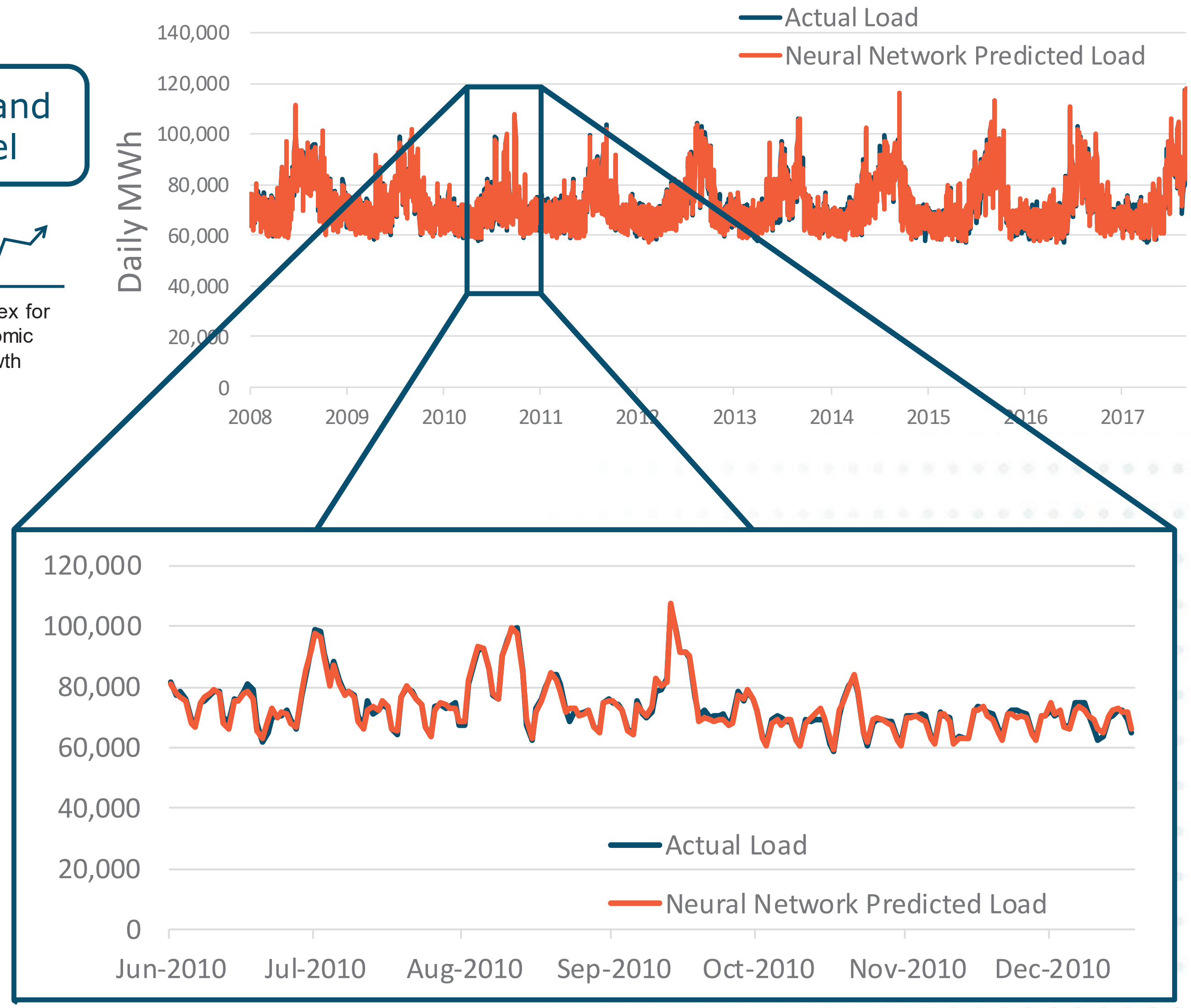
Max & Min Daily Temp

Month & Day-Type

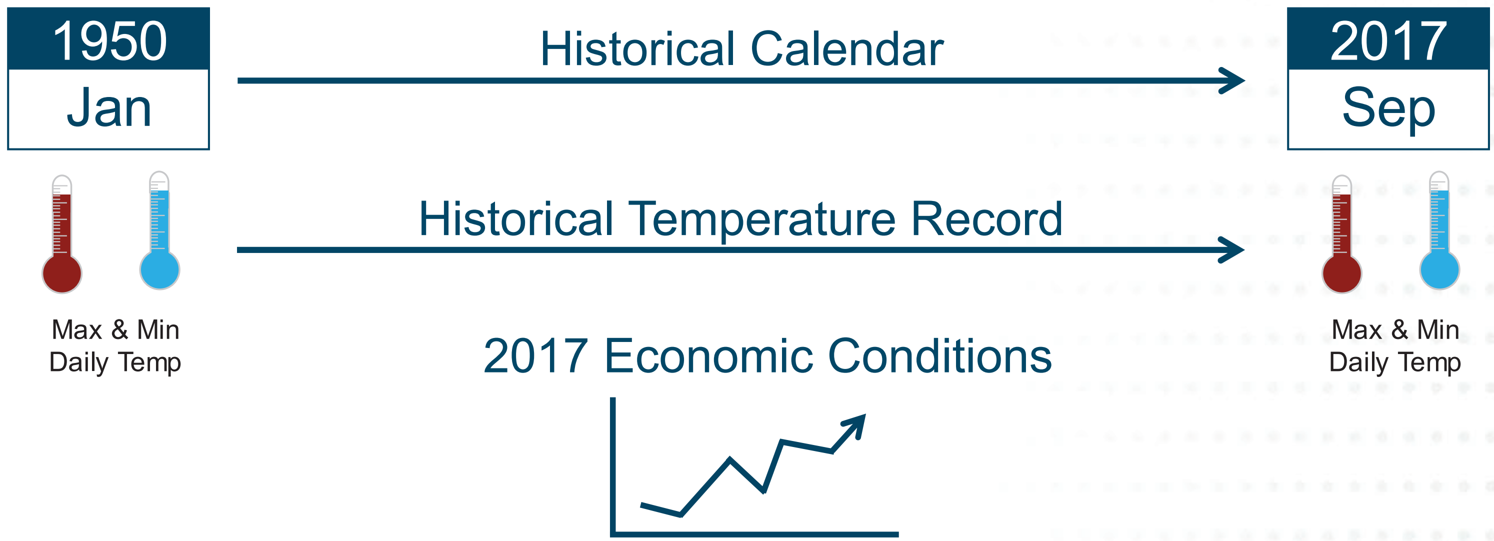
Day Index for Economic Growth

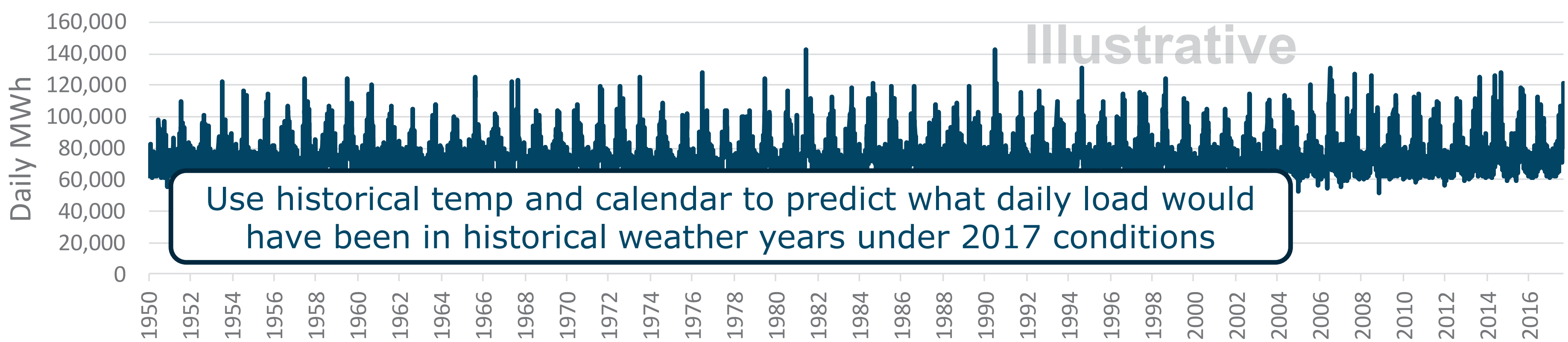
Iterate until model coefficients converge



