DNV·GL

Analysis of Stochastic Dataset for ISO-NE

ISO New England Inc.

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F	24 February 2021	Corrected typographical error in Section 5.	C. Hayes	D. Rife	J. Mault

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Abbreviations

Abbreviation	Meaning
BOEM	Bureau of Ocean Energy Management
BTM	Behind the meter
CDD	Cooling Degree Day
CELT	Capacity, Energy, Loads and Transmission
EE	Energy efficiency
GHI	Global Horizonal Irradiation
HDD	Heating Degree Day
ISO-NE	ISO New England Inc.
KPI	Key Performance Indicators
NEL	Net Energy Load
PDF	Probability Distribution Functions
PV	Photovoltaic
SE	Stochastic Engine
UTC	Coordinated Universal Time

1 INTRODUCTION

ISO New England Inc. ("ISO-NE" or the "Customer") has engaged DNV GL Energy USA, Inc. (hereinafter DNV GL) to provide Data Analysis services of the stochastic wind, solar, and load dataset for ISO-NE ("Probabilistic Analysis" or the "Project").

DNV GL previously modeled hourly wind generation for the 38 existing wind plants within the ISO-NE service area, and 12 hypothetical wind plant locations within the offshore Bureau of Ocean Energy Management (BOEM) lease area south of Martha's Vineyard and Nantucket, MA. Regional distributed behind-the-meter (BTM) solar generation and Gross Load[1] time series were also modeled for the ISO-NE Load Zones of ME, NH, VT, CT, RI, Southeast MA (SEMA), West-Central MA (WCMA), and Northeast MA (NEMA). All datasets were calibrated with available measurements and cover the period of January 2000 through December 2019. These datasets have been used for grid and resource planning exercises. Additional details on these datasets appear in the February 2020 ISO-NE Planning Advisory Committee presentation [1]. The approximate locations of the wind datasets are shown in the figure below.

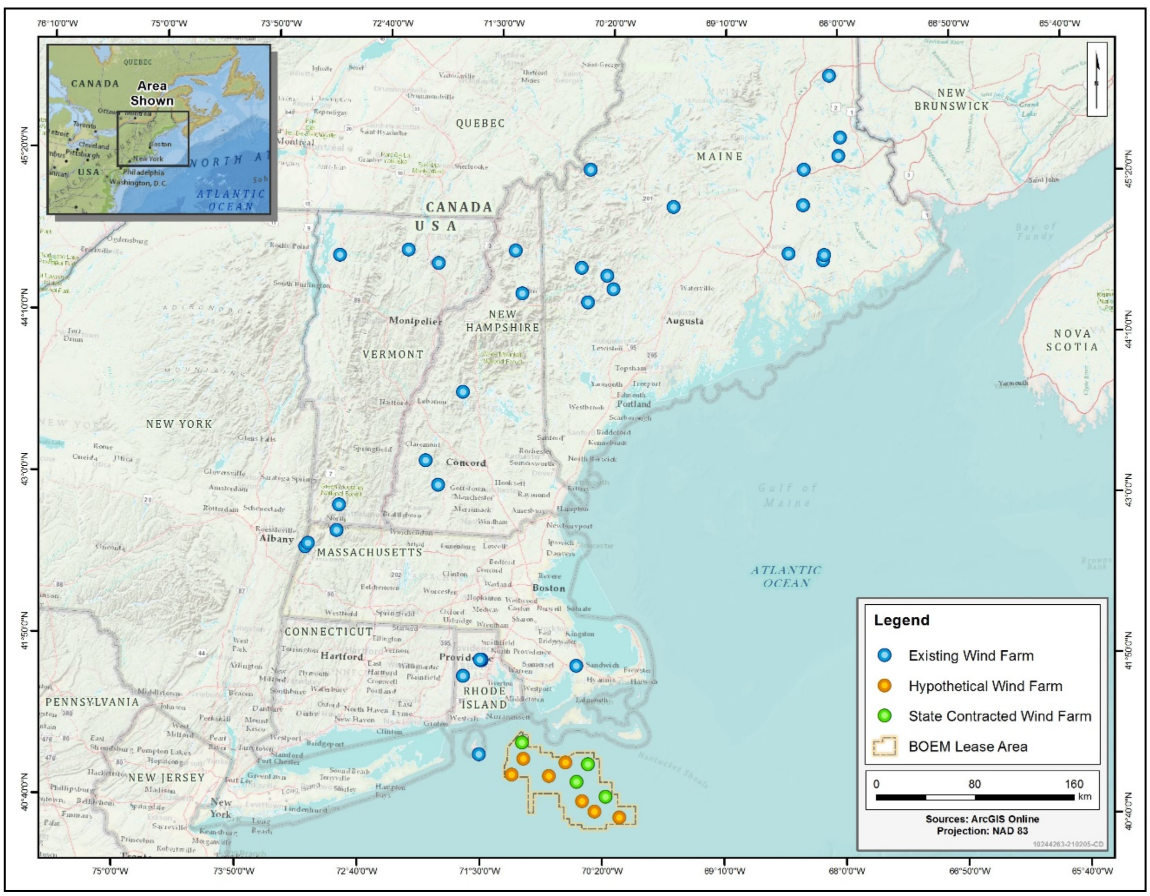

Figure 1-1 Locations of existing, state contracted and hypothetical wind farms

[1] Gross Load is defined as total consumption of gross load minus energy efficiency (EE) with BTM solar reconstituted.

In the present study, DNV GL stochastically modeled the 20-year dataset of onshore and offshore wind generation, BTM distributed solar generation, gross load, and net load[2] data, to assess the full spectrum of operating conditions within the ISO-NE service area. The stochastic modeling methodology is described below.

1.1 Stochastic time series modeling

DNV GL developed a next generation probabilistic model to provide a comprehensive assessment of both typical and unusual wind and solar power production scenarios across the portfolio [2]. The Stochastic Engine (SE) employs a non-parametric bootstrap resampling method to generate synthetic sequences of time series data based on the historical record. It uses historical observation trajectories as multivariate "dependence templates" onto which the stochastic realizations are assembled to duplicate the pairwise rank correlation structure in the historical record. Like other empirical copula methods, the dependence templates used in the SE contain all the information about the inter-site and inter-variable dependencies within the data (both linear and non-linear dependencies). The daily, seasonal, and annual cycles of the original dataset are fully preserved, along with the spatial coherency of weather, wind and solar generation, and load across the entire portfolio of sites (inter-site correlations). The preservation of these inter-site correlations is very important for understanding the relationship of projects across a region. The true value of the SE is its ability to represent the full spectrum of possible weather conditions that drive wind and solar power production, thereby allowing a comprehensive assessment of all possible scenarios across the entire portfolio. Each individual synthetic time series closely mimics the characteristics of the weather that could occur at each project location, based on the historical record. The output is a synthetic series of hourly data with the same statistical properties as the observations. Relevant examples include but are not limited to understanding risks associated with low generation and high demand, revenue risk where time of day or seasonal characteristic are important and robust probabilistic estimates of events, such as low wind years, high-wind shutdown events, large wind ramp events or periods of resource constraints.

DNV GL employed the SE to model 1,000 realistically plausible historical 20-year time series of hourly wind generation for each wind plant, and BTM solar photovoltaic (PV) generation and load for each Load Zone, to capture the full range of meteorological conditions that can occur across the ISO-NE service area. This allows quantification of the variability in the wind and solar resources, and any associated risks of underproduction or rare weather events. The previously generated dataset covering January 2000 through December 2019, as described above, was used to initialize the SE model. This amounts to (20 years × 1,000 synthetic sequences) = 20,000 years of hourly wind and solar production data, load, temperature, relative humidity, wind speed, and solar irradiance.

The SE preserves all trends present in the original dataset. Figure 1-2 presents the distribution of monthly mean gross load values calculated from the 20,000-year stochastic dataset. The original 20-years of input gross load data exhibited a downward trend due to the implementation of energy efficiency programs in recent years. The stochastic dataset preserves this trend.

[2] Net Load is defined as Gross Load minus energy efficiency and BTM distributed solar generation.

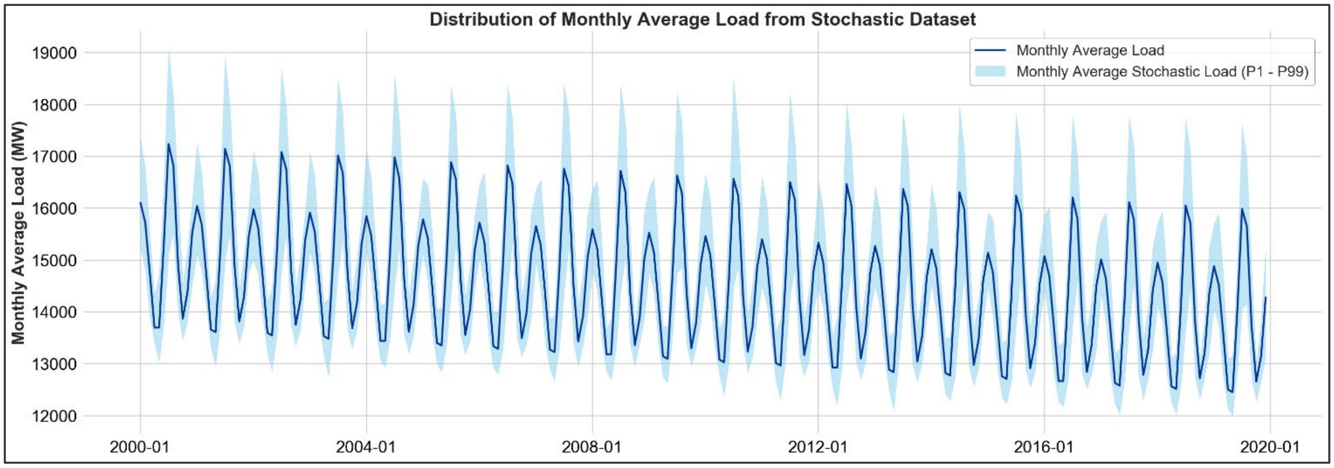

Figure 1-2 Monthly average gross load trend in stochastic dataset

Statistical and probabilistic analyses were performed on the resulting dataset for selected Key Performance Indicators (KPI) to determine the likelihood of various events, including large wind ramp events, extended weather events that may cause resource scarcity (e.g., cold temperatures and low wind generation), and coincident periods of high load during periods of low and high solar and wind generation. DNV GL notes that only operational offshore wind farms or those with state contracts are included in the offshore wind generation component of the analysis below. The operational and state-contracted offshore wind farms were used for the analysis are presented in Table 1-1.

Table 1-1 State contracted offshore wind farms included in analysis

Offshore Wind Farm	Wind Farm Capacity (MW)	Load Zone Point of Interconnection
Vineyard Wind (State Contract)	840.0	SEMA
Mayflower Wind (State Contract)	804.0	SEMA
Revolution Wind (State Contract)	663.6	RI
Park City Wind (State Contract)	800.0	SEMA
Block Island (Operational)	30.0	RI

A prioritized list of KPI tasks included in this report is shown below.

Report Section	**Task**	**Description**
2	1	Reliability of offshore wind during cold snaps and heat waves
3	2	Probability of wind and solar "droughts"
4	3	Correlation of wind, load, and solar generation
4	4	Correlation of wind across Load Zones
4	5	The coincident net peak load between different Load Zones
5	6	Representative 8760s of wind, solar, and load during P1, P5, P10, P50, P90, P95, and P99 production years
6	7	Probability distribution of expected output of onshore/offshore wind outputs for peak/min gross/net load
7	8	Intra-day variability (ramping) of wind, solar and co-variability of wind and solar generation

The results of this analysis for each KPI task are presented in Sections 2-7. Note that Tasks 3, 4, and 5 have been combined and are presented in Section 4.

2 RELIABILITY OF WIND DURING COLD SNAPS AND HEAT WAVES

DNV GL determined the frequency of extended periods of cold or hot temperatures and the accompanying distributions of wind generation and load during those periods.

2.1 Methodology

ISO-NE has requested an investigation of two different methods for determining cold snaps and heat waves. These methods are described below in Sections 2.1.1 and 2.1.2. Cold snaps and heat waves were identified for each Load Zone as well as for all New England.

Cold snaps and heat waves for New England were identified using the average weighted temperature across the eight Load Zones. Weights for each Load Zone were determined by their 2020 forecasted gross Net Energy Load (NEL) values from the 2020 Capacity, Energy, Loads and Transmission (CELT) report [3]. The resulting Load Zone weather weightings are shown in Table 2-1.

Table 2-1 Load Zone weather weighting

2020 CELT Gross NEL		
Load Zone	**Net Energy Load (MWh)**	**Weight**
CT	33,932	23.26%
ME	13,707	9.40%
NH	12,978	8.90%
RI	9,681	6.64%
VT	6,831	4.68%
SEMA	18,470	12.66%
WCMA	19,564	13.41%
NEMA	30,718	21.06%
ISO-NE	145,881	100.00%

During the initial phase of analysis it became apparent the modeled temperature and relative humidity data used by the stochastic engine exhibited a slight under prediction bias. After discussion with ISO-NE, DNV GL has bias corrected the temperature and relative humidity stochastic datasets using a 12x24 matrix of correction values determined from comparison of modeled data to measurements. The goal of the bias correction is to ensure these parameters are representative of the actual measured conditions and to limit any impacts these biases may have on the computed cold snap and heat wave events. It is important to note that the original temperature bias will not have an impact on the input load data used by the Stochastic Engine as the load data are not derived from weather data but are based on historical load observations.

The 20,000 years of hourly records (7.3 million days or 175.2 million hours) from the SE were analyzed to determine the average frequency and duration of cold snaps and heat waves per year using Methods 1 and 2, described below, for each Load Zone, and for the aggregate across New England. The typical range of wind generation, solar generation, and system load during each event is presented.

2.1.1 Method 1: Daily maximum temperature

The first method for determining cold snaps and heat waves utilizes the daily maximum temperature. Cold snaps and heat wave events are defined as any consecutive period of 3 or more days where the maximum daily temperature remains above 90°F (heat wave) or below 32°F (cold snap).

Figure 2-1 presents an example of a cold snap using the modeled average New England temperature and the coincident offshore wind generation as a percent of the total contracted offshore generation capacity.

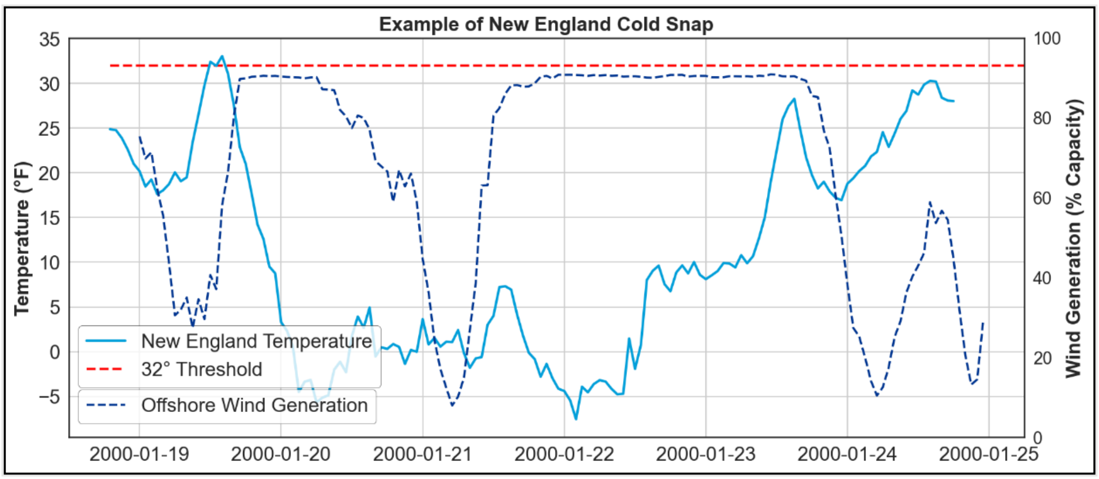

Figure 2-1 Example of the wind generation during 5-day New England cold snap

In this example, the cold snap lasts for a period of 5 days during which the daily maximum temperature did not exceed 32°F (red dashed line). Wind generation remained near capacity throughout the event, with a brief period when generation dropped to near zero on January 21.

2.1.2 Method 2: Heating and cooling degree days

The second method for determining cold snaps and heat waves relies on the calculation of heating and cooling degree days. A heating degree day (HDD) is a measurement designed to quantify the demand for energy needed to heat a building. It is the number of degrees that a day's average temperature is below 65° Fahrenheit (18° Celsius), which is the temperature below which buildings need to be heated. A cooling degree day (CDD) is the number of degrees that a day's average temperature is above 65° Fahrenheit (18° Celsius), which is the temperature above which a building needs to be cooled.

$$HDD = 65°F - mean\ daily\ temperature$$

$$CDD = mean\ daily\ temperature - 65°F$$

The heating/cooling temperature thresholds have been chosen from the distributions of all heating degree and cooling degree days in the 20,000 year stochastic dataset. Figure 2-2 presents the distributions of all heating and cooling degree days for New England. The 90th, 95th, and 99th percentile thresholds for heating and cooling degree days are marked.

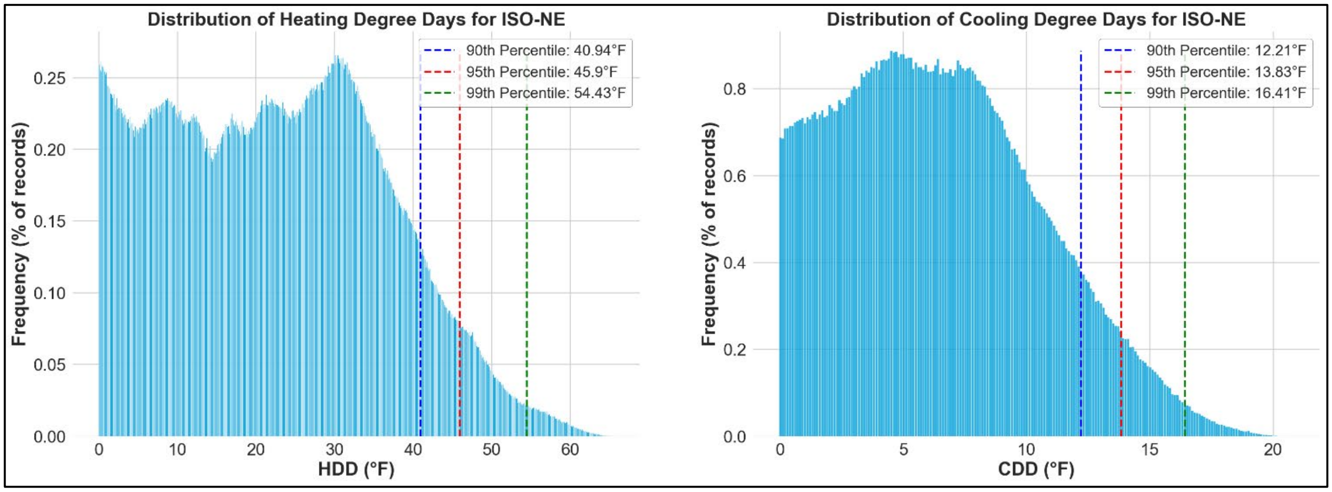

Figure 2-2 Distributions of all heating degree and cooling degree days from stochastic dataset for New England

Table 2-2 presents the 90th, 95th, and 99th percentiles of HDD and CDD distributions for New England and their corresponding daily average temperatures.

Table 2-2 Heating and cooling degree day percent ranks

Percent rank	HDD (°F)	HDD daily average temperature (°F)	CDD (°F)	CDD daily average temperature (°F)
90%	40.94	24.06	12.21	77.21
95%	45.90	19.10	13.83	78.83
99%	54.43	10.57	16.41	81.41

Following discussion with ISO-NE, DNV GL has defined a cold snap or heat wave event as any consecutive period of 3 or more days when the heating or cooling degree day remains above the temperature corresponding to the 95th percentile of all heating or cooling degree days.

Figure 2-3 presents an example of a cold snap using the average New England temperature to determine the heating degree day.

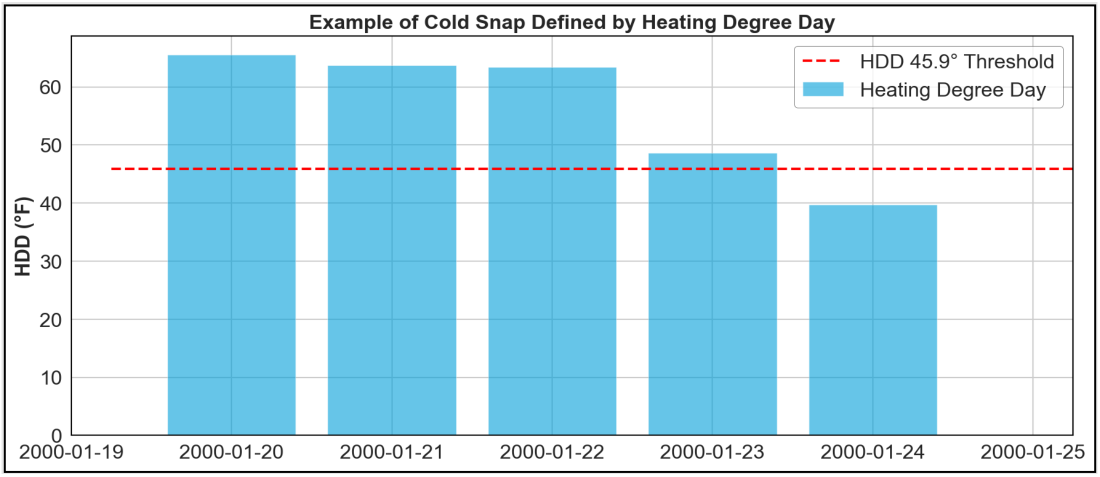

Figure 2-3 Example of a 4-day New England cold snap using heating degree day

Based on the criteria above, the 95th percentile of heating degree days for ISO-NE corresponds to threshold of 45.9°F. This means that any consecutive period of at least 3 days with a HDD greater than 45.9°F will be classified as a cold snap. Note that heating and cooling degree days are reported as a positive number, even though a cooling degree day represents the number of degrees needed to cool a building.

2.2 Analysis

2.2.1 Temperature events using daily peak temperatures (Method 1)

Table 2-3 presents the average number of cold snaps and heat waves per year for all of New England, using the criteria previously defined for Method 1. The average temperature across all events is also provided for both cold snaps and heat waves. There are approximately 4 cold snap events per year with an average duration of about 5 consecutive days. On average, heat waves occur less than once per year with a duration of 3 consecutive days. There was a maximum of 9 cold snap events and 5 heat waves per year in the stochastically modeled dataset.

Table 2-3 Cold snap and heat wave statistics for New England based on stochastic dataset

Statistic	Cold snap	Heat wave
Average events per year	4.2	0.4
Maximum events per year	10	5
Minimum events per year	0	0
Average event duration per year	4.8 Days	3.5 Days
Maximum event duration per year	24	10
Average temperature	25.7°F	92.4°F
Average daily peak load	19,159 MW	24,232 MW
Maximum daily peak load	22,725 MW	27,911 MW

Cold snaps and heat waves are generally driven by synoptic scale weather systems, which typically last for several days, but occasionally last for a few weeks. Thus, the average duration of the cold snap and heat wave events identified within the stochastic dataset is well within the range of expected event durations. To support this assumption and give confidence in the stochastically modeled dataset, 17 years of measured temperature data for New England were examined and cold snap and heat wave events were identified for each year. Table 2-4 presents the results of this analysis. A maximum cold snap event duration of 16 days with an average duration of 4.6 days was determined from the 17 years of measurements for New England. Heat waves calculated using the 17-year measured dataset were determined to have a maximum duration of 5 days and average duration of 3.2 days. In both the measured and stochastically modeled datasets cold snaps were determined to be more frequent and longer in duration than heat waves, based on the cold snap and heat wave temperature thresholds.

Table 2-4 Cold snap and heat wave statistics for New England based on 17 years of measurements

Statistic	Cold snap	Heat wave
Average events per year	4.9	0.64
Maximum events per year	8	2
Minimum events per year	1	0
Average event duration per year	4.6 Days	3.2 Days
Maximum event duration	16 Days	5 Days
Average temperature	24.5°F	91.6°F

Figure 2-4 presents the distribution of event durations for all cold snap and heat wave events of 3 or more consecutive days using the maximum daily peak of the New England average temperature. Although rare, cold snap events can last for significant periods of time, up to 24 consecutive days with daily peak temperatures below 32°F. Similarly, heat waves within New England occasionally last longer than 3 consecutive days; however, heat wave durations are typically shorter than cold snaps with a maximum heat wave duration of 9 consecutive days with daily peak temperatures exceeding 90°F for New England.

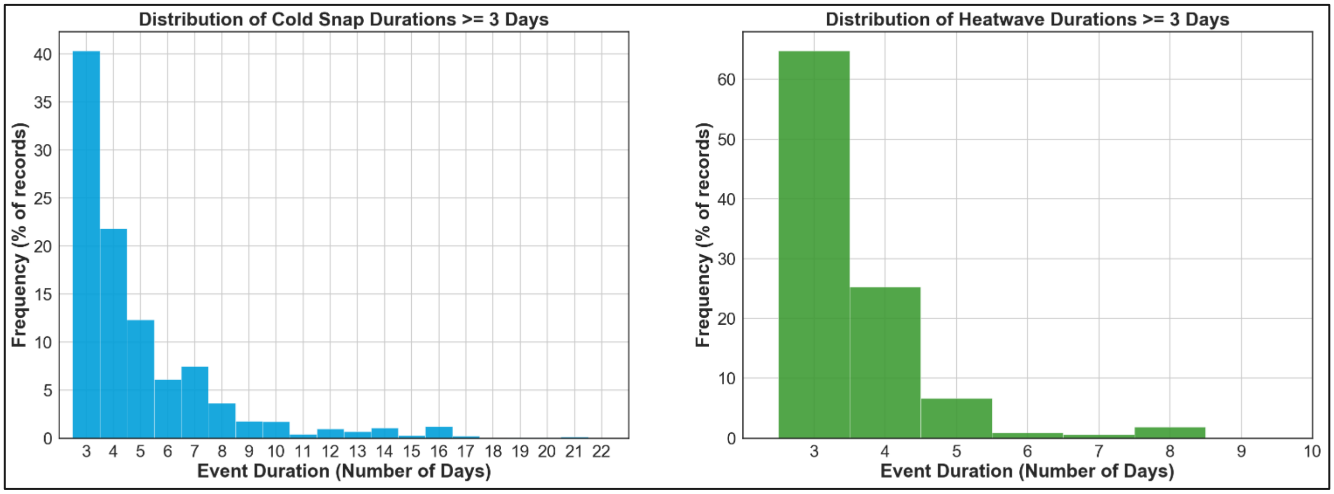

Figure 2-4 Distributions of the total duration of all cold snap and heat wave events lasting at least 3 days for New England

During extended cold snaps or heat waves, fuel supplies may become limited. If variable generation resources such as wind or solar remain low during such events, energy demand may exceed supply due to increased energy usage for heating and cooling. The distributions above indicate that it is very rare for a cold snap with New England daily maximum temperatures of 32°F to last longer than 10 days or a heat wave to last longer than 5 days.

In addition to understanding the durations of cold snaps or heat waves it is useful to quantify how frequently these events occur each year, as shown in Figure 2-5. It is clear that most years contain no heat wave event with less than 1% of all 20,000 years having more than 3 heat waves per year. Cold snap events occur 5 times per year on average. Again, for this example, cold snaps and heat waves are determined from the average New England temperature for events lasting at least 3 consecutive days. No climate change modifications regarding increasing temperature in the future have been made to the stochastic dataset so it is possible a warming climate in the future may lead to a higher frequency of occurrence for heat waves. The higher frequency of cold snaps versus heat waves may be due in part to the choice of the temperature thresholds, which may not be appropriate for the average New England temperature. In the section below we examine the sensitivity of cold snaps and heatwaves to the chosen temperature threshold.

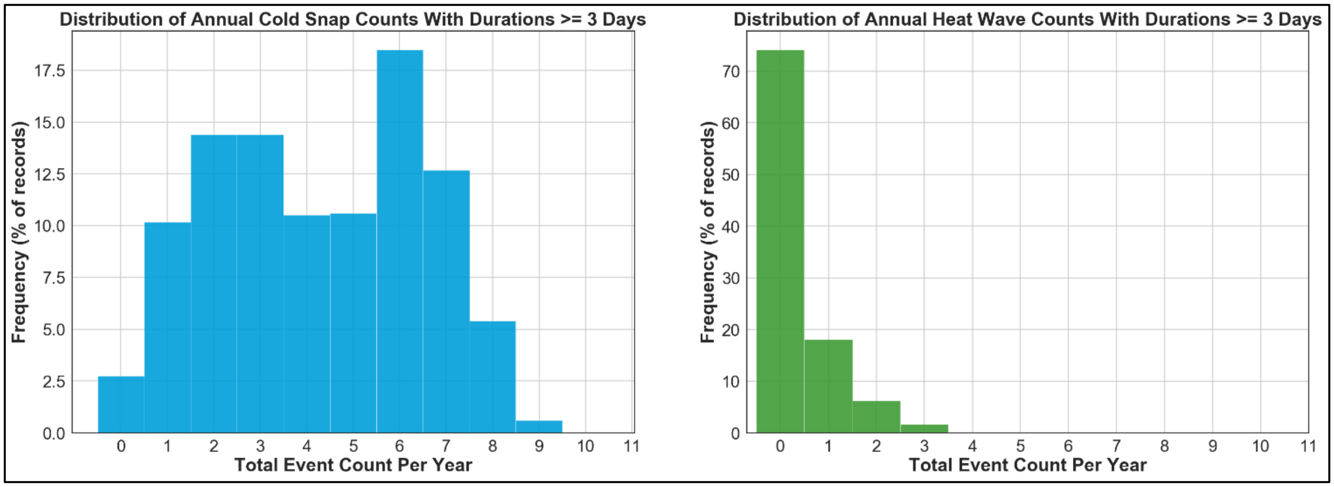

Figure 2-5 Distributions of the number of cold snap and heat wave events for each year within the stochastic dataset

The temperature thresholds used to define cold snaps and heat waves for the broader New England region may not be appropriate for some Load Zones. Based on the defined criteria, Vermont and Maine experience very few heat waves but a significant number of cold snaps. Conversely, Connecticut and Rhode Island experience very few cold snaps but several heat waves. To explore the sensitivity to the thresholds chosen for cold snaps or heat waves, DNV GL determined the average number of cold snaps lasting at least 3 days using daily maximum temperature thresholds of 32°F, 20°F, 15°F, and 10°F. A similar analysis of temperature thresholds for heat waves was performed using daily peak maximum thresholds of 85°F, 90°F, and 95°F.

The tables below summarize the statistics of several key parameters for cold snap and heat wave events lasting at least 3 days for using various temperature thresholds. There are exceedingly few events below 10°F per year for the New England maximum daily temperature, with a maximum of 1 event per year, as shown in Table 2-5. Similarly, heat waves with daily maximum temperatures exceeding 95°F are extremely rare, with a maximum of 1 event per year and total of only 12 events identified in the 20,000 year dataset. Note that for the daily maximum system average temperature there are few records below 10°F and above 95°F so those statistics should be viewed with caution. On average, most cold snaps and heat waves lasted the 3-day minimum but there are some that lasted longer, such as the 24-day stretch with daily maximum temperatures below 32°F.

Understanding the relationship of the cold snaps and heat waves to the coincident daily peak load and the concurrent wind generation can be important for fuel security and/or system reliability studies. The average of the daily load peaks and coincident wind generation during each peak load hour is provided in Table 2-5 to Table 2-13. All cold snaps and heat waves presented in the tables below were required to last at least 3 days. Statistics for the individual Load Zones, as presented below, do vary with VT and ME having few heat waves and RI and CT having fewer cold snaps.

Note that the temperature thresholds used to define cold snaps and heat waves below are inclusive such that the data for cold snaps less than 32°F also include all cold snaps less than 10°F, 15°F, and 20°F.

Similarly, for heat waves the greater than 85°F threshold also includes all events with daily maximum temperatures greater than 90°F and 95°F.

Table 2-5 Summary of cold snaps and heat waves for New England

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0.0	0.1	0.4	4.2	2.4	0.4	0.0
Maximum events per year	1	2	4	10	9	5	2
Minimum events per year	0	0	0	0	0	0	0
Total number of events	14	1,060	7,094	84,912	48,279	7,192	91
Average event duration (days)	3.0	3.1	3.3	4.8	4.3	3.5	3.0
Maximum event duration (days)	3	6	7	24	14	10	4
Average daily maximum temperature (°F)	8.7	11.8	15.0	25.7	88.4	92.4	96.1
Average temperature during daily peak load hour (°F)	5.8	8.0	10.6	20.4	87.1	90.8	94.1
Average daily peak load (MW)	21,748	21,024	20,359	19,159	23,082	24,232	24,458
Maximum daily peak load (MW)	22,276	22,725	22,725	22,725	28,198	27,911	26,726
Temperature at time of maximum peak load hour (°F)	3.5	5.1	5.1	5.1	87.0	92.2	95.3
Average onshore wind generation during daily peak load hour (% capacity)	78%	62%	54%	47%	22%	22%	14%
Average offshore wind generation during daily peak load hour (% capacity)	76%	67%	62%	59%	36%	33%	19%
Onshore wind generation at time of maximum peak load (% capacity)	86%	67%	67%	67%	31%	24%	10%
Offshore wind generation at time of maximum peak load (% capacity)	91%	57%	57%	57%	66%	52%	4%
Average solar generation during daily peak load hour (MW)	0%[1]	3%	3%	8%	48%	50%	50%
Solar generation at time of maximum peak load (% capacity)	0%[1]	0%[1]	0%[1]	0%[1]	71%	79%	67%

1 The sun had gone down prior to the winter peak load hour.

On average, load and temperature are positively correlated during heat waves and negatively correlated during cold snaps, so that colder temperatures lead to higher load in the winter and warmer temperatures lead to higher load in the summer. However, shown in Table 2-5 above, the maximum daily peak load is lower during heat wave events with daily maximum temperatures above 95°F than for heat wave events with daily maximum temperatures above 85°F, meaning the maximum peak load occurs for a "cooler" heat wave. A similar trend is observed for cold snaps below 10°F with the maximum load for those events being less than the maximum load for cold snaps meeting the 15°F criteria. These apparent trends are in contrast to what one would expect, which would be to see an increasing maximum load value as the cold snap temperature decreases and increasing maximum load value for heat waves at higher temperatures. DNV GL has investigated this trend and determined there are several reasons this can occur.

