Energy+Environmental Economics

Overview of PRM Study

Nova Scotia Power Inc.

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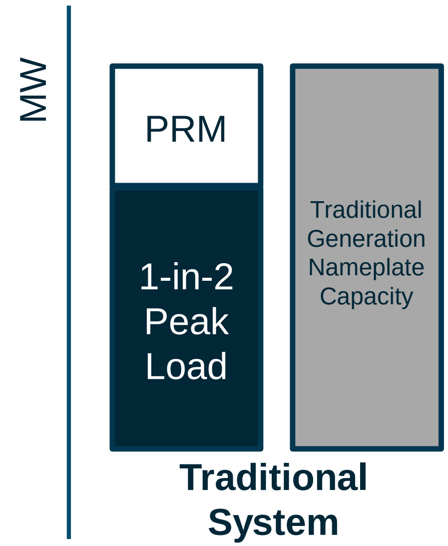
Study Objectives

- **The Planning Reserve Margin (PRM) study provides an update to several assumptions to be used by Nova Scotia Power Inc. (NSPI) in the integrated resource planning (IRP) process**
- **PRM study outline**
  - Background + jurisdictional review of industry best practices
  - Overview of analytical approach & assumptions: E3 RECAP model
  - Calculation of required PRM for NSPI to meet target reliability standard
    - Loss of Load Expectation (LOLE) of 1 day in 10 years (0.1 days/yr)
  - Calculation of existing and potential effective load carrying capability (ELCC) for various dispatch-limited resources
    - Wind
    - Solar
    - Storage
    - Demand Response

Planning Reserve Margin (PRM)

+ **Planning reserves are resources held by the utility above the forecasted median peak load that help maintain reliability even in the event of:**
  - Unplanned forced generator outages
  - Higher than normal peak loads (very cold weather)
  - Operating reserve requirements
+ **PRM is a convention that is typically based on:**
  - Installed capacity of traditional generation vs. 1-in-2 median peak load (e.g. half of the years experience a peak load higher than this and half lower)
+ **PRMs vary by utility but typically range from 12%-20+% depending on system characteristics**
  - Larger systems with more load and resource diversity can generally maintain lower PRMs
  - Islanded systems with limited interconnections and load and resource diversity such as Hawaii must maintain a PRM around 40%

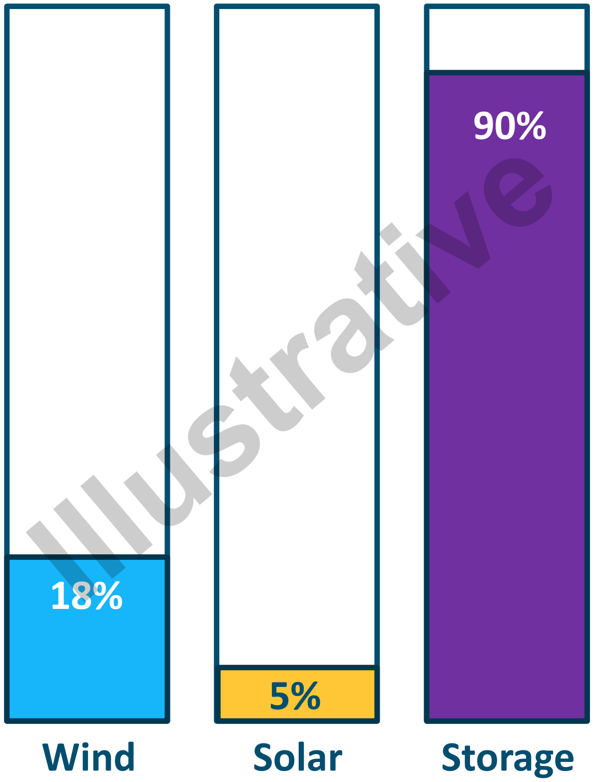


Reliability Planning Process

Step 1		Step 2
Reliability Standard (1-day-in-10-years)	→	**Target Planning Reserve Margin**

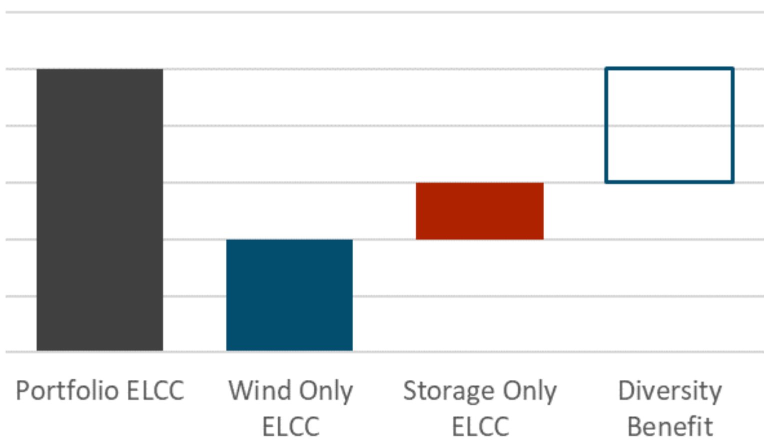
Renewable/Storage Contribution to PRM

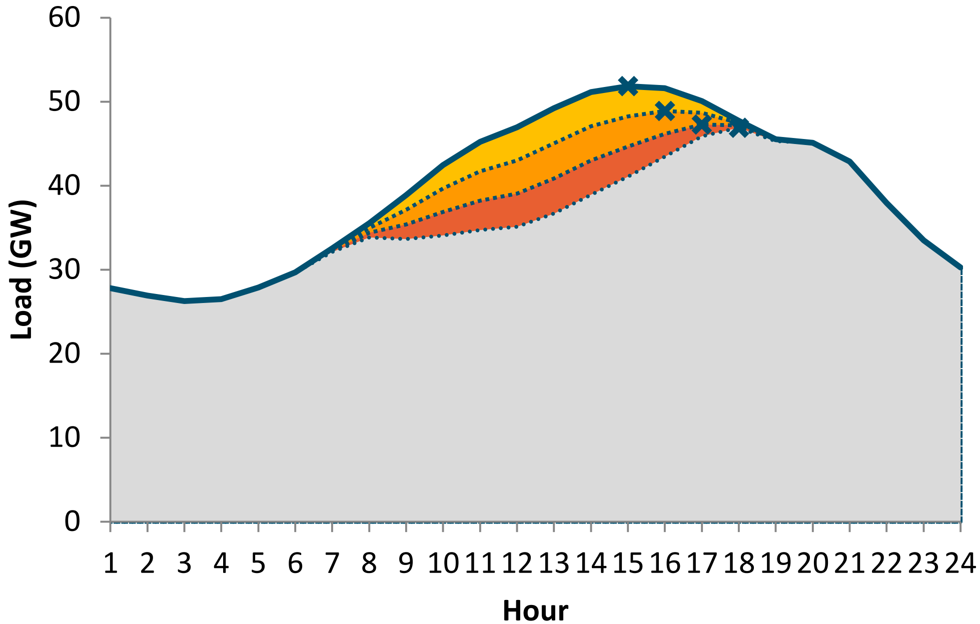
- In systems with high penetrations of renewable energy and storage, utilities must still maintain acceptable reliability through a planning reserve margin
- Effective load carrying capability (ELCC) measures a resource's ability to contribute to PRM
- ELCC is the quantity of "perfect capacity" that could be replaced or avoided with renewables or storage while providing equivalent system reliability
  - A value of 50% means that the addition of 100 MW of that resource could displace the need for 50 MW of firm capacity without compromising reliability
- Calculating ELCC requires computationally intensive models that can accurately account for the correlation and probability of production between load and renewables

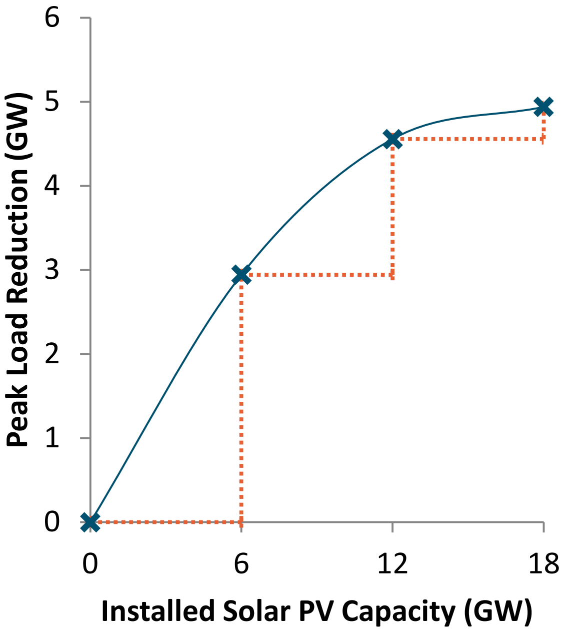


Diminishing Marginal ELCC and Diversity Benefits of Renewables/Storage

- **The ELCC of renewables or storage depends on the other resources on the system**
- **The diminishing marginal peak load impact of solar PV is illustrative of this concept**
- **There are also diversity benefits between resources such that the total contribution of a portfolio of resources may be more than the sum of their parts**







Jurisdictional Review

Overview of Jurisdictional Review

- **E3 conducted a review of reliability standards and planning practices mainly across several North American electric jurisdictions**
  - Reliability metrics and targets used for planning
  - How reliability metrics are converted into planning practices e.g. PRM values
  - PRM metric conventions i.e. de-ratings for forced outages

- **Ultimate conclusion was that NSPI is in-line with industry best practices for reliability planning**
  - NSPI plans to a 1-day-in-10 year standard or 0.1 days/yr loss of load expectation (LOLE)