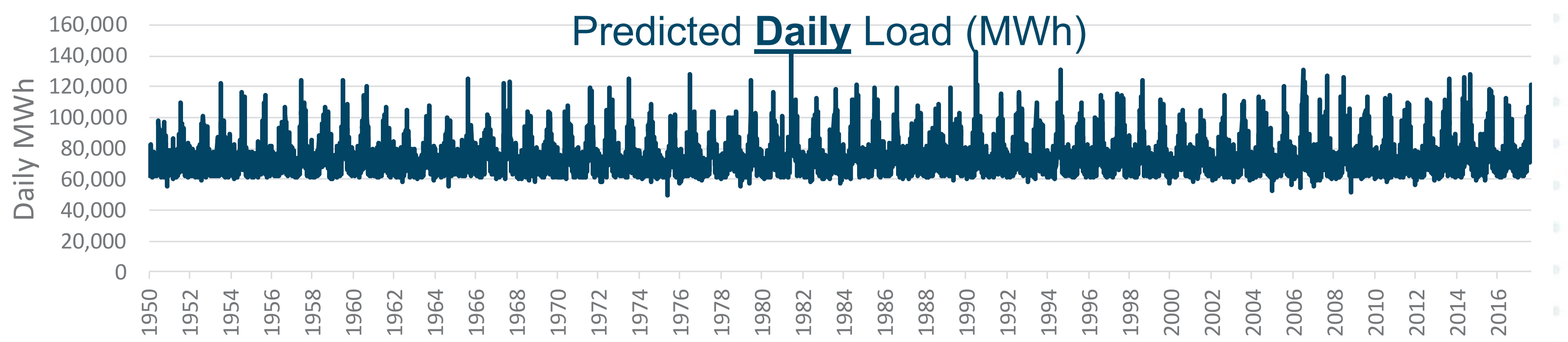


Daily Load Simulations



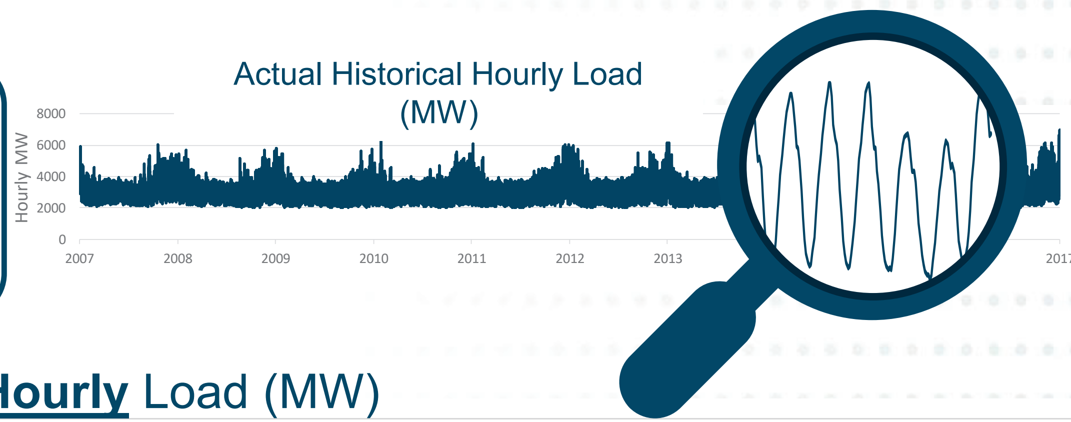


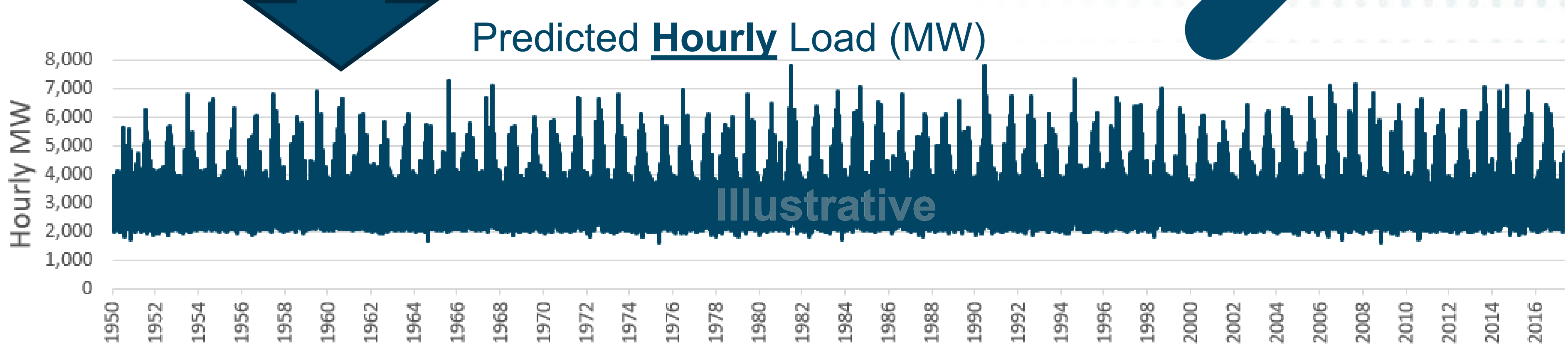
Converting Daily Energy to Hourly Load



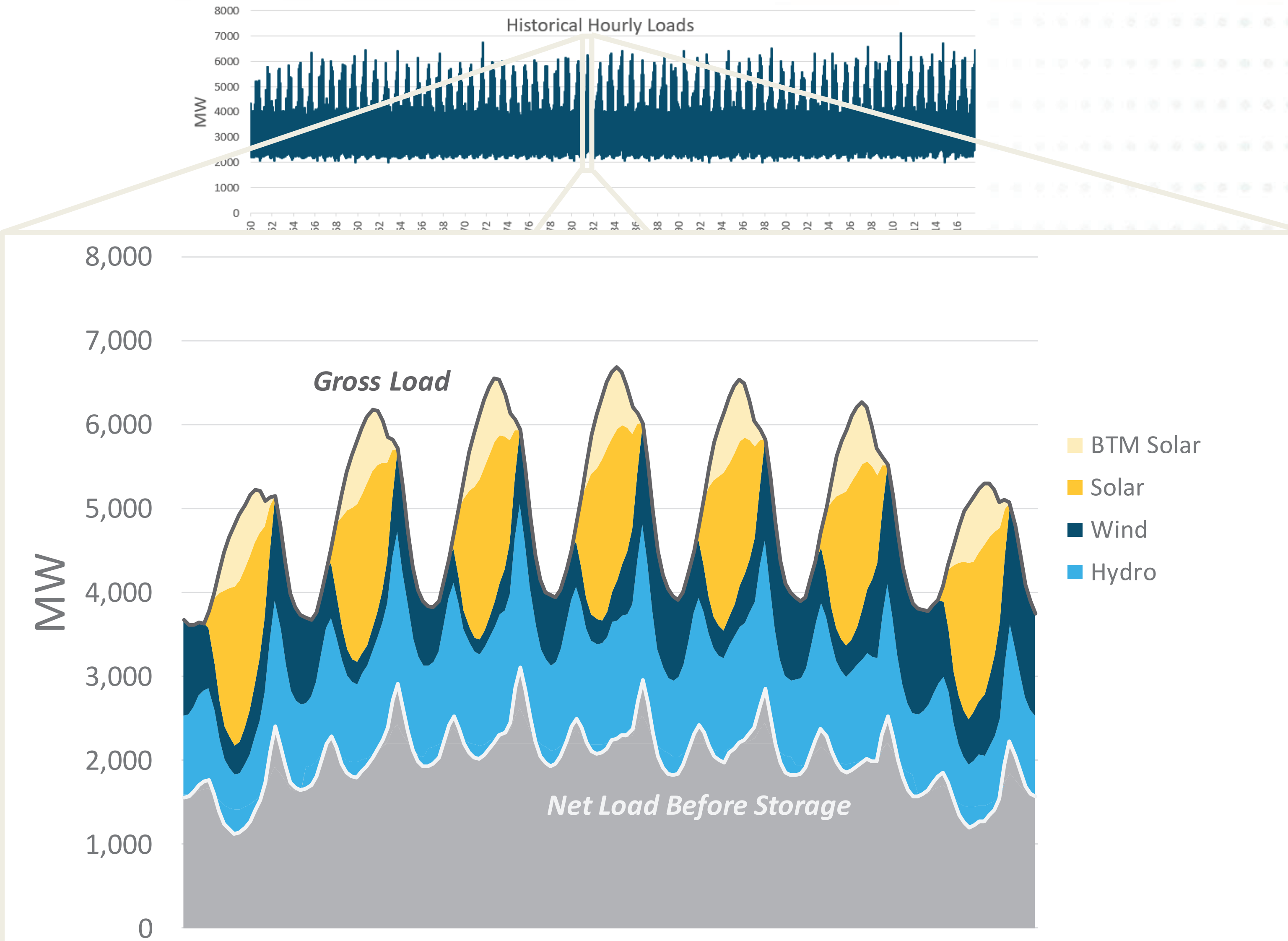
- Convert predicted daily load into hourly load by finding historical day with most similar daily load and using that hourly shape
- Constrained to search over identical day-type within +/-15 days