The maximum load experienced during a heatwave between 85°F and 90°F occurred during the earlier years in the dataset, prior to the implementation of many energy efficiency programs. The daily temperature had a maximum value of 87°F for 3 days when eventually the daily peak load reached to over 28 GW. The dataset used by the stochastic engine exhibits a small increasing temperature trend over time and so although temperatures during later years may be higher than the early part of the dataset the resulting maximum load value associated with those temperatures is less. Figure 2-6 illustrates the observed trends in the original input New England gross load and temperature data.

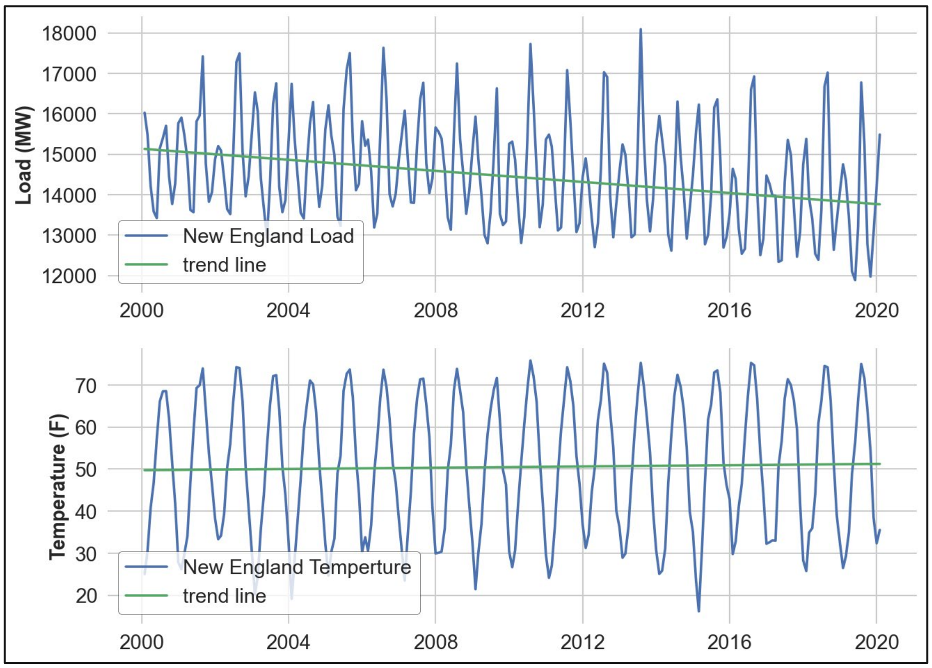

Figure 2-6 Measured trends in New England temperature and gross load

Although the changing relationship in the load and temperature data over the years is likely the main cause for seeing the maximum load value not occur during the coldest cold snap or hottest heat wave, there are also other reasons this can happen. As the maximum load value was taken from the entire stochastic dataset, there is a possibility that the particular stochastic realization it occurred in simply had higher load than most other realizations. It is also possible that a stochastic realization that has many cold snaps and is colder than normal, in theory, could also have lower load than other realizations with warmer winter temperatures. Note that the stochastic realization with a maximum load value of 26.7 GW and coincident temperature of 95°F is not the same as the one where the load reached 28 GW with a coincident temperature of 87°F.

An additional cause for the maximum load to be higher during a "warmer" cold snap or "cooler" heat wave is due to the duration of the cold snap or heat wave. Cold snaps with daily maximum temperatures below 20°F are likely to last longer than those with maximum temperatures below 10°F. Load tends to climb during longer cold snap events so that by the end of a week-long cold snap with daily maximum temperatures of 20°F the maximum load value is likely to be higher than during a shorter 3-day duration cold snap below 10°F. We did see this trend occur in the dataset when limiting the cold snap duration to exactly 3 days (instead of at least 3 days).

Table 2-6 through Table 2-13 present statistical summaries for Load Zones: ME, NH, VT, CT, RI, SEMA, WCMA, and NEMA. At times, the daily maximum temperature trend discussed above also manifests in their datasets.

Table 2-6 Summary of cold snap and heat wave events for ME

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0.0	0.1	0.6	4.5	0.5	0.0	0
Maximum events per year	1	3	4	11	5	3	0
Minimum events per year	0	0	0	0	0	0	0
Total number of events	92	1,837	12,183	89,682	9,182	969	0
Average event duration (days)	3.1	3.3	3.5	4.9	4.0	3.4	0
Maximum event duration (days)	5	6	8	29	10	8	0
Average daily maximum temperature (°F)	7.5	11.6	14.6	24.5	88.3	91.5	-
Average temperature during daily peak load hour (°F)	1.8	5.2	7.9	17.6	84.2	86.2	-
Average daily peak load (MW)	1,870	1,817	1,779	1,693	1,876	1,877	-
Maximum daily peak load (MW)	1,952	1,952	1,952	2,019	2,118	2,118	-
Temperature at time of maximum peak load hour (°F)	-1.9	2.3	2.3[5]	31.8[5]	86.5[5]	90.6	-
Average wind generation during daily peak load hour (% capacity)	68%	63%	55%	45%	19%	16%	-
Wind generation at time of maximum peak load hour (% capacity)	85%	84%	84%[2]	72%[3]	8%[4]	9%	-
Average solar generation during daily peak load hour (MW)	22%	18%	15%	14%	56%	56%	-
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	0%[1]	75%	74%	-

1 The sun had set prior to the winter peak load hour.
2 There were 2 records with a maximum peak load of 1,952 MW. The minimum of the 2 corresponding wind generation values (84% and 87%) has been reported.
3 There were 2 records with a maximum peak load of 2,019 MW. The minimum of the 2 corresponding wind generation values (72% and 86%) has been reported.
4 There were 4 records with a maximum peak load of 2,118 MW. The minimum of the 4 corresponding wind generation values (10%, 9%, 8%, and 10%) has been reported.
5 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value.

Table 2-7 Summary of cold snap and heat wave events for NH

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0.0	0.2	0.7	5.1	2.3	0.2	0.0
Maximum events per year	2	3	5	12	8	4	2
Minimum events per year	0	0	0	0	0	0	0
Total number of events	253	3,240	13,435	102,739	46,181	4,944	178
Average event duration (days)	3.0	3.2	3.5	5.2	4.2	3.6	3.1
Maximum event duration (days)	5	6	12	29	13	10	5
Average daily maximum temperature (°F)	6.9	10.4	14.1	24.8	88.4	92.8	96.9
Average temperature during daily peak load hour (°F)	1.3	4.6	7.3	17.5	86.0	89.6	92.4
Average daily peak load (MW)	1,960	1,908	1,859	1,774	2,115	2,227	2,289
Maximum daily peak load (MW)	2,033	2,034	2,034	2,039	2,456	2,455	2,409
Temperature at time of maximum peak load hour (°F)	-3.3	-0.1	7.6	17.0[3]	86.5	88.7	89.3
Average wind generation during daily peak load hour (% capacity)	69%	63%	52%	44%	23%	20%	15%
Wind generation at time of maximum peak load hour (% capacity)	36%	81%	82%	36%[2]	23%	25%	4%
Average solar generation during daily peak load hour (MW)	41%	30%	23%	25%	45%	49%	51%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	0%[1]	65%	67%	74%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records corresponding to a maximum peak load of 2,039 MW. The minimum of the 2 corresponding wind generation values (36%, 47%) has been reported.
3 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value of 36%.

Table 2-8 Summary of cold snap and heat wave events for VT

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0.1	0.6	1.4	6.4	1.3	0.1	0.0
Maximum events per year	3	4	6	12	6	3	1
Minimum events per year	0	0	0	0	0	0	0
Total number of events	2,798	12,139	28,558	128,740	26,890	1,697	8
Average event duration (days)	3.1	3.3	3.9	6.2	4.0	3.4	3.0
Maximum event duration (days)	6	7	15	43	13	6	3
Average daily maximum temperature (°F)	5.7	8.8	12.8	24.0	87.9	92.5	96.8
Average temperature during daily peak load hour (°F)	-0.7	2.1	6.0	16.6	84.9	88.2	91.2
Average daily peak load (MW)	945	926	911	879	898	940	965
Maximum daily peak load (MW)	1,015	1,019	1,033	1,046	1,054	1,047	1,014
Temperature at time of maximum peak load hour (°F)	-3.0	-0.5	-5.6	23.9[3]	87.1	87.4	86.0
Average wind generation during daily peak load hour (% capacity)	53%	47%	47%	45%	21%	15%	10%
Wind generation at time of maximum peak load hour (% capacity)	46%	68%	72%	51%[2]	12%	11%	4%
Average solar generation during daily peak load hour (MW)	8%	8%	9%	14%	56%	61%	69%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	0%[1]	68%	73%	64%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records corresponding to a maximum peak load of 1,046 MW. The minimum of the 2 corresponding wind generation values (51%, 54%) has been reported
3 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value of 51%.

Table 2-9 Summary of cold snap and heat waves for CT

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0	0.0	0.2	3.0	4.4	1.4	0.2
Maximum events per year	0	1	3	9	14	8	5
Minimum events per year	0	0	0	0	0	0	0
Total number of events	0	81	3,033	59,822	88,494	27,757	4,449
Average event duration (days)	0	3.0	3.0	4.5	5.1	3.8	3.3
Maximum event duration (days)	0	3	5	20	32	11	8
Average daily maximum temperature (°F)	-	13.3	16.3	26.2	89.3	93.9	98.2
Average temperature during daily peak load hour (°F)	-	7.8	10.3	19.6	87.0	91.2	94.5
Average daily peak load (MW)	-	5,566	5,307	4,947	5,893	6,307	6,473
Maximum daily peak load (MW)	-	6,023	6,022	6,066	7,543	7,542	7,492
Temperature at time of maximum peak load hour (°F)	-	8.7[3]	5.9[4]	21.2[5]	88.6[6]	90.9	90.8
Average wind generation during daily peak load hour (% capacity)[2]	-	-	-	-	-	-	-
Wind generation at time of maximum peak load hour (% capacity)[2]	-	-	-	-	-	-	-
Average solar generation during daily peak load hour (MW)	-	38%	31%	19%	47%	49%	49%
Solar generation at time of maximum peak load hour (% capacity)	-	0%[1]	0%[1]	0%[1]	69%	65%	44%

1 The sun had set prior to the winter peak load hour.
2 CT does not have any installed wind capacity.
3 There were 3 records (5.8°F, 8.4°F, 11.9°F) corresponding to a maximum peak load of 6,023 MW. The average has been reported.
4 There were 4 records (4.9°F, 5.2°F, 6.6°F, 6.8°F) corresponding to a maximum peak load of 6,022 MW.
5 There were 2 records (16.9°F, 25.4°F) corresponding to a maximum peak load of 6,066 MW.
6 There were 4 records (91.8°F, 85.3°F, 88.0°F, 89.4°F) corresponding to a maximum peak load of 7,543 MW.

Table 2-10 Summary of cold snap and heat wave events for RI

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0	0.0	0.0	1.7	2.7	0.6	0.1
Maximum events per year	0	2	2	8	10	6	2
Minimum events per year	0	0	0	0	0	0	0
Total number of events	0	6	888	33,613	53,745	12,139	1,341
Average event duration (days)	0	3.0	3.0	4.0	4.5	3.6	3.2
Maximum event duration (days)	0	3	5	15	21	9	5
Average daily maximum temperature (°F)	-	14.2	17.1	26.1	89.2	93.6	97.6
Average temperature during daily peak load hour (°F)	-	10.0	11.2	19.7	86.6	90.1	92.4
Average daily peak load (MW)	-	1,366	1,341	1,244	1,631	1,719	1,700
Maximum daily peak load (MW)	-	1,413	1,413	1,419	2,004	2,004	1,974
Temperature at time of maximum peak load hour(°F)		10.7	6.9[5]	13.4	87.8[5]	90.4	92.8
Average wind generation during daily peak load hour (% capacity)[4]	-	74%	69%	63%	38%	36%	30%
Wind generation at time of maximum peak load hour (% capacity)[4]	-	93%	92%[2]	64%	11%[3]	3%	2%
Average solar generation during daily peak load hour (MW)	-	0%[1]	48%	35%	49%	50%	49%
Solar generation at time of maximum peak load hour (% capacity)	-	0%[1]	0%[1]	0%[1]	71%	69%	63%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records corresponding to a maximum peak load of 1,419 MW. The minimum of the 2 corresponding wind generation values (92%, 92%) has been reported.
3 There were 2 records corresponding to a maximum peak load of 2,004 MW. The minimum of the 2 corresponding wind generation values (67%, 11%) has been reported.
4 RI wind generation includes both existing and state contracted offshore wind.
5 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for the temperature bin.

Table 2-11 Summary of cold snap and heat wave events for SEMA

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0	0.0	0.0	1.6	2.2	0.2	0.0
Maximum events per year	0	1	2	7	9	5	1
Minimum events per year	0	0	0	0	0	0	0
Total number of events	0	4	599	31,525	43,018	4,830	161
Average event duration (days)	0	3.0	3.0	3.9	4.5	3.3	3.1
Maximum event duration (days)	0	3	6	13	21	8	4
Average daily maximum temperature (°F)	-	13.8	17.2	26.3	88.5	92.5	95.9
Average temperature during daily peak load hour (°F)	-	9.7	11.2	20.0	85.9	89.0	90.8
Average daily peak load (MW)	-	2,594	2,605	2,358	3,103	3,223	3,079
Maximum daily peak load (MW)	-	2,721	2,746	2,746	3,750	3,738	3,568
Temperature at time of maximum peak load hour (°F)	-	6.5	8.5[3]	8.5[3]	87.3	91.3	95.1
Average wind generation during daily peak load hour (% capacity)[4]	-	65%	72%	57%	33%	29%	24%
Wind generation at time of maximum peak load hour (% capacity)[4]	-	88%	45%[2]	45%[2]	45%	5%	3%
Average solar generation during daily peak load hour (MW)	-	0%[1]	37%	26%	47%	47%	44%
Solar generation at time of maximum peak load hour (% capacity)	-	0%[1]	0%[1]	0%[1]	73%	60%	55%

1 The sun had set prior to the winter peak load hour.
2 There were 3 records corresponding to a maximum peak load of 2,746 MW. The minimum of the 3 corresponding wind generation values (94%, 92%, and 45%) have been reported.
3 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for the temperature bin.
4 Southeast MA wind generation includes existing and state-contracted offshore wind.

Table 2-12 Summary of cold snaps and heat waves for WCMA

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0.0	0.1	0.5	4.9	1.5	0.2	0.0
Maximum events per year	2	3	4	11	8	5	1
Minimum events per year	0	0	0	0	0	0	0
Total number of events	25	1,850	9,927	98,952	30,276	4,596	88
Average event duration (days)	3.0	3.0	3.4	5.2	4.1	3.5	3.2
Maximum event duration (days)	3	5	11	30	13	10	5
Average daily maximum temperature (°F)	8.0	11.6	14.9	25.4	88.9	92.8	95.9
Average temperature during daily peak load hour (°F)	2.5	5.3	8.3	18.7	86.2	89.7	92.5
Average daily peak load (MW)	2,948	2,929	2,849	2,670	3,230	3,304	3,263
Maximum daily peak load (MW)	3,229	3,229	3,229	3,229[2]	3,834	3,812	3,625
Temperature at time of maximum peak load hour (°F)	0.0	0.1	0.1	6.2[3]	86.7	92.7	95.5
Average wind generation during daily peak load hour (% capacity)	56%	62%	58%	56%	24%	19%	13%
Wind generation at time of maximum peak load hour (% capacity)	95%	96%	96%	53%	50%	11%	20%
Average solar generation during daily peak load hour (MW)	33%	36%	27%	24%	50%	52%	53%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	0%[1]	60%	67%	60%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records corresponding to a maximum peak load of 3,229 MW. The minimum of the 2 corresponding wind generation values (96% and 53%) have been reported.
3 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for the temperature bin.

Table 2-13 Summary of cold snap and heat wave events for NEMA

Statistic	Temperature threshold						
	<10°F	<15°F	<20°F	<32°F	>85°F	>90°F	>95°F
Average events per year	0	0.0	0.1	2.1	2.0	0.3	0.0
Maximum events per year	0	2	3	9	8	6	2
Minimum events per year	0	0	0	0	0	0	0
Total number of events	0	22	1,521	42,888	39,533	6,653	246
Average event duration (days)	0	3.0	3.0	4.2	4.2	3.6	3.3
Maximum event duration (days)	0	3	6	16	13	10	5
Average daily maximum temperature (°F)	-	13.3	16.8	26.1	88.8	92.6	96.0
Average temperature during daily peak load hour (°F)	-	8.3	11.3	20.3	86.3	89.5	92.1
Average daily peak load (MW)	-	4,274	4,158	3,842	4,785	4,960	4,940
Maximum daily peak load (MW)	-	4,445	4,445	4,445	5,743	5,727	5,567
Temperature at time of maximum peak load hour (°F)	-	9.3	5.6[2]	6.3[3]	84.9	88.8	95.4
Average wind generation during daily peak load hour (% capacity)[4]	-	-	-	-	-	-	-
Wind generation at time of maximum peak load (% capacity)[4]	-	-	-	-	-	-	-
Average solar generation during daily peak load hour (MW)	-	31%	33%	22%	47%	49%	47%
Solar generation at time of maximum peak load hour (% capacity)	-	0%[1]	0%[1]	0%[1]	76%	67%	42%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records (6.4°F, 4.7°F) corresponding to a maximum peak load of 4,445 MW. The average has been reported.
3 There were 3 records (6.4°F, 7.8°F, 4.7°F) corresponding to a maximum peak load of 4,445 MW.
4 Northeast MA does not have any installed wind capacity.

The following analysis examines the variability of wind and solar generation during these cold snap and heat wave events, and therefore is a measure of the reliability of the variable energy resources. Distributions of wind and solar generation that were coincident to the daily peak load hour during each cold snap and heat wave event were created, illustrating the range of load and wind generation during cold snap and heat wave events for New England.

Summary statistics for onshore and offshore wind and solar generation during each cold snap and heat wave have been determined and are presented in Table 2-14 to Table 2-16. For example, during cold snaps whose maximum daily temperature is 32°F or lower, the 95th percentile of onshore wind generation is 84% of capacity while the average daily peak load for all temperature events is 19,212 MW. Put another way, 90% of wind generation values range between 13% and 84% of capacity during a cold snap. Given that cold snap events occur during winter, when winds are generally at their most vigorous, wind generation is generally moderate to high with the median onshore generation value being at 45% of capacity during cold snaps less than 32°F. The less energetic winds in the summer months yield a median onshore wind generation value of only 18% of capacity during a heat wave greater than 90°F. Based on the trends seen in the tables below, we see that wind generation tends to be lower during heat waves while solar generation tends to be higher.

Table 2-14 Selected quantiles of onshore wind generation coincident to the daily load peak for New England cold snaps and heat waves

Temperature (°F)	Onshore wind (% capacity)							
	Min	P1	P5	P50	P95	P99	Max	Average daily peak load (MW)
<10[1]	61.2%	61.5%	63.2%	80.8%	87.6%	88.1%	88.3%	21,748
<15	5.9%	7.1%	9.2%	68.8%	87.4%	88.9%	90.9%	21,017
<20	4.8%	7.0%	9.4%	63.0%	85.7%	88.1%	91.0%	20,365
<32	2.3%	7.0%	13.0%	45.2%	83.9%	87.6%	92.6%	19,212
>85	1.7%	3.5%	5.2%	19.4%	44.8%	58.1%	78.7%	23,096
>90	1.9%	3.8%	6.3%	18.0%	51.2%	64.4%	76.6%	24,157
>95	6.7%	6.9%	8.1%	11.5%	25.8%	30.6%	36.6%	24,442

1 Only 14 events so use results with caution.

Table 2-15 Selected quantiles of offshore wind generation coincident to the daily load peak for New England cold snaps and heat waves

Temperature (°F)	Offshore Wind (% capacity)							
	Min	P1	P5	P50	P95	P99	Max	Average Daily Peak Load (MW)
<10[1]	37.2%	38.0%	39.4%	89.6%	93.4%	93.7%	93.8%	21,748
<15	2.3%	12.7%	18.5%	74.3%	93.1%	94.3%	96.4%	21,017
<20	0.2%	1.7%	12.1%	67.0%	92.5%	93.9%	96.5%	20,365
<32	0.2%	1.4%	4.9%	69.4%	92.5%	93.9%	97.1%	19,212
>85	0.0%	1.1%	2.2%	25.8%	87.2%	91.6%	96.4%	23,096
>90	0.2%	1.3%	2.4%	20.6%	87.5%	91.8%	96.0%	24,157
>95	1.4%	1.8%	2.1%	6.8%	65.9%	87.4%	92.6%	24,442

1 Only 14 events so use results with caution.

The lack of values below 10 degrees in Table 2-16 indicates that the sun had set prior to the load peak.

Table 2-16 Selected quantiles of solar generation coincident to the daily load peak for New England cold snaps and heat waves

Temperature (°F)	Solar generation (% capacity)							
	Min	P1	P5	P50	P95	P99	Max	Average daily peak load (MW)
<10[1]	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	21,748
<15	0.0%	0.0%	0.0%	0.0%	0.1%	41.3%	52.2%	21,017
<20	0.0%	0.0%	0.0%	0.0%	0.1%	40.1%	52.2%	20,365
<32	0.0%	0.0%	0.0%	0.0%	26.5%	48.7%	77.7%	19,212
>85	0.0%	10.7%	20.4%	48.9%	72.5%	78.7%	85.1%	23,096
>90	0.0%	11.2%	21.8%	54.4%	73.5%	79.4%	83.4%	24,157
>95	0.1%	10.5%	20.2%	56.5%	74.3%	76.8%	78.8%	24,442

1 Sun had set for these events.

Although wind generation during heat waves is lower than it is during cold snaps it is important to note that wind generation during cold snaps and heat waves is not necessarily lower than the seasonal norm, and is highly dependent on the severity, regional extent, and duration of each event.

Distributions of the daily wind generation coincident to the daily peak load for the cold snaps and heat waves are presented in Figure 2-7 and Figure 2-8, and provide a graphical representation of the wind generation statistics shown in the preceding tables. The onshore and offshore distributions are clearly very different during cold snaps, and offshore generation exhibits a much higher frequency of events with generation above 80% capacity.

A primary driver for the differences in the onshore and offshore distributions during cold snaps is the difference in the onshore and offshore wind speed distribution shapes, as shown in Figure 5-4 and Figure 5-5 in Section 5. The relationship of the offshore turbine power curves to the offshore wind speed frequency distribution, in addition to the limited geographic area results in the aggregate offshore wind generation frequency distribution lying at or near rated power. The offshore wind farms can operate and produce at rated power for wind speeds between 14 m/s and 30 m/s, which contributes to the "spike" seen on the right side of the offshore generation distribution below. The modeled onshore turbines tend to cut out sooner (between 18 m/s and 22 m/s) and have a more gradual ramp up in the power curve so there are fewer instances where the onshore turbines generate at rated power.

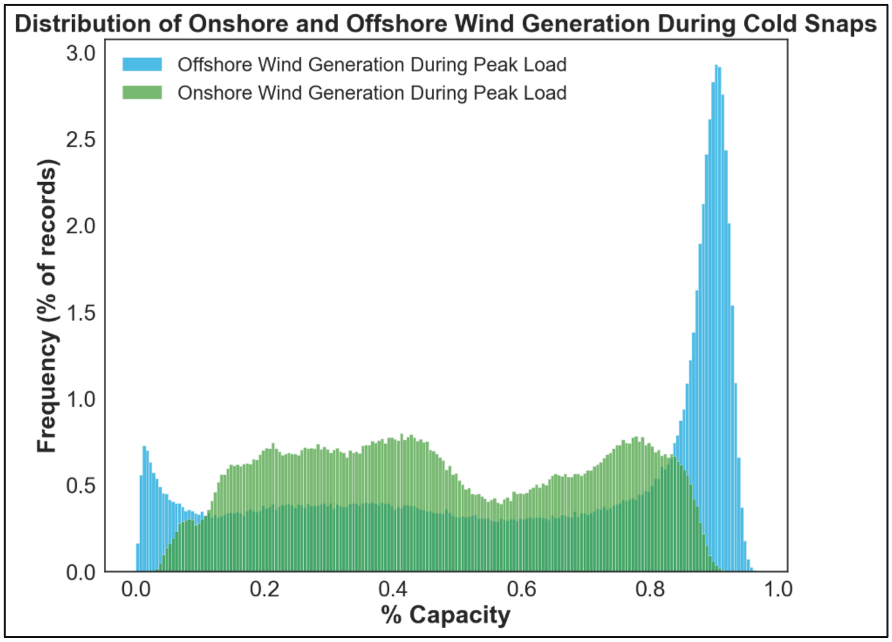

Figure 2-7 Distributions of onshore and offshore wind generation coincident to the daily load peak during cold snaps with daily maximum temperatures less than 32°F

Both the onshore and offshore wind generation distributions exhibit very different profiles during heat wave events when compared with their cold snap counterparts. Figure 2-8 presents distributions of the onshore and offshore wind generation coincident to the daily load peak during heat waves lasting at least 3 days with daily peak temperatures greater than 90°F.

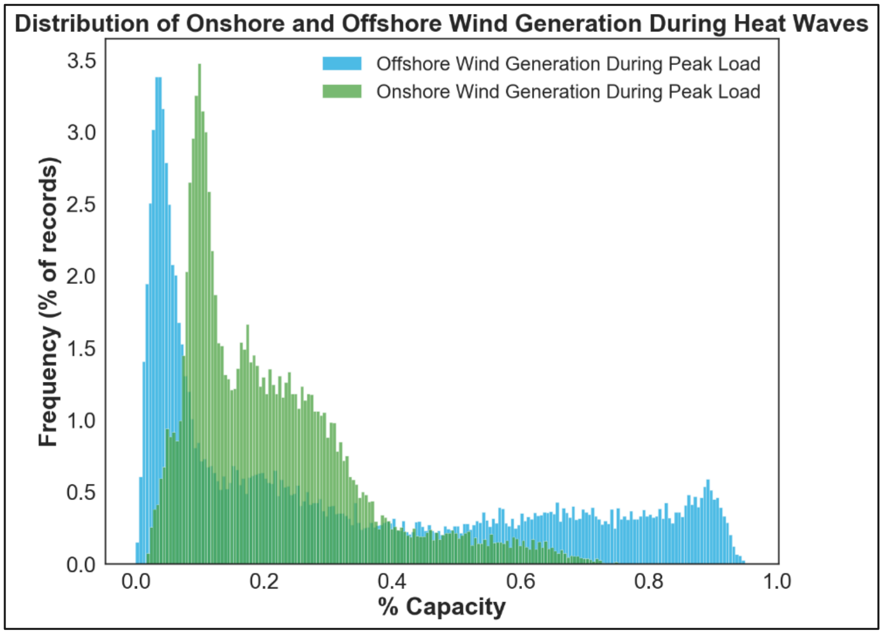

Figure 2-8 Distributions of onshore and offshore wind generation coincident to the daily load peak during heat waves with daily maximum temperatures greater than 90°F

Wind generation during heat waves is much lower on average than generation during cold snaps and has a significantly lower frequency of generation records near rated capacity during the afternoon load peak.

While understanding wind generation during the peak load hour can be important for transmission planning it may also be helpful for economic or energy security studies to understand the distributions of daily average wind generation during cold snaps and heat waves.

Similar to Figure 2-7 which presented distributions of wind generation at the time of the peak load Figure 2-9 present distributions of the daily average wind generation during cold snaps and heat waves. Similar to above, offshore generation has a relatively high number of days where the average generation was near rated capacity. When looking at wind generation during heat waves, we see a very different multi-modal trend when compared with its cold snap counterpart. It is also quite different than the distributions of wind generation coincident to the daily peak load for heat waves.

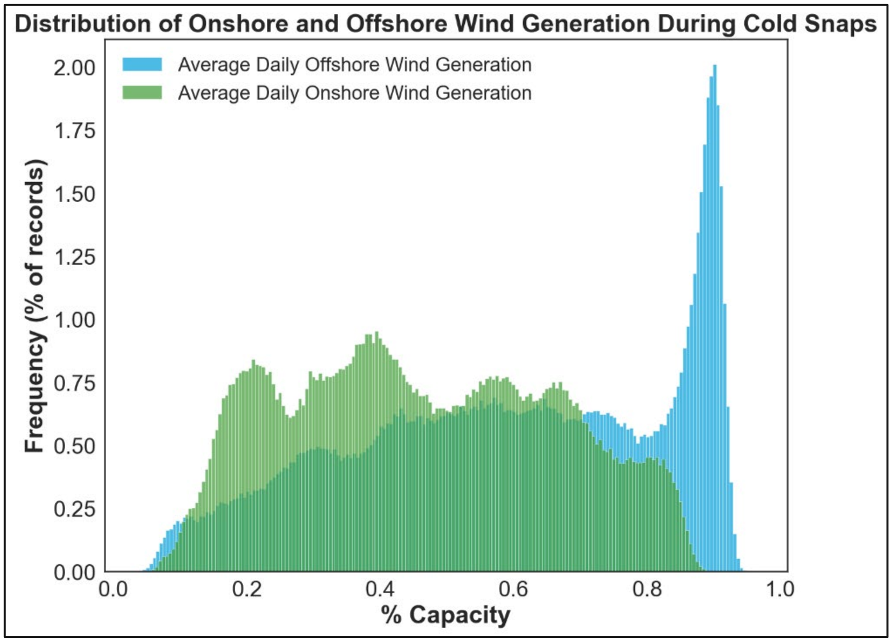

Figure 2-9 Distributions of daily average onshore and offshore wind generation during cold snaps with daily maximum temperatures less than 32°F

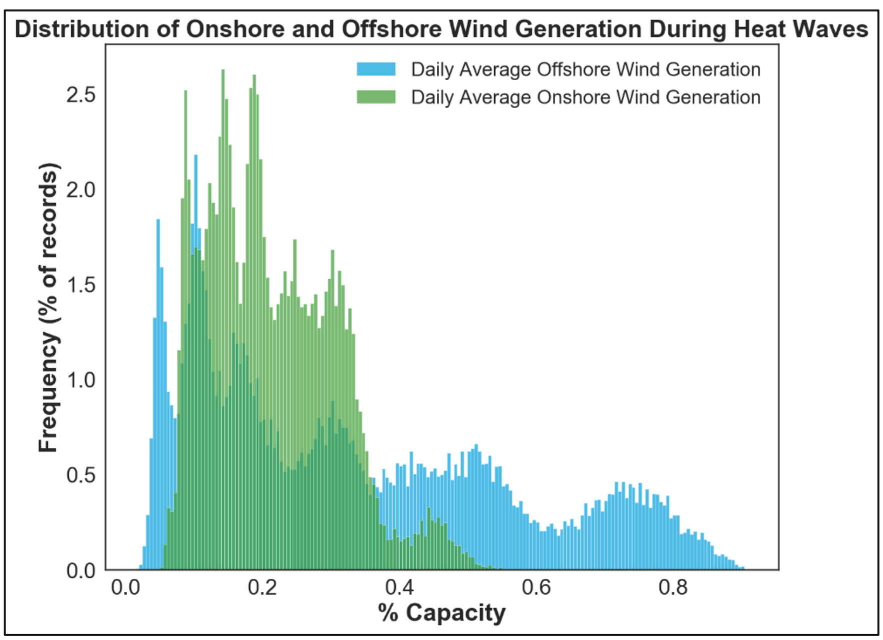

Figure 2-10 Distributions of daily average onshore and offshore wind generation during heat waves with daily maximum temperatures greater than 90°F

DNV GL has investigated the drivers for the multi-modal behavior of the generation distributions during heat waves and has found that heat wave events tend to stratify into distinct groupings of pressure and weather conditions, as seen by the distributions of pressure and wind speed in Figure 2-11.

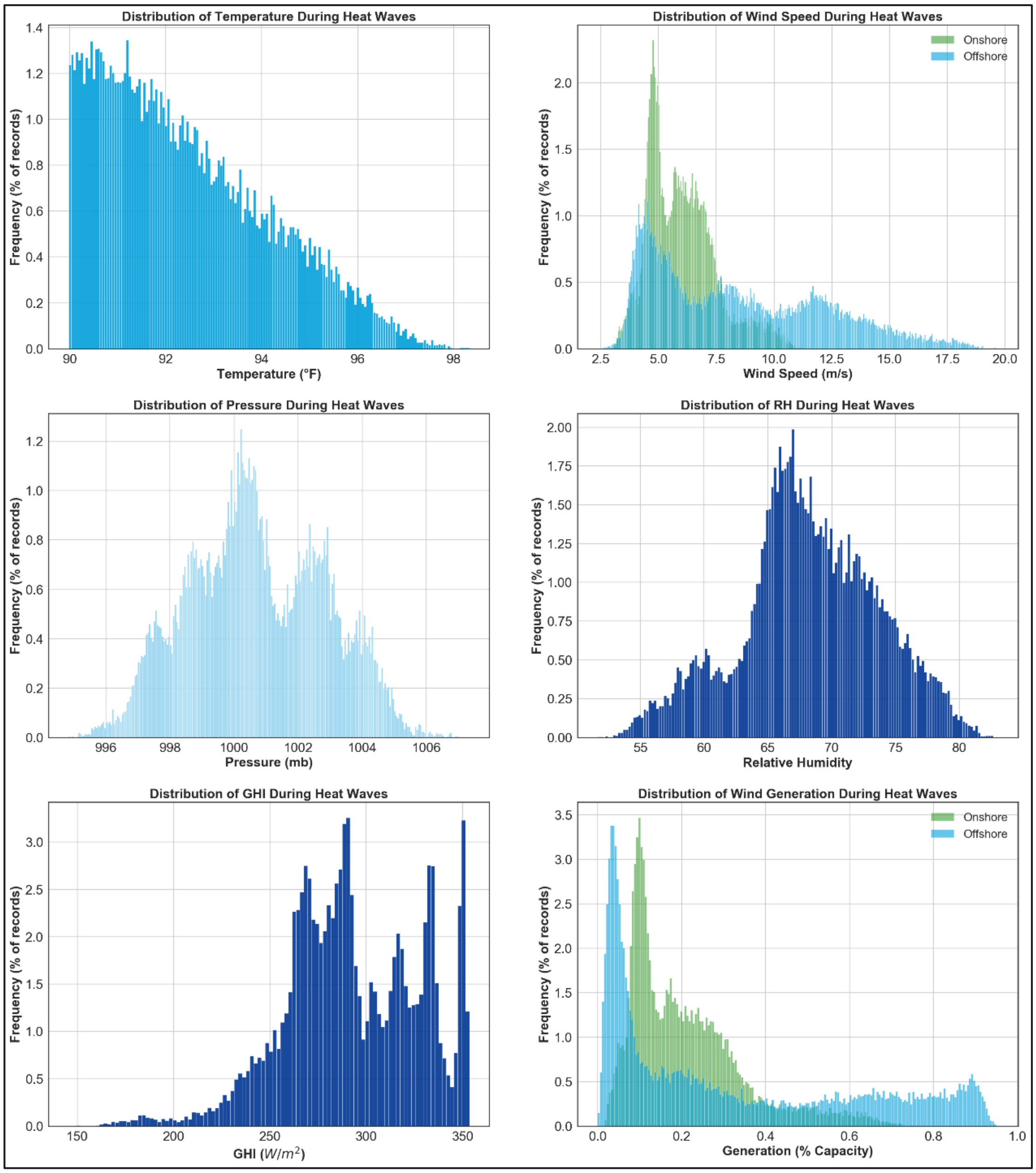

Figure 2-11 Distributions of temperature, wind speed, pressure, relative humidity, GHI, and wind generation during heat wave events with daily maximum temperatures greater than 90°F

During heat waves, surface pressure and wind speeds exhibit a more distinct relationship such that lower wind speeds accompany high-pressure events. This occurs for both onshore and offshore winds.