Jurisdictional Summary

Jurisdiction / Utility	Reliability Metric	Metric Value	Notes
AESO	EUE	800 MWh/year (0.0014%)	AESO monitors capacity and can take action if modeled EUE exceeds threshold; 34% PRM achieved in 2017 w/o imports
CAISO	PRM	15%	No explicit reliability standard
ERCOT	N/A	N/A	Tracks PRM for information purposes; “Purely information” PRM of 13.75% achieves 0.1 events/yr; Economically optimal = 9.0%; Market equilibrium = 10.25%
Florida	LOLE	0.1 days/year	15% PRM required in addition to ensuring LOLE is met
ISO-NE	LOLE	0.2/0.1/0.01 days/year	Multiple LOLE targets are used to establish demand curve for capacity market
MISO	LOLE	0.1 days/year	7.9% UCAP PRM; 16.8% ICAP PRM
Nova Scotia	LOLE	0.1 days/year	20% PRM to meet 0.1 LOLE standard
NYISO	LOLE	0.1 days/year	LOLE is used to set capacity market demand curve; Minimum Installed Reserve Margin (IRM) is 16.8%; Achieved IRM in 2019 is 27.0%
PacifiCorp	N/A	N/A	13% PRM selected by balancing cost and reliability; Meets 0.1 LOLE
Hawaii (Oahu)	LOLE	0.22 days/yr	Relatively small system size and no interconnection results in 45% PRM
PJM	LOLE	0.1 days/year	LOLE used to set target IRM (16%) which is used in capacity market demand curve
SPP	LOLE	0.1 days/year	PRM assigned to all LSE’s to achieve LOLE target: 12% Non-coincident PRM & 16% Coincident PRM
Australia	EUE	0.002%	System operator monitors forecasted reliability and can intervene in market if necessary
Great Britain	LOLH	3 hours/year	5% (Target PRM 2021/22) 11.7% (Observed PRM 2018/19)
Ireland	LOLH	8 hours/year	LOLH determines total capacity requirement (10% PRM) which is used to determine total payments to generators (Net-CONE * PRM)

RECAP Model
Overview & Assumptions

E3 Renewable Energy Capacity Planning Model (RECAP)

- **RECAP is a loss-of-load-probability (LOLP) model for evaluating power system reliability for high penetration scenarios**
- **Initially developed to support the California ISO with renewable integration modeling more than 10 years ago**
- **Has been progressively updated and used by a number of utilities and regulators across North America**
  - CPUC
  - Portland General Electric
  - SMUD
  - WECC
  - LADWP
  - Florida Power & Light
  - El Paso Electric
  - Pacific Northwest
  - Nova Scotia Power
  - Xcel Minnesota
  - HECO

RECAP: E3's Renewable Energy Capacity Planning Model

+ **RECAP is a loss-of-load probability (LOLP) model used to test the resource sufficiency of electricity system portfolios**
  - This study uses a 1-day-in-10-year standard (0.1 days/yr LOLE) to determine the target PRM
+ **RECAP evaluates sufficiency through time-sequential simulations over thousands of years of plausible load, renewable, 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

Inputs

Load
- *Hourly load for many weather years*

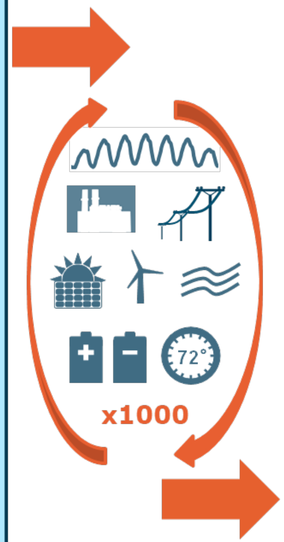
Dispatchable Generation
- *Capacity*
- *FOR*
- *Maintenance*

Renewables
- *Capacity*
- *Hourly generation profiles for many weather years*

Hydro
- *Hydro availability for many hydro years*
- *Max/min constraints*

Storage
- *Capacity*
- *Duration*
- *Roundtrip efficiency*
- *FOR*

Demand Response
- *Capacity*
- *Max # of calls*
- *Duration of each call*



Outputs

LOLE
- *Loss of load expectation*
- *Days/yr of total expected lost load per year*

LOLH
- *Loss of load hours*
- *Hours/yr of total expected lost load per year*

EUE
- *Expected unserved energy*
- *MWh/yr of energy that cannot be served*

ELCC
- *Effective load carrying capability*
- *Equivalent quantity of 'perfect capacity' for a variable or energy-limited resource*

TPRM
- *Target planning reserve margin*
- *PRM required to achieve a specified reliability threshold (i.e. LOLE, ALOLP, or EUE)*

RECAP Methodology

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

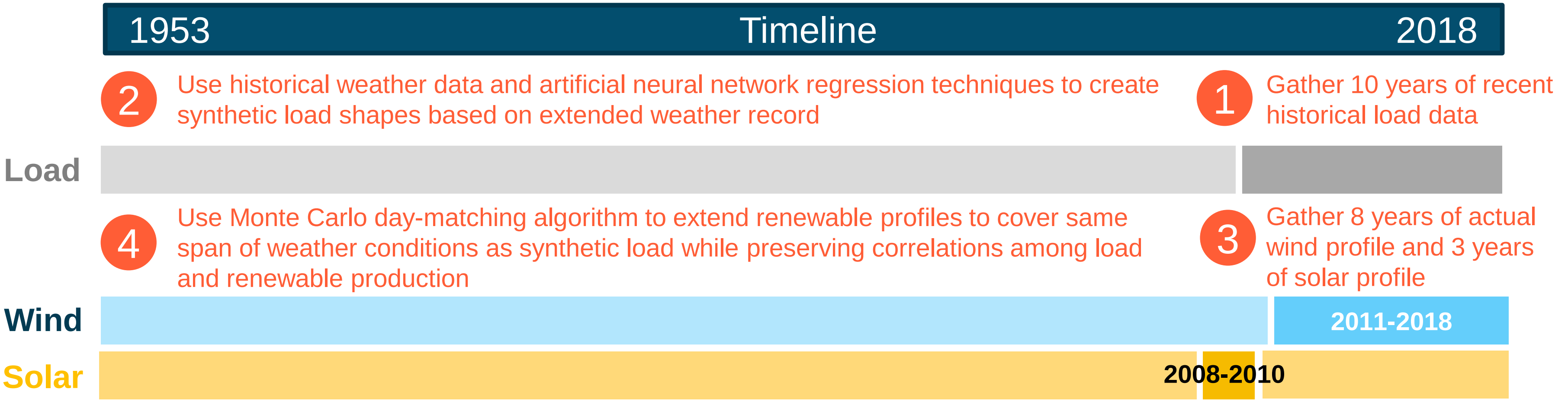
Dispatch Demand Response

72°

Step 8

Calculate Loss of Load

- Actual historical NSPI hourly load from 2009 to 2018
- Actual historical NSPI wind profiles from 2011 to 2018
- Simulated historical NSPI solar profiles from 2008 to 2010
- Weather and date information from 1953 to 2018



Dispatchable Resources in 2020

- E3 used the net operating capacity (MW) and DAFOR (%) to stochastically represent the dispatchable generating capability of these resources in the RECAP model

Category	Fuel/Tech Type	Unit Name	Operating Capacity (MW)	DAFOR (%)
Conventional Thermal	HFO/N Gas	Tufts Cove 1	78	36.0%
		Tufts Cove 2	93	19.1%
		Tufts Cove 3	147	2.0%
		Tufts Cove 4	49	2.9%
		Tufts Cove 5	49	5.1%
		Tufts Cove 6	46	1.6%
	Coal/Petcoke	Pt Aconi	168	1.9%
		Lingan 1	153	1.7%
		Lingan 2	0	1.7%
		Lingan 3	153	4.2%
		Lingan 4	153	5.0%
		Trenton 5	150	6.8%
		Trenton 6	154	4.4%
		Tupper 2	150	1.9%
	Oil	Burnside 1	33	10.0%
		Burnside 2	33	10.0%
		Burnside 3	33	10.0%
		Burnside 4	33	10.0%
		Victoria Junction 1	33	10.0%
		Victoria Junction 2	33	10.0%
		Tusket	33	10.0%
Renewable	Hydro	Dispatchable Hydro	162	5%
	Biomass	Port Haweksbury	43	1.2%
		IPP Biomass	31	1.2%
	Biogas	IPP Biogas	2	1.2%
Total Operating Capacity (MW)			**2,012**	

Hydro / Tidal Resources Overview

+ **For modeling purposes, hydro is grouped into 3 categories**
  - **Dispatchable:** hydro units can be dispatched at maximum output with no limit on duration
  - **Tidal:** Annapolis is modelled as resource with variable hourly profile similar to wind
  - **Wreck Cove:** Can be dispatched under constraints including maximum output, minimum output, and daily maximum energy

Hydro and Tidal Resources

Hydro Group	Resource Name	Maximum Capacity (MW)	Minimum Capacity (MW)	Other Constraints in RECAP
Firm Hydro	Tusket	2.4	0.9	Assumed to be available at maximum capacity during peak load hours
	St Margarets	10.8	0	
	Sheet Harbour	10.8	0.4	
	Dickie Brook	3.8	0.1	
	Nictaux	8.3	0	
	Lequille	11.2	0	
	Avon	6.75	0	
	Black River	22.5	6	
	Paradise	4.7	2	
	Mersey	42.5	6	
	Fall River	0.5	0	
	Sissiboo	24	6	
	Bear River	13.4	0	
Subtotal		162		
Tidal	Annapolis	19		Annual output profile
Subtotal		19		Daily Energy Budget (MWh)
Wreck Cove	Wreck Cove	212	0	500 - 1100
Subtotal		212		
Total		393		