AUG
Weekday





Calculating Renewable Resources



Predicting Renewable Output

INPUT: example hourly historical renewable production data (solar)

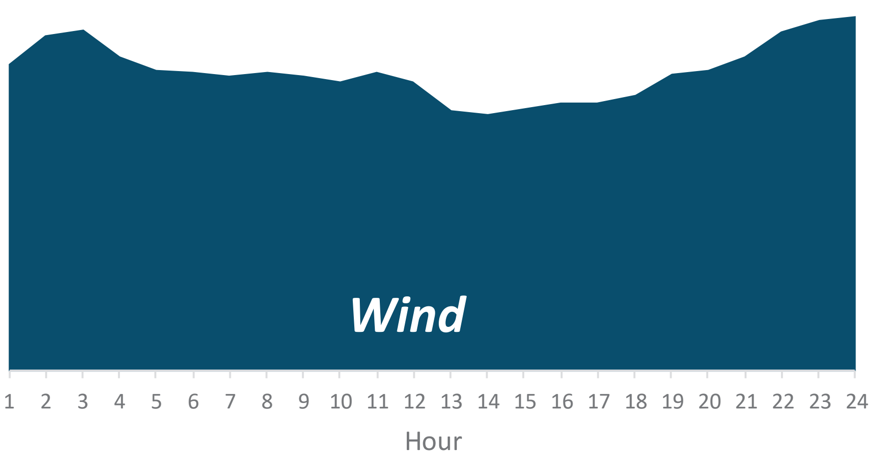
OUTPUT: predicted 24-hr renewable output profile for each day of historical load

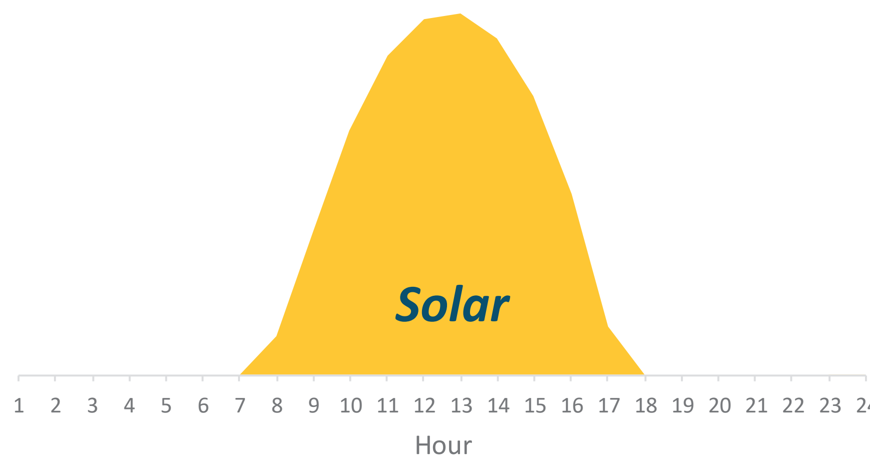
+ **Renewable generation is uncertain, but its output is correlated with many factors**
  - Season
    - Eliminate all days in historical renewable production data not within +/- 15 calendar days of day trying to predict
  - Load
    - High load days tend to have high solar output and can have mixed 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