2.2.2 Temperature events using heating and cooling degree days (Method 2)

DNV GL has analyzed the stochastic dataset using heating and cooling degree days to define a cold snap or heat wave, as opposed to the daily maximum temperature.

Table 2-17 below presents the 95th percentiles of the heating and cooling degree days for New England and each Load Zone. These values were used for the daily threshold such that if the HDD was greater than 45.90°F for New England for at least 3 consecutive days a cold snap was identified. For heat waves, if the CDD was greater than 13.83°F for at least 3 consecutive days a heat wave was identified.

Table 2-17 Heating and cooling degree day 95th percentile values

Load Zone	HDD (°F)	CDD (°F)
New England	45.90	13.83
ME	49.15	10.87
NH	50.62	12.26
VT	53.26	12.88
CT	45.05	14.91
RI	42.11	14.32
SEMA	41.19	13.69
WCMA	47.96	12.71
NEMA	42.36	14.91

Table 2-18 presents the average number of cold snaps and heat waves per year for New England, using the heating and cooling degree criteria previously defined for Method 2. A cold snap or heat wave occurs when the HDD or CDD temperature, respectively, is above the 95th percentile of all heating or cooling degree days.

For New England there are approximately 1.6 HDD cold snap events per year with an average duration of about 4 consecutive days. On average, heat waves occur less than once per year with a duration of nearly 4 consecutive days. There was a maximum of 8 cold snap and 5 heat wave events in one year in the stochastically modeled dataset.

Table 2-18 Summary of cold snaps and heat waves for New England

Statistic	Cold snap	Heat wave
Average events per year	1.6	0.7
Maximum events per year	8	5
Minimum events per year	0	0
Average event duration per year	3.5	3.8
Maximum event duration per year	15	9
Average degree day temperature	52.2	15.8
Average daily peak load	19,644	24,430
Maximum daily peak load	22,725	28,102

Although the average and maximum event count and duration presented above in Table 2-18 are slightly less than those determined using the daily maximum temperature they are still on the same order of magnitude, indicating the use of the 95th percentile for the degree day thresholds is likely reasonable.

Figure 2-12 presents the distribution of event durations for all cold snap and heat wave events of 3 or more consecutive days using the average New England temperature. Although rare, cold snap events can last for significant periods of time, up to 15 consecutive days with a heating degree day temperature above 45.90°F. Similarly, heat waves within New England occasionally last longer than 3 consecutive days, but heat wave durations are typically shorter than cold snaps with a maximum heat wave duration of 9 consecutive days with cooling degree day temperatures exceeding 13.83°F for New England.

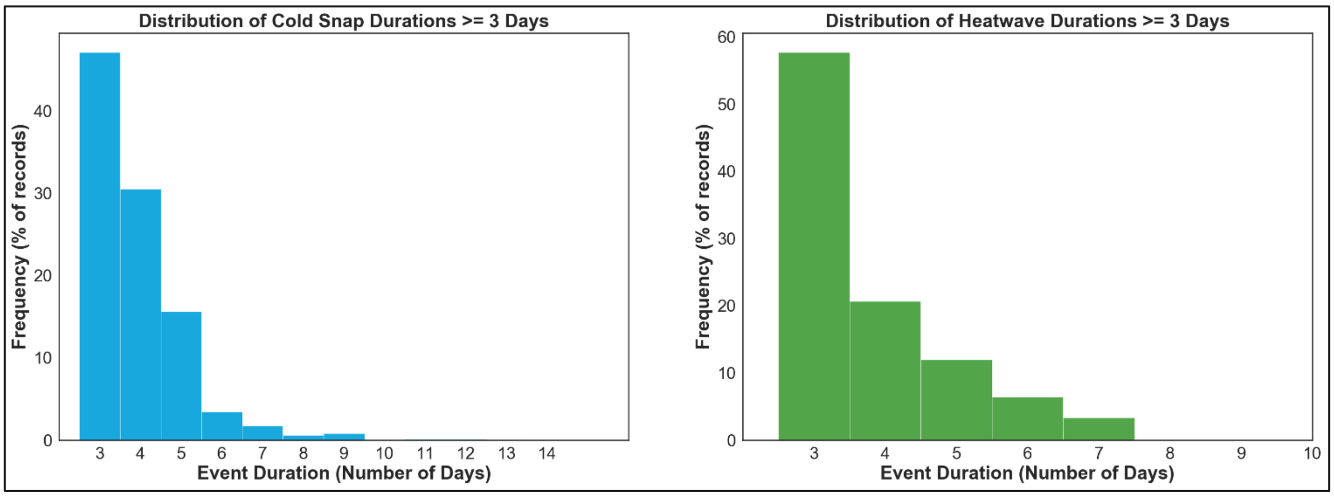

Figure 2-12 Distributions of the total duration of all cold snap and heat wave events lasting at least 3 days for New England

Figure 2-13 presents the distributions of cold snap event counts (defined by degree day) per year from the stochastic dataset. The majority of years do not have a cold snap or heatwave that meets the chosen degree day criteria. Although this trend is similar to that for heat waves using the daily maximum temperature it is significantly different than that for cold snaps using the daily maximum temperature thresholds presented in the section above, indicating that the use of the 95th percentile for heating degree days appears to be more conservative than a daily maximum temperature threshold of 32°F.

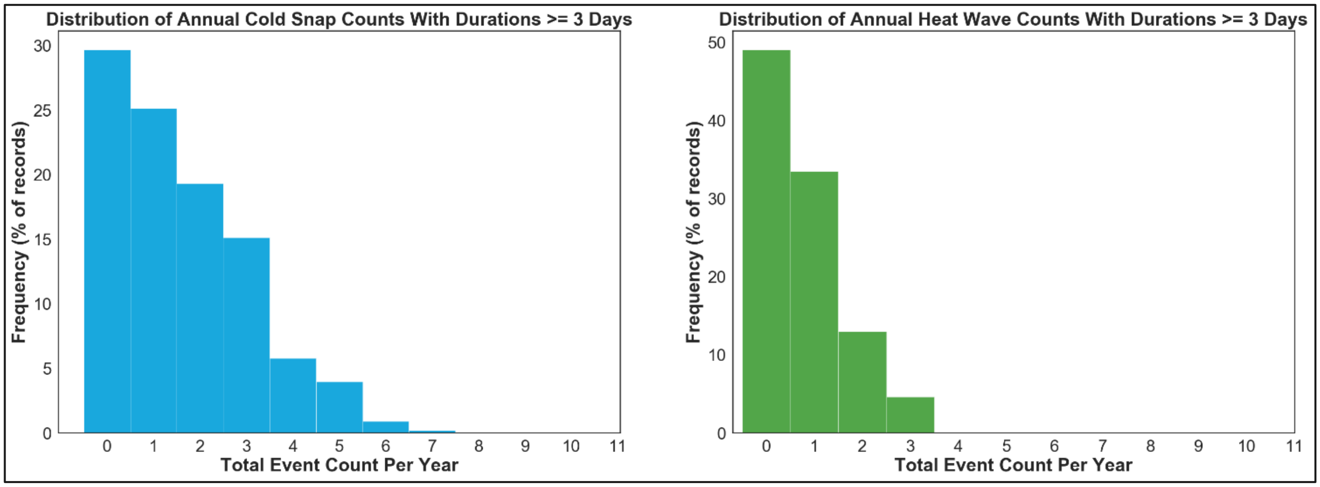

Figure 2-13 Distribution of the number of cold snap and heat wave events per year.

Similar to Section 2.2.1, the heating degree and cooling degree day thresholds used to define cold snaps and heat waves for the broader New England region may not be appropriate for some Load Zones. To explore the sensitivity to the thresholds chosen for cold snaps or heat waves, DNV GL determined the average number of cold snaps lasting at least 3 days using heating and cooling degree temperature thresholds of based on the 90th, 95th, and 99th percentiles of heating and cooling degree days.

Table 2-19 presents the heating and cooling degree thresholds that correspond to the 90th, 95th, and 99th percentile ranks of the respective HDD and CDD distributions for each Load Zone.

Table 2-19 Heating and cooling degree day 90th, 95th, and 99th percentile values

Load Zone	HDD (°F)			CDD (°F)		
Percentile	**99th**	**95th**	**90th**	**90th**	**95th**	**99th**
New England	54.43	45.90	40.94	12.21	13.83	16.41
ME	58.14	49.15	43.82	9.42	10.87	13.29
NH	59.96	50.62	45.28	10.75	12.26	14.92
VT	63.40	53.26	47.86	11.40	12.88	15.53
CT	53.60	45.05	40.38	13.16	14.91	17.84
RI	50.53	42.11	37.62	12.69	14.32	16.99
SEMA	49.20	41.19	36.95	12.22	13.69	15.97
WCMA	56.98	47.96	42.66	11.03	12.71	15.51
NEMA	50.84	42.36	37.60	13.17	14.91	17.63

The tables below summarize the statistics of several key parameters for cold snap and heat wave events lasting at least 3 days for using HDD and CDD thresholds based on the 90th, 95th, and 99th percentiles of the HDD and CDD distributions.

Note that the heating and cooling degree day temperature thresholds used to define cold snaps and heat waves below are inclusive such that the data for cold snaps with HDD > 40.94 degrees (90th percentile) also include all cold snaps with HDD > 54.43 (99th percentile).

Table 2-20 Summary of HDD and CDD cold snap and heat wave events for New England

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>54.4°F	>45.9°F	>40.9°F	>12.2°F	>13.8°F	>16.4°F
Average events per year	0.2	1.6	3.6	1.5	0.7	0.0
Maximum events per year	3	8	10	7	5	3
Minimum events per year	0	0	0	0	0	0
Total number of events	4,633	31,752	72,261	30,966	14,784	949
Average event duration (days)	3.2	3.9	4.7	4.2	3.8	3.2
Maximum event duration (days)	7	15	28	15	9	6
Average daily degree day (°F)	58.4	52.2	47.9	14.6	15.8	17.7
Average temperature at time of peak load hour (°F)	9.8	15.1	19.2	87.9	89.3	91.8
Average daily peak load hour (MW)	20,484	19,644	19,236	23,836	24,430	24,854
Maximum daily peak load hour (MW)	22,725	22,725	22,725	28,198	28,102	27,577
Temperature at time of maximum peak load hour (°F)	5.1	5.1	5.1	87.0	86.5	91.6
Average onshore wind generation during daily peak load hour (% capacity)	52%	50%	47%	22%	24%	23%
Average offshore wind generation during daily peak load hour (% capacity)	61%	58%	58%	40%	41%	35%
Onshore wind generation at time of maximum peak load hour (% capacity)	67%	67%	67%	31%	27%	61%
Offshore wind generation at time of maximum peak load hour (% capacity)	57%	57%	57%	66%	70%	90%
Average solar generation during daily peak load hour (% capacity)	4%	15%	12%	50%	52%	53%
Solar generation at time of maximum peak load hour (% capacity)	0%	0%	0%	71%	71%	57%

Table 2-21 Summary of HDD and CDD cold snap and heat wave events for ME

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	> 58.1°F	>49.2°F	>43.8°F	>9.4°F	>10.9°F	>13.3°F
Average events per year	0.3	1.7	3.7	1.0	0.5	0.0
Maximum events per year	3	7	10	5	4	2
Minimum events per year	0	0	0	0	0	0
Total number of events	5,513	33,460	74,930	19,981	9,875	811
Average event duration (days)	3.4	4.0	4.7	4.1	3.6	3.4
Maximum event duration (days)	7	13	25	11	9	6
Average daily degree day (°F)	62.7	55.9	51.3	11.6	12.7	14.4
Average temperature at time of peak load (°F)	5.7	11.7	16.0	83.1	84.1	86.2
Average daily peak load (MW)	1,805	1,735	1,703	1,868	1,890	1,896
Maximum daily peak load (MW)	1,952	1,952	1,952	2,118	2,118	2,118
Temperature at time of maximum peak load hour (°F)	15.9	15.9	15.9	86.5[4]	86.5[4]	90.6
Average wind generation during daily peak load hour (% capacity)	55%	50%	47%	21%	23%	21%
Wind generation at time of maximum peak load hour (% capacity)	9%	9%	9%	8%[2]	8%[3]	9%
Average solar generation during daily peak load hour (% capacity)	15%	17%	15%	54%	55%	55%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	75%	75%	74%

1 The sun had set prior to the peak load hour.
2 There were 4 records with a maximum peak load of 2,118 MW. The minimum of the 4 corresponding wind generation values (10%, 9%, 8%, and 10%) has been reported.
3 There were 4 records with a maximum peak load of 2,118 MW. The minimum of the 4 corresponding wind generation values (10%, 9%, 8%, and 10%) has been reported.
4 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for HDD/CDD bin.

Table 2-22 Summary of HDD and CDD cold snap and heat wave events for NH

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>59.6°F	>50.6°F	>45.3°F	>10.8°F	>12.3°F	>14.9°F
Average events per year	0.2	1.6	3.8	1.2	0.6	0.1
Maximum events per year	3	7	10	5	4	2
Minimum events per year	0	0	0	0	0	0
Total number of events	4,894	31,666	75,362	24,792	11,396	1,186
Average event duration (days)	3.3	3.9	4.7	3.9	3.7	3.1
Maximum event duration (days)	7	13	28	9	8	5
Average daily degree day (°F)	64.4	57.7	52.9	13.1	14.2	16.3
Average temperature at time of peak load (°F)	5.0	10.3	14.7	87.3	88.4	91.1
Average daily peak load (MW)	1,898	1,828	1,792	2,196	2,238	2,327
Maximum daily peak load (MW)	2,034	2,039	2,039	2,456	2,455	2,455
Temperature at time of maximum peak load hour (°F)	-0.1	17.0	17.0[4]	89.9[4]	88.7	93.5
Average wind generation during daily peak load hour (% capacity)	51%	47%	44%	25%	25%	18%
Wind generation at time of maximum peak load hour (% capacity)	81%	36%	36%[2]	27%[3]	25%	32%
Average solar generation during daily peak load hour (% capacity)	27%	30%	27%	47%	50%	55%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	76%	67%	65%

1 The sun had set prior to the peak load hour.
2 There were 2 records with a maximum peak load of 2,039 MW. The minimum of the 2 corresponding wind generation values (36% and 47%) has been reported.
3 There were 3 records with a maximum peak load of 2,456 MW. The minimum of the 3 corresponding wind generation values (27%, 38%, and 41%) has been reported.
4 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for HDD/CDD bin.

Table 2-23 Summary of HDD and CDD cold snap and heat wave events for VT

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>63.4°F	>53.3°F	>47.9°F	>11.4°F	>12.9°F	>15.5°F
Average events per year	0.2	1.6	3.8	1.2	0.6	0.1
Maximum events per year	3	7	10	6	4	2
Minimum events per year	0	0	0	0	0	0
Total number of events	4,308	31,852	75,288	24,821	11,224	1,952
Average event duration (days)	3.2	3.8	4.6	4.1	3.7	3.1
Maximum event duration (days)	7	13	17	12	8	5
Average daily degree day (°F)	68.2	60.9	55.5	13.7	14.9	17.2
Average temperature at time of peak load (°F)	-0.8	5.8	10.6	85.0	86.1	88.8
Average daily peak load (MW)	943	910	893	910	923	973
Maximum daily peak load (MW)	1,019	1,036	1,036	1,054	1,054	1,047
Temperature at time of maximum peak load hour (°F)	-0.5	-5.7	8.1	85.4[4]	87.1	86.1[4]
Average wind generation during daily peak load hour (% capacity)	49%	47%	46%	21%	20%	12%
Wind generation at time of maximum peak load hour (% capacity)	68%	25%	24%	8%[2]	12%	11%[3]
Average solar generation during daily peak load hour (% capacity)	8%	13%	13%	54%	58%	68%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	66%	68%	78%

1 The sun had set prior to the peak load hour.
2 There were 2 records with a maximum peak load of 1,054 MW. The minimum of the 2 corresponding wind generation values (8% and 12%) has been reported.
3 There were 2 records with a maximum peak load of 1,047 MW. The minimum of the 2 corresponding wind generation values (11% and 11%) has been reported.
4 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for HDD/CDD bin.

Table 2-24 Summary of HDD and CDD cold snap and heat wave events for CT

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>53.6°F	>45.1°F	>40.4°F	>13.2°F	>14.9°F	>17.8°F
Average events per year	0.2	1.6	3.5	1.7	0.9	0.1
Maximum events per year	3	7	10	9	5	3
Minimum events per year	0	0	0	0	0	0
Total number of events	3,546	32,614	70,216	33,667	17,084	1,234
Average event duration (days)	3.0	3.8	4.8	4.2	3.7	3.1
Maximum event duration (days)	6	15	21	13	8	5
Average daily degree day (°F)	57.2	51.0	47.1	15.7	17.0	19.2
Average temperature at time of peak load (°F)	10.1	15.9	19.8	90.2	91.8	94.7
Average daily peak load (MW)	5,333	5,048	4,919	6,347	6,480	6,630
Maximum daily peak load (MW)	6,022	6,066	6,066	7,543	7,543	7,514
Temperature at time of maximum peak load hour (°F)	6.9[3]	16.9	21.2[4]	88.6[5]	88.6[6]	92.9
Average wind generation during daily peak load hour (% capacity)[2]	-	-	-	-	-	-
Wind generation at time of maximum peak load hour (% capacity)[2]	-	-	-	-	-	-
Average solar generation during daily peak load hour (% capacity)	31%	21%	20%	50%	50%	51%
Solar generation at TIME of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	69%	70%	67%

1 The sun had set prior to the winter peak load hour.
2 CT does not have any installed wind capacity.
3 There were 5 records (4.8°F, 5.2°F, 11.1°F, 6.6°F and 6.8°F) corresponding to a maximum peak load of 6,022 MW. The average has been reported.
4 There were 2 records (16.9°F and 25.4°F) corresponding to a maximum peak load of 6,066 MW.
5 There were 4 records (91.8°F, 85.3°F, 88.0°F, and 89.4°F) corresponding to a maximum peak load of 7,543 MW.
6 There were 2 records (91.8°F and 85.3°F) corresponding to a maximum peak load of 7,543 MW.

Table 2-25 Summary of HDD and CDD cold snap and heat wave events for RI

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>50.5°F	>42.1°F	>37.6°F	>12.7°F	>14.3°F	>17.0°F
Average events per year	0.2	1.5	3.5	1.5	0.8	0.1
Maximum events per year	3	7	10	8	5	2
Minimum events per year	0	0	0	0	0	0
Total number of events	4,060	30,417	69,838	30,869	15,902	1,132
Average event duration (days)	3.1	3.9	4.6	4.4	3.7	3.2
Maximum event duration (days)	7	13	20	11	8	5
Average daily degree day (°F)	54.3	48.2	44.2	15.1	16.3	18.2
Average temperature at time of peak load (°F)	13.0	19.0	22.7	87.7	89.4	92.2
Average daily peak load (MW)	1,302	1,245	1,224	1,704	1,747	1,783
Maximum daily peak load (MW)	1,413	1,419	1,419	2,004	2,004	1,977
Temperature at time of maximum peak load hour (°F)	6.9[5]	13.4	17.3	87.8[5]	87.8	92.0[5]
Average wind generation during daily peak load hour (% capacity)[6]	67%	62%	61%	40%	42%	43%
Wind generation at time of maximum peak load hour (% capacity)[6]	92%[2]	64%	65%	11%[3]	11%	9%[4]
Average solar generation during daily peak load hour (% capacity)	41%	38%	34%	51%	52%	53%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	71%	69%	70%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records corresponding to a maximum peak load of 1,413 MW. The minimum of the 2 corresponding wind generation values (92% and 92%) has been reported.
3 There were 2 records corresponding to a maximum peak load of 2,004 MW. The minimum of the 2 corresponding wind generation values (67% and 11%) has been reported.
4 There were 2 records corresponding to a maximum peak load of 1,977 MW. The minimum of the 2 corresponding wind generation values (9% and 14%) has been reported.
5 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for the temperature bin.
6 RI wind generation includes both existing and state contracted offshore wind.

Table 2-26 Summary of HDD and CDD cold snap and heat wave events for SEMA

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>49.2°F	>41.2°F	>36.9°F	>12.2°F	>13.7°F	>16.0°F
Average events per year	0.2	1.5	3.5	1.5	0.7	0.0
Maximum events per year	3	7	11	8	5	2
Minimum events per year	0	0	0	0	0	0
Total number of events	4,156	29,848	69,186	30,103	14,193	986
Average event duration (days)	3.2	3.9	4.6	4.6	3.8	3.0
Maximum event duration (days)	7	13	27	13	10	6
Average daily degree day (°F)	53.1	47.1	43.2	14.2	15.3	17.0
Average temperature at time of peak load (°F)	14.0	19.8	23.6	86.4	87.8	89.7
Average daily peak load (MW)	2,482	2,362	2,306	3,172	3,266	3,365
Maximum daily peak load (MW)	2,746	2,746	2,746	3,750	3,750	3,712
Temperature at time of maximum peak load hour (°F)	8.5[4]	8.5[4]	8.5[4]	87.3	87.2	89.1
Average wind generation during daily peak load hour (% capacity)[5]	61%	57%	56%	36%	36%	33%
Wind generation at time of maximum peak load hour (% capacity)[5]	45%[2]	45%[2]	45%[3]	45%	3%	88%
Average solar generation during daily peak load hour (% capacity)	33%	30%	26%	48%	50%	52%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	73%	75%	73%

1 The sun had set prior to the winter peak load hour.
2 There were 3 records corresponding to a maximum peak load of 2,746 MW. The minimum of the 3 corresponding wind generation values (94%, 92%, and 45%) have been reported.
3 There were 4 records corresponding to a maximum peak load of 2,746 MW. The minimum of the 4 corresponding wind generation values (94%, 92%, 45%, and 55%) have been reported.
4 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for the temperature bin.
5 Southeast MA wind generation includes existing and state contracted offshore wind.

Table 2-27 Summary of HDD and CDD cold snap and heat wave events for WCMA

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>57.0°F	>48.0°F	>42.7°F	>11.0°F	>12.7°F	>15.5°F
Average events per year	0.2	1.7	3.8	1.3	0.6	0.0
Maximum events per year	3	9	11	6	4	3
Minimum events per year	0	0	0	0	0	0
Total number of events	4,388	34,018	76,708	25,252	11,303	885
Average event duration (days)	3.1	3.9	4.8	4.0	3.7	3.1
Maximum event duration (days)	6	15	28	10	9	6
Average daily degree day (°F)	61.3	54.5	50.0	13.6	14.8	17.1
Average temperature at time of peak load (°F)	6.0	11.9	16.5	86.4	87.8	90.7
Average daily peak load (MW)	2,885	2,760	2,697	3,302	3,379	3,373
Maximum daily peak load (MW)	3,229	3,229	3,229	3,834	3,830	3,800
Temperature at time of maximum peak load hour (°F)	0.1	6.2[3]	6.2[3]	86.7	87.8	88.8
Average wind generation during daily peak load hour (% capacity)	56%	56%	56%	26%	27%	18%
Wind generation at time of maximum peak load hour (% capacity)	96%	53%[2]	53%[2]	50%	33%	15%
Average solar generation during daily peak load hour (% capacity)	29%	26%	25%	52%	54%	53%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	60%	62%	68%

1 The sun had set prior to the winter peak load hour.
2 There were 2 records corresponding to a maximum peak load of 3,229 MW. The minimum of the 2 corresponding wind generation values (96% and 53%) have been reported.
3 Value taken from hourly record that corresponds to the maximum load and minimum wind generation value for the temperature bin.

Table 2-28 Summary of HDD and CDD cold snap and heat wave events for NEMA

Statistic	Cold snap (heating degree day)			Heat wave (cooling degree day)		
	>50.8°F	>42.4°F	>37.6°F	>13.2°F	>14.9°F	>17.6°F
Average events per year	0.2	1.5	3.5	1.4	0.7	0.1
Maximum events per year	3	8	11	6	4	4
Minimum events per year	0	0	0	0	0	0
Total number of events	4,604	29,799	69,591	28,644	13,814	1,042
Average event duration (days)	3.2	3.9	4.6	4.3	3.8	3.5
Maximum event duration (days)	7	16	27	12	10	9
Average daily degree day (°F)	55.0	48.8	44.4	15.7	16.9	18.9
Average temperature at time of peak load (°F)	13.0	18.2	22.4	86.7	88.3	90.9
Average daily peak load (MW)	4,067	3,892	3,785	4,883	5,009	5,037
Maximum daily peak load (MW)	4,445	4,445	4,445	5,743	5,735	5,650
Temperature at time of maximum peak load hour (°F)	6.3[2]	6.3[2]	6.3[2]	84.9[3]	91.1	92.9
Average wind generation during daily peak load hour (% capacity)[4]	-	-	-	-	-	-
Wind generation at time of maximum peak load hour (% capacity)[4]	-	-	-	-	-	-
Average solar generation during daily peak load hour (% capacity)	33%	24%	22%	48%	50%	51%
Solar generation at time of maximum peak load hour (% capacity)	0%[1]	0%[1]	0%[1]	59%	51%	67%

1 The sun had set prior to the winter peak load hour.
2 There were 3 records (6.4°F, 7.8°F, and 4.7°F) corresponding to a maximum peak load of 4,445 MW. The average has been reported.
3 There were 2 records (84.7°F and 85.1°F) corresponding to a maximum peak load of 5,743 MW.
4 Northeast MA does not have any installed wind capacity.

Summary statistics for wind and solar generation during each New England cold snap and heat wave have been determined and are presented in Table 2-29 to Table 2-31. For example, during cold snaps whose heating degree day temperature is greater than 54.33°F (the 95th percentile), the 95th percentile of onshore wind generation is 86% of capacity while the average daily peak load for all temperature events is 19,212 MW. This is very similar to the values obtained using Method 1 for cold snaps with a daily maximum temperature of 32°F (84% generation with an average daily peak load of 19,212 MW).

Table 2-29 Selected quantiles of onshore wind generation coincident to the daily load peak for HDD and CDD New England cold snaps and heat waves

HDD/ CDD	Onshore wind (% capacity)							
	Min	P1	P5	P50	P95	P99	Max	Average daily peak load (MW)
54.43	4.8%	6.8%	8.5%	60.2%	85.7%	88.2%	90.9%	20,479
45.90	2.3%	7.6%	16.1%	50.1%	84.5%	88.0%	92.4%	19,688
40.94	2.3%	7.8%	14.3%	45.2%	83.6%	87.5%	92.4%	19,297
12.21	1.7%	3.3%	5.2%	20.1%	45.7%	59.2%	77.4%	23,792
13.83	1.8%	3.3%	5.4%	22.0%	50.7%	63.2%	77.4%	24,397
16.41	1.9%	3.2%	6.7%	22.4%	50.7%	61.5%	73.8%	24,819

Table 2-30 Selected quantiles of offshore wind generation coincident to the daily load peak for HDD and CDD New England cold snaps and heat waves

HDD/ CDD	Offshore wind (% capacity)							
	Min	P1	P5	P50	P95	P99	Max	Average daily peak load (MW)
54.43	0.8%	8.5%	14.5%	61.4%	92.2%	93.8%	96.5%	20,479
45.90	0.2%	1.6%	6.6%	66.6%	92.4%	94.0%	96.9%	19,688
40.94	0.2%	1.5%	5.6%	66.7%	92.4%	93.9%	97.1%	19,297
12.21	0.2%	1.2%	2.5%	32.4%	87.2%	91.4%	96.0%	23,792
13.83	0.2%	1.3%	2.7%	32.4%	88.0%	91.6%	95.8%	24,397
16.41	0.4%	1.3%	2.2%	24.6%	88.3%	91.6%	95.8%	24,819

Table 2-31 Selected quantiles of solar generation coincident to the daily load peak HDD and CDD New England cold snaps and heat waves

HDD/ CDD	Solar generation (% capacity)							
	Min	P1	P5	P50	P95	P99	Max	Average daily peak load (MW)
54.43	0.0%	0.0%	0.0%	0.0%	0.1%	42.3%	52.2%	20,479
45.90	0.0%	0.0%	0.0%	0.1%	33.7%	52.6%	73.3%	19,688
40.94	0.0%	0.0%	0.0%	0.1%	32.7%	55.9%	77.7%	19,297
12.21	0.0%	12.1%	23.3%	52.7%	73.5%	79.0%	85.1%	23,792
13.83	0.0%	12.6%	24.5%	54.9%	74.6%	79.4%	84.7%	24,397
16.41	0.2%	12.6%	24.6%	56.6%	74.4%	78.5%	81.3%	24,819

Based on the analysis presented above it can be concluded that as cold snap intensity increases so does wind generation, indicating that during a strong cold snap where temperatures remain below 10°F for 3 consecutive days, wind generation is very likely to be high during the peak load hour. A look at the data indicates this appears to be due to passing cold fronts associated with strong low-pressure systems that drive wind speeds across New England. Conversely, as heat waves become more intense with daily peak temperatures greater than 90°F for at least three consecutive days it is clear that wind generation on average decreases during the peak load hour. This decrease of wind generation during heat waves appears to be due to a high-pressure ridge that sets up over New England and suppresses wind speeds. The formation of the upper-level ridge also tends to reduce cloud cover which generally increases solar generation during heat waves.

3 THE PROBABILITY OF WIND AND SOLAR "DROUGHTS"

The stochastic dataset has been used to determine the probability of extended periods of low onshore and offshore net wind generation as well as low solar generation. The daily peak load and net load coincident to each low-generation period has also been examined. Note that in the mainstream view of probability, the probability of an event is exactly its long-run relative frequency [4], and thus the two terms are used synonymously in this report.

3.1 Methodology

A wind and solar "drought" or "lull" is defined as a specified number of consecutive days where the average daily generation (wind or solar) is below a specified percentage of capacity. Based on DNV GL's review of available literature and discussion with ISO-NE, we have chosen to define a wind generation lull as a period when the mean daily net generation value remained below 15% capacity for a period of at least 3 consecutive days. Net wind generation is inclusive of turbine wakes, estimated electrical losses, and stochastically modeled turbine availability and represents a more realistic representation of wind generation compared to gross power, which does not account for estimated electrical or availability losses. Figure 3-1 presents an example of a wind generation lull where daily average offshore wind generation remained below 15% capacity for 3 days.

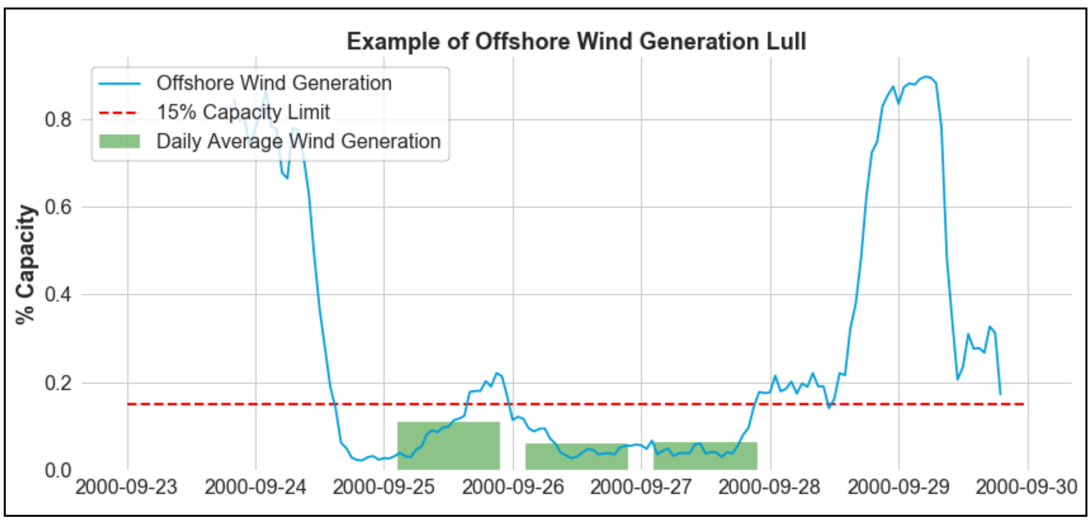

Figure 3-1 Example of 3-day offshore wind lull

The wind lull analysis has been performed on the onshore wind generation, offshore wind, and the total combined onshore and offshore wind generation. Table 3-1 below presents the current capacity of each wind region in terms of megawatts.

Table 3-1 Total wind and solar capacity

	Capacity (MW)
Onshore wind	1,319.65
Offshore wind[3]	3,137.60
Total onshore + offshore wind	4,457.25
Solar[4]	7,725.90

For the solar lull analysis, DNV GL initially investigated the use of a static 15% capacity limit for solar generation; however, after discussion with ISO-NE, it was determined that this is likely not appropriate for solar lulls due to the strong diurnal and seasonal trend in solar generation. Since the maximum possible solar generation during the winter months is lower than during the summer months, a dynamic threshold is used. As shown in Table 3-2, a solar lull is defined as a period of at least 3 consecutive days where the daily maximum solar generation remained below 15% of the monthly maximum solar generation. For example, if the maximum solar generation during January 2001 was 65% of total solar capacity then the threshold for a solar lull during that month would be 65% × 15% = 9.75%. If a period of 3 consecutive days or more had a maximum solar generation value of less than 9.75% of capacity then it qualified as a lull.

Table 3-2 Basic wind and solar lull criteria

	Criteria
Wind lull	3 or more consecutive days where the daily average wind generation remained below 15% of rated capacity
Solar lull	3 or more consecutive days the daily peak solar generation remained below 15% of the monthly maximum solar capacity

3.2 Analysis and wind and solar lulls

3.2.1 Wind lulls

Wind lulls lasting 3 or more days with daily average net wind generation below 15% capacity occur approximately 3.9 times per year for the offshore resource, as shown in Table 3-3. The higher overall offshore production limits extended periods of generation below 15% capacity. Onshore wind lulls are somewhat more common with approximately 5.7 events per year for average daily net wind generation below 15% of capacity. Note that the results presented in Table 3-3 through Table 3-5 are inclusive such that events that fall in the <15% capacity bin are also included within the <20% and <25% capacity bins.