Transmission Lines

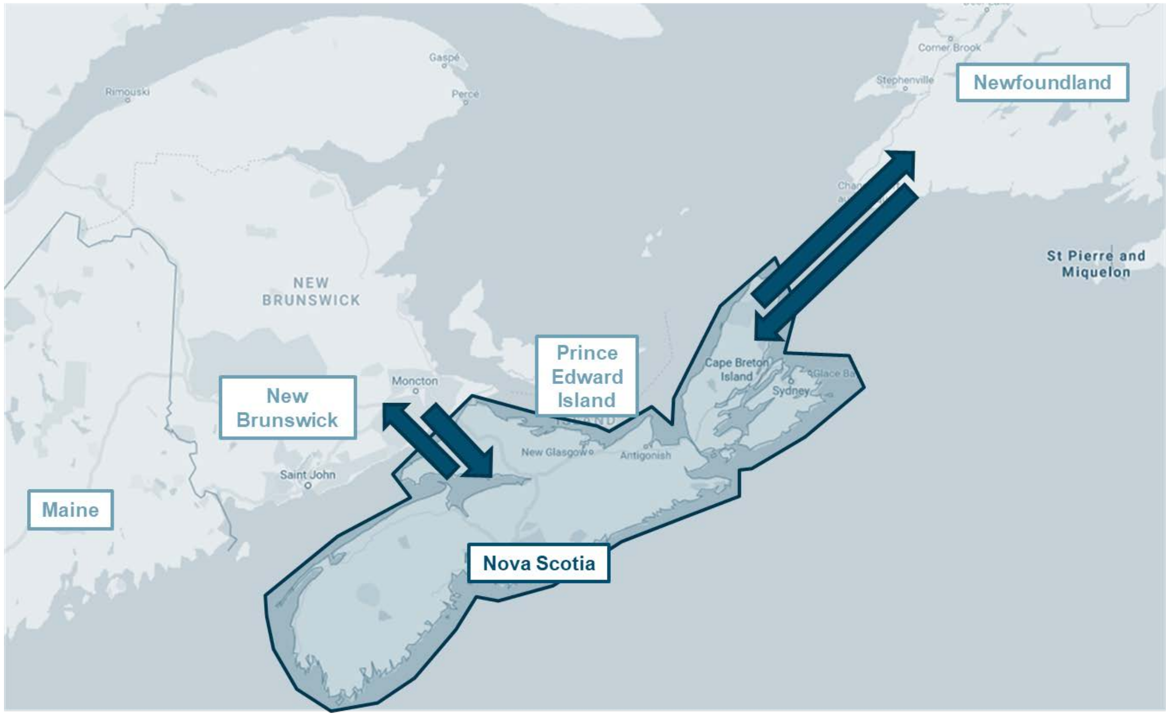
+ No internal transmission constraints assumed within Nova Scotia

+ Maritime Link

- Day time capacity of 153 MW starting in 2020
- Pole 1 transmission line
  - 250 MW
  - 96% availability
- Pole 2 transmission line
  - 250 MW
  - 96% availability
- Combined DAFOR of ML+LIL+Muskrat Falls = 2%

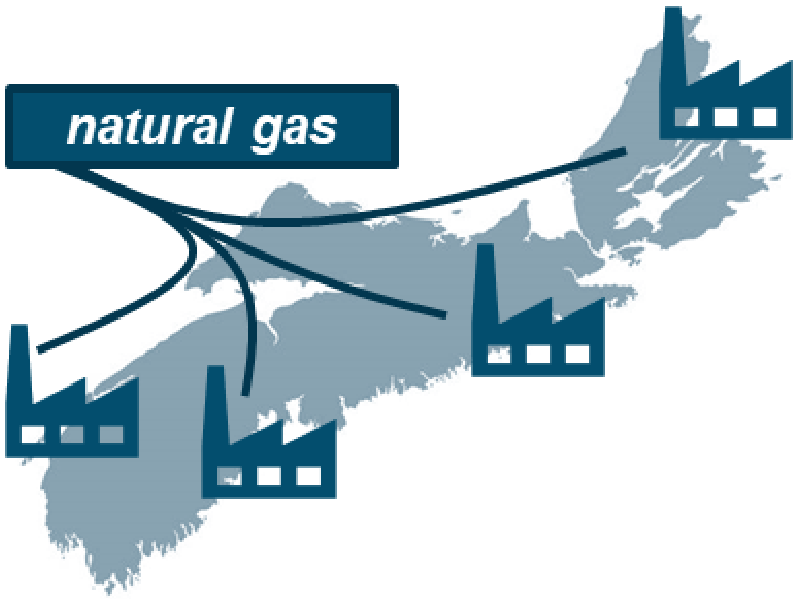
+ Base Energy

- Muskrat Falls: 153 MW
- 7 am – 11 pm



Fuel Supply

- **This analysis assumes any fuel supply constraints are represented in the de-rated adjusted forced outage rate (DAFOR) and are not correlated with one another**
  - To the extent that outages are correlated, this would increase the target PRM
- **Access to firm natural gas fuel supply during winter peak electricity events could be challenging to NSPI if new capacity is added which would further constrain gas pipeline import capacity**
- **Various options for firm fuel supply exist**
  - New pipeline capacity
  - On-site fuel storage
  - In-province gas storage
  - LNG import capability
- **More information will be coming on this topic as the IRP progresses**



Results

NSPI 2020 System Reliability and PRM

Metric	Units	High Case	Low Case
Loss of Load Expectation (LOLE)	days/yr	0.19	0.04
Annual LOLP (%)	%	15.4%	3.0%
Loss of Load Hours (LOLH)	hrs/yr	1.29	0.016
Loss of Load Events (LOLEV)	events/yr	0.17	0.03
Expected Unserved Energy (EUE)	MWh/yr	49	7.6
Normalized EUE	% of annual load	0.0005%	0.00008%
1-in-2 Peak Load	MW	2,070	2,070
PRM Requirement	% of peak	21.0%	17.8%

+ **High Operating Reserve Requirement Case:** 100 MW operating reserve requirement in all hours, approximately 5% of NSPI's peak load
+ **Low Operating Reserve Requirement Case:** 33 MW operating reserve requirement in all hours, approximately 1.5% of NSPI's peak load
+ Operating reserves represent the quantity of reserves that must be maintained and which NSPI will shed load to maintain – these values are less than the typical operating reserves that are held by NSPI which can decrease in extreme grid conditions. Operating reserves are necessary to be able to quickly react to unexpected grid conditions that might otherwise result in significant grid problems if operating reserve are not available

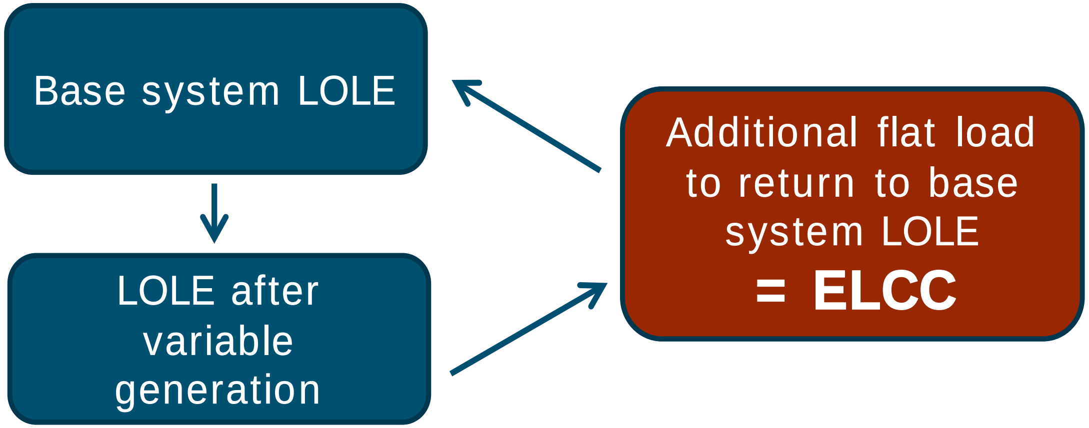
Load and Resource Balance

High Operating Reserve Requirement Case

Load			
Firm Peak Load Net of DSM (MW)	2,070		
Target Reliability Standard	0.1 days/year		
Target PRM	21.0%		
Total Requirement (MW)	**2,504**		
Resource	**Nameplate Capacity (MW)**	**Effective Capacity (MW)**	**Effective Capacity (%)**
Coal	1,081	1,081	100%
Oil	231	231	100%
Natural Gas/Heavy Fuel Oil	462	462	100%
Biomass/Biogas	76	76	100%
Run-of-River Hydro	162	154	95%
Wreck Cove Hydro	212	202	95%
Annapolis Tidal	19	2.3	12%
Wind	596	111	19%
Solar	1.7	0.08	5%
Maritime Link Base Energy Imports	153	151	98%
Total Supply (MW)	**2,994**	**2,470**	78%
Surplus/Deficit (MW)	**-38**		

Effective Load Carrying Capability (ELCC)

- **ELCC measures the ability of dispatch-limited resources to contribute to planning reserve requirements while still maintaining an equivalent level of reliability**
  - ELCC is the quantity of “perfect capacity” that could be replaced or avoided with renewables, storage, or DR
  - A value of 50% means the addition of 100 MW of energy storage would displace the need for 50 MW of firm capacity without compromising reliability
  - ELCC is well-established as the most analytically rigorous method for calculating the capacity of dispatch-limited resources such as solar, wind, hydro, storage, and demand response