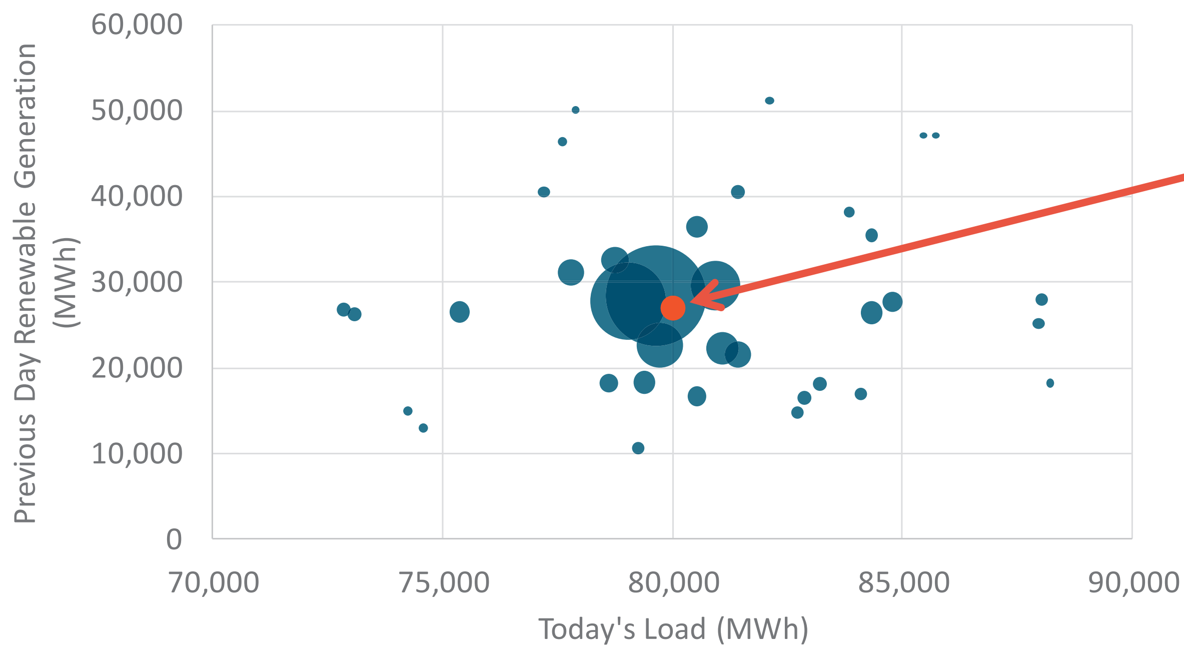




- Renewable profile development is done in aggregate for each resource type in order to capture correlation between solar generators

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

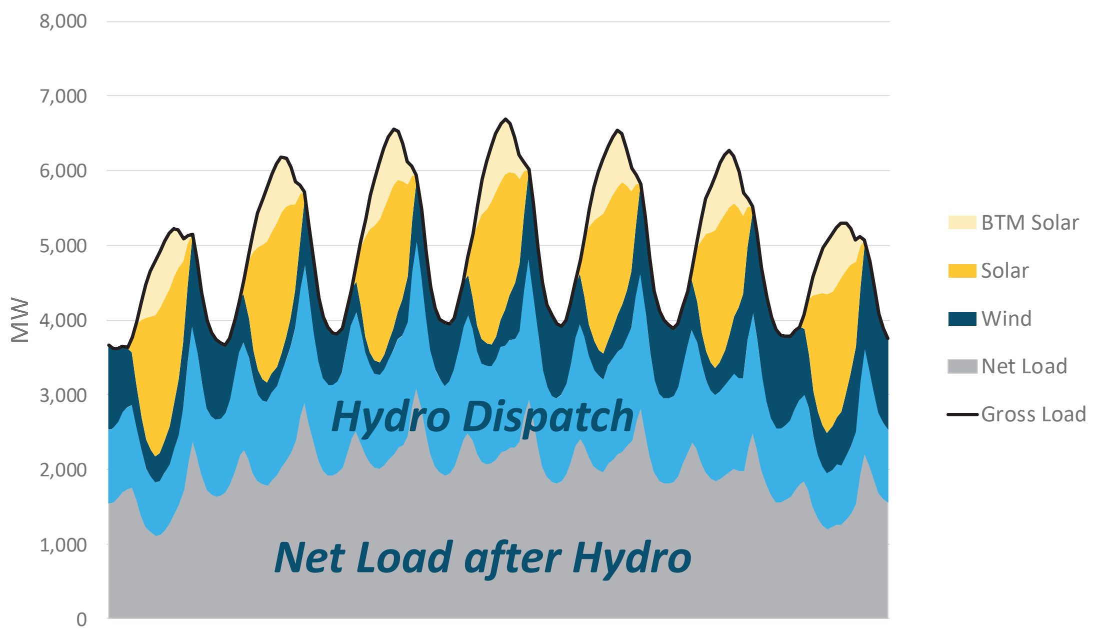
- Inverse distance
- Square inverse distance
- Gaussian distance
- Multivariate normal