[3] Includes existing offshore Block Island wind plant and 4 state-contracted offshore wind plants described in Table 1-1.
[4] Capacity value based on Draft 2020 PV forecast published 14 February 2020, https://www.iso-ne.com/static-assets/documents/2020/02/draft_2020_pv_forecast_021420.pdf. The final forecast value was 7,795.8 MW, a difference of ~70 MW and was not updated in the report due to the minor difference. All raw data is in normalized values and can be re-scaled to any future desired forecast amount.

Table 3-3 Average number of offshore wind lulls per year

Period	Daily average net wind generation capacity thresholds		
	< 15% capacity	< 20% capacity	< 25% capacity
≥3 days	3.9 lulls	7.1 lulls	11.1 lulls
≥4 days	1.7 lulls	2.9 lulls	5.3 lulls
≥5 days	0.6 lulls	1.3 lulls	2.4 lulls

Table 3-4 Average number of onshore wind lulls per year

Period	Daily average net wind generation capacity thresholds		
	< 15% capacity	< 20% capacity	< 25% capacity
≥3 days	5.7 lulls	13.6 lulls	20.4 lulls
≥4 days	3.1 lulls	7.9 lulls	12.4 lulls
≥5 days	1.4 lulls	4.5 lulls	8.2 lulls

Offshore wind generation dominates the total wind aggregate and so the results presented in Table 3-5 are very similar to those for the offshore generation alone.

Table 3-5 Average number of wind lulls per year for combined onshore and offshore generation

Period	Daily average net wind generation capacity thresholds		
	< 15% capacity	< 20% capacity	< 25% capacity
≥3 days	3.5 lulls	7.2 lulls	11.8 lulls
≥4 days	1.4 lulls	3.1 lulls	6.1 lulls
≥5 days	0.5 lulls	1.5 lulls	2.9 lulls

Figure 3-2 presents the distributions of offshore and onshore wind lull counts per year for lulls lasting at least 3 days with a mean net wind generation capacity less than 15% capacity. For offshore wind, 1.5% of the 20,000-year dataset experience no wind lulls. However, for onshore wind all 20,000 years experienced at least one wind lull with daily average wind generation below 15% capacity.

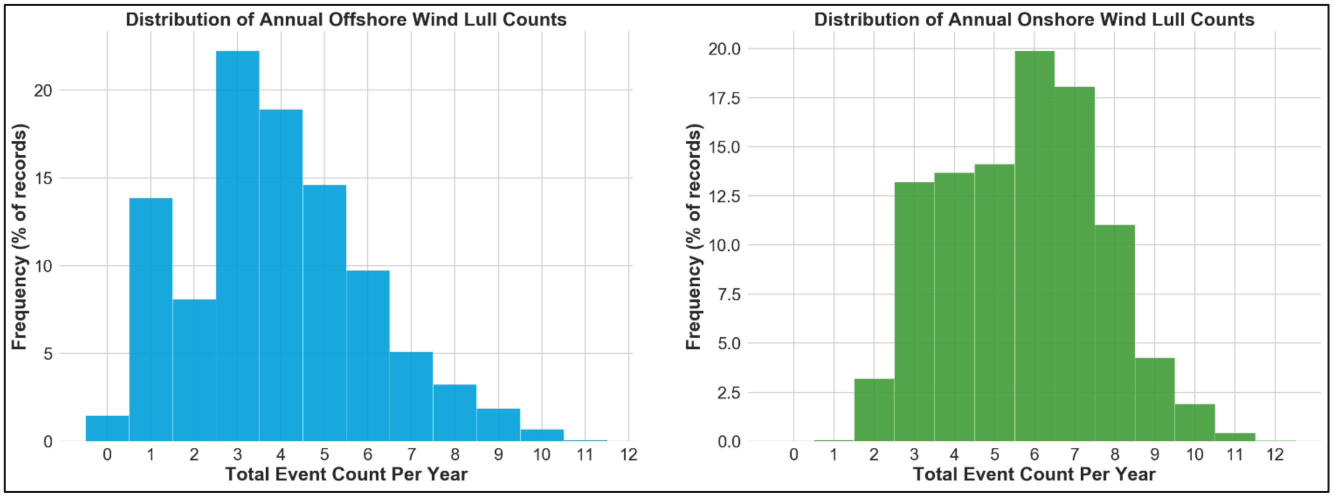

Figure 3-2 Distributions of wind lull counts per year offshore and onshore wind generation

Figure 3-3 presents distributions of the offshore and onshore wind lull durations lasting at least 3 days with daily average net wind generation below 15% capacity. On average, offshore generation lulls exhibited an average duration of 3.6 days and a maximum duration of 9 days. Onshore wind lulls with generation below 15% capacity lasted 4.1 days with a maximum duration of 18 days. Virtually all (99.9%) of offshore and onshore wind lulls lasted less than 8 days and 15 days, respectively.

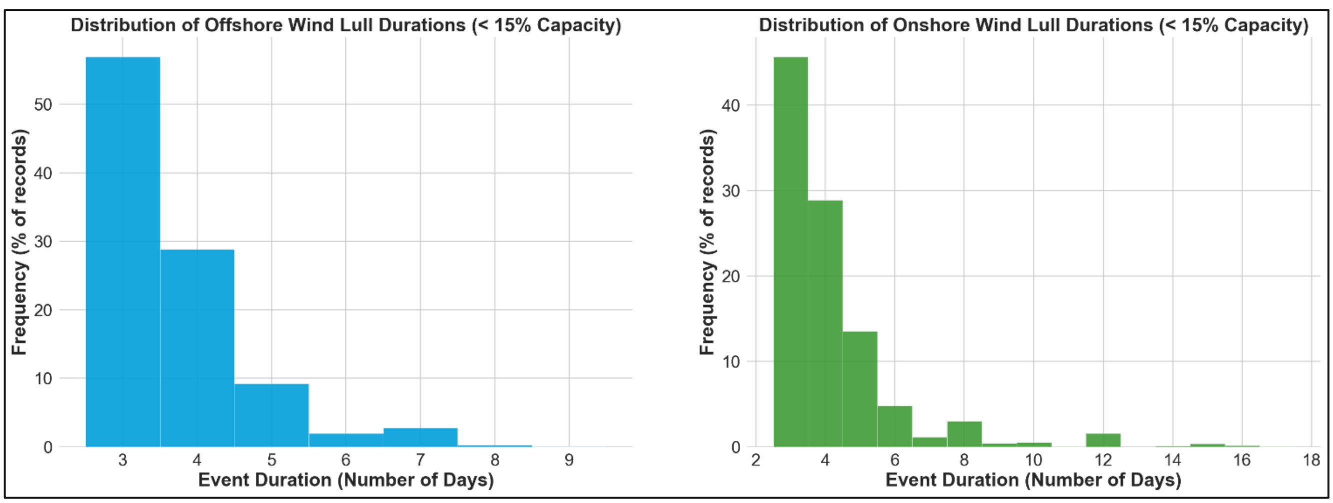

Figure 3-3 Distributions of offshore and onshore wind lull durations

The predominance of more frequent and vigorous weather systems and large-scale storms during winter leads to stronger overall winds and higher average wind generation. Wind lulls are more frequent during summer, due to the lower average wind generation during the warm season. Because wind lulls are generally driven by stationary high-pressure ridges over New England, they can occur at any time of the year and there is moderate probability of occurrence during the winter months.

Table 3-6 and Table 3-7 present the breakdown of the average number of offshore, onshore, and total wind generation "lulls" per month for lulls lasting at least 3 days with an average generation capacity below 15%. In both cases, a lull is defined as 3 or more consecutive days with an average net wind generation below 15% capacity. Clearly, some months are more likely to experience a wind lull than others. For example, of the 20,000 Januarys in the dataset, only 617 of them contained a valid wind lull event where the daily offshore wind generation remained below 15% capacity for 3 days. For August, there were 13,695 wind lulls recorded, with some Augusts having as many as 5 events, while others had no events. The third column in the tables below presents the frequency of occurrence of wind lulls for each month. These values represent the total number of months that had at least one wind lull divided by 20,000. For both offshore and onshore wind generation, the month of August is the most likely to experience at least one wind lull.

Table 3-6 Monthly summary of offshore wind lulls

Month	Average number of 3+ day offshore wind lulls	Maximum number of 3+ day offshore wind lulls	Frequency of occurrence of 3+day offshore wind lulls
January	0.03	1	3.1%
February	0.12	1	11.6%
March	0.05	2	5.1%
April	0.05	2	5.3%
May	0.25	3	20.5%
June	0.25	3	24.3%
July	0.91	4	61.7%
August	1.27	5	68.5%
September	0.54	3	48.8%
October	0.32	3	30.3%
November	0.07	2	6.7%
December	0.05	1	5.3%

Table 3-7 Monthly summary of onshore wind lulls

Month	Average number of 3+ day onshore wind lulls	Maximum number of 3+ day onshore wind lulls	Frequency of occurrence of 3+day onshore wind lulls
January	0.02	1	2.4%
February	0.06	1	5.5%
March	0.04	2	4.1%
April	0.12	3	9.9%
May	0.57	4	39.5%
June	0.83	3	63.0%
July	1.38	5	79.9%
August	1.41	6	87.0%
September	0.73	3	62.0%
October	0.32	3	30.7%
November	0.14	2	12.5%
December	0.07	1	6.7%

Table 3-8 Monthly summary of total combined wind generation lulls

Month	Average number of 3+ day onshore wind lulls	Maximum number of 3+ day onshore wind lulls	Frequency of occurrence of 3+day onshore wind lulls
January	0.01	1	1.5%
February	0.06	1	6.4%
March	0.03	1	3.2%
April	0.04	1	4.4%
May	0.23	2	18.8%
June	0.24	2	22.4%
July	0.87	4	54.2%
August	1.20	5	63.5%
September	0.49	3	45.4%
October	0.22	2	20.6%
November	0.06	1	5.5%
December	0.04	1	3.5%

For Table 3-6 through Table 3-8, the sum of the monthly average wind lull counts is exactly the average wind lull count per year, as enumerated in Table 3-3 through Table 3-5. Based on the foregoing results, there is a 68%, 87%, and 54% probability that daily average offshore, onshore, and combined wind generation, respectively, will remain below 15% capacity for a period of 3 consecutive days during August. It is noted that there is a slight decrease in wind lull frequency for the total combined offshore and onshore generation when compared to both the offshore and onshore results separately. This small reduction in wind lull events is likely the result of a greater geographic distribution of wind generation, slightly reducing the chance that wind will stay low across the entire region at the same time.

Table 3-9 below presents some basic statistics on the offshore and onshore wind lulls lasting at least 3 days with daily average generation below 15% of capacity.

Table 3-9 Statistics on wind lulls for all of New England based on stochastic dataset

Statistic	Offshore	Onshore	Combined generation
Average wind lulls per year	3.9	5.7	3.5
Maximum wind lulls per year	11	12	10
Minimum wind lulls per year	0	1	0
Average wind lull duration per year	3.6	4.1	3.6
Maximum wind lull duration per year	9	18	9

3.2.2 Solar lulls

This section presents an analysis of the frequency of BTM solar generation lulls. As discussed above, a solar lull is determined to exist when the daily maximum solar generation is less than 15% of the monthly solar maximum for at least 3 consecutive days. Table 3-10 presents the average number of solar generation lulls per year using increasing thresholds of 15% to 30% of monthly maximum capacity. Based on the solar lull criteria, the number of solar lulls that occur each year are far fewer than for wind lulls. The relative infrequency of solar lulls may be due in part to the classification method, but also due to the fact that the aggregation of solar generation across the entire region helps to mitigate extended periods of low solar generation due to snow or cloud cover. Similar to the wind generation lulls, the counts in Table 3-10 below are inclusive such that the lulls less than 15% capacity are included in the lulls less than 25% capacity.

Table 3-10 Average number of aggregate solar generation lulls per year

Period	Average solar lulls per year			
	< 15% capacity	< 20% capacity	< 25% capacity	< 30% capacity
≥ 3 days	0.1	0.5	1.2	2.2
≥ 4 days	0.0	0.0	0.3	0.7
≥ 5 days	0.0	0.0	0.1	0.3

Solar lulls were more likely to occur during the winter months as solar generation is lower on average during those months due to snow and cloud cover, and a reduced level of solar insolation. In fact, as shown in Table 3-11, no solar lulls with a daily maximum generation below 15% of the monthly maximum occurred during the months of April through October. When a solar lull did occur, the average duration was 3.0 days with a maximum duration of 4 days maximum, as shown in Table 3-13, which presents some basic statistics on solar lulls lasting at least 3 days.

Table 3-11 Monthly summary of solar lulls with maximum daily generation below 15% of monthly maximum capacity

Month	Average number of 3+ day solar lulls	Maximum number of 3+ day solar lulls	Frequency of occurrence of 3+ day solar lulls
January	0.07	1	7.5%
February	0.02	1	1.6%
March	0.01	2	0.8%
April	0.00	1	0.1%
May	0.00	0	0.0%
June	0.00	0	0.0%
July	0.00	0	0.0%
August	0.00	0	0.0%
September	0.00	0	0.0%
October	0.00	0	0.0%
November	0.01	2	0.9%
December	0.00	1	0.5%

It is noted that as the solar generation threshold increases to 30% of monthly maximum capacity more months experience a solar lull, although July continues to remain lull free.

Table 3-12 Monthly summary of solar lulls with maximum daily generation below 30% of monthly maximum capacity

Month	Average number of 3+ day solar lulls	Maximum number of 3+ day solar lulls	Frequency of occurrence of 3+ day solar lulls
January	0.21	2	20.6%
February	0.29	3	27.7%
March	0.31	2	26.9%
April	0.16	2	14.7%
May	0.21	3	20.9%
June	0.04	2	4.0%
July	0.00	0	0.0%
August	0.00	1	0.1%
September	0.05	1	4.8%
October	0.22	3	21.0%
November	0.50	3	41.3%
December	0.24	3	21.2%

Table 3-13 Statistics on solar lulls lasting at least 3 days for all of New England

Statistic	Solar lull < 15% monthly maximum capacity	Solar lull < 30% monthly maximum capacity
Average lulls per year	0.11	2.23
Maximum lulls per year	2	7
Minimum lulls per year	0	0
Average lulls duration per year	3.0	3.5
Maximum lulls duration per year	4	11

3.2.3 System load during wind lulls

Considering the significant amount of offshore wind generation expected within the ISO-NE region over the next few decades, wind lulls will have increasing impacts on fuel security and system reliability, particularly when they occur during periods of high demand. DNV GL has analyzed the load coincident to offshore wind lulls. Table 3-14 presents summary statistics of daily peak load coincident with lulls in offshore wind generation lasting at least 3 days, and for capacity thresholds of 15%, 20%, and 25%. There appears to be relatively little variation in the daily peak load and net load when filtering for the various capacity thresholds. However, there is a slight trend indicating that as the wind lull threshold decreases, load tends to increase a small bit. These differences are partly due to the addition of more records. Wind lulls that are under 25% of capacity are likely to have more records during the winter months and shoulder seasons (autumn and spring) when load is lower.

Table 3-14 Summary statistics for gross load and net load during offshore wind lull events

Statistic	Threshold					
	Offshore wind < 15% capacity		Offshore wind < 20% capacity		Offshore wind < 25% capacity	
	Load	Net load	Load	Net load	Load	Net load
Minimum daily peak	12,227	6,240	12,227	6,241	12,227	6,078
Mean daily peak	18,469	15,545	18,123	15,750	17,847	15,357
Median daily peak	18,183	15,755	17,893	15,893	17,577	15,620
Max daily peak	27,795	25,170	27,795	25,126	27,982	25,687

Figure 3-4 presents the distributions of the daily peak load values for each wind lull threshold. Note that the distributions are inclusive such that the distribution for wind lulls less than 15% of capacity are included in the dataset of wind lulls less than 25% of capacity. It is clear that as the wind threshold decreases there is a greater frequency of higher load values. This follows with the assumption that the weaker winds occur during the summer months when load tends to be higher. Note that a correlation of hourly wind generation during a wind lull with the daily peak load revealed no discernable relationship.

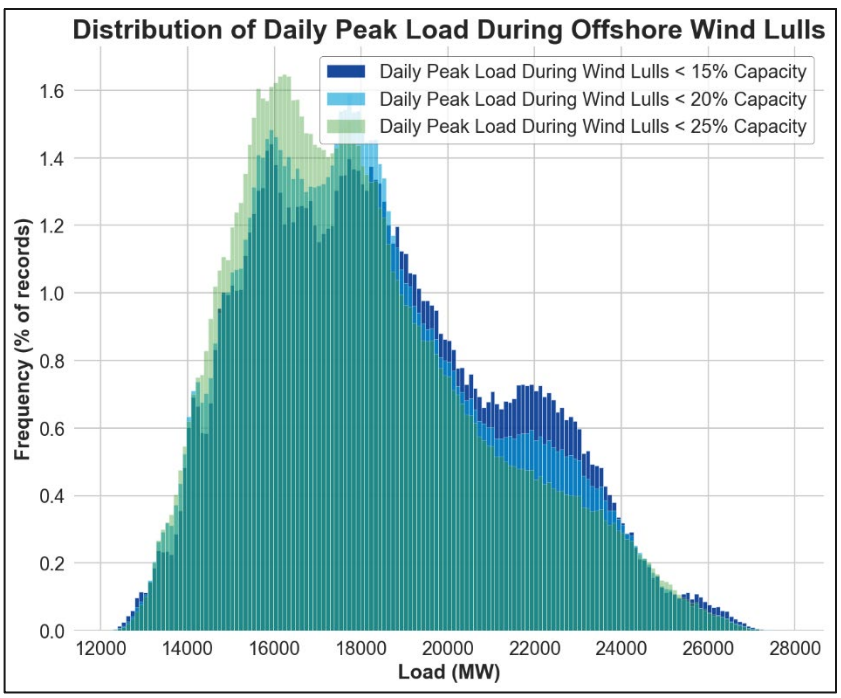

Figure 3-4 Distributions of gross load for wind lulls less than 15%, 20%, and 25% capacity

Table 3-15 presents a list of selected quantiles of daily peak gross load for offshore wind lulls of at least 3 days.

Table 3-15 Selected quantiles of daily load peaks for offshore wind lulls

Mean daily wind capacity threshold	Daily peak gross load						
	Min	P1	P5	P50	P95	P99	Max
< 15%	12,227	13,411	14,357	18,183	23,694	25,525	27,795
< 20%	12,227	13,438	14,286	17,893	23,602	25,206	27,795
< 25%	12,227	13,455	14,277	17,577	23,566	25,244	27,982

Table 3-16 presents selected percentiles of the daily peak load values for all offshore wind lulls lasting at least 3 days with average daily wind generation below 15% capacity. Also presented is the corresponding minimum, mean, median, and maximum offshore wind generation values that are coincident to the daily peak load. For example, for all wind lull records where the daily peak load was greater than the P90 load value (22,775 MW) the median wind generation was 5.2% of capacity with a minimum of 0.0%.

Table 3-16 Wind generation coincident to the daily load peak quantiles during wind lulls

Load probability of exceedance	Daily peak load (MW)	Offshore wind capacity during peak load hour			
		Min	Mean	Median	Max
P1	13,411	0.0%	6.9%	4.8%	68.6%
P5	14,357	0.0%	6.8%	4.8%	68.6%
P10	14,981	0.0%	6.8%	4.8%	68.6%
P50	18,183	0.0%	6.6%	4.8%	54.0%
P90	22,775	0.0%	7.0%	5.2%	38.7%
P95	23,694	0.1%	7.0%	5.2%	38.7%
P99	25,525	0.6%	5.1%	4.4%	30.7%

The wind generation capacity values presented above are the values coincident to the daily peak load hour so in theory they can be greater than the 15% minimum daily average, but it appears that most wind generation during the peak load hour is below 15% capacity. A correlation analysis revealed no correlation between wind generation during the peak load hour and the daily peak load. However, it does appear that during a wind lull the maximum wind generation value does tend to decrease as load increases so that if peak load climbs to over 24,000 MW during a wind lull it is likely that offshore wind generation will not exceed 30% of capacity during that hour. It is likely the reason for the apparent dependency of maximum wind generation with daily peak load is simply to due seasonal behavior, as mentioned earlier. Load increases during the summer months when wind generation decreases.

3.2.4 Wind lulls coincident to a New England cold snap or heat wave

To address concerns over resource reliability, DNV GL has analyzed the dataset of wind and solar lulls alongside the identified New England cold snaps and heat waves to determine if there are coincident periods when a wind or solar lull occurs at the same time as a cold snap or heat wave. As described in Section 2, a New England cold snap using Method 1 is defined as 3 consecutive days with a daily maximum temperature below 32°F while heat waves are defined as 3 consecutive days with a daily maximum temperature exceeding 90°F. Wind lulls are defined as periods of at least 3 consecutive days with daily average wind generation below 15% capacity and solar lulls were defined as periods of at least 3 consecutive days where the maximum solar generation was less than 15% of the monthly maximum. The results presented below are also representative of overlapping wind and solar lulls with cold snaps and heat waves defined using Method 2.

Table 3-17 shows the number of days a cold snap, heat wave, wind lull or solar lull occurred at the same time. An event was considered to be overlapping if at least one of the cold snap, heat wave, or wind/solar lull days during an event was coincident.

Table 3-17 Number of days with overlapping cold snaps, heat waves, wind lulls, and solar lulls

	Cold snap		Heat wave	
	Days	% of all days[2]	Days	% of all days[2]
Offshore wind lull	451 days	0.006%	4,035 days	0.055%
Onshore wind lull	213 days	0.003%	1,534 days	0.021%
Total wind lull[1]	1 day	0.000%	4,113 days	0.056%
Solar lull	383 days	0.005%	0 days	0.000%
Wind and solar lull	0 days	0.000%	0 days	0.000%

1 Total wind is the onshore wind plus existing and state-contracted offshore wind.
2 Out of a total of 7.3 million days in the 20,000 year dataset.

Although coincident temperature events and wind and solar lulls do occur they are relatively rare. As illustrated in Section 2, wind generation tends to be stronger during more intense cold snaps due to passing frontal systems, reducing the likelihood of a cold snap occurring at the same time as a wind lull. The greater number of overlapping heat waves and wind lulls also follows the trends seen in Section 2 as building high pressure which suppresses wind speeds also allows for more hot and sunny conditions, which also explains why there are no overlapping solar lulls with heat waves. Out of a possible 7.3 million days in the dataset, only 4,035 of them (0.06%) had an overlapping offshore wind lull and heat wave. A maximum of 2 overlapping offshore wind lulls and New England heat waves occurred during a single year, while a maximum of 1 event per year occurred for all other scenarios.

Given that onshore wind lulls are more common than offshore wind lulls it was surprising to see that overlapping heat waves and cold snaps are more common with wind lulls identified in the offshore wind generation than onshore. An investigation into the causes for this revealed that offshore wind lulls tend to occur when temperatures are higher. Often when a heat wave occurs it accompanies building high pressure over New England. These ridges are often centered offshore and when combined with the limited geographic extent of the wind farms in the BOEM lease area create a higher likelihood that an offshore wind lull will occur at the same time as the associated heat wave. The greater diversity in the onshore wind resource means that it is less likely to be affected by any single weather system and so there will be fewer occurrences of overlapping wind lulls and heat waves.

Figure 3-5 presents distributions of the daily peak temperature and pressure coincident to the peak load hour for the overlapping wind lull and heat wave days. It is clear that the overlapping offshore wind lulls and heat waves are associated with both higher temperatures and higher pressure, as described above.

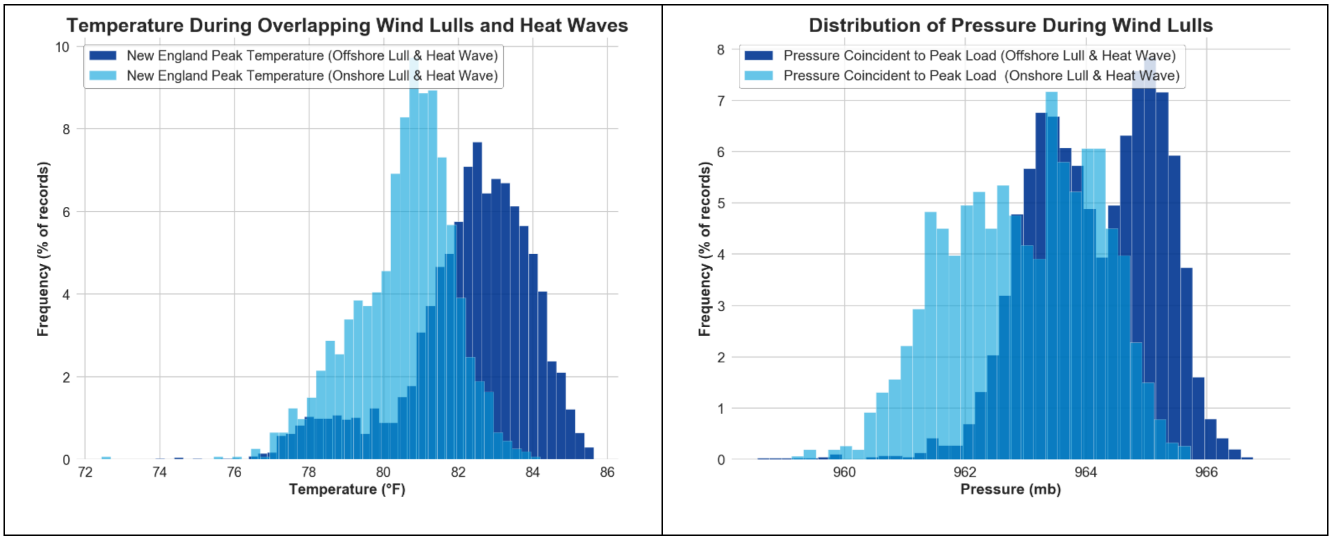

Figure 3-5 Distributions of temperature and pressure for overlapping wind lulls and heat waves

Although rare, it is important to understand what the ISO-NE system conditions may look like during one of these events.

Figure 3-6 presents the distribution of daily peak load values that correspond to the 4,035 overlapping offshore wind lull and heat wave days while Table 3-18 presents selected quantiles from the distributions.

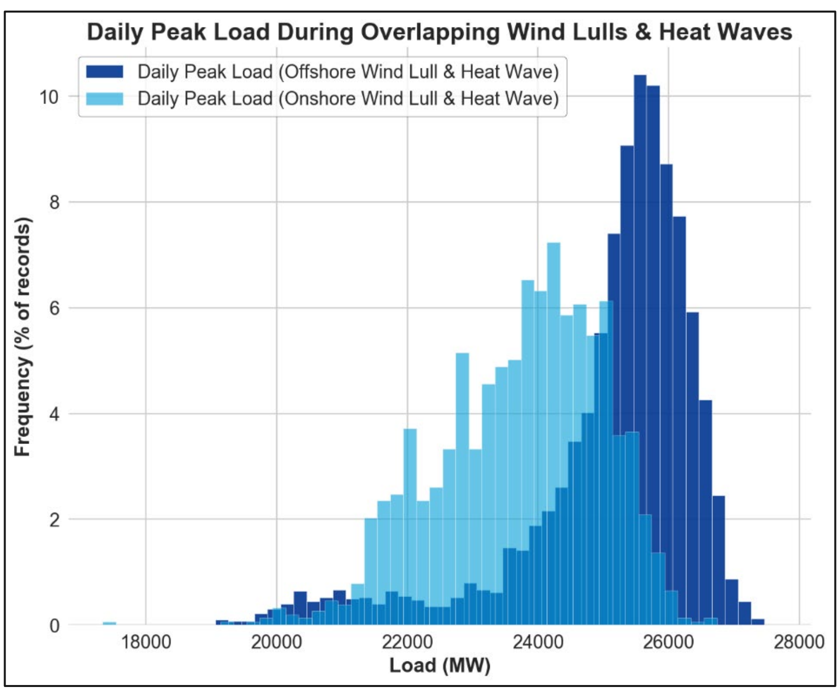

Figure 3-6 Distribution of daily peak load values during overlapping wind lulls and cold snaps

Table 3-18 Probability of exceedance values of daily peak load associated with each overlapping event

Probability of exceedance	Wind lull and heat wave		Wind lull and cold snap		Solar lull and cold snap
	Offshore	Onshore	Offshore	Onshore	Solar
Min	19,160	17,438	16,501	17,732	16,847
P1	20,259	20,739	16,631	17,912	17,173
P5	21,816	21,655	16,788	17,996	17,326
P50	25,581	24,008	17,795	18,727	18,550
P95	26,703	25,617	18,626	19,893	19,869
P99	27,048	26,043	18,815	20,047	20,139
Max	27,795	26,987	19,152	20,296	20,408

Table 3-19 shows the exceedance values for the net load coincident to the daily gross load peak.

Table 3-19 Probability of exceedance values of daily peak net load associated with each overlapping event

Probability of exceedance	Wind lull and heat wave		Wind lull and cold snap		Solar lull and cold snap
	Offshore	Onshore	Offshore	Onshore	Solar
Min	14,521	14,524	12,404	17,732	16,847
P1	16,868	16,775	13,600	17,912	17,173
P5	18,474	17,741	16,757	17,994	17,326
P50	20,940	20,032	17,795	18,727	18,550
P95	23,077	22,314	18,626	19,893	19,869
P99	23,997	23,130	18,815	20,047	20,139
Max	25,126	24,367	19,152	20,296	20,408

Based on the results in the table above, there can be rare instances when a wind lull and heat wave will occur at the same time while gross load climbs to over 27 GW, potentially raising system reliability concerns. However, no concurrent solar and wind lulls were identified, so it is likely that solar generation will be moderate to high during concurrent wind lulls. Figure 3-7 presents the distribution of solar generation capacity during the peak load hour for all overlapping days of offshore wind lulls and heat waves while Table 3-20 presents the selected quantiles from the distribution. As expected, solar generation is generally moderate to high during overlapping wind lulls and heat waves.

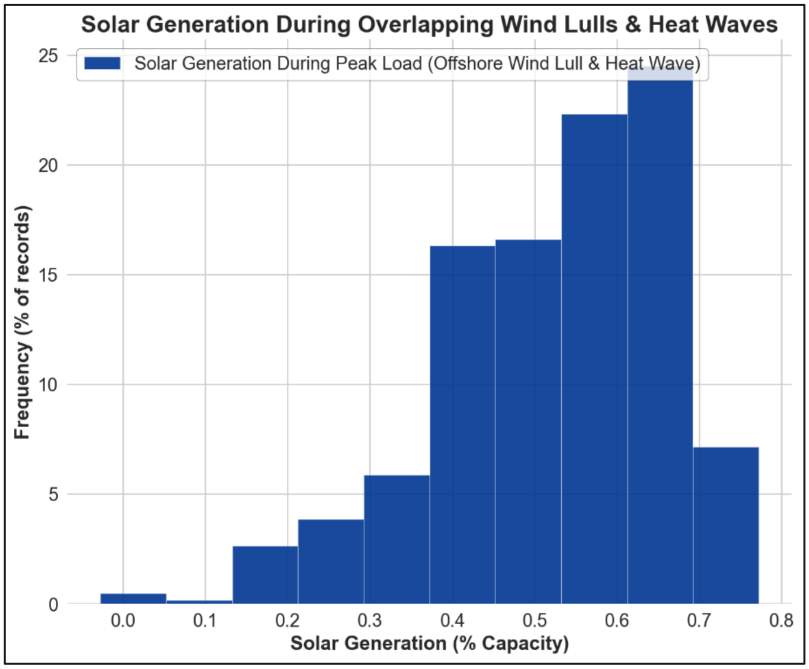

Figure 3-7 Distribution of solar capacity during overlapping offshore wind lulls and heat waves

Table 3-20 Probability of exceedance values of solar generation associated with each overlapping heat wave and wind lull

	Solar capacity (% capacity)
Min	1.2%
P1	21.5%
P5	26.5%
P50	57.9%
P95	73.9%
P99	76.1%
Max	82.3%

To conclude, wind generation lulls of 3 or more days with daily average wind generation below 15% of capacity occur approximately 4 times per year for offshore generation and 6 times per year for onshore generation. The lower average onshore wind speeds and onshore generation capacity factor are likely the driver for the increased number of lulls onshore. On average, generation during the summer months is lower than during the winter, so there is a greater likelihood that wind generation lulls will occur during the summer when load is higher than during the winter. However, because wind lulls are often triggered by persistent high-pressure ridges they can technically occur at any time of the year.

4 CORRELATION OF WIND, LOAD, AND SOLAR

The wind, solar, and load time series for each stochastic realization were aggregated for each region and correlation analysis performed to quantify the strength of linear association between the datasets. Pearson correlation coefficients were computed based on hourly, monthly, and annual values. A Pearson correlation coefficient measures the statistical relationship between two continuous variables, and is based on the method of covariance. It gives information about both the magnitude and direction of correlation between two variables. A negative correlation coefficient means the two variables are negatively correlated (one goes up while the other goes down), while a positive coefficient indicates the variables are positively correlated (both go up or down at the same time). Table 4-1 presents a description of the degree of correlation quality as it relates to the Pearson coefficient [5].

Table 4-1 Quality of correlation for Pearson coefficient ranges

Quality of correlation	Pearson coefficient
Perfect	±1.00
High	±0.50 to ±0.99
Moderate	±0.30 to ±0.49
Low	±0.01 to ±0.29
None	0.00

4.1 Analysis

The analysis below investigates the correlation of both gross load and net load across Load Zones as well as wind and BTM solar generation. Note that gross load is defined as total consumption of gross load minus energy efficiency with BTM solar reconstituted. Net load is defined as gross load minus energy efficiency and BTM solar generation. Correlations were performed on an hourly, monthly, and annual basis to capture changes in relationships between Load Zone variables that occur when looking at seasonal and annual values. For example, wind generation may have no correlation between Load Zones on an hourly basis, but on a monthly basis the seasonal variability may indicate a relationship exists such as a negative correlation between solar and wind, where wind is high during months when solar is low. Similarly, on an annual basis, it can be useful to understand if years with high/low solar generation are going to be positively or negatively correlated with years of high/low wind generation.

The correlation of hourly gross and net load across each Load Zone is shown in Figure 4-1. As expected, hourly gross load is highly correlated across Load Zones; however, due to differing amounts of BTM solar generation in each region, the net load is not as well correlated across all zones. This is likely because on an hourly basis, net load for some Load Zones such as VT can be negative due to solar generation being greater than gross load.