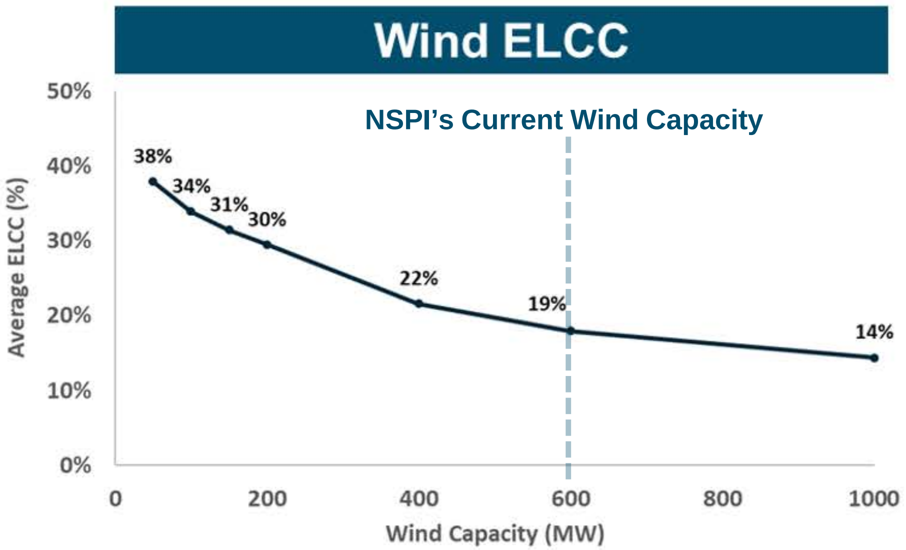
Effective Capacity of All Resources

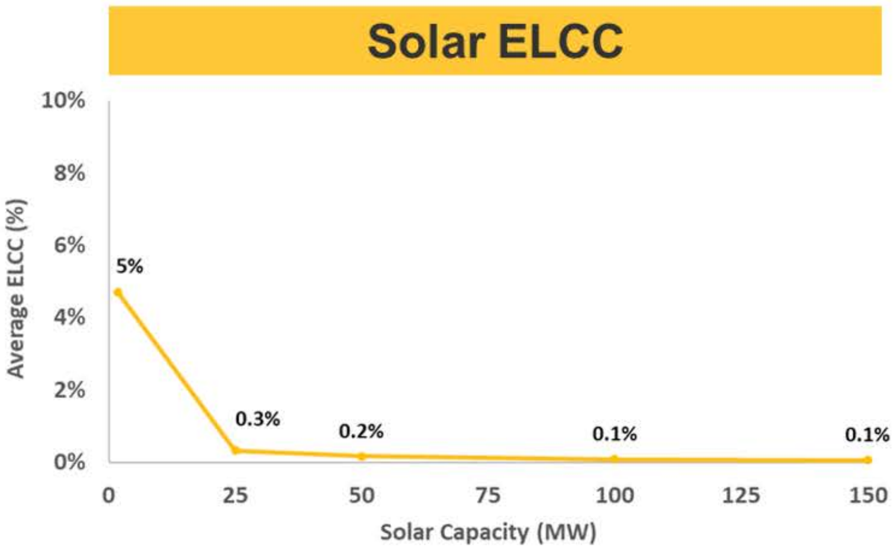
- Dispatchable resources are by convention generally counted at their nameplate capacity in PRM accounting
- Due to forced outages, and "ELCC" equivalency can be calculated for these resources to compare on equal basis with renewables as shown below

Resource	Nameplate Capacity (MW)	Effective Capacity (MW)	Effective Capacity (%)
Coal	1081	958	92%
Oil	231	191	78%
HFO/NG	462	376	75%
Biomass/Biogas	76	69	97%
Run-of-River Hydro	162	154	95%
Wreck Cove Hydro	212	201	95%
Annapolis Tidal	19	2.3	12%
Wind	596	113	19%
Solar	2	0.09	5%
Maritime Link Base Energy Imports	153	150	98%
Total	**2,994**	**2,215**	

ELCC of Wind and Solar

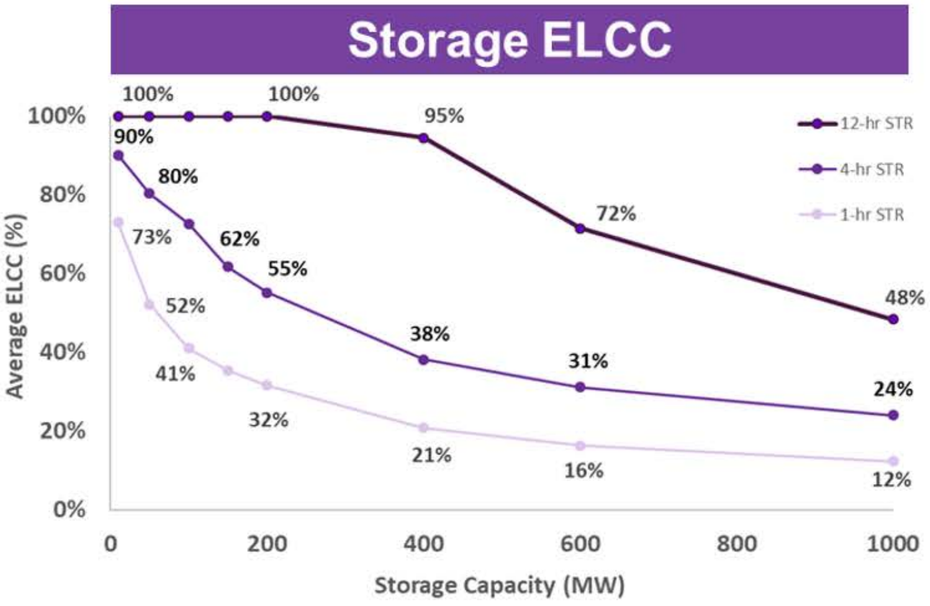
+ **Both wind and solar exhibit declining ELCC as penetrations increase – a phenomenon seen across all geographies and all resources**

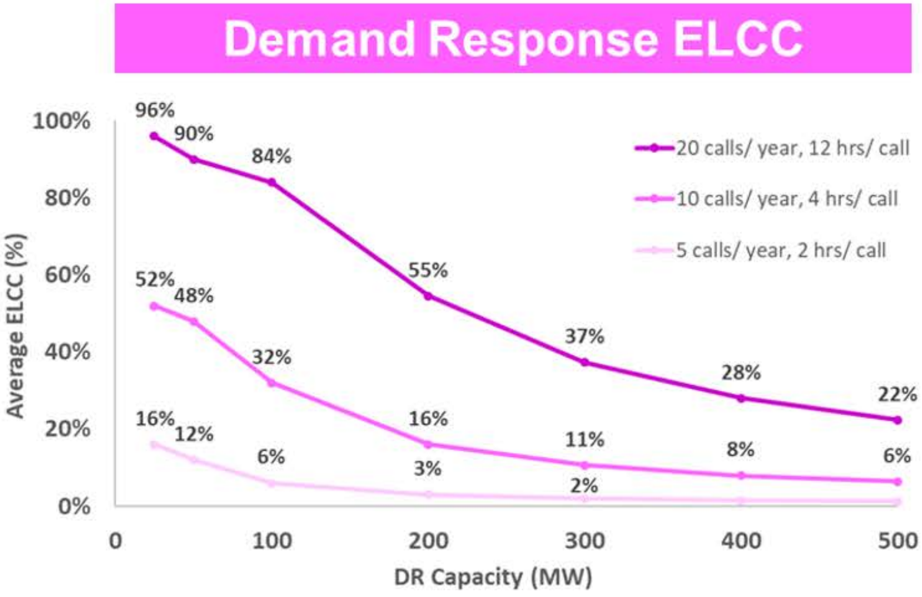




ELCC of Storage and Demand Response

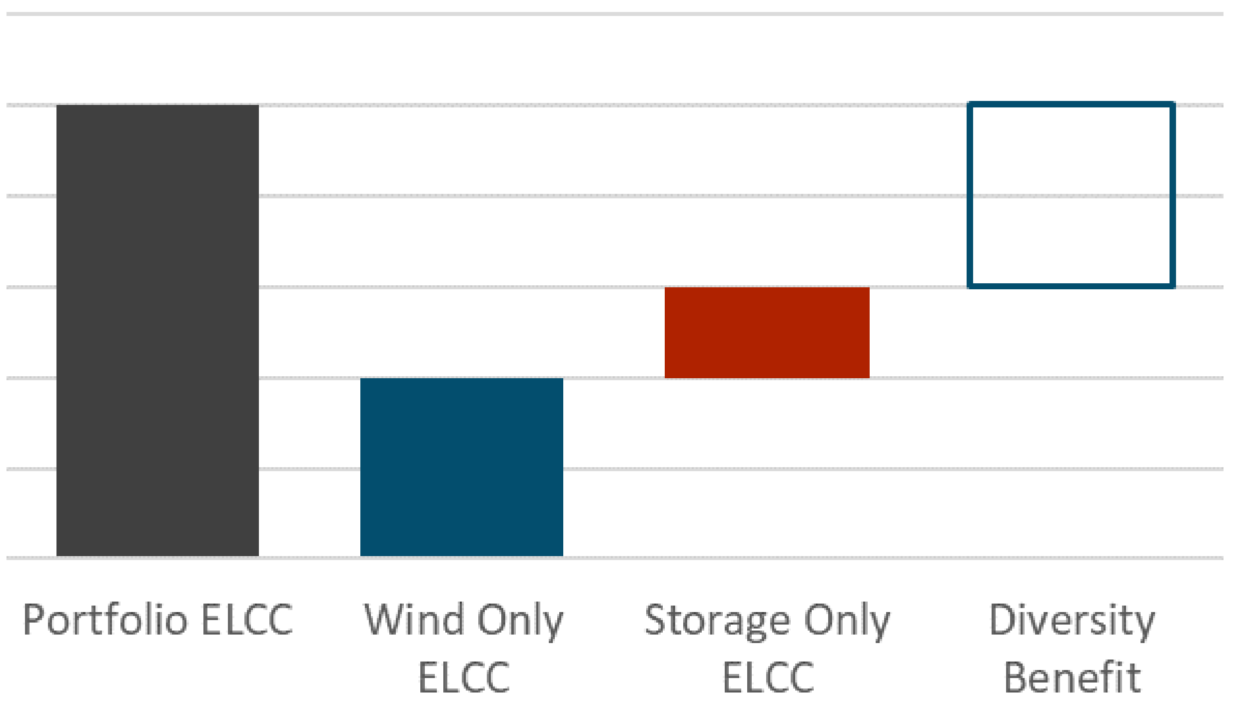
- Energy storage and demand response (DR) also exhibit diminishing returns as penetration increases
- The demand response results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide