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

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

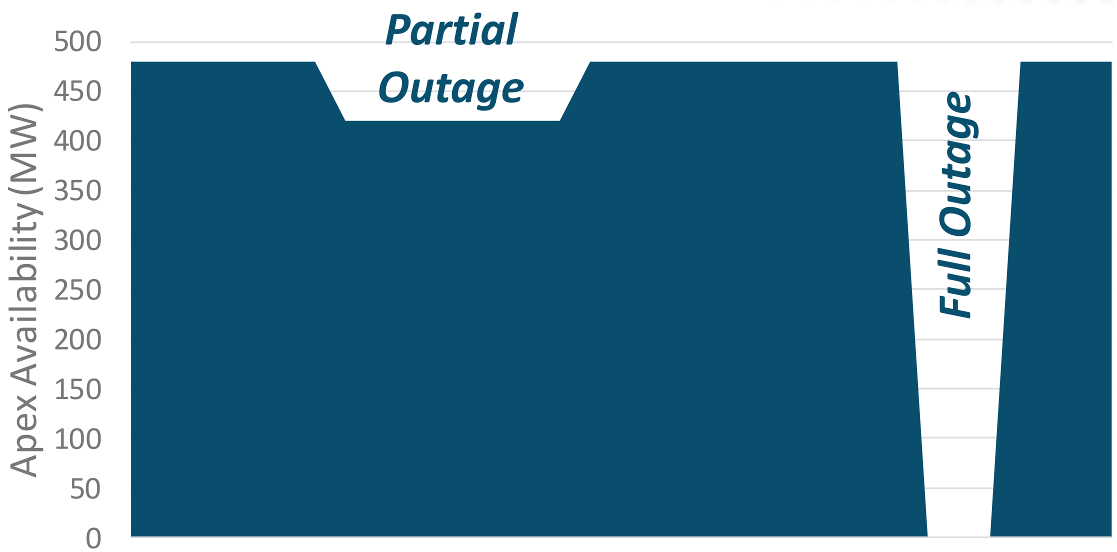
Hydro Dispatch

- 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



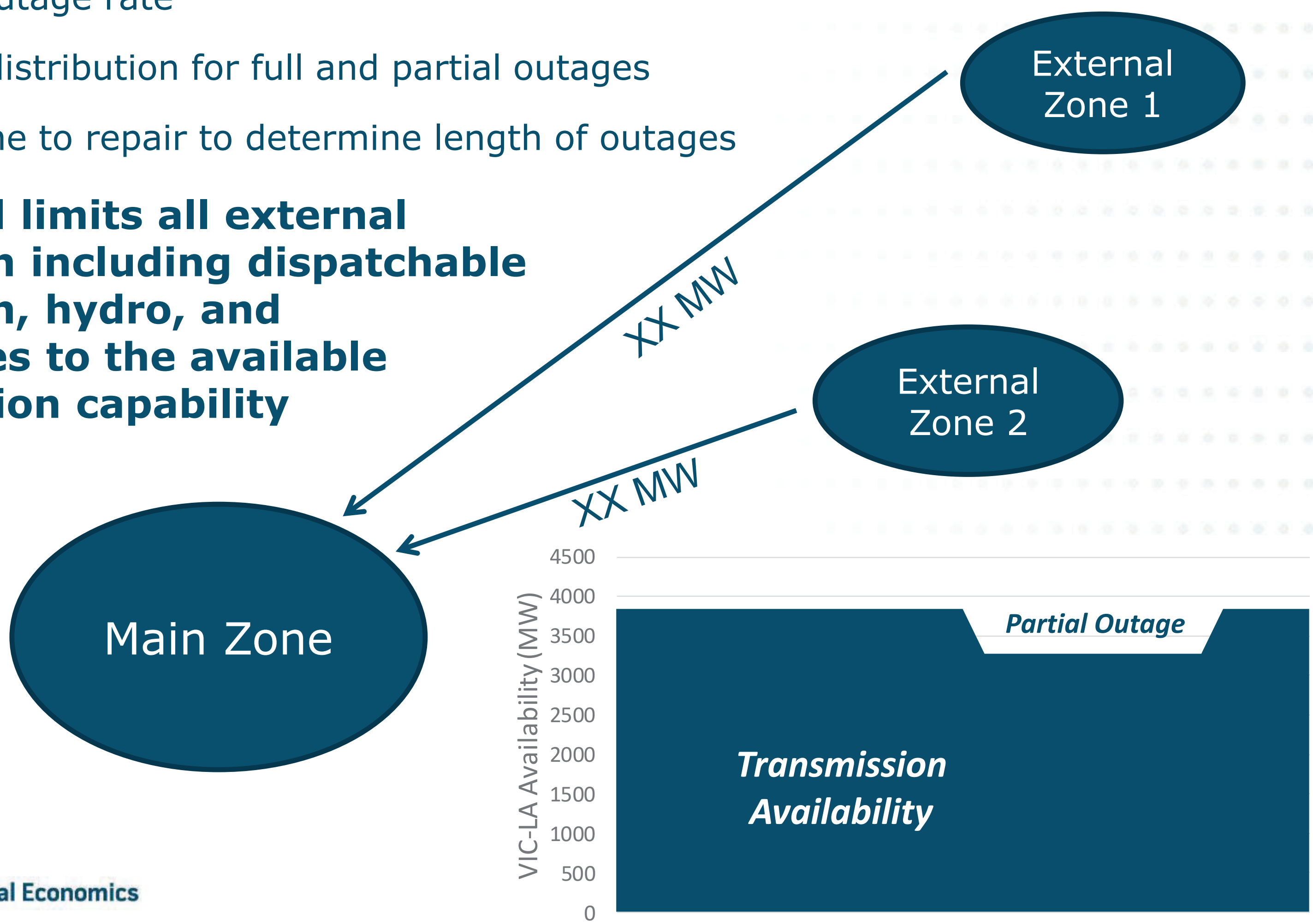
Available Generation

+ 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



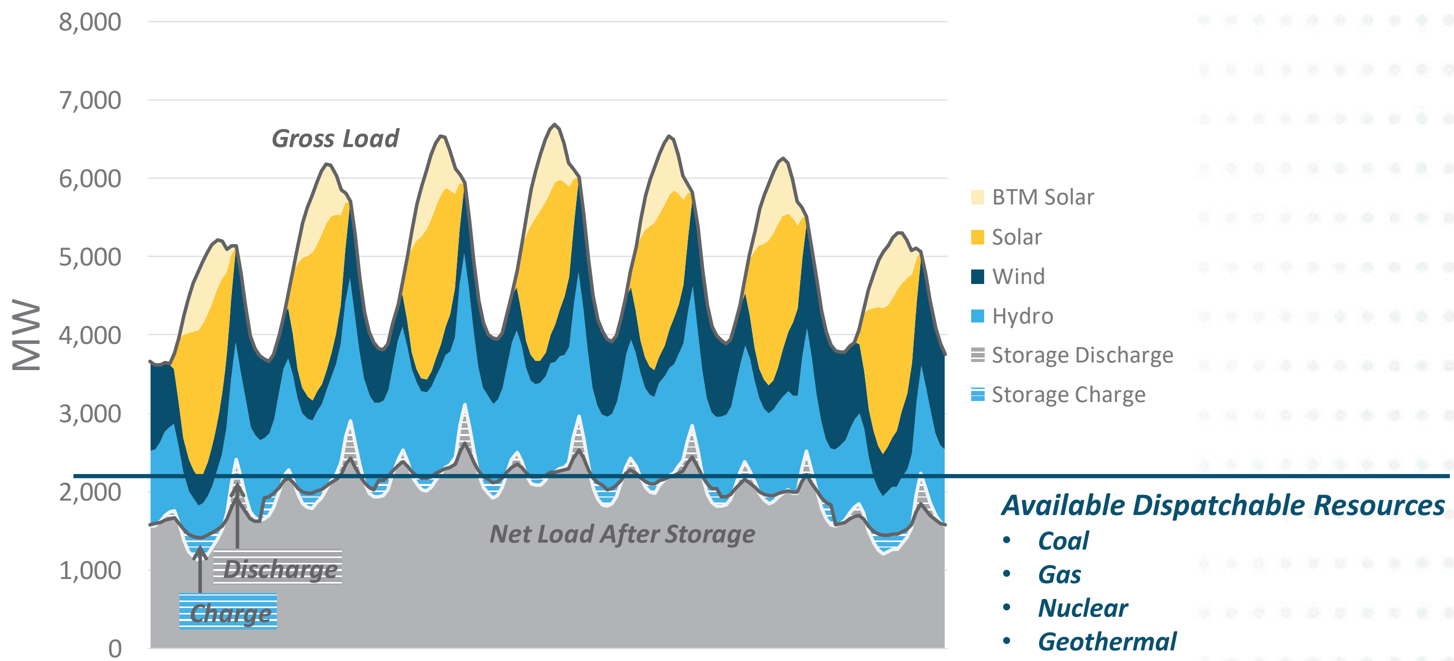
Transmission