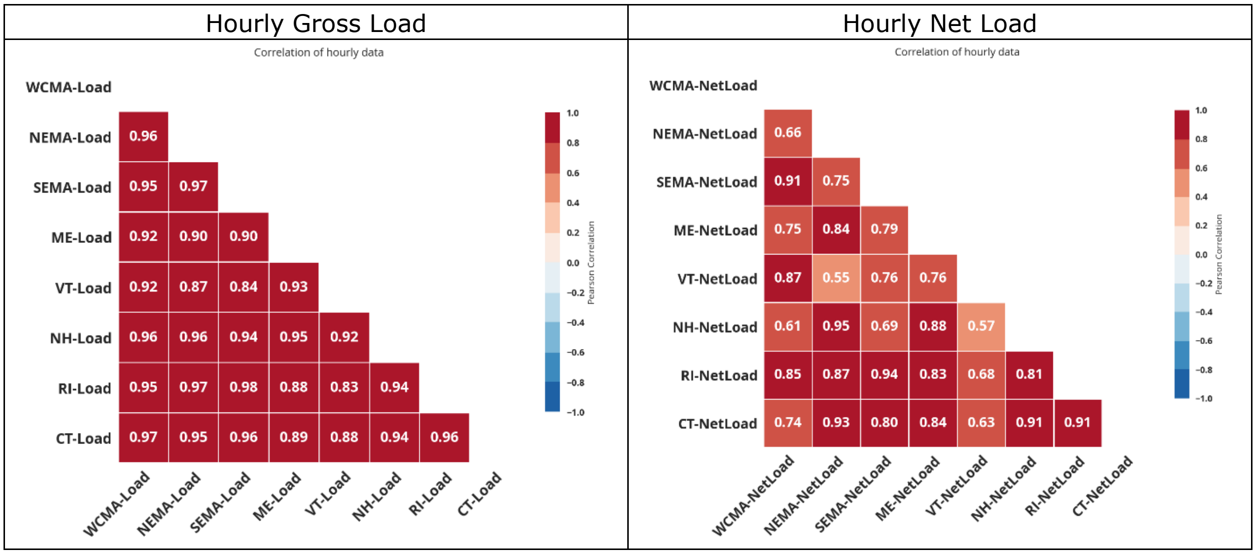

Figure 4-1 Pearson correlation coefficients for hourly gross load and net load across Load Zones

When averaged to monthly means as shown in Figure 4-2, the correlation between Load Zones for both gross load and net load decreases slightly for some Load Zones. This decrease is likely due to changes in seasonal load profiles. For example, due to colder winter temperatures in northern regions, the VT load is likely to increase at a higher rate during the winter months than RI would. The differing seasonal load profile primarily affects VT.

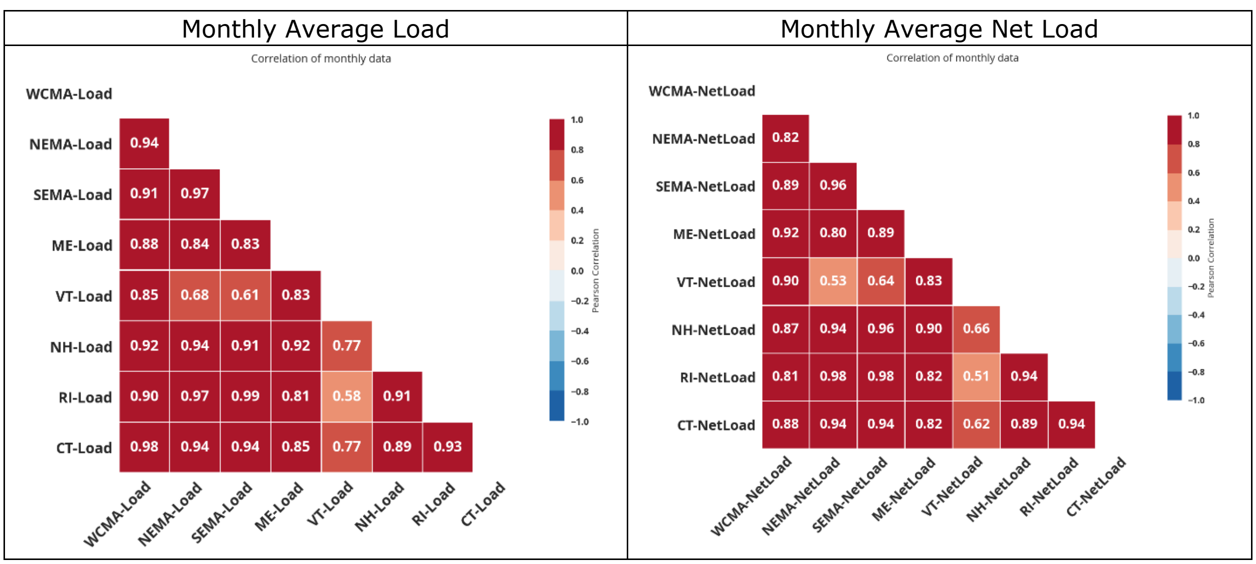

Figure 4-2 Pearson correlation coefficients for monthly mean load and net load across Load Zones

The correlation between Load Zones further decreases when examining the gross load and net load data on an annual basis as shown in Figure 4-3.

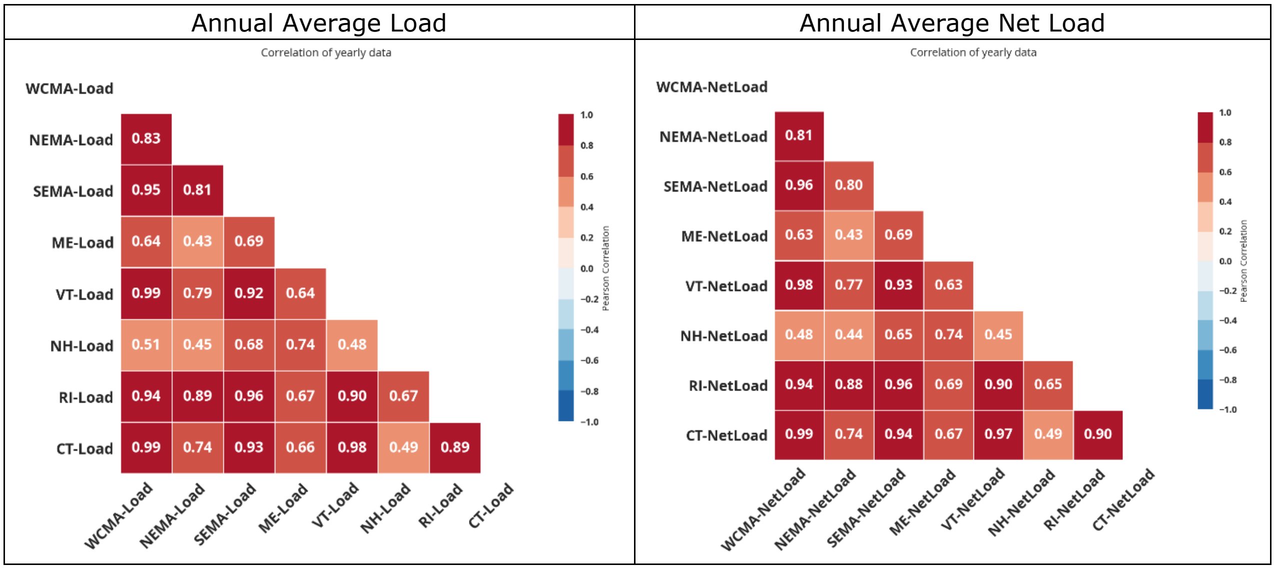

Figure 4-3 Pearson correlation coefficients for annual mean load and net load between Load Zones

This decrease in correlation quality across Load Zones is technically due to differences in interannual variations in annual weather that affects the load between the regions. From a practical perspective, on an annual basis the average load values lose the clear trend in their relationship as shown in Figure 4-4 for Load Zones NH and NEMA.

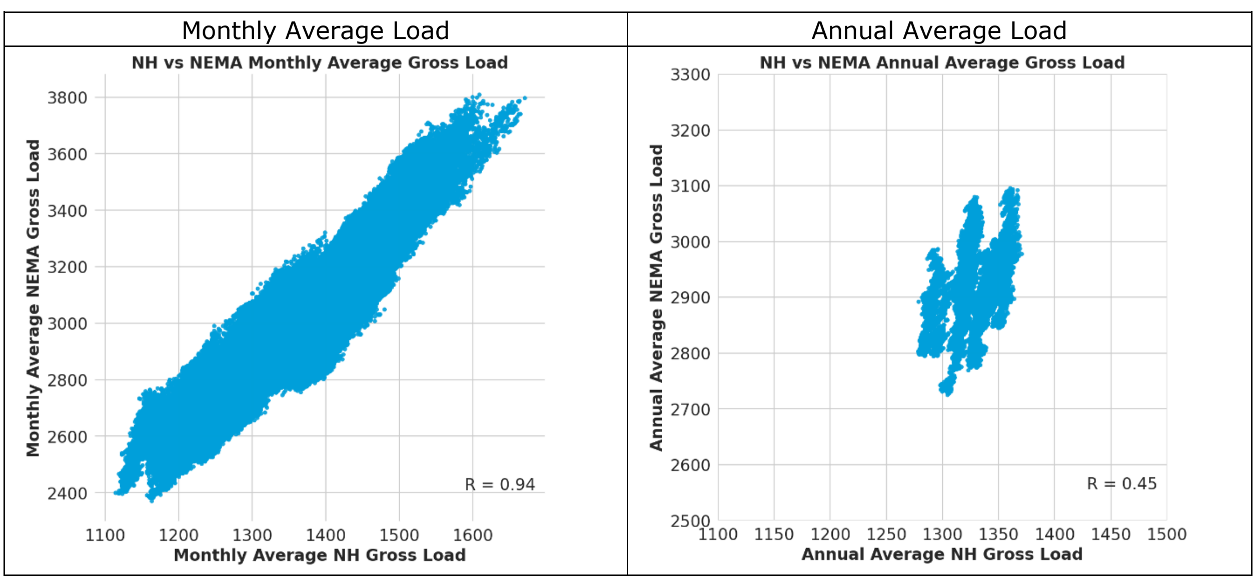

Figure 4-4 Correlation of monthly and annual gross load between NH and NEMA Load Zones

Next, a correlation of wind generation[5] across the different Load Zones was performed. Note that there is no existing or planned wind generation in CT and NEMA. Wind generation for RI includes both existing onshore and offshore generation as well as future state-contracted offshore generation. Similarly, SEMA wind generation includes the existing onshore wind farms as well as the future state contracted offshore wind farms. As a result, both RI and SEMA wind generation are heavily weighted by the future state-contracted offshore generation. On an hourly basis there is a moderate to high correlation between wind generation for each Load Zone, as shown in Figure 4-5. Adjacent zones, such as ME and NH, and RI and SEMA, have higher Pearson coefficients than zones that are geographically separated, such as ME and WCMA.

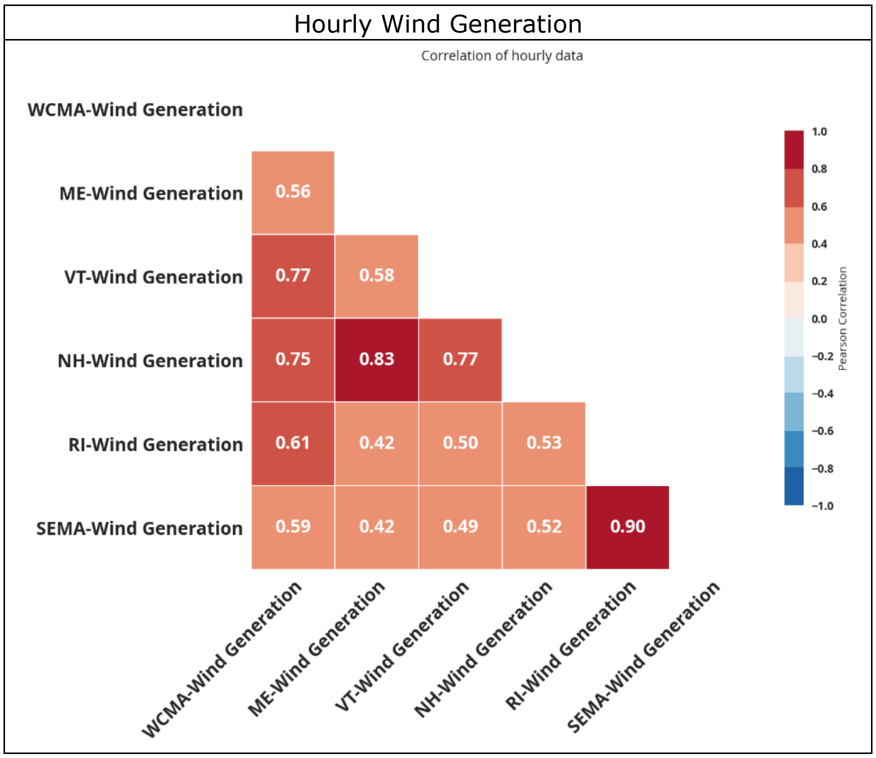

Figure 4-5 Pearson correlation coefficients for hourly wind generation across Load Zones

On a monthly basis, wind generation is strongly correlated across all Load Zones, with most Pearson coefficients greater than 0.9, as shown in Figure 4-6. This is expected due to the similarity of seasonal variations in wind speed across all of New England, with stronger winds during the winter months and weaker winds during the summer months.

[5] Net wind generation, which includes both electrical and stochastically modeled wind farm availability, is used for this correlation analysis and so the Pearson correlation coefficients are likely to be lower than they would be for gross wind generation, which would not be impacted by the variations in wind farm availability.

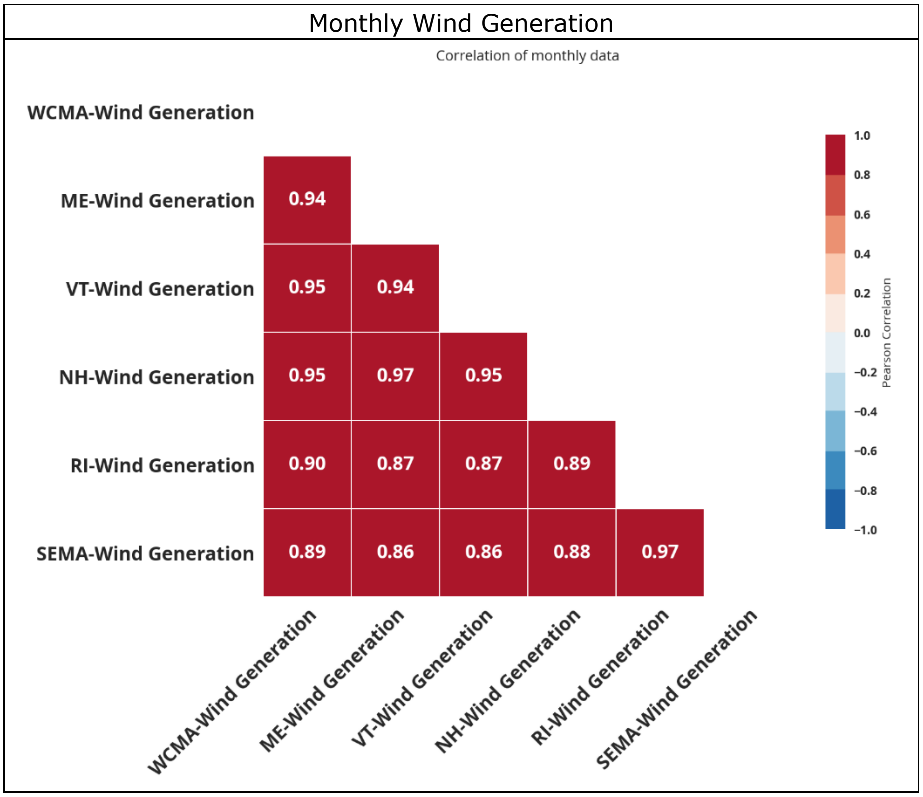

Figure 4-6 Pearson correlation coefficients for monthly wind generation across Load Zones

Correlations of the average annual wind generation across all Load Zones are presented in Figure 4-7.

Annual generation is less well correlated than average monthly generation. Similar to the decreased correlation in annual average gross load, this loss of correlation in wind generation across Load Zones can be attributed, in part, to differences in inter-annual variations in windiness between the regions. Annual wind generation values for a single Load Zone have little variation from year to year. Another contributing factor to the decreased correlation in annual wind generation between Load Zones is due to small variations in the stochastically generated annualized losses. Some Load Zones will experience slightly different availability losses each year, although on average over 20,000 years the losses for each Load Zone will be equivalent. DNV GL has presented the correlations based on net wind generation as it is more likely to be representative of the relationship that would be experienced between operating wind farms.

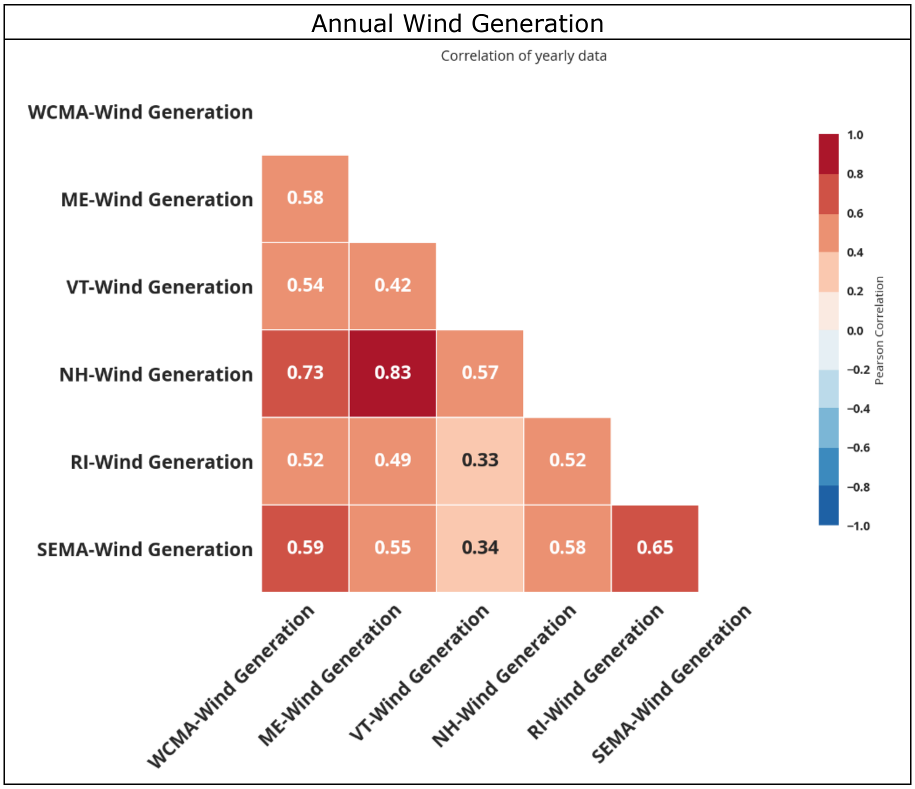

Figure 4-7 Pearson correlation coefficients for annual wind generation across Load Zones

Figure 4-8 through Figure 4-10 present the Pearson coefficients for the hourly, monthly, and average annual solar generation for each Load Zone. Solar generation is well correlated for the hourly and monthly averaging periods, but like wind generation, the annual values are less well correlated, owing to the differences in inter-annual variations between regions.

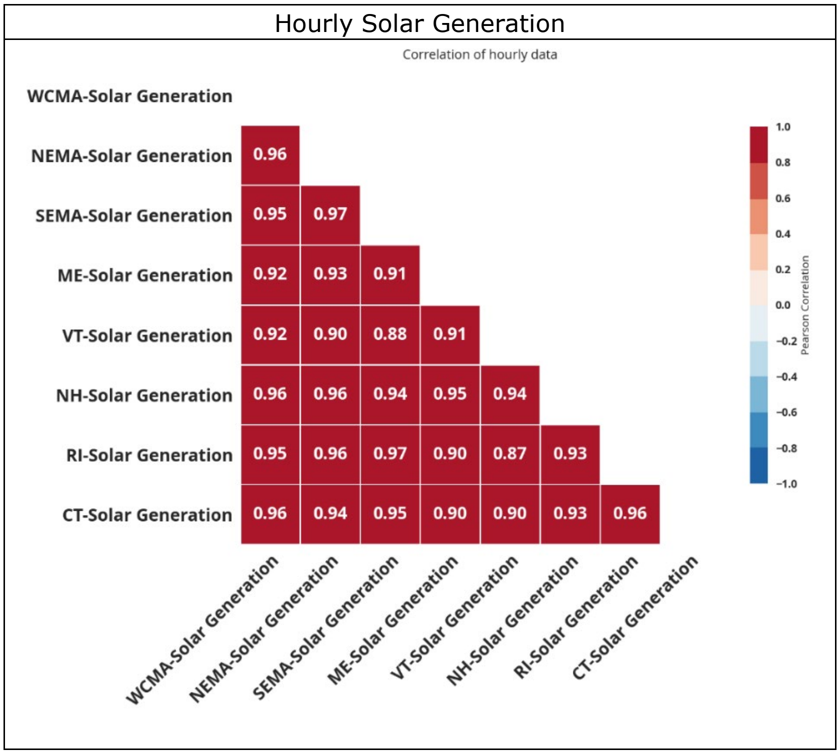

Figure 4-8 Pearson correlation coefficients for hourly solar generation across Load Zones

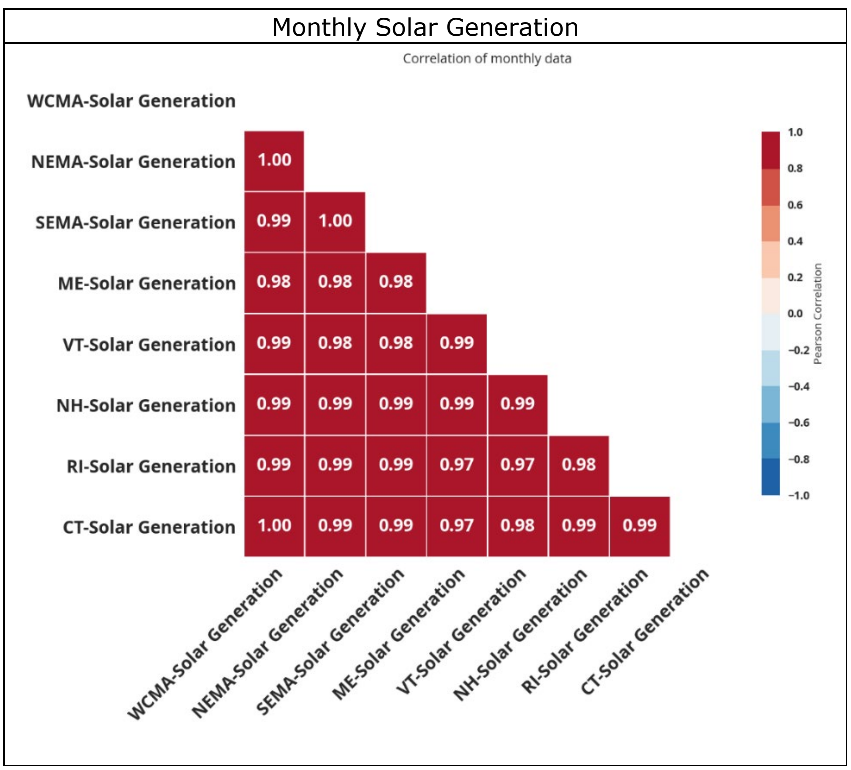

Figure 4-9 Pearson correlation coefficients for monthly average solar generation across Load Zones

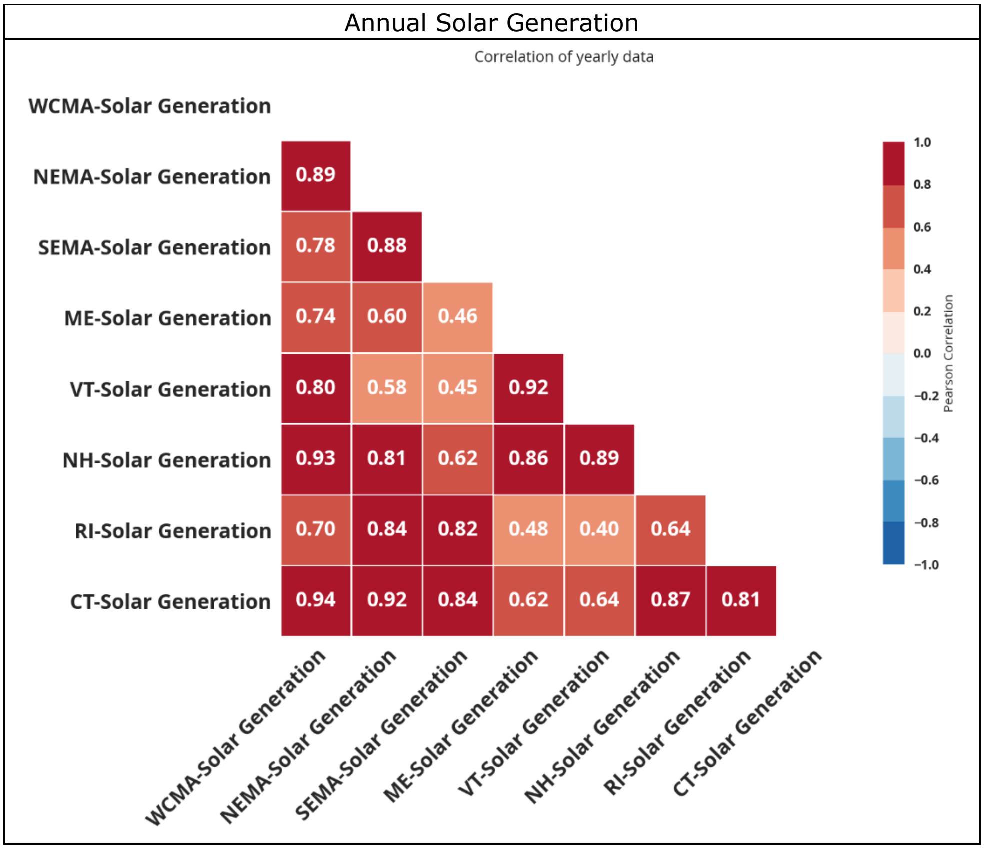

Figure 4-10 Pearson correlation coefficients for annual average solar generation as % capacity across Load Zones

Next, load, wind, and solar generation within each Load Zone were correlated to determine the strength of linear association. These correlations are presented in Table 4-2 to Table 4-4 for hourly, monthly, and annual data. Note that CT and NEMA do not have any modeled wind generation. Also, RI and SEMA wind generation includes the combined onshore and offshore generation associated with each Load Zone. Based on these results, there is a lack of correlation between load and wind generation, whereas a weak positive correlation exists between load and solar generation. Hourly wind and solar generation exhibit a very weak negative correlation, and this is likely due to lower average wind generation during the afternoon when solar generation is at its peak. The opposite relationship exists during the early morning and evening hours, when solar generation is at its minimum.

The positive net load to solar correlations for NH and NEMA indicate that more solar could be added to these Load Zones while the moderate to strong negative net load to solar correlations for VT, SEMA, and WCMA indicates an abundance of BTM solar.

Table 4-2 Pearson correlation coefficients of hourly data between load, wind, and solar generation within each Load Zone

	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	ISO-NE
Load - Wind	-0.01	0.00	0.01		-0.03	-0.03	-0.04		-0.02
Net Load - Wind	0.05	0.02	0.22		0.09	0.11	0.14		0.10
Solar - Wind	-0.12	-0.08	-0.24		-0.18	-0.16	-0.19		-0.18
Load - Solar	0.36	0.37	0.30	0.36	0.38	0.36	0.36	0.39	0.39
Net Load - Solar	-0.20	0.14	-0.66	-0.03	-0.32	-0.54	-0.65	0.08	-0.23
Load - Solar+Wind	0.18	0.31	0.31		0.18	0.13	0.36		0.34
Net Load - Solar+Wind	-0.06	0.13	-0.62		-0.09	-0.14	-0.65		-0.15
Load - Offshore Wind									-0.00
Net Load - Offshore Wind									0.10
Solar - Offshore Wind									-0.17
Onshore Wind - Offshore Wind									0.51

Monthly wind and solar generation exhibit a moderate to strong negative correlation within each Load Zone, which again is due to the seasonal variations in wind and solar generation. Solar generation is highest during the summer months when wind speeds tend to be lower, whereas during winter wind generation tends to be higher and solar generation lower (solar insolation is greatly decreased during winter).

Table 4-3 Pearson correlation coefficients of monthly average data between load, wind, and solar within each Load Zone

	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	ISO-NE
Load - Wind	0.07	-0.08	0.32		-0.42	-0.43	-0.08		-0.24
Net Load - Wind	0.28	0.01	0.59		-0.24	-0.15	0.33		-0.03
Solar - Wind	-0.73	-0.66	-0.78		-0.66	-0.65	-0.80		-0.70
Load - Solar	-0.24	-0.08	-0.51	0.08	0.25	0.23	-0.03	0.13	0.06
Net Load - Solar	-0.51	-0.22	-0.81	-0.09	-0.03	-0.20	-0.53	-0.03	-0.24
Load - Solar+Wind	-0.02	-0.19	-0.52		-0.40	-0.43	-0.04		-0.26
Net Load - Solar+Wind	0.13	-0.21	-0.80		-0.31	-0.26	-0.53		-0.33
Load - Offshore Wind									-0.25
Net Load - Offshore Wind									-0.05
Solar - Offshore Wind									-0.66
Onshore Wind - Offshore Wind									0.88

Annual wind and solar generation within VT and SEMA have a moderate negative correlation, such that years with lower average wind generation tend to have higher than average solar generation. One potential explanation is that "sunnier" than normal years over New England correspond to frequent and persistent high-pressure systems. High-pressure systems are typified by clear and calm conditions, with suppressed wind speeds. There does not appear to be a meaningful relationship between wind and solar generation for NH, ME, and WCMA as indicated by the near zero correlation coefficients.

Table 4-4 Pearson correlation coefficients of annual average data between load, wind, and solar within each Load Zone

	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	ISO-NE
Load - Wind	0.42	0.21	-0.02		0.02	0.01	0.12		0.09
Net Load - Wind	0.42	0.22	0.01		0.03	0.04	0.12		0.10
Solar - Wind	-0.05	0.01	-0.18		-0.09	-0.21	-0.07		-0.11
Load - Solar	0.05	0.37	-0.16	0.20	0.40	0.45	0.16	0.36	0.24
Net Load - Solar	-0.02	0.32	-0.28	0.17	0.30	0.35	0.06	0.33	0.18
Load - Solar+Wind	0.42	0.32	-0.16		0.08	0.06	0.17		0.16
Net Load - Solar+Wind	0.42	0.31	-0.25		0.07	0.07	0.08		0.15
Load - Offshore Wind									0.06
Net Load - Offshore Wind									0.07
Solar - Offshore Wind									-0.18
Onshore Wind - Offshore Wind									0.63

Annual load and solar generation exhibit a moderate positive correlation for CT, NH, RI, SEMA, and NEMA, which indicates that years with high load tend to correspond to higher than average solar generation. One potential driver is that during years with higher solar generation more days with mostly clear skies occur. As a result, temperatures are slightly higher, which in turn drives load slightly higher.

DNV GL has also examined the linear relationship between onshore and offshore (existing and state-contracted) wind generation by performing a correlation analysis for hourly, monthly, and annual average generation capacity. Results in Table 4-5 indicate moderate correlation for hourly and annual records and a strong correlation for monthly generation. When compared with the monthly correlations, the weaker correlation for annual values likely represents regionally specific interannual variations in the wind resource and wind generation. Interestingly, the hourly correlation appears to be slightly weaker between the offshore and onshore aggregate wind generation than the correlation of wind generation between Load Zones.

Table 4-5 Pearson correlation coefficients of hourly, monthly, and annual onshore and offshore wind generation

	Hourly	Monthly	Annual
Offshore - Onshore Wind	0.51	0.88	0.63

4.2 Correlation summary

Hourly, monthly, and annual average wind generation, solar generation and load were compared with each other for each Load Zone. On an hourly basis, wind generation within each Load Zone did not appear to be correlated to solar generation, gross or net load. However, there was a moderate positive relationship between hourly gross load and solar generation, likely due to their very diurnally dependent profiles.

On a monthly level, SEMA, RI, and ISO-NE exhibited a moderate to weak negative relationship between gross load and wind while VT exhibited a moderate positive relationship between gross load and wind. There remained no significant relationship between wind and gross load for the other regions. The solar and wind relationship showed a high negative correlation for all regions, while for gross load and solar there was no consistent trend across all regions.

Annually, gross load and solar have a moderate to weak positive correlation for most regions, with the exception of ME and VT. ME had a moderate positive correlation between gross load and wind, while NH, SEMA, RI, and NEMA had moderate positive correlations between gross load and solar. Correlations between all other parameters within each region were very weak.

In general, gross load is well correlated across all Load Zones on an hourly, monthly, and annual basis. However, net load is not as well correlated as some Load Zones, most notably VT, have periods where solar generation exceed the power demand, resulting in negative net load and reducing the strength of the correlation.

Hourly wind generation is moderately correlated across adjacent Load Zones but weakly correlated between farther apart Load Zones. The correlation of wind across Load Zones improves with monthly averaging periods but not annual averaging periods.

5 REPRESENTATIVE 8760S

This task aims to produce 1-year hourly time series (referred to as an "8760") of wind generation, solar generation, and load for representative years where the total annual wind and solar generation and load fall within the P1, P5, P10, P50, P90, P95, and P99 of the 20,000-year stochastic dataset for each Load Zone, as well as the aggregate onshore and offshore wind generation.

5.1 Methodology

The wind generation data from individual wind farms were aggregated within each Load Zone, and for the total onshore and state contracted offshore regions. Additionally, solar, gross load and net load data were aggregated across all Load Zones to produce system level gross load, net load, and solar capacity.

To create the P1, P5, P10, P50, P90, P95, and P99 8760s for wind generation the data for each Load Zone were first converted from percent capacity to megawatts (MW) by multiplying the hourly wind capacity values by the total current wind capacity (in MW) for the Load Zone. Next, the total energy in terms of terawatt-hours (TWh) was calculated for each year of each realization (20,000 years) by summing the hourly wind generation value. A distribution from the 20,000 annual energy values was then created and the 1st, 5th, 10th, 50th, 90th, 95th, and 99th percentiles were determined. The year and realization that correspond to each of the percentiles was identified and used to create the 8760 corresponding to each P-level. Finally, the wind generation data were converted back to % capacity prior to the creation of the 8760. The resulting 8760 created for a PXX wind generation year will also include the corresponding solar, gross load, net load and weather data columns. A similar process is used for determining the PXX 8760s for solar generation, gross load, and net load. For 8760s created using weather data as the determining PXX parameter (temperature, surface pressure, wind speed, and relative humidity) annual averages were used instead of annual sums. It should be noted that February 29th was excluded during the creation of the 8760s to ensure all years had exactly 8760 hourly records.