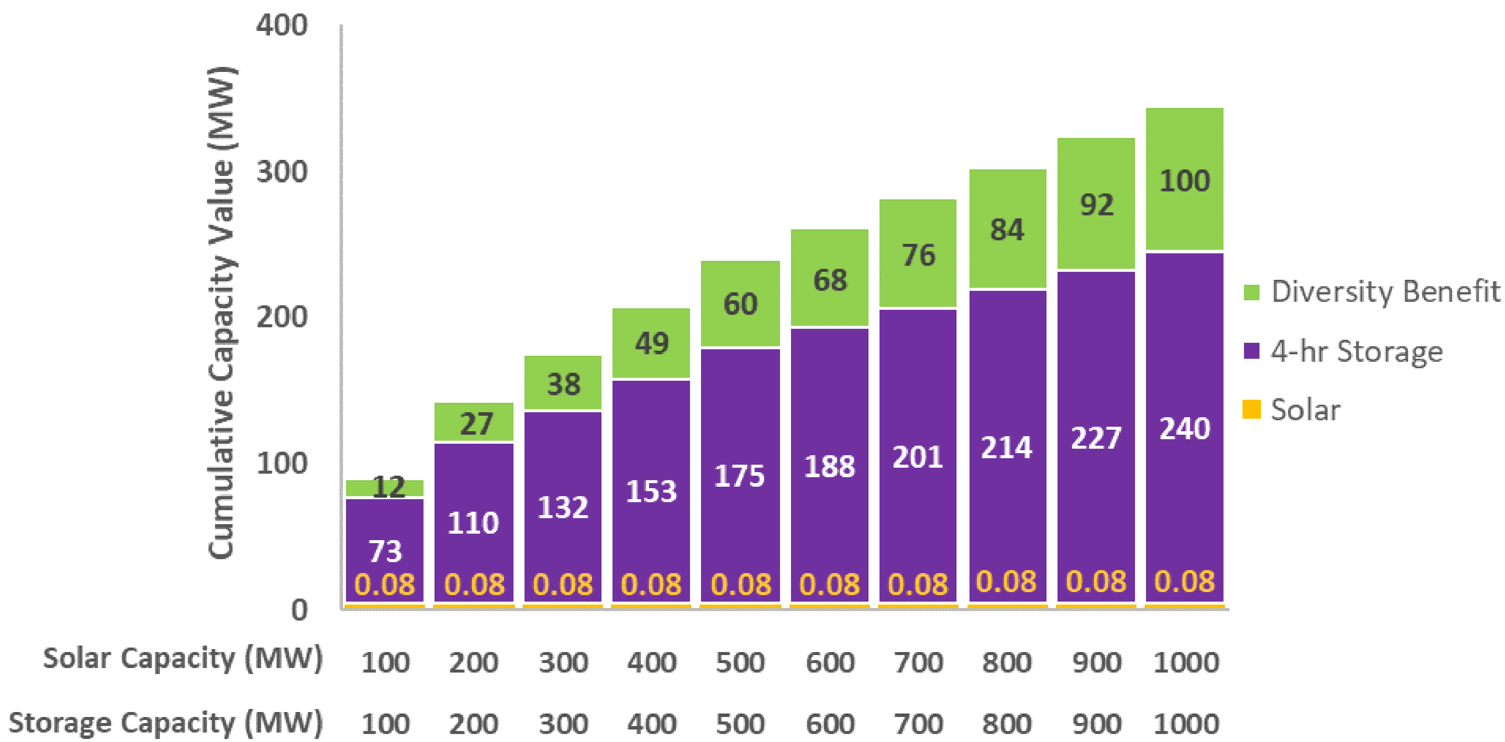
Portfolio ELCC & Diversity

+ **The ELCC of a portfolio of resources is often more than the sum of their parts – creating a diversity benefit that must be allocated between the resources**



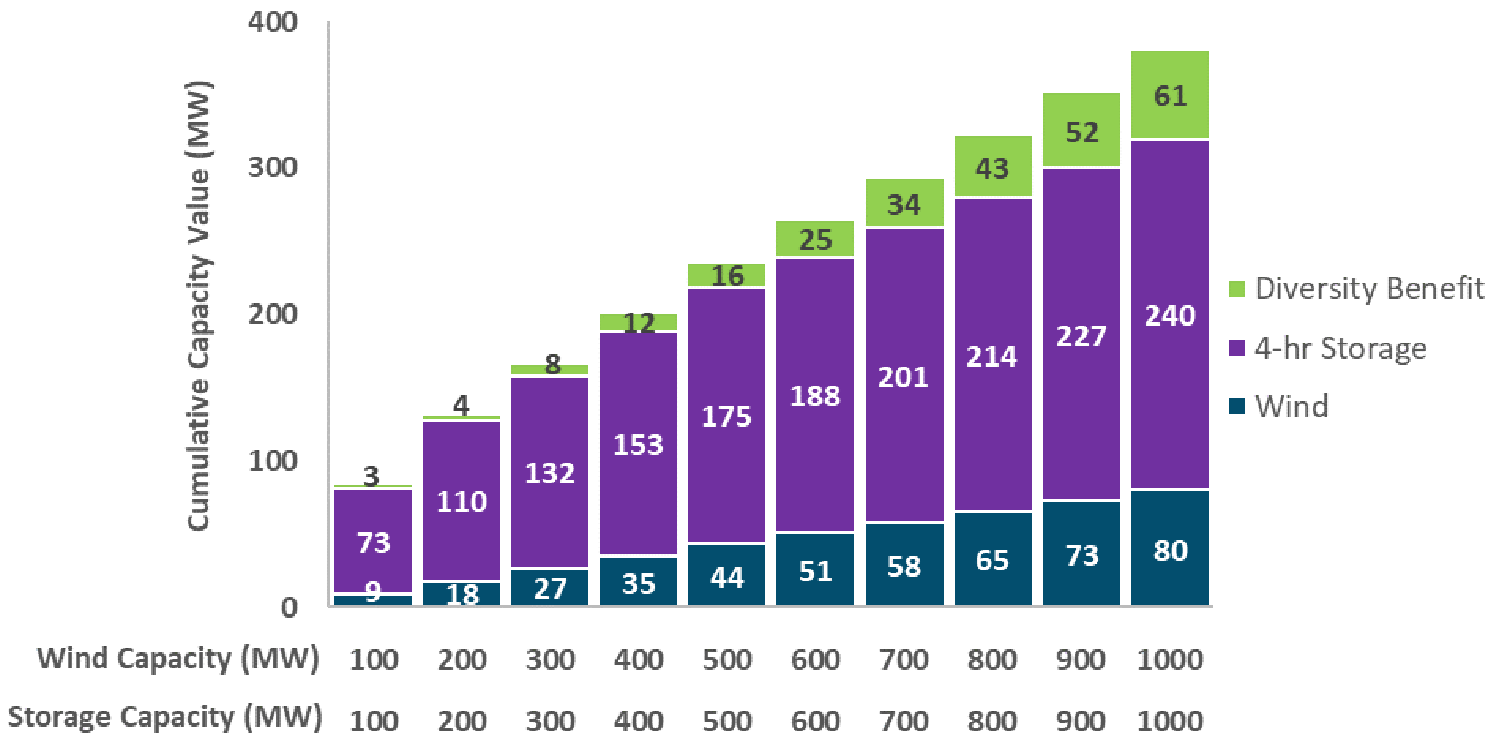
Diversity Benefit of Solar + Storage

- Stand-alone solar provides negligible capacity value to the system due to low coincidence between generation and evening winter peak load
- Solar and storage pair well together due to the diurnal pattern of solar and the ability of storage to shift that energy to the evening peak



Diversity Benefit of Wind + Storage

+ **Wind and solar also create a diversity benefit, but it is smaller than solar due to the potential for multiple days of low wind generation which depletes storage**



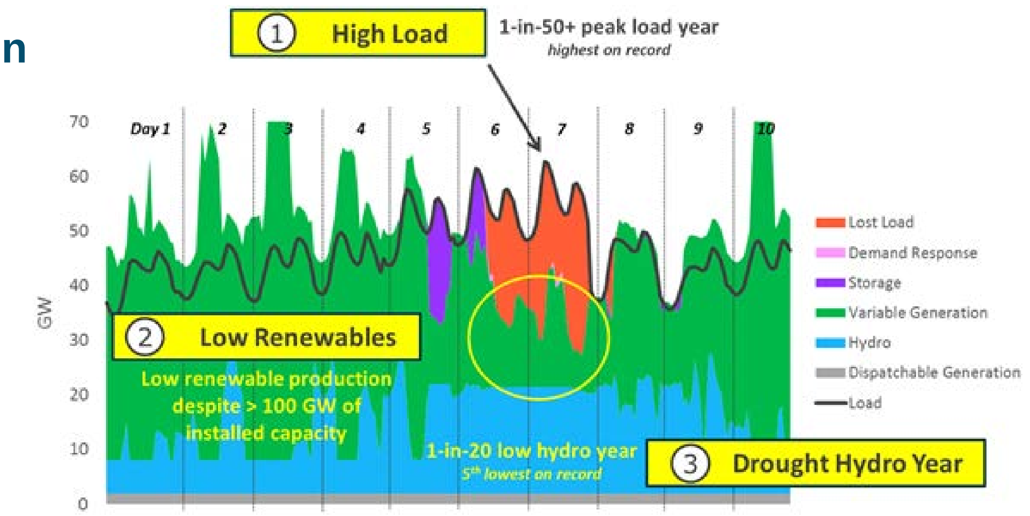
Conclusions

- **NSPI requires a 17.8% - 21.0% PRM to maintain a 0.1 days/yr loss of load expectation (LOLE) target**
  - Dependent upon the specific portfolio
- **Dispatch-limited resources such as wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system**