- **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

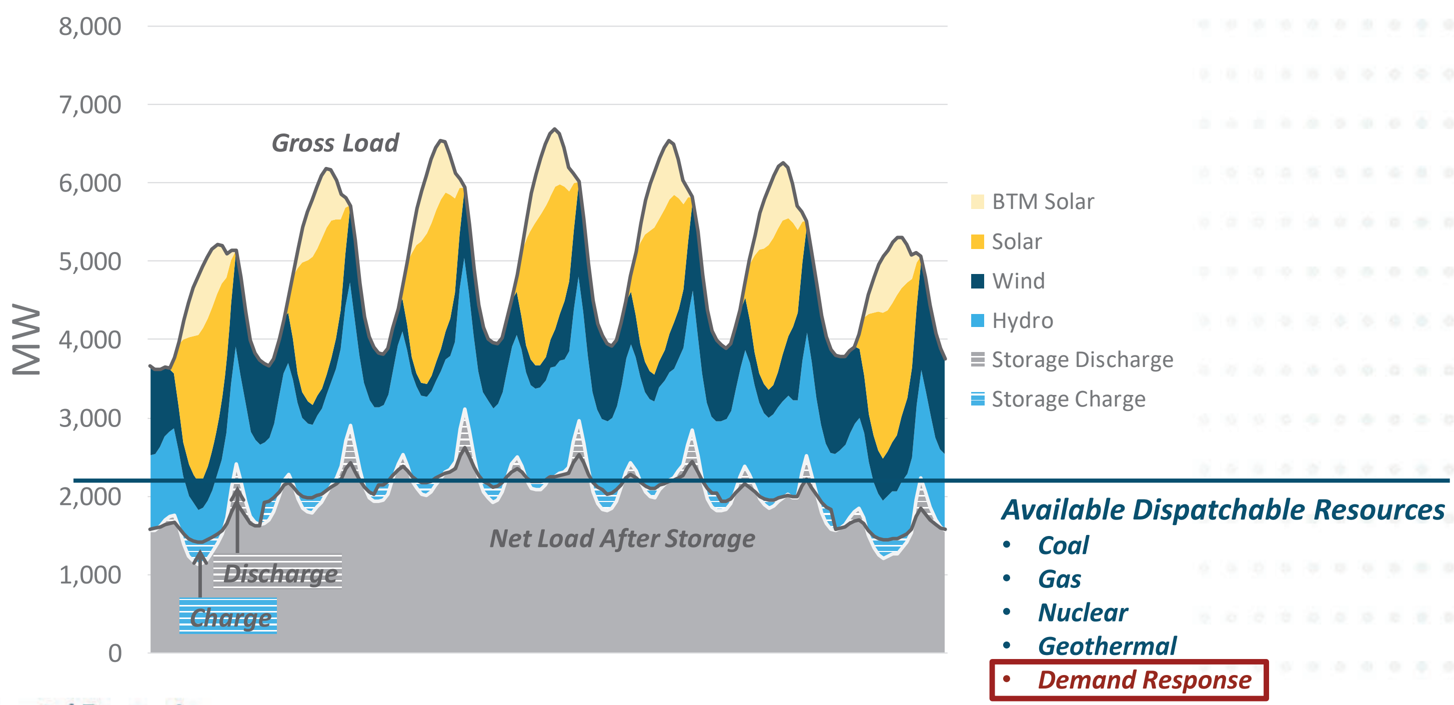
- Storage is dispatched for reliability purposes only in this model
- When net load is greater than available generation, storage always discharges if state of charge is greater than zero
- When net load is less than zero storage always charges
- When net load is greater than zero, storage charges from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