It is important to note that the 8760s do not represent the probabilistic (PXX) values for each hourly record, but rather the total annual value. For example, a P99 wind generation 8760 represents the year where the total annual energy production of that time series falls in the 99th percentile of all 20,000 annual wind energy production values.

Table 5-1 presents the percentile values for each variable independently to show the range of data contained in the stochastic data set. Note that wind speed reported below is the average wind speed across all onshore windfarms.

Table 5-1 Stochastic data uncorrelated percentile values

Percentile	Onshore wind gross (TWh)	Offshore wind gross (TWh)	Total wind gross (TWh)	Solar (TWh)	Gross load (TWh)	Avg wind speed (m/s)	Avg temp (°F)	Avg RH (%)	Avg pressure (mb)	Avg GHI (W/m²)
P1	3.641	12.356	16.001	9.191	119.752	6.737	48.186	65.544	999.172	160.427
P5	3.686	12.522	16.193	9.431	121.871	6.776	48.584	65.901	999.324	163.883
P10	3.743	13.117	16.874	9.567	122.961	6.837	48.924	66.257	1000.173	165.155
P50	3.957	13.889	17.792	9.759	127.720	7.024	50.311	67.068	1000.881	169.684
P90	4.175	14.446	18.526	10.119	132.449	7.217	52.105	68.013	1001.426	173.973
P95	4.257	14.520	18.703	10.192	133.692	7.277	52.392	68.358	1002.692	175.633
P99	4.299	14.619	18.861	10.329	136.167	7.316	53.165	68.752	1002.973	176.508

Table 5-2 presents an example of the total annual New England onshore wind generation value that corresponds to the 1st percentile of all annual onshore gross generation values. As a reminder, total installed onshore wind generation capacity was 1,319.65 MW, total offshore wind generation capacity was 3,137.6 MW, and total New England solar capacity was 7,725.9 MW. The annual onshore wind generation value of 3.295 TWh corresponds to the 1st percentile of all annual onshore wind gross generation values. The value comes from stochastic realization 339 and the year 2006. The corresponding annual total offshore wind generation, total solar generation, gross load, average wind speed, average temperature, average relative humidity, average surface pressure, and average solar irradiance are also provided along with the percentile rank of that value. Wind speed represents the average onshore windfarm wind speed.

Table 5-2 Example of New England onshore wind gross generation P1 realization

Realization 339 year 2006	Onshore wind gross (TWh)	Offshore wind gross (TWh)	Total wind gross (TWh)	Solar (TWh)	Gross load (TWh)	Avg wind speed (m/s)	Avg temp (°F)	Avg RH (%)	Avg pressure (mb)	Avg GHI (W/m²)
Value	3.641	12.540	16.170	9.910	128.411	6.738	52.031	67.414	1000.933	171.064
Percentile (%)	1.000	5.395	4.505	76.290	54.565	1.030	88.360	69.175	59.705	64.710

5.1.1 File contents

Each 8760 data file is in csv format and contains a "realization" and "date" column which indicate the stochastic realization and year of the time series. The date and time stamps are in Coordinated Universal Time (UTC) and represent the time at the top of each hourly record. All corresponding time series parameters are included in the files and are shown in Table 5-3. Wind generation and solar generation are expressed as percent of capacity for each Load Zone. Note that for Load Zones RI and SEMA the wind generation in the 8760s represents the combination of the existing and future state contracted offshore generation for those regions. CT and NEMA have no installed wind capacity. The 8760s for offshore wind generation alone were determined using the existing Block Island facility and the future state-contracted offshore wind plants.

Table 5-3 Parameters included in Load Zone 8760s

Parameters in Each File
Date
Realization
Wind speed (m/s)[1]
Gross load (MW)
Net load (MW)
Wind generation gross power (% Capacity)
Wind generation net power (% Capacity)
Solar generation (% Capacity)
GHI (W/m^2)
Temperature (°F)
Relative humidity (%)
Surface pressure (mb)

1 Average wind farm wind speed at turbine nacelle

The section below presents an analysis of the wind, solar, and load distributions used to generate the representative 8760s.

5.2 Analysis

The annual average wind generation in terms of net capacity factor for the total onshore and offshore aggregate generation is shown in Figure 5-1. The distributions of 20,000 annual production values are non-Gaussian and exhibit a multi-modal shape. Average annual wind speeds exhibit a similar distribution, which is the key driver in the wind production.

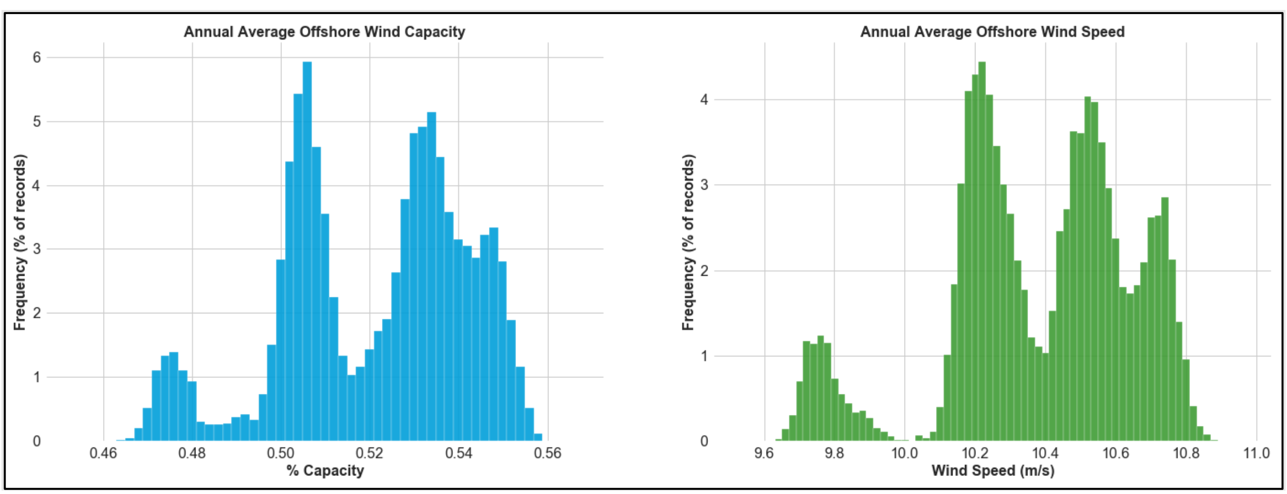

Figure 5-1 Distribution of average annual offshore wind generation in percent capacity (left), and average annual wind speed (right)

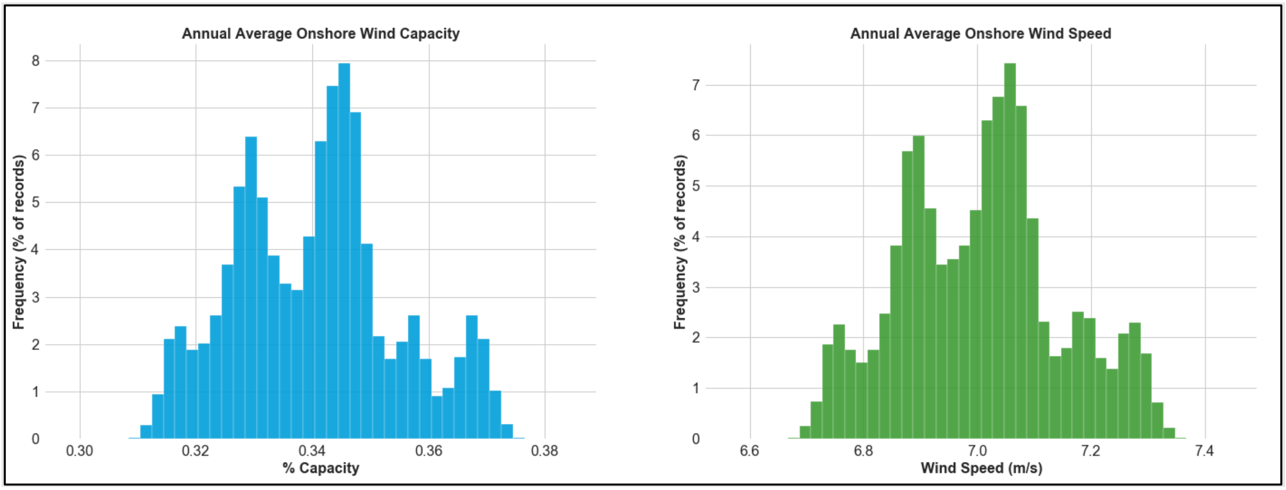

Figure 5-2 Distribution of average annual onshore wind generation in percent capacity (left) and average annual wind speed (right)

Most wind energy assessment methodologies assume a normal or gaussian distribution of annual production values. An investigation of this multi-modal distribution reveals that the underlying 20-year data used as an input the stochastic model has this same distribution of annual wind speeds. As a bootstrap resampling model, the stochastic engine's underlying approach involves sampling with replacement from the original data. Even though the stochastic engine will express the full range of possible conditions based on the historical record, it does not modify the underlying distribution of the original data, nor can it model events which have never occurred within the historical record. Therefore, when the stochastic data are averaged to annual values, they replicate the distribution of annual values from the original data. It is likely that if there existed a much longer record of wind speed data (say 50 to 100 years), the distributions of annual values would exhibit normality. That said, DNV GL did identify what appears to be a weak 3- to 5-year periodicity in the annual wind speed values, but the length of the dataset is insufficient to say anything statistically meaningful about the potential periodicity.

An examination of the aggregate onshore and offshore hourly wind speed data reveals large differences between onshore and offshore wind speed frequency distributions. Figure 5-3 presents the offshore and onshore wind speed frequency distributions and illustrates their differences. The right tail of the offshore wind speed distribution extends much further than that for the onshore, and thus there is a higher frequency of offshore wind speeds near rated power of the offshore turbine power curve.

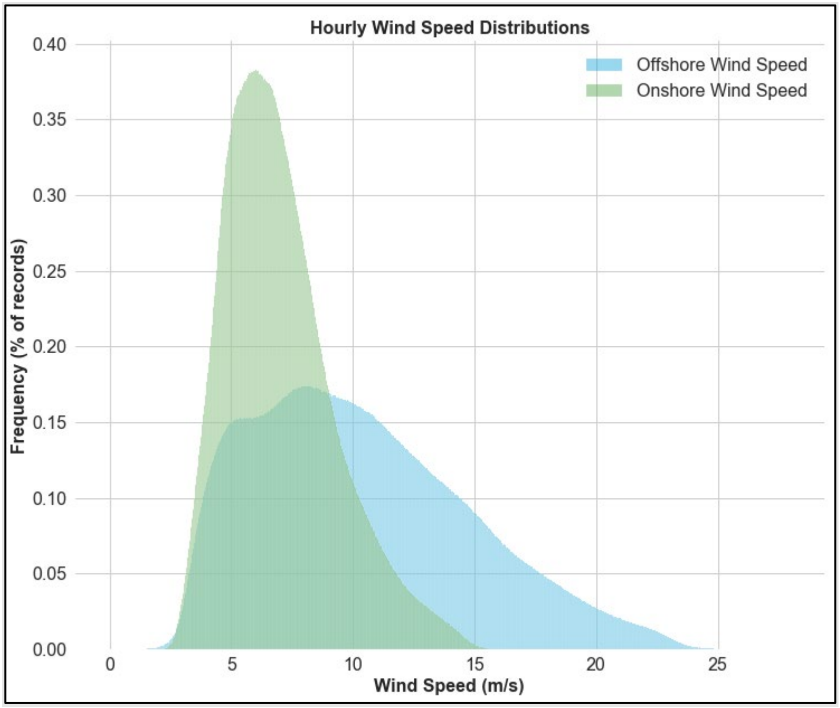

Figure 5-3 Frequency distribution of wind speeds for hourly onshore and offshore aggregates

These large differences in the wind speed frequencies, combined with their relationships to the turbine power curves, contribute to differences in the onshore and offshore distributions of hourly wind generation.

The offshore wind's wider range of values, combined with the respective power curves' sharp ramping and ability to capture winds over 25 m/s, results in the offshore wind farms generating at or near their rated power for significant periods. Figure 5-4 presents the distributions of hourly offshore wind generation and wind speed overlaid with an average offshore turbine power curve. Nearly 20% of hourly wind speed records are greater than 14 to 15 m/s, which is near the offshore turbines rated power, and explains why nearly 10% of aggregate offshore generation records are above 85% of rated capacity.

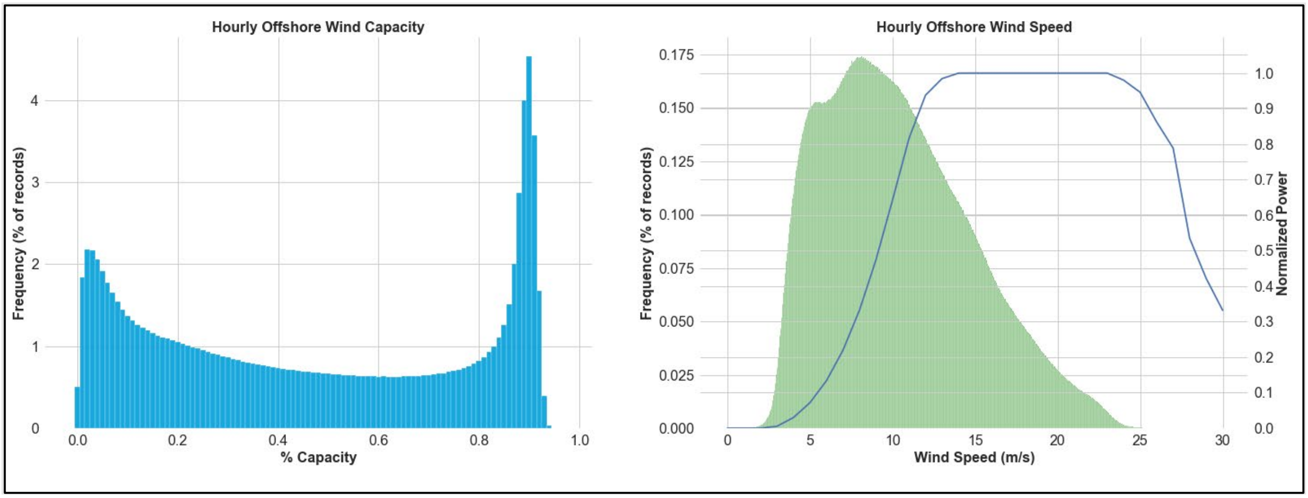

Figure 5-4 Frequency distribution of aggregate offshore hourly wind capacity and wind speed

Figure 5-5 presents the aggregate onshore wind generation and wind speed frequency distribution. The wind generation closely follows a Weibull distribution, which more closely follows the New England average wind speed frequency distribution.

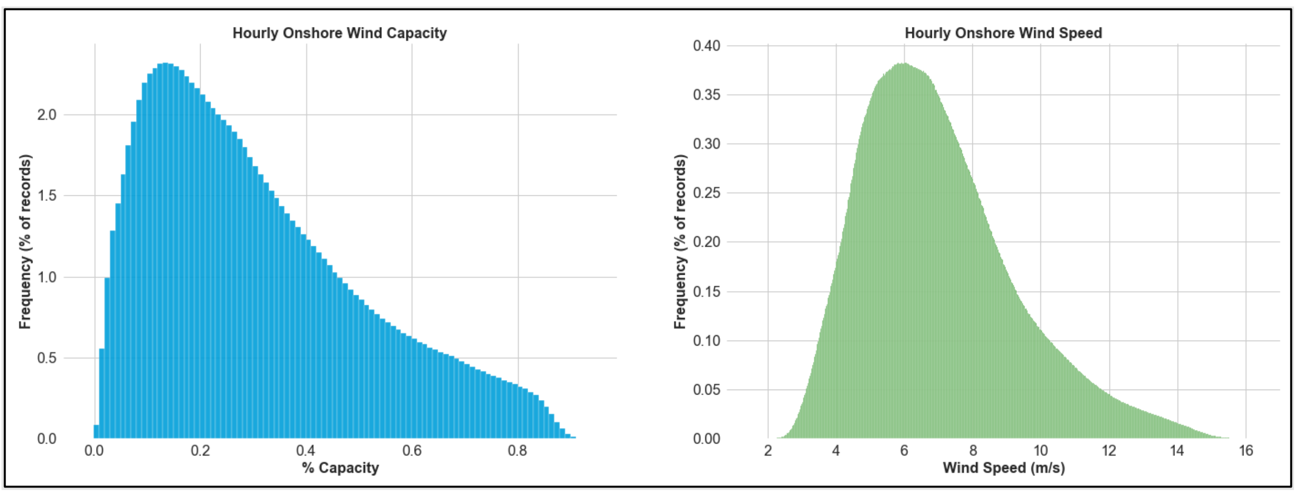

Figure 5-5 Aggregate onshore hourly wind capacity and wind speed frequency distribution

It appears that the shape of this distribution is due in part to the aggregation of the diverse onshore wind resource. On an individual wind farm basis the wind generation distribution tends more toward the offshore shape, with the exception of not having as many high generation records, as shown in Figure 5-6 for an onshore wind farm in Maine.

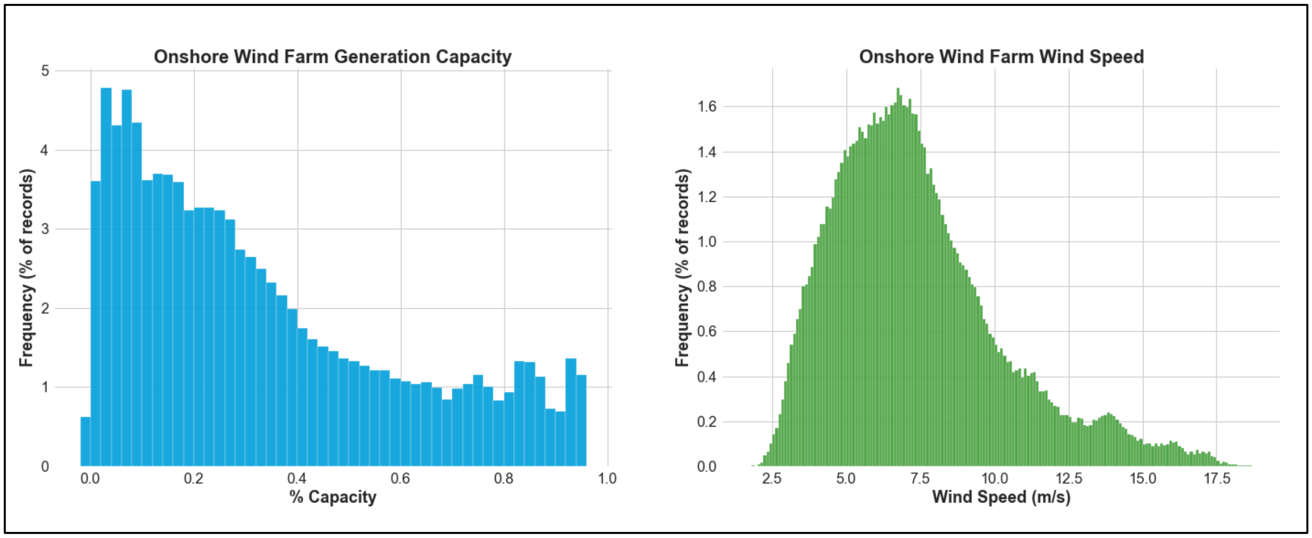

Figure 5-6 Wind generation and wind speed frequency distributions of hourly wind capacity and wind speed data

6 DISTRIBUTIONS OF WIND GENERATION FOR PEAK AND MINIMUM LOAD DAYS

The analysis in this section aims to determine if the wind generation distributions are similar between the peak load and net load days. To this end, distributions of onshore and offshore (existing and state-contracted) wind generation that correspond with days where the peak load value lies in the top 95% and 99% daily peak load and net load, and the bottom 1% and 5% of the daily minimum gross load and net load. As mentioned earlier in this report, "load" is synonymous with "gross load" which is defined as total consumption of gross load minus energy efficiency with BTM solar reconstituted. Net load is gross load minus energy efficiency and BTM distributed solar generation.

6.1 Methodology

Using the stochastic dataset, DNV GL has followed the methodology outlined below.

1. Determine the upper 5th and top 1st percentiles of daily peak gross load. Create probability distribution functions (PDFs) for each hour of the day for onshore aggregate wind generation and the corresponding PDFs for the offshore aggregate.
2. Determine the bottom 1st and lower 5th percentiles of minimum daily gross load. Create PDFs for each hour of the day for onshore aggregate wind and the corresponding PDFs for the offshore aggregate.
3. Find the upper 5th and top 1st percentiles of daily peak net load (gross load – energy efficiency and solar). Create PDFs for each hour of the day for onshore aggregate wind and the corresponding PDFs for the offshore aggregate.
4. Determine the bottom 1st and lower 5th percentiles of minimum daily net load (gross load – energy efficiency and solar). Create PDFs for each hour of the day for both the onshore and offshore aggregate wind.

6.2 Analysis

The results of this analysis are shown in Figure 6-1 through Figure 6-8. Although there is some variation between the wind generation on peak gross load days and peak net load days, overall the average wind generation for each hour of the day as well as the minimum and maximum values are very similar.

The most notable difference between wind generation on peak gross load days and peak net load days is for the offshore resource on P99 gross load and net load days. The average offshore wind generation on peak gross load days is higher by approximately 2.5% as shown in Figure 6-2.

The corresponding tables containing the 1st, 5th, 10th, 90th, 95th, 99th percentiles as well as the mean and median net wind generation for each hour of the day are presented in Appendix A1.

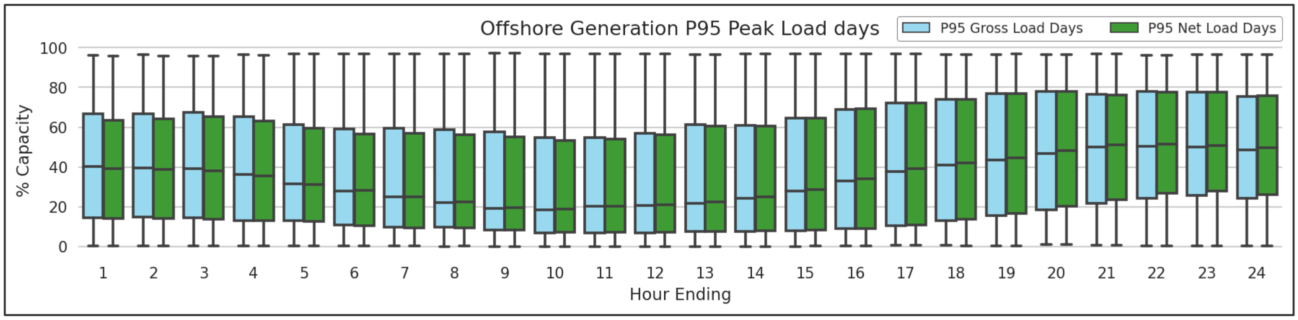

Figure 6-1 Hourly distributions of net offshore wind generation for days with peak load or net load greater than the 95th percentile of daily peaks

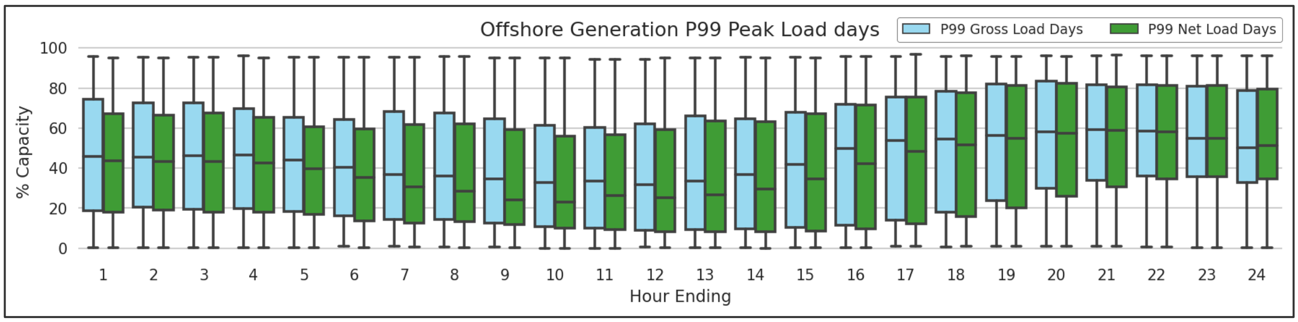

Figure 6-2 Hourly distributions of net offshore wind generation for days with peak load or net load greater than the 99th percentile of daily peaks

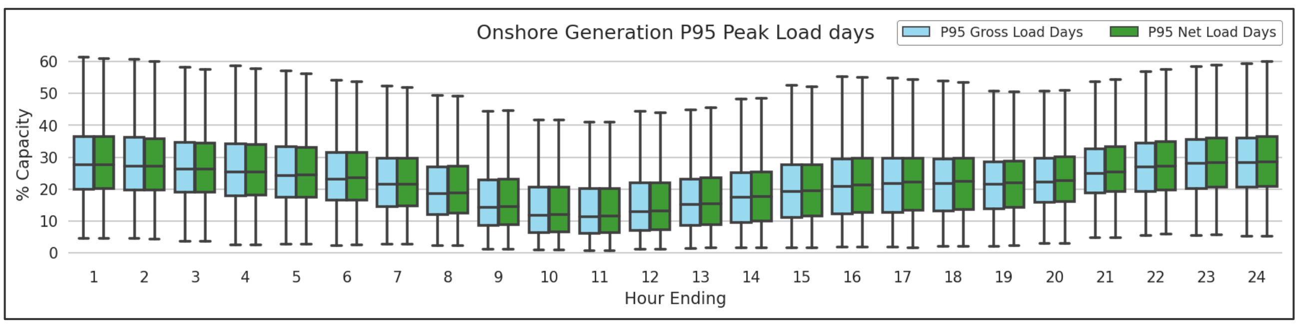

Figure 6-3 Hourly distribution of net onshore wind for days with peak load or net load greater than the 95th percentile of daily peaks

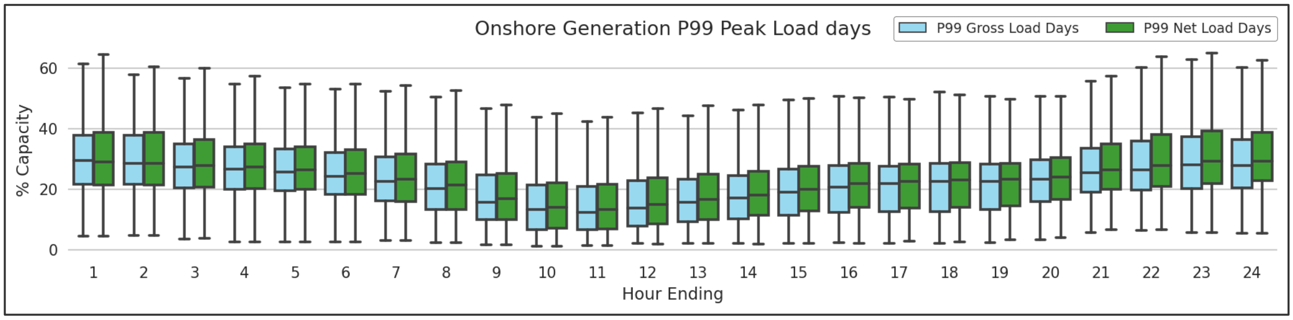

Figure 6-4 Hourly distributions of net onshore wind generation for days with peak load or net load greater than the 99th percentile of daily peaks

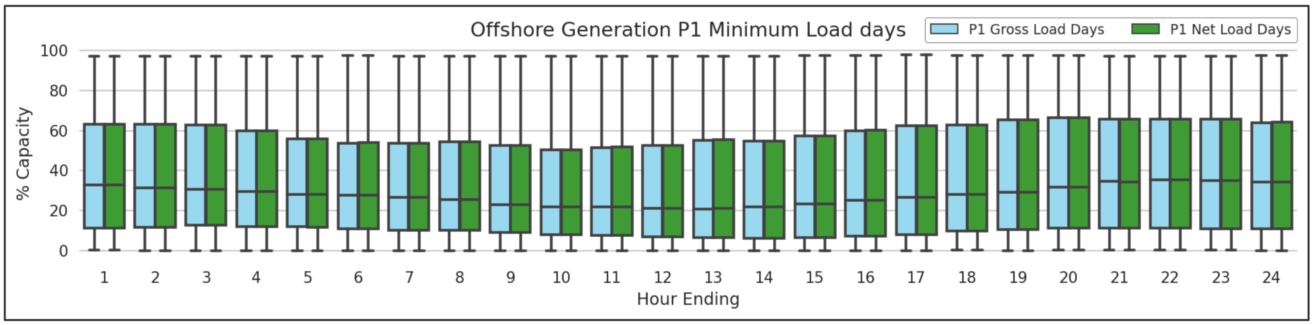

Figure 6-5 Hourly distributions of net offshore wind generation for days with daily minimum load or net load less than the 1st percentile of daily minimums

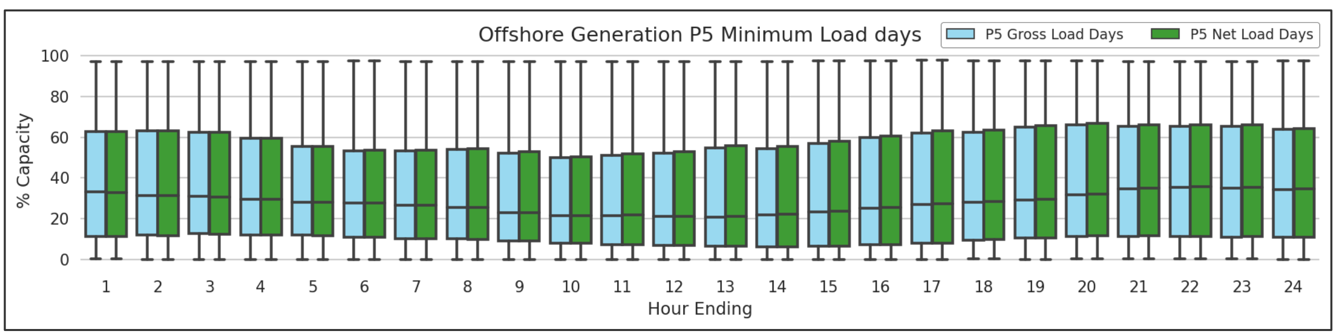

Figure 6-6 Hourly distributions net offshore wind generation for days with daily minimum load or net load less than the 5th percentile of daily minimums

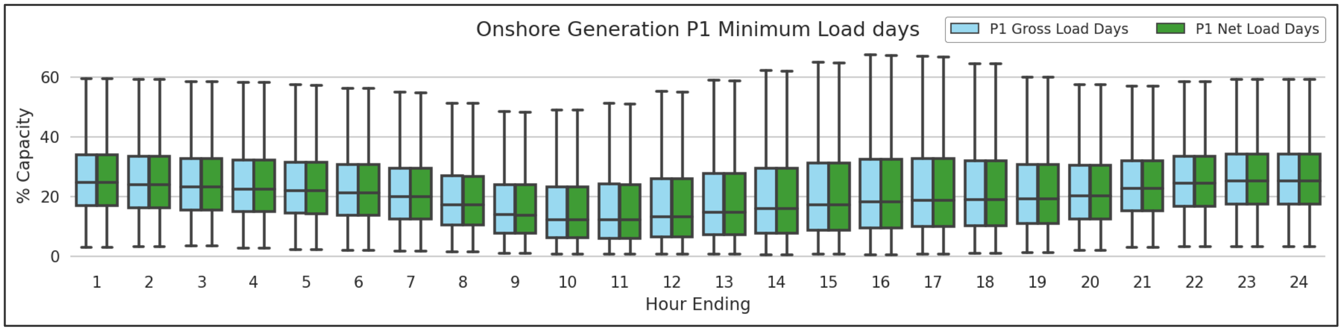

Figure 6-7 Hourly distributions of net onshore wind generation for days with daily minimum load or net load less than the 1st percentile of daily minimums

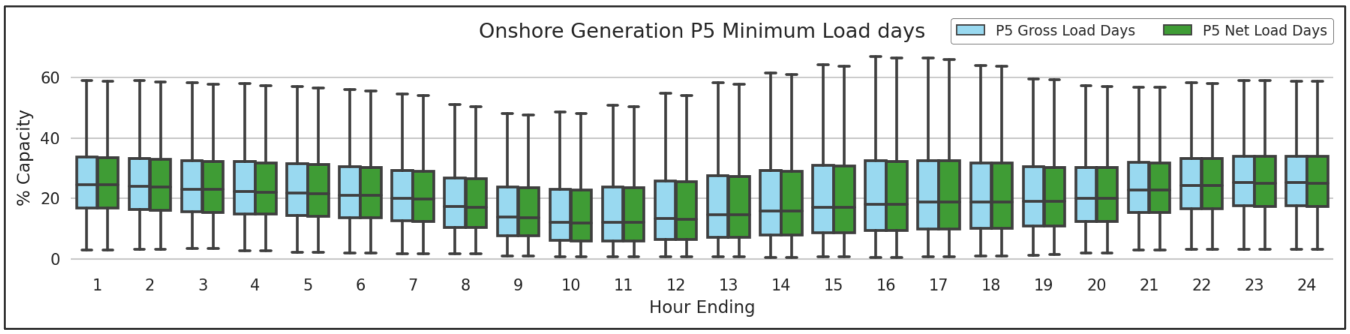

Figure 6-8 Hourly distributions of net onshore wind generation for days with daily minimum load or net load less than the 5th percentile of daily minimums

The distributions of onshore and offshore wind generation exhibit little variation during the peak and minimum gross and net load days. This is likely because the peak (minimum) net load days are often coincident with peak (minimum) gross load days, and so the wind generation will be very similar.

Note that the wind generation during peak load days exhibits a different diurnal profile than that during minimum load days. This may be due in part to seasonal differences in wind generation (peak days are during the summer while minimum days are during the shoulder seasons).

7 INTRA-DAY VARIABILITY OF WIND AND SOLAR GENERATION

Quantifying wind and solar ramp rates aids understanding of both the typical and maximum hour-to-hour changes in generation associated with weather dependent energy resources. DNV GL has performed an analysis of the stochastic dataset to determine the range and frequency of wind generation and solar generation ramps.