Energy+Environmental Economics

Appendix

+ **Reliability metrics measure outages in terms of**
  - Frequency
  - Duration
  - Magnitude
+ **Target reliability metrics are not standard across the industry and are often not rigorously justified**



+ **1-day-in-10-year LOLE is often used but this metric does not capture the duration or magnitude of individual events**
+ **E3 research has shown that for traditional and high-renewable systems with equivalent LOLE, the high-renewable systems tend to have more severe (higher magnitude) events**
  - This is due to variability in renewable resource availability
+ **While LOLE is the most common reliability metric standard, E3 recommends that jurisdictions should investigate establishing alternative standards that more explicitly take economics into account**

https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf

RECAP Model Overview

+ **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

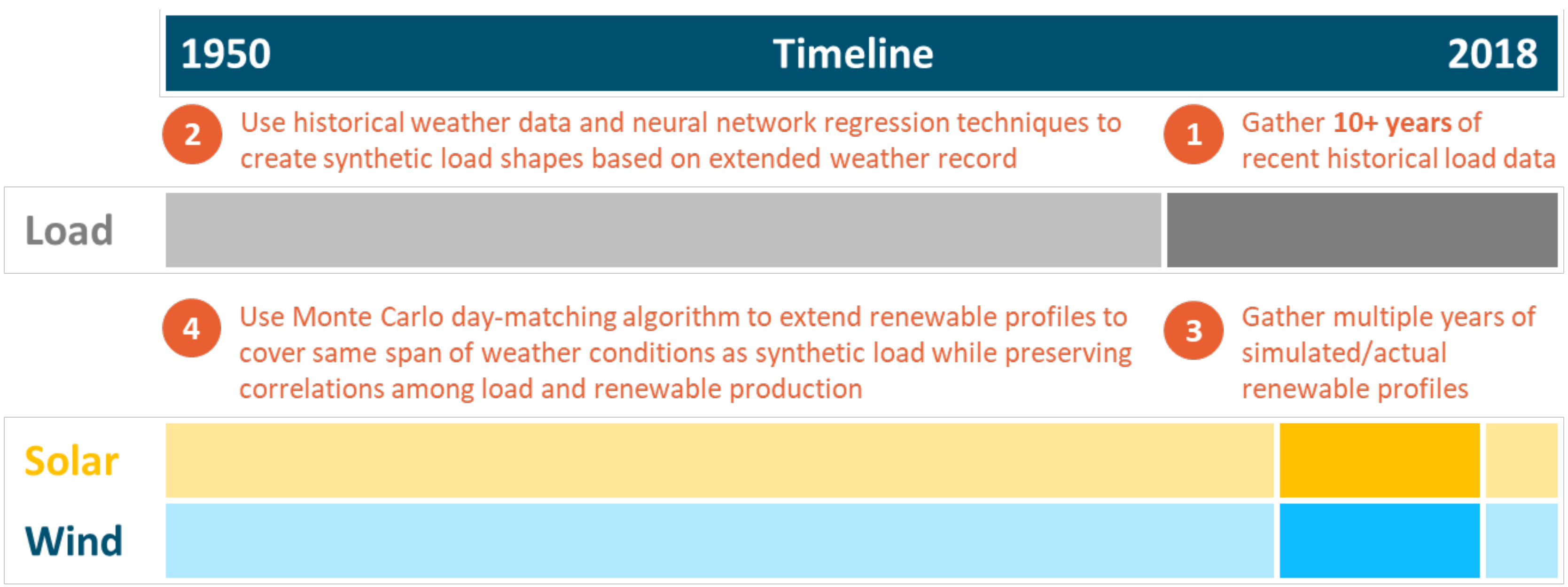
RECAP calculates reliability metrics for high renewable systems:

- **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

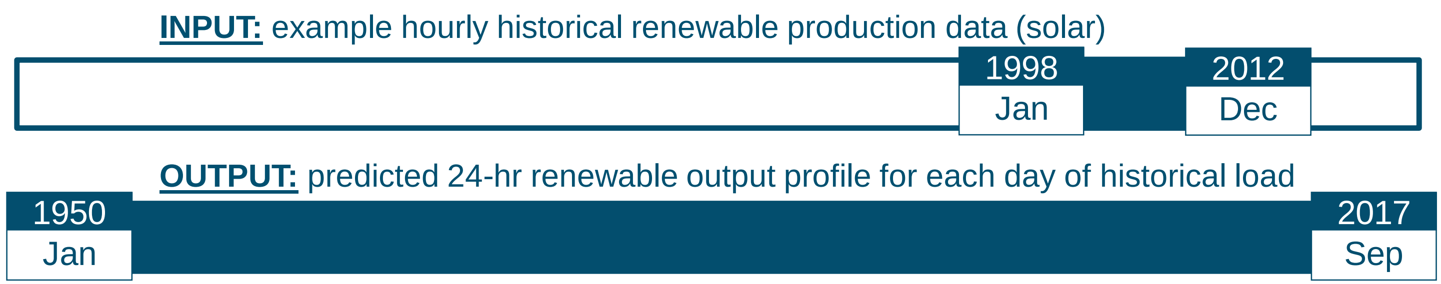
Information about E3's RECAP model can be found here: https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

Developing Hourly Loads and Renewable Profiles

+ **Capturing a wide range of potential load, wind, and solar conditions while preserving the underlying relationships among them is crucial to performing a robust loss-of-load-probability analysis**
+ **Raw data covering a sufficient range of conditions is often unavailable**
+ **RECAP's process for extending profiles to cover a large range of years is shown below**



Predicting Renewable Output



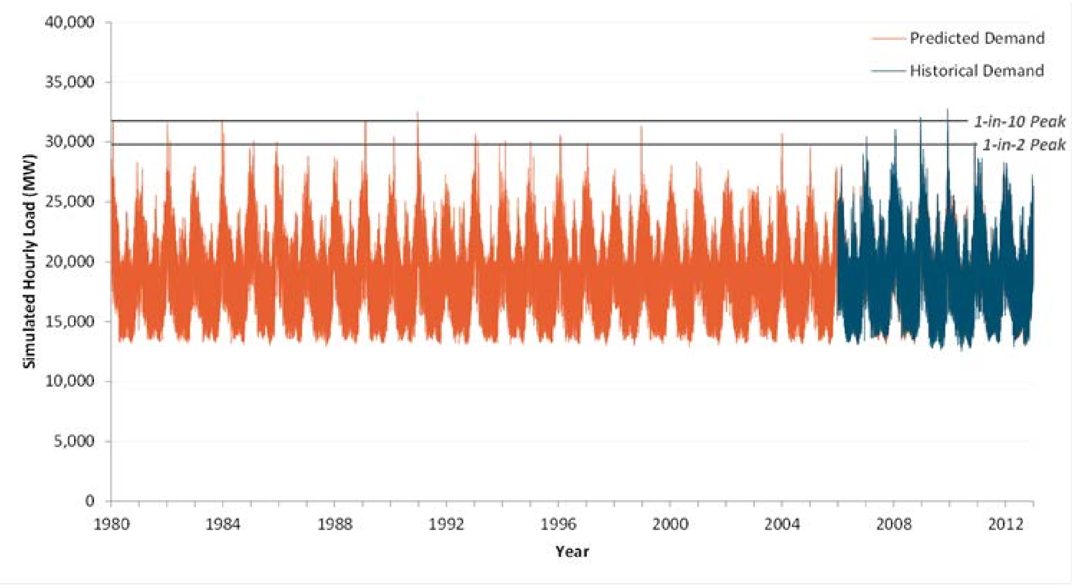
- **Renewable generation is uncertain, but its output is correlated with many factors**
  - Season
    - Eliminate all days in historical renewable production data not within +/- 15 calendar days of day trying to predict
  - Load
    - High load days tend to have high solar output and can have mixed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

Backcasting Hourly Loads

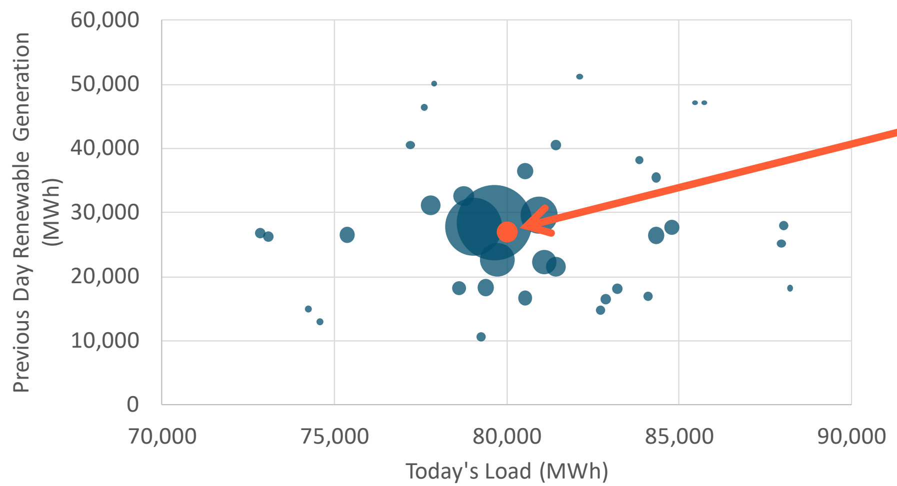
+ **Developing a robust set of hourly load profiles that is representative of a broad distribution of possible weather conditions – particularly extreme events that are often correlated with higher risk of loss of load – is a challenge for reliability modelers**