Demand Response

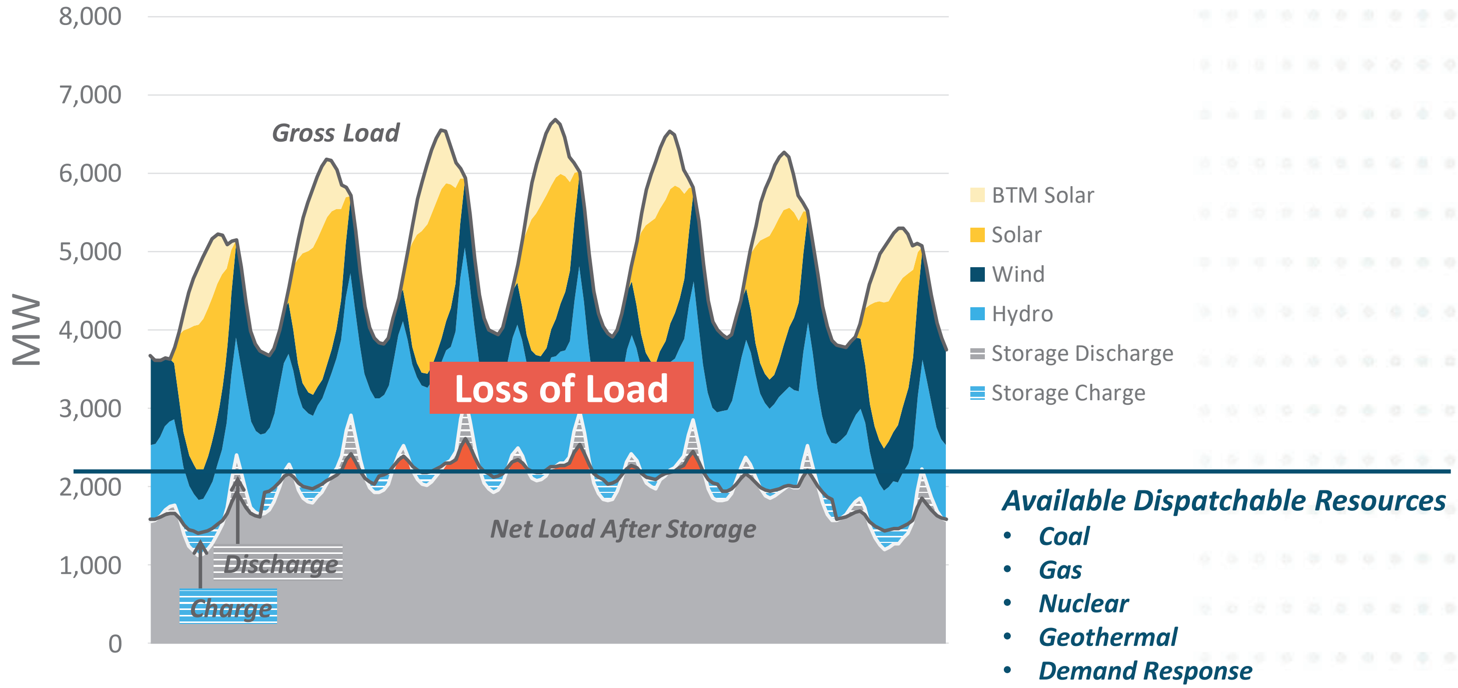
+ **Demand response is treated as the dispatchable resource of last resort – if net load after storage is greater than available dispatchable resources it is added to available resources**

+ **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



Thank You!

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