7.1 Methodology

A ramp is defined as the change in generation over time, expressed in the equation below.

$$\frac{\Delta\, Generation}{\Delta\, Time}$$

Time spans of 1, 2, 3, and 4 hours were examined. For this study, the units of generation are percent of capacity. To qualify as an up or down ramp the time changes must be non-decreasing for up ramps (time derivative greater than or equal to zero), and non-increasing for down ramps (time derivative less than or equal to zero) over the specified time interval.

An example of a number of wind ramps identified within a time series from the stochastic dataset is shown in the below. Up ramps over a 3-hour period are marked in red and down ramps in blue.

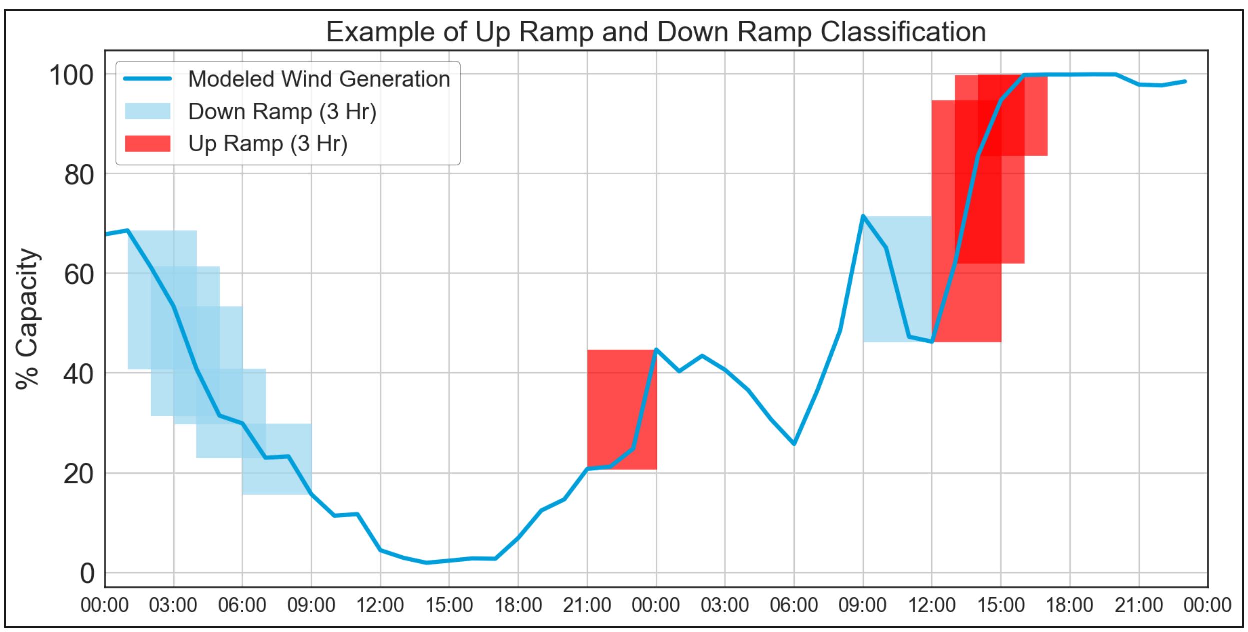

Figure 7-1 Example of up and down ramps over a 3-hour window for a threshold of at least 15% change in capacity

DNV GL has computed the up and down ramps for the offshore (existing and state-contracted) and onshore wind generation, solar generation, and the combined onshore and offshore wind plus solar generation from the stochastic dataset. The combined wind and solar generation were investigated to determine if they work together to mitigate ramps in renewable generation. The aggregated wind and solar data have been normalized by the total combined generation capacity of wind + solar. This has the effect of decreasing the generation as a percent total capacity at night due to the loss of over 7,700 MW of BTM solar PV.

An additional metric for quantifying the variability of wind or solar over a day is known as the "mileage," which is the total amount of hour-to-hour change that occurs throughout a day. The mileage of wind or solar generation over a single day is the sum of the absolute value of all 1-hour ramps.

Note that for this study, DNV GL has chosen to evaluate up ramp and down ramp events separately. From a grid operations perspective it can be easier to mitigate up ramps through wind farm control mechanisms or curtailment, while there is often little control over down ramps and so energy shortfalls to meet system load must often come from alternative sources.

7.2 Analysis

The magnitude and number of both up and down ramps as percent of capacity are nearly identical for both onshore and offshore wind generation, as shown Table 7-1 and Table 7-2.

Table 7-1 Mean and maximum magnitude of wind and solar generation up ramps

		Up ramps % of nameplate	
Ramp span	**Region source**	**Mean ramp (% capacity)**	**Max ramp (% capacity)**
1 hour	Onshore wind	2.4%	16.6%
	Offshore wind	4.8%	43.6%
	Solar	7.8%	30.6%
	Wind + solar	3.4%	20.8%
2 hours	Onshore wind	5.4%	26.5%
	Offshore wind	10.6%	63.1%
	Solar	15.4%	49.6%
	Wind + solar	8.5%	34.6%
3 hours	Onshore wind	8.7%	35.0%
	Offshore wind	17.7%	74.4%
	Solar	21.9%	65.8%
	Wind + solar	14.4%	45.0%
4 hours	Onshore wind	12.1%	41.6%
	Offshore wind	25.4%	81.1%
	Solar	26.5%	78.9%
	Wind + solar	20.2%	53.9%

The combination of all wind and solar generation does mitigate the ramps somewhat but onshore generation ramps still appear to be smaller.

Table 7-2 Mean and maximum magnitude of wind and solar generation down ramps

		Down ramps % of nameplate	
Ramp span	**Region source**	**Mean ramp (% capacity)**	**Max ramp (% capacity)**
1 hour	Onshore wind	-2.4%	-16.6%
	Offshore wind	-4.7%	-38.9%
	Solar	-7.7%	-29.5%
	Wind + solar	-3.3%	-20.1%
2 hours	Onshore wind	-5.4%	-26.8%
	Offshore wind	-10.1%	-55.7%
	Solar	-15.2%	-49.4%
	Wind + solar	-8.1%	-34.6%
3 hours	Onshore wind	-8.6%	-34.2%
	Offshore wind	-16.6%	-67.7%
	Solar	-21.6%	-65.0%
	Wind + solar	-13.8%	-47.0%
4 hours	Onshore wind	-11.9%	-39.6%
	Offshore wind	-23.6%	-75.3%
	Solar	-26.5%	-78.8%
	Wind + solar	-19.6%	-56.2%

Considering the variation in the average wind generation ramps it may be useful to look at the volatility of wind and solar generation over a typical day. The average mileage per day represents the total magnitude of change in generation during a typical day and is presented in Table 7-3. The relatively small geographic extent of the offshore wind area likely allows for more volatility throughout the day. Note that this does not mean that offshore wind generation is consistently going up and down throughout the day, but rather when generation changes do occur, they are typically larger than onshore.

Table 7-3 Average mileage per day

Ramp span	Region source	Average mileage per day (% capacity)	Maximum mileage per day (% capacity)
1 hour	Onshore wind	58.8%	156.0%
	Offshore wind	114.2%	444.8%
	Solar	106.1%	197.2%
	Wind + solar	82.1%	172.8%

Table 7-4 presents the frequency of up and down ramps greater than 0% capacity that exceed various capacity thresholds for ramp that span periods of 1 to 4 hours for offshore and onshore wind generation. For all 1-hour offshore wind generation ramps that were greater than 0% capacity, only 6% of them exceeded 15% capacity. Based on the criteria for wind ramps described above, up ramps are slightly more frequent than down ramps for changes in generation of at least 15% capacity. This may be due to passing frontal systems that drive rapid and strong increases in wind speeds, while down ramps often occur following the passage of frontal systems, which tends to be associated with a more gradual weakening of winds.

Table 7-4 Percent of wind ramps that exceed specified wind generation capacities

Ramp span	Capacity threshold	% of all up ramps			% of all down ramps		
		Onshore	Offshore	Wind+Solar	Onshore	Offshore	Wind+Solar
1 Hour	> 15%	0.0%	6.0%	0.6%	0.0%	5.5%	0.6%
	> 20%	0.0%	2.4%	0.0%	0.0%	2.0%	0.0%
	> 25%	0.0%	0.9%	0.0%	0.0%	0.7%	0.0%
	> 30%	0.0%	0.3%	0.0%	0.0%	0.2%	0.0%
2 Hours	> 15%	2.4%	25.5%	21.0%	2.3%	24.1%	18.9%
	> 20%	0.4%	15.1%	9.8%	0.4%	13.6%	8.1%
	> 25%	0.1%	8.8%	2.3%	0.1%	7.3%	2.0%
	> 30%	0.0%	5.0%	0.2%	0.0%	3.8%	0.3%
3 Hours	> 15%	12.0%	49.2%	44.3%	11.4%	47.2%	41.5%
	> 20%	3.7%	36.0%	30.9%	3.4%	33.5%	28.7%
	> 25%	1.0%	25.6%	19.4%	0.9%	22.8%	16.8%
	> 30%	0.2%	17.7%	9.3%	0.2%	14.9%	7.4%
4 Hours	> 15%	28.4%	68.0%	60.5%	27.0%	65.8%	58.2%
	> 20%	12.2%	56.1%	49.2%	11.4%	53.1%	47.7%
	> 25%	4.7%	45.0%	38.4%	4.1%	41.4%	36.2%
	> 30%	1.6%	35.2%	26.8%	1.2%	31.2%	23.9%

There are very few wind generation up or down ramps that exceed 30% of the aggregate capacity over a 1-hour period. Over a 4-hour period approximately 36% of offshore up ramps and 35% of offshore down ramps are greater than 31% of the aggregate capacity.

Figure 7-2 through Figure 7-5 present the distribution of up ramps and down ramps for offshore and onshore wind generation in terms of aggregate capacity for time spans of 1, 2, 3, and 4 hours. Up ramps and down ramps are presented separately.

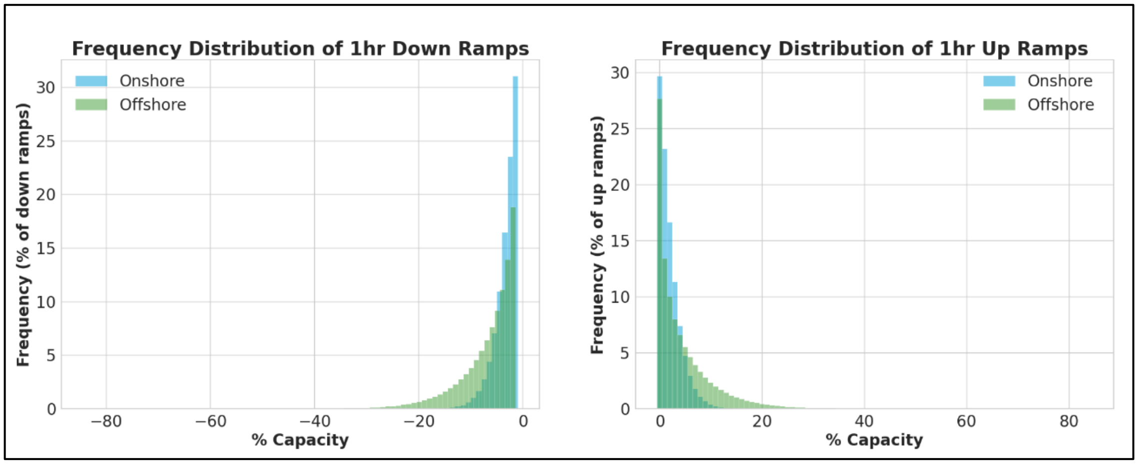

Figure 7-2 1-hour wind ramps for offshore and onshore generation

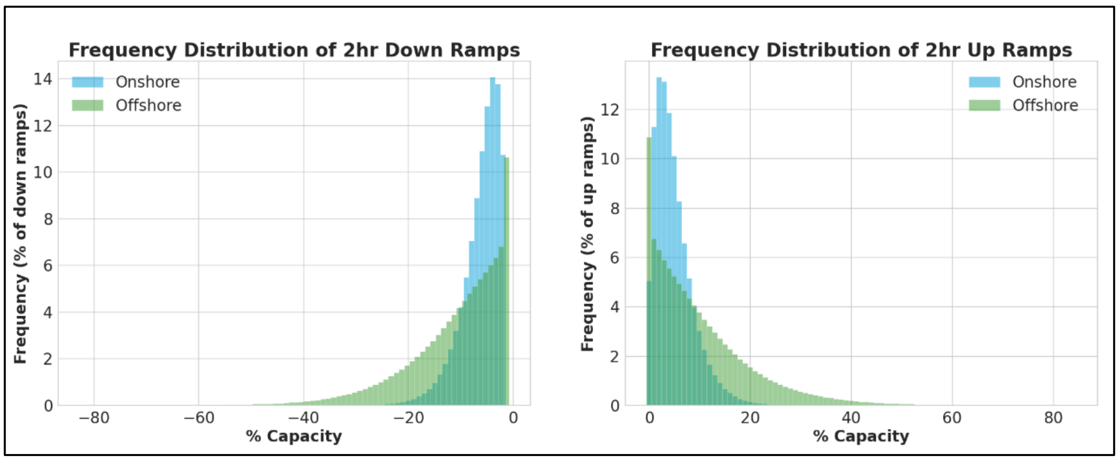

Figure 7-3 2-hour wind ramps for offshore and onshore generation

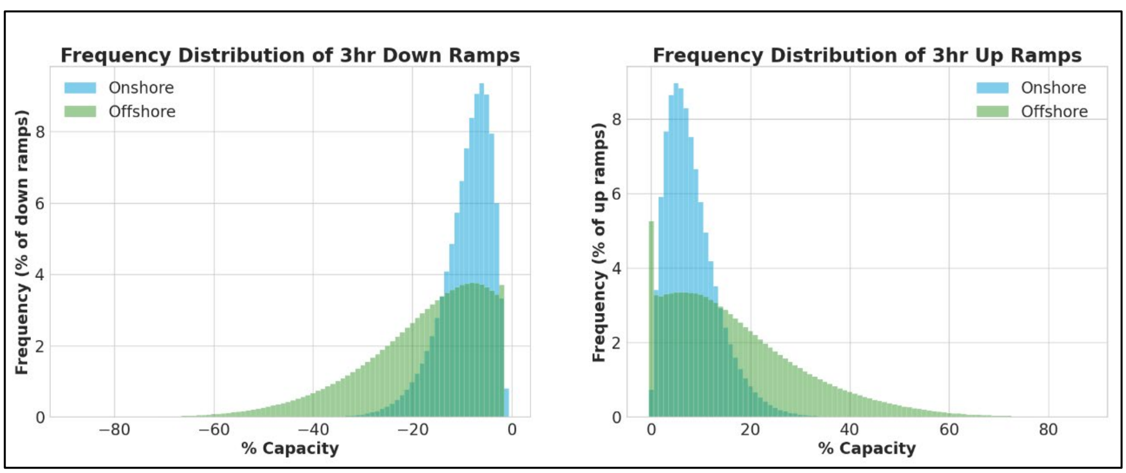

Figure 7-4 3-hour ramps for offshore and onshore wind generation

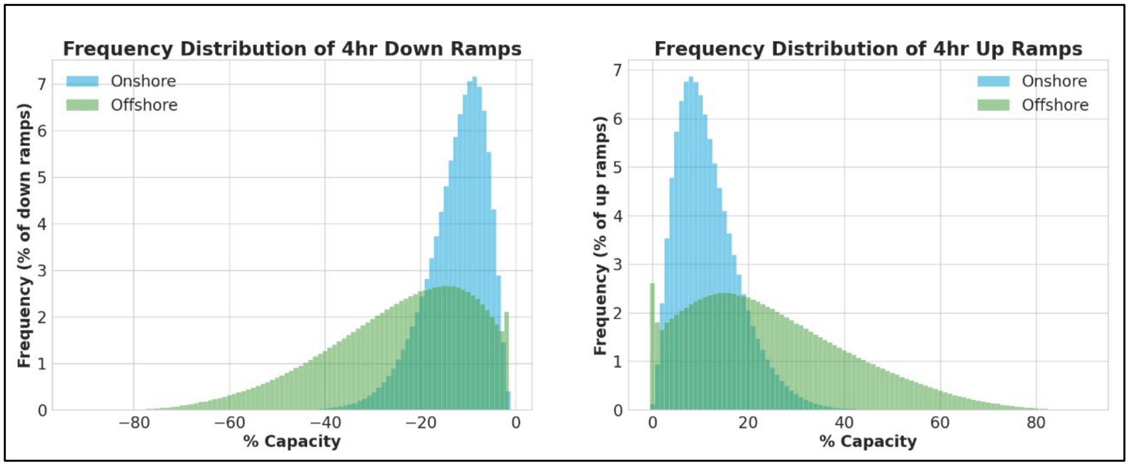

Figure 7-5 4-hour ramps for offshore and onshore wind generation

Wind generation ramps for offshore are overall higher in magnitude than for the onshore aggregate, where the onshore farms benefit from the smoothing or "portfolio effect" of geographic diversity, as well as the fact that wind flow is slowed by local terrain and roughness effects. To support the assumption that the offshore wind speeds are the drivers to the ramp differences, Figure 7-6 shows the distributions of the 3-hour wind speed ramps for offshore and onshore.

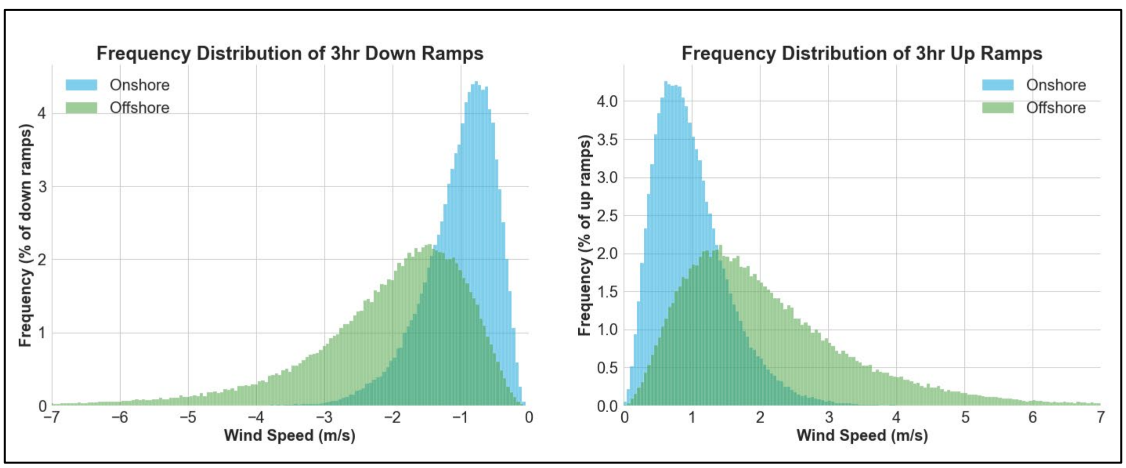

Figure 7-6 Frequency distributions of wind speed ramps over 3-hours for onshore and offshore wind

The probability of exceedance for wind generation ramps over 1, 2, 3, and 4-hour periods is presented in Table 7-5 through Table 7-8. The ramp rates are presented in terms of percent of capacity. For example, for 3-hour offshore aggregate wind generation up ramp events in Table 7-7, 10% exceeded 37.9% of the aggregate capacity. While for onshore aggregate wind generation there were no 3-hour ramp events that exceeded 32% capacity.

Table 7-5 Probability of exceedance for all onshore and offshore wind generation up and down ramps over a 1-hour period; values are percent of capacity

	Offshore		Onshore		Wind + solar	
Probability of exceedance	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**
Mean	4.8%	-4.7%	2.4%	-2.5%	3.5%	-3.4%
P50 (median)	2.9%	-2.9%	1.9%	-1.9%	2.0%	-2.0%
P90	12.1%	-11.9%	5.4%	-5.4%	9.4%	-9.0%
P95	16.0%	-15.5%	6.7%	-6.7%	11.4%	-11.0%
P99	24.5%	-23.1%	9.7%	-9.7%	14.3%	-14.2%
Max	85.1%	-83.9%	29.9%	-28.4%	36.1%	-32.6%

Table 7-6 Probability of exceedance for all onshore and offshore wind generation up and down ramps over a 2-hour period; values are percent of capacity

	Offshore		Onshore		Wind + solar	
Probability of exceedance	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**
Mean	10.6%	-10.1%	5.4%	-5.4%	8.6%	-8.2%
P50 (median)	8.0%	-7.8%	4.6%	-4.6%	6.6%	-6.0%
P90	23.8%	-22.5%	10.4%	-10.4%	19.9%	-19.0%
P95	30.0%	-27.9%	12.7%	-12.6%	22.8%	-22.0%
P99	42.8%	-39.0%	17.6%	-17.4%	26.8%	-26.9%
Max	85.3%	-82.2%	40.7%	-43.8%	51.4%	-55.1%

Table 7-7 Probability of exceedance for all onshore and offshore wind generation up and down ramps over a 3-hour period; values are percent of capacity

	Offshore		Onshore		Wind + Solar	
Probability of exceedance	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**
Mean	17.7%	-16.6%	8.7%	-8.6%	14.6%	-13.9%
P50 (median)	14.7%	-14.1%	7.7%	-7.6%	13.0%	-12.0%
P90	37.1%	-34.3%	15.8%	-15.6%	29.6%	-28.4%
P95	44.8%	-41.0%	18.8%	-18.5%	32.7%	-32.0%
P99	58.9%	-53.6%	25.1%	-24.5%	37.5%	-38.1%
Max	88.8%	-88.0%	50.4%	-48.1%	55.7%	-60.3%

Table 7-8 Probability of exceedance for all onshore and offshore wind generation up and down ramps over a 4-hour period; values are percent of capacity

	Offshore		Onshore		Wind + solar	
Probability of exceedance	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**	**Up ramp**	**Down ramp**
Mean	25.4%	-23.6%	12.1%	-11.9%	20.3%	-19.7%
P50 (median)	22.7%	-21.3%	11.0%	-10.8%	19.6%	-18.9%
P90	49.7%	-45.6%	21.1%	-20.7%	37.5%	-36.5%
P95	57.5%	-52.9%	24.7%	-24.1%	40.5%	-40.3%
P99	70.5%	-65.1%	31.9%	-30.9%	46.0%	-47.0%
Max	91.8%	-92.0%	58.0%	-52.6%	66.9%	-69.1%

Over a 1-hour period, 99% of wind generation ramps are less than 24.5% capacity for offshore and 9.7% capacity for onshore. Over a 4-hour period, 99% of offshore up ramps and down ramps are less than 70.5% capacity and 65% capacity, respectively. For onshore, 99% of 4-hour wind generation ramps are less than approximately 32% of aggregate capacity.

The smaller wind generation ramps onshore are expected given the geographic diversity of the onshore wind farms, which helps to smooth the hour-to-hour system level variations due to passing weather systems. This is because most weather systems will not simultaneously impact all wind farms across all New England. This is not the case with the smaller footprint of the offshore wind farms in the BOEM lease area south of Martha's Vineyard and Nantucket.

Understanding if there is a time-of-day dependence to wind ramps can be important for planning operations. For example, if wind ramps are generally weaker at night but stronger during the day, it may be useful to have additional reserves available during the day should wind suddenly decrease faster than expected. This time-of-day dependence has been investigated and the results are presented in Figure 7-7 to Figure 7-10 and Tables B-1 through B-24 in Appendix B.

Although there are fluctuations throughout the day there do not appear to be any major diurnal trends in the onshore and offshore wind ramp rates. What time-of-day dependence exists is likely related to the fact that wind speeds tend to climb in the late afternoon/early evening and decrease during the early morning hours. It does appear there is slightly more variation in wind ramps during the early morning hours around 3 a.m. to 4 a.m. than compared to the evening hours around 7 p.m.

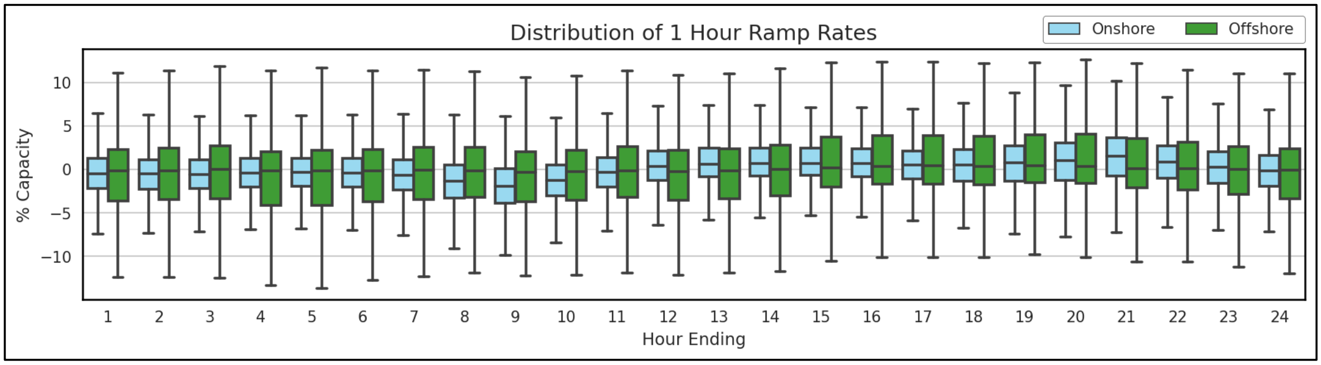

Figure 7-7 Distribution of 1-hour offshore and onshore wind generation ramps for each hour of the day

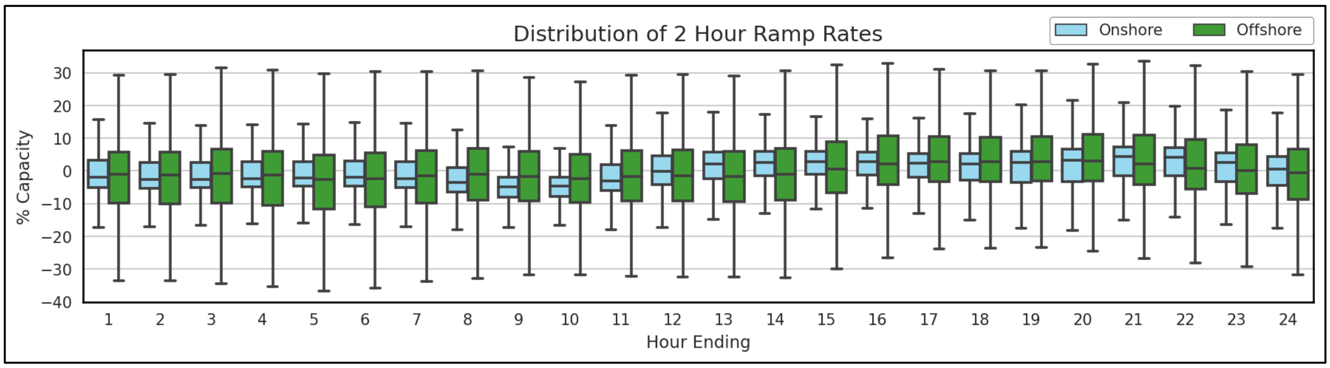

Figure 7-8 Distribution of 2-hour offshore and onshore wind generation ramps for each hour of the day

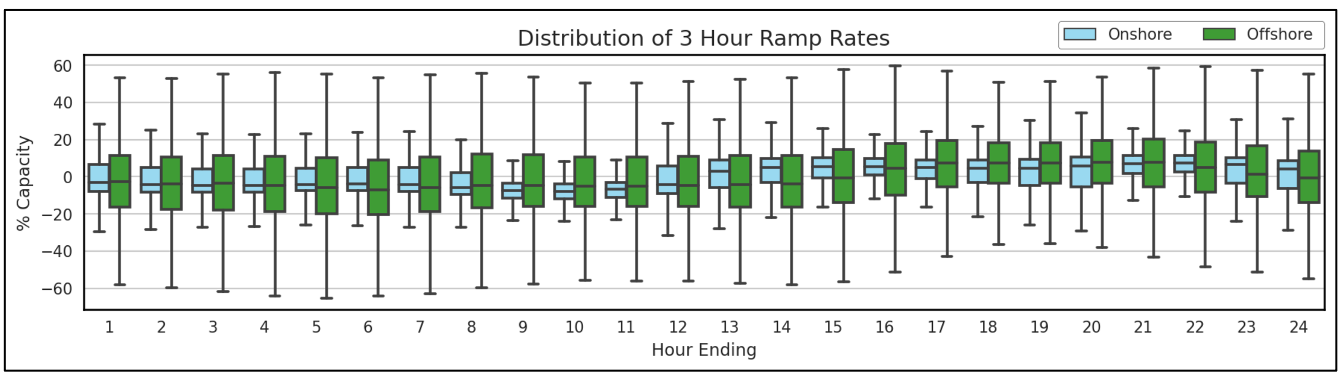

Figure 7-9 Distribution of 3-hour offshore and onshore wind generation ramps for each hour of the day

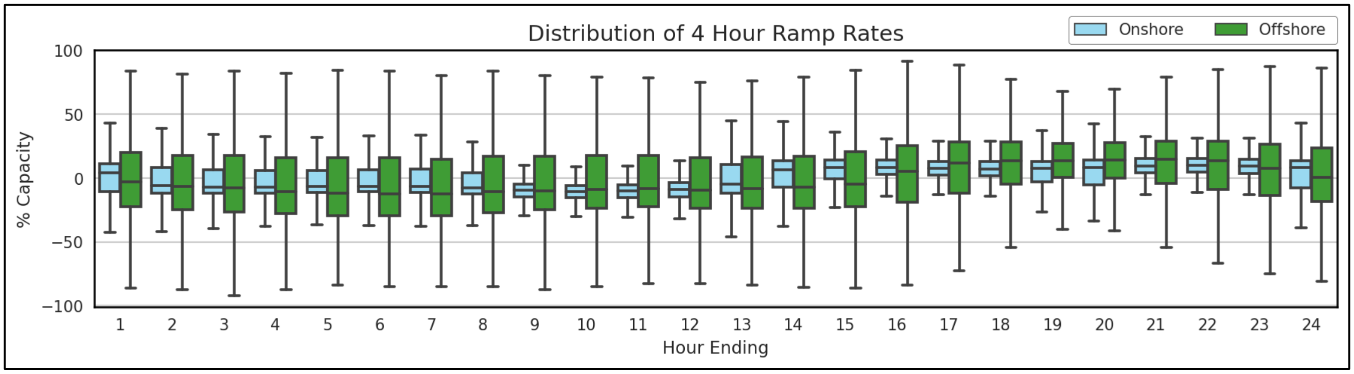

Figure 7-10 Distribution of 4-hour offshore and onshore wind generation ramps for each hour of the day

There is a noticeable diurnal trend in ramp rates when solar generation is combined with wind in Figure 7-11 through Figure 7-14. This trend can be attributed to the sunrise and sunset times. Of note though is that during the evening when solar generation is waning there is a slight increase in the wind generation.