+ **E3 develops a neural network regression using actual hourly loads from recent historical years (5-10 years) and a longer record of key weather indicators (30-70 years)**

+ **The result is a profile of hourly loads that represent how today's electric demands would behave under a wide range of plausible weather conditions**



- 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

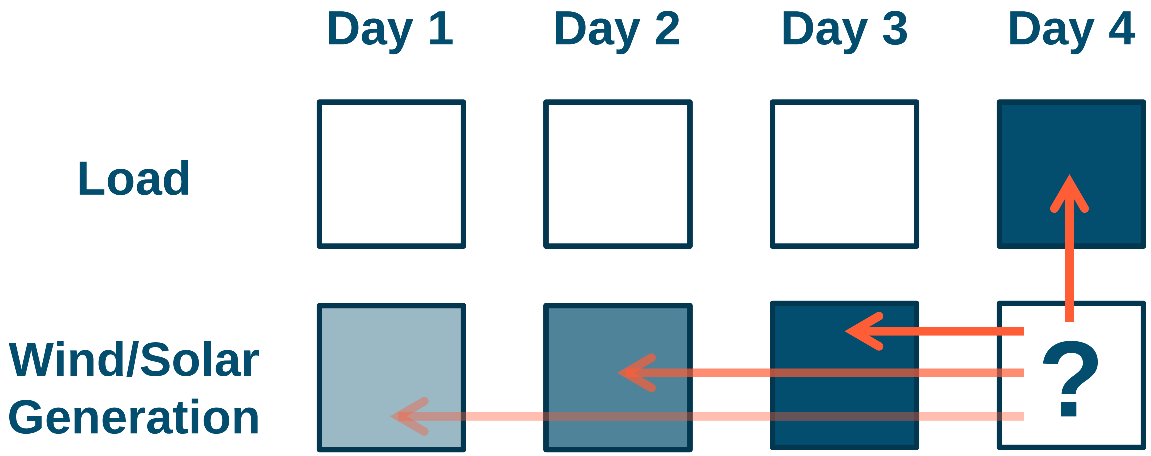
Probability of sample i being selected $= \dfrac{\frac{1}{Distance_i}}{\sum_{j=1}^{n} \frac{1}{Distance_j}}$

Where $distance_i = \text{abs}[\text{load}_{\text{Aug 12}} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug 12}} - \text{renew}_i]/\text{stderr}_{\text{renew}}$

36

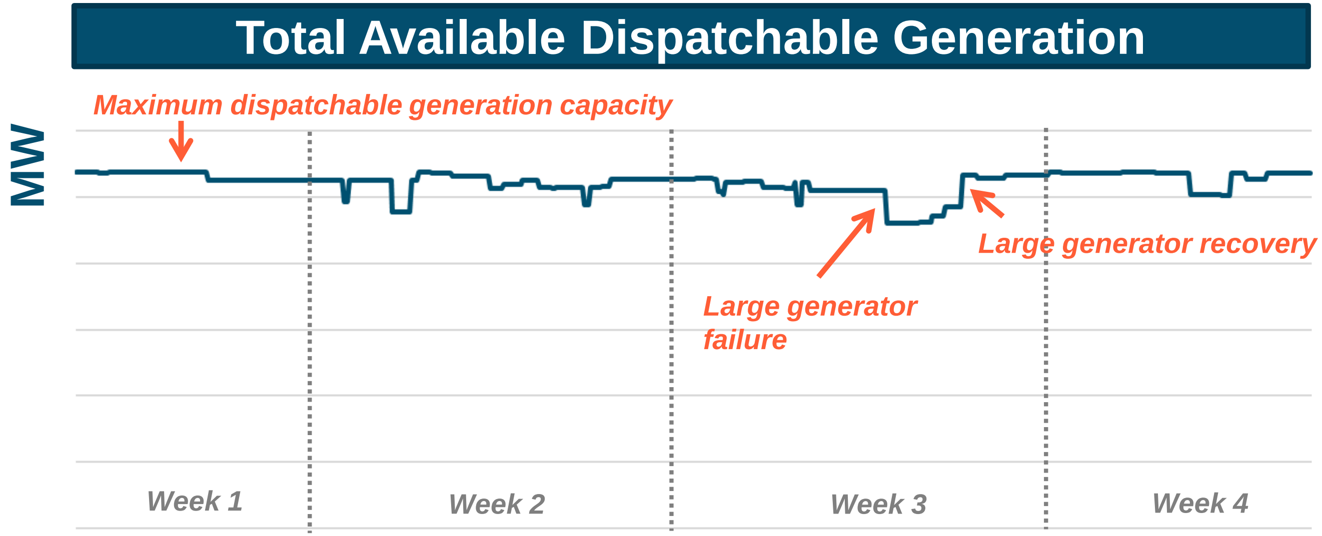
Synthesizing Hourly Wind/Solar Profiles

- To select a daily wind/solar profile, the model analyzes the load on the day as well as the previous 3+ days of wind/solar generation (with the most recent days being weighted highest)
- The model searches through the actual load and wind/solar historical record to find similar days and assigns each daily wind/solar profile a similarity rating to the day being predicted based on load and preceding days' wind/solar
- The model probabilistically selects a daily wind/solar profile through monte carlo analysis using similarity ratings as probability weights



Stochastic Outages

+ **Hourly dispatchable generator and transmission availability is calculated by stochastically introducing forced outages based on each generator's**
    - Forced outage rate (FOR)
    - Mean time to failure (MTTF)
    - Mean time to repair (MTTR)



Wind and Solar ELCC

Wind Capacity (MW)	ELCC (MW)	Average ELCC	Marginal ELCC
50	19	38%	38%
100	34	34%	30%
150	47	31%	27%
200	59	30%	24%
400	86	22%	14%
600	108	18%	11%
1,000	144	14%	9%
1,500	182	12%	8%
2,000	212	11%	6%
5,000	288	6%	3%

Solar Capacity (MW)	ELCC (MW)	Average ELCC	Marginal ELCC
1.7	0.08	4.7%	4.7%
25	0.08	0.3%	0.0%
50	0.08	0.2%	0.0%
100	0.08	0.1%	0.0%
150	0.08	0.1%	0.0%
200	0.08	0.0%	0.0%
400	0.08	0.0%	0.0%

1 and 2-hr Duration Storage ELCC

1-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	7	73%	73%
50	26	52%	47%
100	41	41%	30%
150	53	35%	24%
200	63	32%	21%
400	83	21%	10%
600	98	16%	8%
1,000	122	12%	6%

2-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	9	90%	90%
50	33	65%	59%
100	57	57%	48%
150	71	47%	28%
200	82	41%	22%
400	108	27%	13%
600	130	22%	11%
1,000	170	17%	10%

4 and 12-hr Duration Storage

4-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	9	90%	90%
50	40	80%	78%
100	73	73%	65%
150	93	62%	40%
200	110	55%	35%
400	153	38%	21%
600	187	31%	17%
1,000	240	24%	13%

12-hr Storage Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
10	10	100%	100%
50	50	100%	100%
100	100	100%	100%
150	150	100%	100%
200	200	100%	100%
400	378	95%	89%
600	429	72%	26%
1,000	484	48%	14%

Demand Response ELCC

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	4	16%	16%
50	6	12%	8%
100	6	6%	0%
200	6	3%	0%
300	6	2%	0%
400	6	2%	0%
500	6	1%	0%

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	13	52%	52%
50	24	48%	44%
100	32	32%	16%
200	32	16%	0%
300	32	11%	0%
400	32	8%	0%
500	32	6%	0%

Demand Response ELCC

DR Capacity (MW)	ELCC (MW)	ELCC %	Marginal ELCC%
25	24	96%	96%
50	45	90%	84%
100	84	84%	78%
200	109	55%	25%
300	112	37%	3%
400	112	28%	0%
500	112	22%	0%

Solar + Storage ELCC

Solar Capacity (MW)	Storage Capacity (MW)	Solar Standalone ELCC (MW)	4-hr Storage Standalone ELCC (MW)	Solar + Storage ELCC (MW)	Diversity Benefit (MW)
100	100	0.1	73	85	12
200	200	0.1	110	138	27
300	300	0.1	132	170	38
400	400	0.1	153	203	49
500	500	0.1	175	235	60
600	600	0.1	188	256	68
700	700	0.1	201	277	76
800	800	0.1	214	298	84
900	900	0.1	227	319	92
1,000	1,000	0.1	240	340	100

Wind + Storage ELCC

Wind Capacity (MW)	Storage Capacity (MW)	Wind Standalone ELCC (MW)	4-hr Storage Standalone ELCC (MW)	Wind + Storage ELCC (MW)	Diversity Benefit (MW)
100	100	9	73	85	3
200	200	18	110	132	4
300	300	27	132	166	8
400	400	35	153	201	12
500	500	44	175	235	16
600	600	51	188	264	25
700	700	58	201	293	34
800	800	65	214	323	43
900	900	73	227	352	52
1,000	1,000	80	240	381	61

Nova Scotia

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year
  - NPCC Regional Reliability Directory #1

Reserve Margin

- 20% planning reserve margin to meet LOLE standard

Loss of Load Modeling

- Probabilistic Assessment of System Adequacy (PASA) module of PLEXOS

Reserve Margin Accounting – Resource

- Net capability for dispatchable resources
- ELCC for renewable resources

Reserve Margin Accounting – Load

- Median peak load

SPP

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- PRM is derived to meet 0.1 LOLE
- Resulting non-coincident PRM is 12.0% for general entities and 9.8% for hydro-based entities
- Equivalent coincident PRM is 16.0%
- PRM updated every 2 years
- Each Load Responsibly Entity must procure capacity resources

Loss of Load Modeling

- GridView and SERVM

Reserve Margin Accounting – Resource

- Net capability for dispatchable resources
- Wind/solar capacity credit counted using heuristic top load hour methodology

Reserve Margin Accounting – Load

- Peak load under median median weather conditions
- Behind-the-meter generation subtracted from gross load
- Operating reserves not included but are on the list for future consideration

MISO

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- PRM is derived to meet 0.1 LOLE
- UCAP PRM is 7.9% of each LSE's CP
- ICAP PRM is 16.8% of MISO CP
- PRM updated annually

Loss of Load Modeling

- SERVM

Reserve Margin Accounting – Resource

- UCAP: Capacity de-rated for forced outages
- ICAP: Installed capacity
- Renewable credit established by ELCC study
  - Wind: 15.2%
  - Solar: 50%

Reserve Margin Accounting – Load

- Median forecasted peak net internal demand
- Operating reserves are not included

ERCOT

Reliability Metric(s) and Standard

- No explicit standard

Reserve Margin

- Recent study concluded:
  - Market equilibrium reserve margin: 10.25%
  - Economically optimal reserve margin: 9%
    - VOLL: $9,000/MWh
- "Purely information" target PRM of 13.75% (acknowledges higher than economically optimal)
  - Achieves 0.1 events/yr
- Reserve margin is ultimately determined by suppliers' costs and willingness to invest based on market prices

Reserve Margin Accounting – Resource

- Dispatchable units are counted by seasonal net sustained capacity
- Hydro is counted by peak seasonal capacity contribution
- Renewable units are de-rated by seasonal peak-average capacity contribution methodology
  - Non-coastal wind: 14%
  - Coastal wind: 59%
  - Solar: 75%

Reserve Margin Accounting – Load

- Median peak load
- Operating reserves added to load

Loss of Load Modeling

- SERVM

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- Minimum Installed Reserve Margin (IRM) requirement is set to meet 0.1 LOLE
- Minimum IRM is 16.8% in 2019
- Demand curve approach is utilized such that achieved IRM exceeds minimum IRM in most cases
  - Linear slope between minimum IRM (1.5x CONE) and all capacity offered
  - 27% achieved in 2018
- Updated annually
- Local capacity requirements (LCRs) existing for different zones
- Achieved IRM is based on demand curve bidding process

Reserve Margin Accounting – Resource

- IRM based on installed nameplate capacity
  - UCAP requirement is based on capacity de-rated for forced outages but requirement is lower than IRM
- Renewables are de-rated using heuristics for winter and summer

Reserve Margin Accounting – Load

- Peak load is predicted from normal weather conditions simulated over 20 historical weather years (50/50 peak)
- Operating reserves are not included

Loss of Load Modeling

- GE-MARS

ISO-NE

Reliability Metric(s) and Standard

- LOLE: Demand Curve
  - 0.2 days/year
  - 0.1 days/year
  - 0.01 days/year

Reserve Margin

- Updated annually
- Demand curve reserve margin points for 2019
  - 13.1% (0.2 LOLE)
  - 16.8% (0.1 LOLE)
  - 26.1% (0.01 LOLE)

Loss of Load Modeling

- GE-Mars

Reserve Margin Accounting – Resource

- Dispatchable resources counted at installed nameplate capacity
- Renewables qualified capacity is performance based, counted by the resource's median output during "reliability hours" over 5 years
- Reliance on the interties is counted

Reserve Margin Accounting – Load

- Peak load is predicted from median (50/50) weather conditions
- Energy efficiency is considered as passive demand resource and not embedded in load
- Behind-the-meter PV is counted as a resource
- Operating reserves are included

PJM

Reliability Metric(s) and Standard

- LOLE: 0.1 events/year
  - BAL-502-RFC-02

Reserve Margin

- Installed Reserve Margin (IRM) is set to meet 0.1 LOLE
- IRM is used as an input into capacity auction demand curve
  - The recommended IRM for 2019/20 period is 16.0%
    - 1.5x Net-CONE @ IRM – 0.2%
    - 0.75x Net-CONE @ IRM + 2.9%
    - 0x Net-CONE @ IRM + 8.8%
- Updated annually
- Locational Deliverability Areas (LDAs) are modeled in addition to IRM

Reserve Margin Accounting – Resource

- Dispatchable units are counted by summer net dependable capacity in IRM
- Renewables' ICAP calculated using heuristic capacity credit (similar to ELCC)

Reserve Margin Accounting – Load

- Median peak load
- Behind-the-meter PV is embedded into load

Loss of Load Modeling

- Probabilistic Reliability Index Study Model (PRISM)
  - PRM internal tool

CAISO

Reliability Metric(s) and Standard

- No explicit reliability standard

Reserve Margin

- Resource Adequacy program sets the Planning Reserve Margin (PRM) to at 15% on a monthly basis
- LSEs are responsible for procuring RA
- RA program contains system, local, and flexible RA requirements

Loss of Load Modeling

- RECAP used to calculate DER values
- SERVM model used to calculate renewable ELCCs

Reserve Margin Accounting – Resource

- Monthly Net Qualifying Capacity (NQC) to calculate total available capacity
- NQC of renewable resources is counted by ELCC
- LSEs can use imports to meet the RA requirements

Reserve Margin Accounting – Load

- Peak load is 1-in-2 weather normalized
- Behind-the-meter PV and energy efficiency are embedded in peak demand
- Operating reserves are not included

AESO

Reliability Metric(s) and Standard

- EUE: 800 MWh/year; NormEUE: 0.0014%

Reserve Margin

- Publishes quarterly reports monitoring the existing and forecasted reliability of the system
- If the forecasted EUE drops below the threshold metric, the AESO can take actions to bridge the supply gap
- 2017 reserve margin
  - 34% w/o intertie
  - 44% w/ intertie
- *Currently in process of developing a capacity market*

Reserve Margin Accounting – Resource

- N/A

Reserve Margin Accounting – Load

- N/A

Loss of Load Modeling

- SERVM

Florida

Reliability Metric(s) and Standard

- LOLE: 0.1 days/year

Reserve Margin

- Minimum reserve margin planning criterion of 15% in addition to LOLP threshold
- Analysis report published every other year
- FRCC calculates both generation-only reserve margin which does not include DSM and total reserve margin

Loss of Load Modeling

- Internal probabilistic modelling

Reserve Margin Accounting – Resource

- Installed capacity

Reserve Margin Accounting – Load

- Peak load is based on median weather conditions
- Operating reserves are not included

Reliability Metric(s) and Standard

- No explicit planning standard but calculates multiple metrics

Reserve Margin

- Selected a PRM of 13% in 2017 IRP
- Updated every 2 years
- Considers reliability, cost, and risk in determining target PRM
  - Tests system reliability and production cost in 10-year planning horizon given the PRM from 11% to 20%

Loss of Load Modeling

- Internal Planning and Risk (PaR) model

Reserve Margin Accounting – Resource

- Thermal units are counted at maximum dependable capacity at the time of system summer and winter peak
- Hydro is counted by the maximum capacity that is sustainable for one hour at the time of system summer peak
- Variable renewables (solar and wind) are de-rated by the peak capacity contribution among hours with the highest loss-of-load probability for east BAA and west BAA separately
- DR (Class 1 DSM) is counted as nameplate capacity

Reserve Margin Accounting – Load

- Peak load in the base case is based on normal weather year (1-in-2) from 20 weather years period
- Operating reserves are included
- Class 2 demand side management (DSM) resources such as energy efficiency, are embedded in load

Australia

Reliability Metric(s) and Standard

- Expected Unserved Energy (EUE): 0.002% of total energy demand
  - Standard is set based on the economically optimal value, with recognition of the shortcomings of the metric (doesn't account for length of outages, etc.)

Reserve Margin

- No explicit reserve margin requirement
- Australian Energy Market Operator forecasts EUE and can intervene in the market by procuring additional generator capability if necessary

Reserve Margin Accounting – Resource

- N/A

Reserve Margin Accounting – Load

- N/A

Loss of Load Modeling

- Internal modeling

Great Britain

Reliability Metric(s) and Standard

- LOLH: 3 hours/year
  - National Grid estimated LOLE during 2017/2018 winter is 0.001 hours/year
- Standard is set based on economic optimum

Reserve Margin

- No required standard, but de-rated capacity margin is monitored
  - De-rated for forced outages
- Modeled target de-rated margin in 2021 = 5%
- Achieved de-rated margin in 2018 = 12%

Reserve Margin Accounting – Resource

- Generators de-rated to account for availability for each technology (e.g. CCGT = 85%) of nameplate

Reserve Margin Accounting – Load

- Median winter peak

Loss of Load Modeling

- Internal modeling

The Republic of Ireland

Reliability Metric(s) and Standard

- LOLE: 8 hours/year
- Standard is set based on economic optimum

Reserve Margin Accounting – Resource

- Dispatchable units are de-rated for FOR in the capacity requirement and capacity market

Reserve Margin Accounting – Load

- N/A

Loss of Load Modeling

- Internal modeling

Reserve Margin

- LOLE standard is used to determine a MW capacity requirement
- The capacity requirement is used to determine capacity payments to generators
  - Net-CONE * Capacity Requirement determines total capacity payments which are divided between all generators
  - Generators paid based on de-rated capacity for FOR
  - Renewable units are subject to de-rating factors (i.e., Wind: 0.103; Solar PV: 0.055)

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Thank You

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