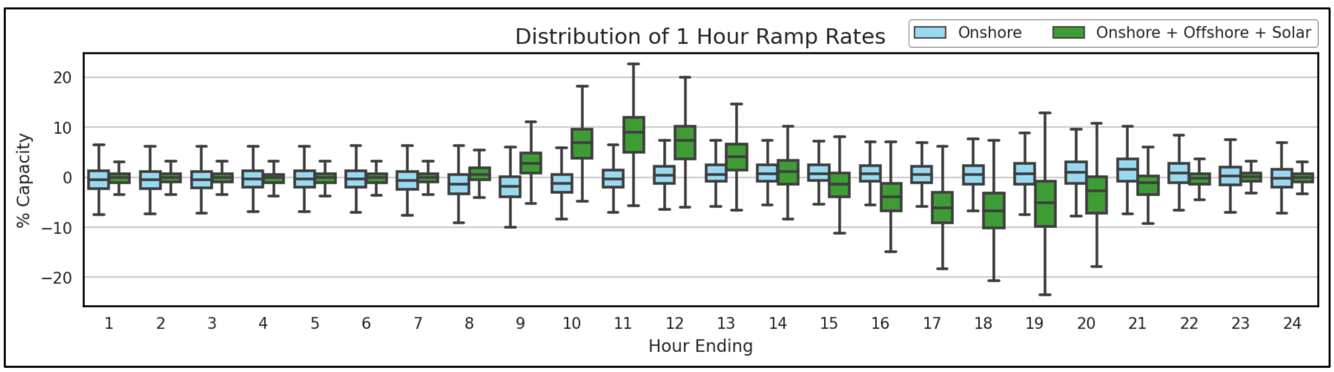

Figure 7-11 Distribution of 1-hour ramps for combined onshore and offshore wind and solar

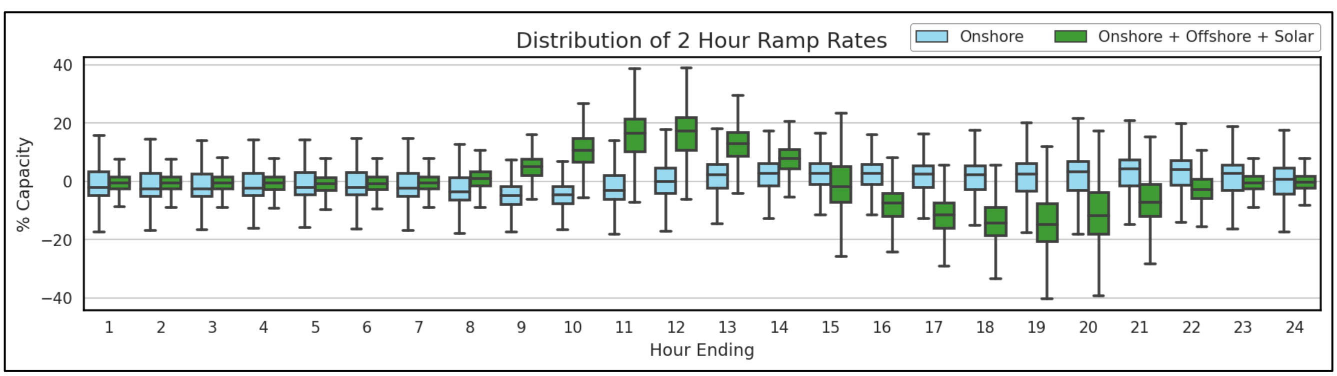

Figure 7-12 Distribution of 2-hour ramps for combined onshore and offshore wind and solar

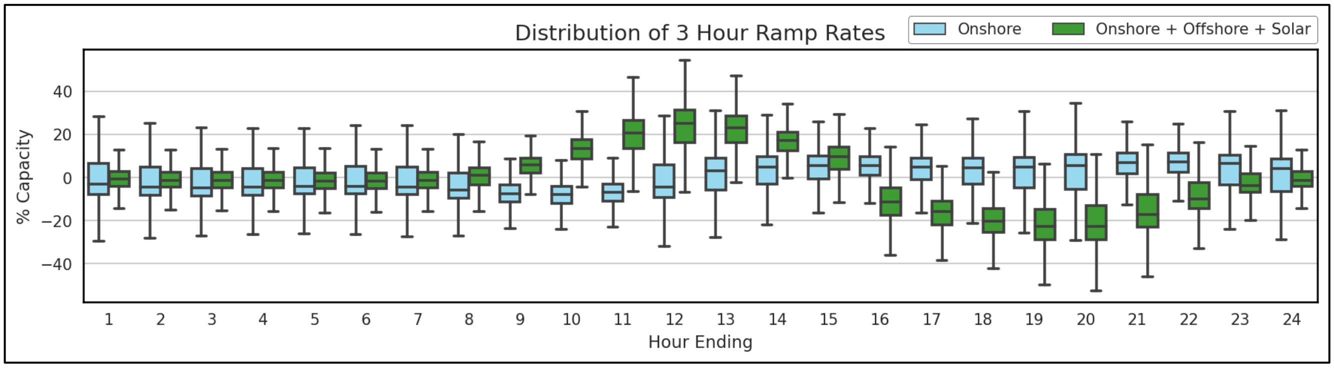

Figure 7-13 Distribution of 3-hour ramps for combined onshore and offshore wind and solar

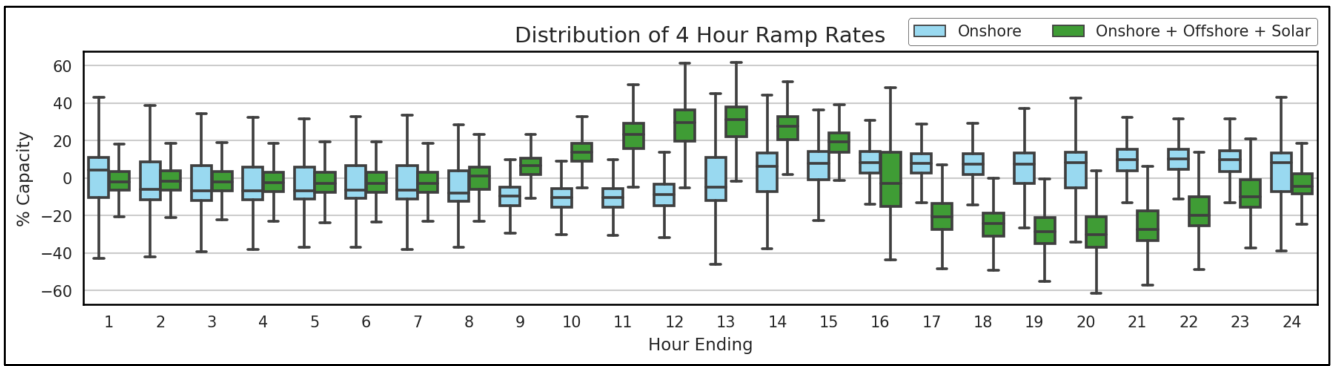

Figure 7-14 Distribution of 4-hour ramps for combined onshore and offshore wind and solar

The solar ramps are presented Figure 7-15 through Figure 7-18. The diurnal pattern of solar generation drives the hour-to-hour up and down ramps, but there is slight asymmetry in the up and down ramp distributions. When evaluating solar generation on an aggregate level, it is the morning and evening ramps that are likely to dominate the generation ramp calculations. Weather dependent generation ramps are generally mitigated by the geographic spread and number of rooftop systems such that any passing cloud bank that may cause a sudden drop in generation at a home or town will have minimal impact on the average aggregate. The only event likely to cause a largescale up or down ramp during the afternoon hours would be a solar eclipse occurring on a sunny day. DNV GL has not modeled solar eclipse events. A large passing cold front could have the potential to decrease solar generation across of New England at once but it is unlikely it would result in a sudden “drop” in generation.

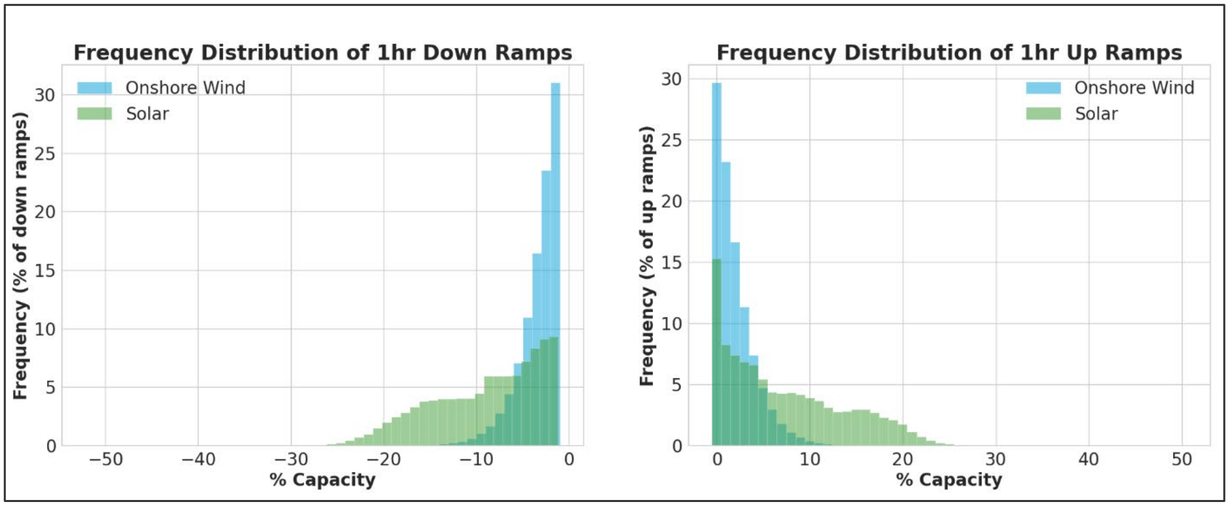

Figure 7-15 Frequency distribution of 1-hour up and down ramps of aggregate solar generation and onshore wind

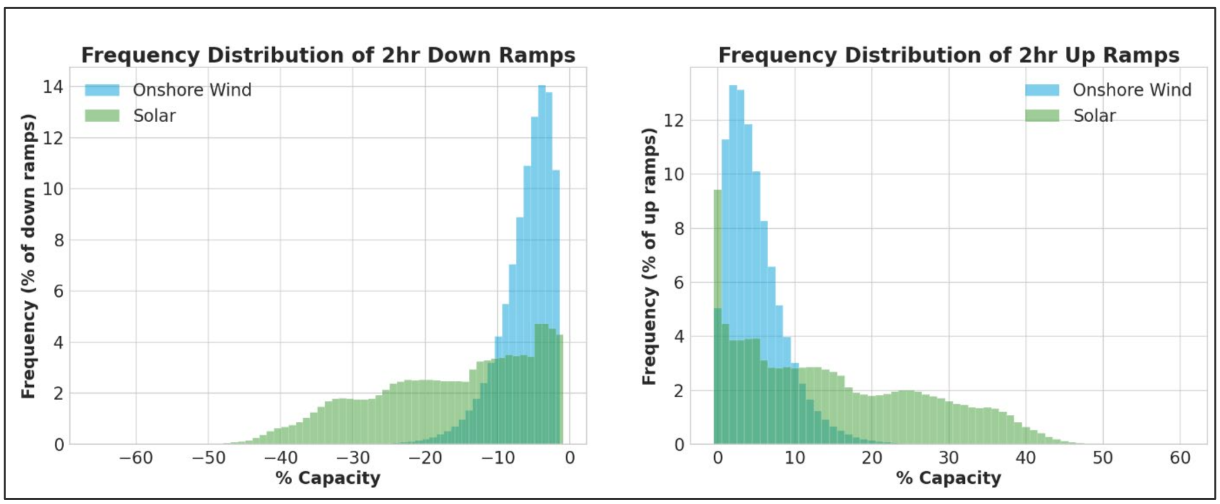

Figure 7-16 Frequency distribution of 2-hour up and down ramps of aggregate solar generation and onshore wind

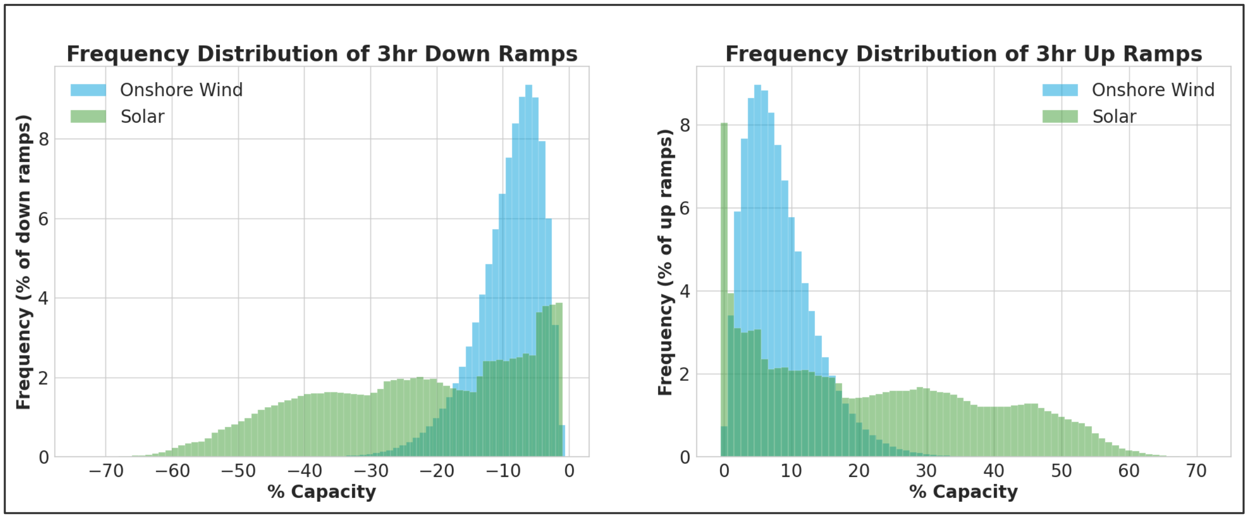

Figure 7-17 Frequency distribution of 3-hour up and down ramps of aggregate solar generation and onshore wind

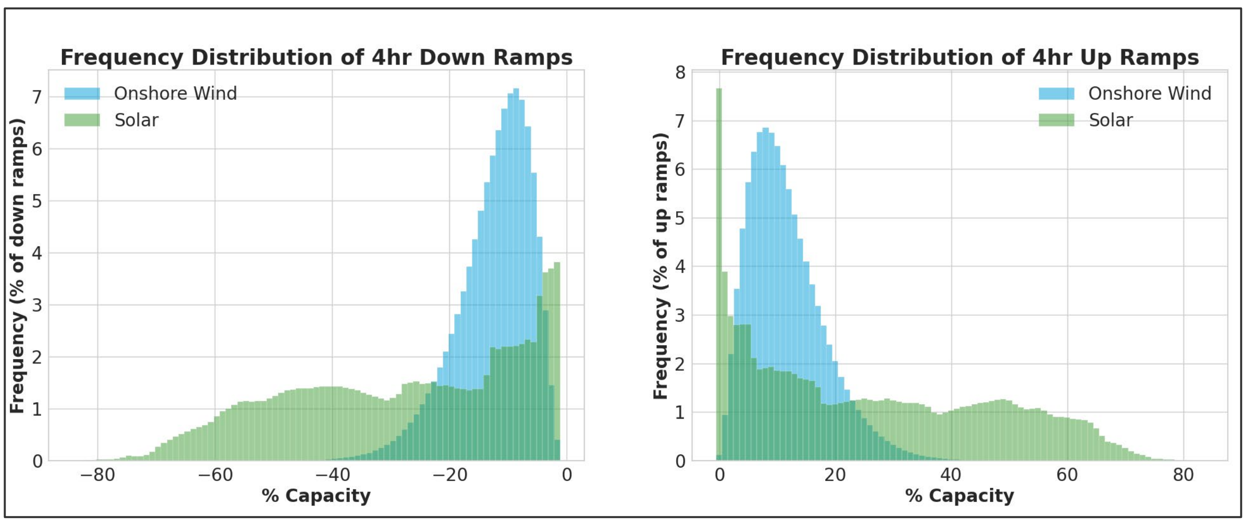

Figure 7-18 Frequency distribution of 4-hour up and down ramps of aggregate solar generation and onshore wind

Table 7-9 presents the solar generation capacity values that correspond to each quantile for up ramps and down ramps.

Table 7-9 Probability of exceedance values for all solar up and down ramps as percent of capacity

Probability of exceedance	Up ramp				Down ramp			
	1-hr	**2-hr**	**3-hr**	**4-hr**	**1-hr**	**2-hr**	**3-hr**	**4-hr**
Mean	7.7%	15.4%	21.9%	26.3%	-7.6%	-15.2%	-21.6%	-26.3%
P50 (median)	6.1%	13.2%	18.8%	22.6%	-6.4%	-13.0%	-19.8%	-23.6%
P90	17.5%	33.5%	47.0%	57.2%	-16.6%	-32.0%	-44.8%	-55.1%
P95	19.7%	37.3%	51.7%	62.8%	-18.8%	-35.5%	-49.7%	-60.7%
P99	22.7%	42.3%	58.0%	69.9%	-22.2%	-41.3%	-57.4%	-68.6%
Max	51.7%	62.0%	72.6%	84.2%	-51.6%	-65.3%	-73.5%	-83.6%

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APPENDIX A – TABLES OF GENERATION QUANTILES FOR P1, P5, P95 AND P99 LOAD DAYS

A.1 Tables for Section 6 Figures

Table A-1 Probability of exceedance for offshore wind generation during P95 gross load days; corresponds to Figure 6-1

Hour ending	Offshore wind during P95 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.5%	2.7%	4.5%	40.2%	42.2%	85.5%	89.1%	92.0%
2	1.1%	2.6%	4.6%	39.7%	41.9%	84.4%	88.5%	91.8%
3	1.2%	3.2%	5.1%	39.1%	41.6%	84.7%	88.5%	91.7%
4	1.6%	3.6%	5.8%	36.3%	40.5%	85.2%	88.9%	91.9%
5	1.6%	3.7%	5.6%	31.4%	38.2%	84.1%	88.3%	91.7%
6	1.8%	3.2%	4.7%	27.9%	36.2%	83.3%	88.2%	91.8%
7	1.7%	3.2%	4.7%	24.8%	35.4%	84.4%	88.8%	92.0%
8	1.3%	2.7%	4.4%	22.2%	34.7%	83.6%	88.4%	91.9%
9	1.0%	2.2%	3.6%	19.3%	33.2%	82.3%	88.1%	91.7%
10	1.0%	2.0%	3.4%	18.6%	31.8%	80.6%	87.3%	91.4%
11	0.8%	2.0%	3.3%	20.1%	32.0%	80.6%	87.1%	91.1%
12	0.8%	1.7%	3.0%	20.7%	32.5%	81.9%	87.5%	91.4%
13	0.7%	1.6%	2.7%	21.7%	33.8%	81.6%	87.3%	91.5%
14	0.8%	1.6%	2.8%	24.3%	34.5%	81.4%	87.8%	91.7%
15	0.7%	1.4%	2.5%	27.9%	36.7%	83.3%	88.5%	92.0%
16	1.1%	1.9%	2.9%	32.9%	39.5%	84.8%	89.0%	92.2%
17	1.8%	3.0%	4.2%	37.8%	42.1%	86.8%	89.9%	92.6%
18	2.5%	3.9%	5.5%	41.0%	43.9%	87.5%	90.2%	92.7%
19	2.5%	3.9%	5.7%	43.5%	45.8%	88.5%	90.6%	92.9%
20	2.5%	4.2%	6.4%	46.9%	47.9%	89.1%	91.0%	93.1%
21	2.3%	4.1%	6.5%	50.1%	49.1%	88.9%	90.8%	93.0%
22	1.6%	3.9%	6.3%	50.4%	49.8%	89.1%	90.9%	93.0%
23	1.6%	3.7%	6.4%	50.0%	49.9%	88.5%	90.6%	92.8%
24	1.6%	3.4%	6.2%	48.5%	48.6%	87.7%	90.1%	92.6%

Table A-2 Probability of exceedance for offshore wind generation during P95 net load days – Corresponds to Figure 6-1

Hour ending	Offshore wind during P95 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.4%	2.7%	4.6%	39.2%	40.9%	83.8%	88.4%	91.7%
2	1.1%	2.6%	4.7%	38.6%	40.7%	82.4%	87.5%	91.4%
3	1.2%	3.1%	5.1%	38.2%	40.5%	82.8%	87.5%	91.3%
4	1.6%	3.5%	5.7%	35.4%	39.5%	83.1%	88.0%	91.6%
5	1.6%	3.6%	5.5%	31.2%	37.4%	81.6%	87.4%	91.3%
6	1.8%	3.2%	4.7%	28.2%	35.5%	81.3%	87.4%	91.5%
7	1.7%	3.1%	4.6%	25.1%	34.8%	82.5%	88.1%	91.8%
8	1.4%	2.7%	4.4%	22.4%	34.0%	81.8%	87.6%	91.7%
9	1.1%	2.2%	3.6%	19.6%	32.6%	80.3%	87.3%	91.5%
10	1.0%	2.1%	3.5%	19.0%	31.3%	79.2%	86.6%	91.2%
11	0.8%	2.1%	3.4%	20.3%	31.8%	79.9%	86.7%	90.9%
12	0.8%	1.7%	3.1%	21.0%	32.4%	81.3%	87.1%	91.2%
13	0.7%	1.6%	2.8%	22.3%	33.8%	81.2%	86.9%	91.3%
14	0.8%	1.6%	2.8%	24.9%	34.6%	80.9%	87.4%	91.6%
15	0.7%	1.4%	2.4%	28.7%	36.9%	82.8%	88.1%	91.8%
16	1.1%	1.9%	2.9%	34.0%	39.8%	84.4%	88.7%	92.0%
17	1.7%	2.9%	4.3%	39.1%	42.6%	86.5%	89.7%	92.5%
18	2.4%	4.0%	5.8%	42.2%	44.4%	87.3%	90.0%	92.6%
19	2.5%	4.1%	6.0%	44.7%	46.3%	88.3%	90.5%	92.8%
20	2.5%	4.3%	7.0%	48.2%	48.6%	88.9%	90.9%	93.0%
21	2.3%	4.2%	7.1%	51.3%	49.8%	88.7%	90.7%	92.9%
22	1.5%	4.1%	6.9%	51.4%	50.6%	88.9%	90.8%	93.0%
23	1.6%	3.8%	7.2%	50.8%	50.6%	88.5%	90.6%	92.8%
24	1.6%	3.5%	6.9%	49.6%	49.4%	87.7%	90.2%	92.6%

Table A-3 Probability of exceedance for offshore wind generation during P99 gross load days – Corresponds to Figure 6-2

Hour ending	Offshore wind during P99 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.1%	2.0%	3.5%	45.7%	46.2%	87.5%	89.9%	92.3%
2	0.9%	2.0%	3.7%	45.4%	46.0%	86.5%	89.4%	92.1%
3	0.9%	2.5%	4.5%	46.2%	46.2%	86.7%	89.3%	91.9%
4	1.4%	3.0%	5.0%	46.7%	45.7%	86.7%	89.3%	92.1%
5	1.4%	3.3%	5.6%	44.2%	43.2%	85.0%	88.5%	91.5%
6	2.4%	3.7%	5.3%	40.5%	41.5%	83.7%	87.8%	91.3%
7	2.5%	4.3%	6.1%	36.9%	41.1%	83.5%	87.5%	91.3%
8	2.1%	4.5%	6.6%	36.0%	40.7%	82.0%	86.9%	91.1%
9	1.8%	4.1%	6.4%	34.8%	38.8%	80.2%	85.9%	90.9%
10	1.0%	3.9%	5.4%	32.9%	36.8%	78.5%	84.6%	90.2%
11	0.7%	3.7%	5.1%	33.4%	36.8%	77.8%	84.7%	90.0%
12	1.3%	3.0%	4.5%	31.6%	37.2%	80.3%	85.9%	90.2%
13	1.3%	2.6%	3.8%	33.6%	38.7%	80.3%	85.3%	90.4%
14	1.0%	2.5%	3.5%	36.7%	39.3%	80.8%	86.8%	91.2%
15	1.0%	2.2%	3.3%	41.9%	41.7%	83.7%	88.4%	91.7%
16	1.3%	2.7%	4.1%	49.8%	45.1%	85.7%	89.3%	92.2%
17	2.3%	3.5%	4.9%	54.0%	48.0%	87.6%	90.3%	92.7%
18	2.6%	4.1%	5.6%	54.4%	49.8%	88.4%	90.6%	92.9%
19	2.1%	3.7%	5.8%	56.3%	52.1%	89.5%	91.1%	93.0%
20	2.2%	3.5%	6.3%	58.1%	53.9%	89.9%	91.4%	93.2%
21	2.1%	3.3%	6.2%	59.3%	54.8%	89.6%	91.2%	93.2%
22	1.4%	2.8%	5.2%	58.5%	55.0%	89.7%	91.3%	93.2%
23	1.2%	2.4%	5.2%	54.9%	54.1%	89.7%	91.3%	93.2%
24	1.1%	2.0%	4.2%	50.3%	51.7%	89.2%	91.0%	93.0%

Table A-4 Probability of exceedance for offshore wind generation during P99 net load days – Corresponds to Figure 6-2

Hour ending	Offshore wind during P99 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.2%	2.2%	3.6%	43.5%	44.0%	86.0%	89.2%	92.1%
2	1.0%	2.2%	3.8%	43.3%	43.5%	84.5%	88.6%	91.8%
3	1.0%	2.9%	4.7%	43.5%	43.5%	84.8%	88.5%	91.6%
4	1.6%	3.4%	5.3%	42.7%	42.8%	84.8%	88.6%	91.7%
5	1.5%	3.9%	5.7%	39.8%	40.5%	82.7%	87.6%	91.1%
6	2.4%	3.9%	5.3%	35.3%	38.7%	81.4%	87.1%	90.9%
7	2.3%	4.0%	5.8%	30.8%	37.9%	81.6%	86.3%	90.7%
8	1.8%	3.6%	6.1%	28.3%	37.3%	79.7%	85.3%	90.6%
9	1.5%	3.0%	5.9%	24.0%	35.4%	77.5%	84.2%	90.5%
10	0.9%	3.0%	5.0%	23.0%	33.7%	76.1%	83.4%	89.9%
11	0.6%	3.3%	4.8%	26.3%	34.0%	76.2%	84.0%	89.9%
12	1.2%	2.6%	4.4%	25.2%	34.5%	78.4%	84.9%	90.2%
13	1.2%	2.4%	3.7%	26.6%	36.1%	79.2%	84.6%	90.2%
14	0.9%	2.1%	3.3%	29.7%	37.0%	79.5%	85.9%	91.0%
15	0.9%	1.9%	3.0%	34.7%	39.7%	82.4%	87.6%	91.6%
16	1.2%	2.4%	3.8%	42.1%	43.2%	84.8%	88.9%	92.1%
17	2.2%	3.4%	4.7%	48.5%	46.4%	87.2%	90.0%	92.7%
18	2.6%	4.2%	5.9%	51.7%	48.4%	88.1%	90.4%	92.9%
19	2.1%	3.8%	6.3%	54.7%	50.9%	89.1%	91.0%	93.0%
20	2.2%	3.7%	8.1%	57.6%	53.1%	89.6%	91.3%	93.2%
21	2.1%	3.5%	8.5%	58.8%	54.2%	89.5%	91.1%	93.2%
22	1.4%	3.0%	7.2%	58.3%	55.0%	89.7%	91.2%	93.2%
23	1.3%	2.5%	8.0%	54.9%	54.5%	89.7%	91.3%	93.3%
24	1.1%	2.1%	7.6%	51.4%	53.1%	89.3%	91.0%	93.1%

Table A-5 Probability of exceedance for onshore wind generation during P95 gross load days – Corresponds to Figure 6-3

Hour ending	Onshore wind during P95 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	6.5%	11.5%	13.6%	27.7%	28.3%	43.1%	46.3%	52.9%
2	6.6%	11.2%	13.8%	27.2%	27.9%	42.3%	45.6%	52.0%
3	5.9%	10.5%	13.4%	26.3%	27.0%	41.1%	44.8%	51.4%
4	4.7%	10.0%	12.8%	25.3%	26.1%	39.8%	43.6%	50.4%
5	4.4%	9.8%	12.1%	24.3%	25.2%	38.6%	42.1%	48.9%
6	4.7%	9.6%	11.8%	23.2%	24.1%	37.3%	40.9%	47.8%
7	4.9%	8.0%	10.3%	21.5%	22.4%	35.5%	39.5%	46.1%
8	4.0%	6.4%	8.1%	18.6%	19.8%	32.2%	35.5%	42.6%
9	2.8%	4.2%	5.3%	14.4%	16.1%	28.7%	31.8%	40.3%
10	1.9%	2.9%	3.9%	11.8%	14.1%	27.7%	31.1%	40.3%
11	2.1%	2.9%	3.6%	11.4%	13.9%	28.8%	33.0%	39.4%
12	2.5%	3.6%	4.5%	12.8%	15.4%	30.8%	35.2%	42.7%
13	2.8%	4.4%	5.5%	15.1%	17.2%	32.5%	37.9%	49.5%
14	2.9%	5.2%	6.3%	17.4%	18.9%	34.1%	40.8%	53.8%
15	3.0%	5.8%	7.2%	19.3%	20.8%	36.4%	43.3%	58.1%
16	3.5%	6.0%	7.9%	20.9%	22.3%	38.5%	45.8%	60.8%
17	3.7%	6.3%	8.3%	21.7%	22.8%	39.8%	46.9%	60.2%
18	3.7%	6.2%	7.9%	21.8%	22.7%	39.3%	45.7%	59.2%
19	4.1%	6.6%	8.2%	21.6%	22.4%	37.8%	44.2%	56.2%
20	5.2%	7.3%	9.6%	22.1%	23.1%	36.6%	42.7%	53.0%
21	7.7%	9.5%	12.4%	24.9%	25.9%	39.9%	45.4%	53.9%
22	8.2%	10.0%	13.2%	26.9%	27.5%	42.8%	47.0%	55.3%
23	7.9%	10.2%	13.9%	28.0%	28.3%	43.5%	47.0%	57.4%
24	7.4%	10.6%	14.3%	28.2%	28.7%	43.8%	47.6%	57.1%

Table A-6 Probability of exceedance for onshore wind generation during P95 net load days – Corresponds to Figure 6-3

Hour ending	Onshore wind during P95 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	6.6%	11.2%	13.4%	27.6%	28.2%	43.0%	46.1%	53.1%
2	6.6%	11.0%	13.6%	27.1%	27.8%	42.1%	45.3%	52.0%
3	5.9%	10.3%	13.3%	26.2%	26.9%	41.0%	44.6%	51.4%
4	4.7%	9.9%	12.6%	25.3%	26.1%	39.8%	43.7%	51.0%
5	4.4%	9.8%	11.9%	24.4%	25.2%	38.5%	42.3%	49.6%
6	4.6%	9.5%	11.7%	23.5%	24.2%	37.2%	41.0%	48.2%
7	4.8%	7.9%	10.4%	21.6%	22.5%	35.4%	39.6%	46.8%
8	3.9%	6.5%	8.3%	18.9%	20.0%	32.2%	35.7%	43.6%
9	2.8%	4.4%	5.5%	14.5%	16.3%	28.8%	32.3%	41.9%
10	1.9%	3.1%	4.1%	12.0%	14.4%	27.9%	31.6%	42.2%
11	2.2%	3.1%	3.8%	11.6%	14.2%	29.0%	33.4%	40.7%
12	2.6%	3.7%	4.6%	13.1%	15.7%	30.9%	35.5%	44.0%
13	3.1%	4.6%	5.7%	15.3%	17.5%	32.7%	38.1%	51.1%
14	3.6%	5.5%	6.6%	17.5%	19.2%	34.6%	41.2%	55.0%
15	3.7%	6.2%	7.5%	19.5%	21.1%	37.1%	44.2%	58.7%
16	4.2%	6.6%	8.2%	21.2%	22.7%	39.3%	46.6%	61.2%
17	4.3%	6.8%	8.6%	22.1%	23.3%	40.5%	48.0%	60.6%
18	4.2%	6.6%	8.3%	22.3%	23.1%	39.8%	47.0%	59.9%
19	4.6%	6.9%	8.6%	22.0%	22.8%	38.4%	45.2%	57.7%
20	5.6%	7.6%	10.0%	22.7%	23.7%	37.3%	44.0%	55.7%
21	8.0%	9.8%	12.8%	25.3%	26.5%	40.5%	46.5%	55.8%
22	8.5%	10.3%	13.9%	27.3%	28.0%	43.4%	47.9%	57.9%
23	8.0%	10.6%	14.6%	28.3%	28.8%	44.0%	48.0%	59.5%
24	7.5%	11.1%	15.0%	28.5%	29.2%	44.3%	48.6%	59.6%

Table A-7 Probability of exceedance for onshore wind generation during P99 gross load days – Corresponds to Figure 6-4

Hour ending	Onshore wind during P99 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	5.7%	7.5%	15.7%	29.5%	29.5%	43.6%	46.4%	50.0%
2	6.0%	7.3%	15.4%	28.5%	29.0%	43.2%	46.7%	51.1%
3	5.0%	7.5%	14.6%	27.5%	27.7%	41.6%	46.1%	51.9%
4	3.9%	7.0%	13.0%	26.8%	26.7%	39.7%	45.4%	51.4%
5	3.7%	9.2%	12.2%	25.8%	26.1%	38.4%	43.2%	48.9%
6	3.9%	10.4%	13.5%	24.3%	25.2%	37.9%	42.5%	48.0%
7	4.2%	8.7%	12.5%	22.5%	23.5%	36.8%	41.6%	47.3%
8	3.5%	6.9%	10.4%	20.3%	21.0%	33.4%	37.5%	43.3%
9	2.5%	4.7%	6.6%	15.6%	17.6%	30.4%	34.7%	42.3%
10	2.1%	3.4%	4.6%	13.3%	15.5%	29.7%	35.0%	44.6%
11	2.6%	3.3%	4.1%	12.5%	15.0%	31.2%	34.8%	39.5%
12	3.2%	4.0%	4.8%	13.8%	16.5%	34.2%	38.2%	43.7%
13	4.2%	5.1%	6.0%	15.6%	18.0%	35.6%	40.1%	52.2%
14	4.9%	6.1%	7.1%	17.2%	19.3%	33.8%	44.3%	57.8%
15	5.4%	6.9%	8.3%	19.1%	21.1%	34.7%	48.2%	63.8%
16	5.1%	7.6%	8.8%	20.8%	22.5%	36.0%	51.8%	67.1%
17	5.2%	8.0%	9.1%	22.0%	22.8%	36.3%	52.3%	64.1%
18	4.8%	6.9%	8.3%	22.7%	22.9%	37.0%	49.9%	62.5%
19	4.7%	6.9%	8.2%	22.7%	22.9%	36.2%	50.1%	58.7%
20	5.6%	7.1%	8.2%	23.3%	23.8%	37.7%	47.4%	54.8%
21	7.9%	8.9%	10.1%	25.4%	26.3%	41.3%	48.7%	53.5%
22	8.1%	9.1%	10.2%	26.5%	27.5%	43.8%	49.2%	53.5%
23	7.3%	8.6%	11.5%	28.1%	28.4%	44.4%	48.0%	53.3%
24	6.9%	7.9%	12.5%	27.9%	28.5%	44.4%	48.4%	54.7%

Table A-8 Probability of exceedance for onshore wind generation during P99 net load days – Corresponds to Figure 6-4

Hour ending	Onshore wind during P99 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	6.0%	8.3%	14.5%	29.2%	29.8%	44.3%	46.8%	50.2%
2	6.1%	7.9%	14.5%	28.6%	29.3%	43.6%	46.9%	51.1%
3	5.3%	8.3%	14.2%	27.8%	28.2%	42.3%	46.1%	51.8%
4	4.0%	7.9%	12.8%	27.3%	27.2%	40.5%	45.5%	51.4%
5	3.8%	9.8%	12.0%	26.4%	26.5%	38.9%	43.4%	49.0%
6	4.1%	11.0%	13.2%	25.2%	25.7%	s38.4%	42.7%	48.1%
7	4.4%	9.8%	12.5%	23.5%	24.1%	37.5%	42.0%	47.4%
8	3.7%	8.0%	10.4%	21.5%	21.7%	33.6%	37.5%	43.7%
9	2.7%	5.2%	6.8%	16.9%	18.1%	30.3%	34.7%	42.5%
10	2.3%	3.9%	4.8%	14.0%	16.0%	29.9%	35.2%	44.7%
11	2.7%	3.5%	4.4%	13.4%	15.7%	31.9%	35.2%	40.2%
12	3.3%	4.3%	5.0%	14.9%	17.3%	35.0%	38.9%	44.8%
13	4.4%	5.4%	6.3%	16.6%	19.0%	36.4%	41.8%	53.7%
14	5.1%	6.3%	7.5%	18.0%	20.5%	36.5%	46.2%	58.9%
15	5.5%	7.1%	8.8%	20.0%	22.4%	39.4%	50.6%	65.0%
16	5.3%	7.9%	9.5%	21.8%	23.8%	41.3%	54.6%	68.3%
17	5.3%	8.3%	9.6%	22.7%	24.0%	42.5%	55.1%	65.0%
18	4.8%	7.8%	9.4%	23.2%	24.0%	42.7%	53.9%	63.5%
19	4.8%	7.7%	9.1%	23.4%	24.1%	42.2%	52.7%	60.5%
20	5.7%	7.5%	10.5%	24.0%	25.0%	41.3%	49.9%	57.9%
21	8.1%	9.3%	11.8%	26.5%	27.8%	44.2%	50.4%	56.0%
22	8.3%	9.6%	13.3%	28.0%	29.2%	46.2%	50.6%	57.7%
23	7.3%	8.8%	13.8%	29.4%	30.1%	45.4%	49.6%	58.9%
24	6.9%	8.0%	14.3%	29.3%	30.2%	45.4%	50.5%	58.7%

Table A-9 Probability of exceedance for offshore wind generation during P5 gross load days – Corresponds to Figure 6-5

Hour ending	Offshore wind during P5 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.4%	2.7%	4.4%	33.0%	38.7%	86.0%	89.6%	92.4%
2	1.1%	2.5%	4.4%	31.4%	38.2%	85.0%	89.2%	92.3%
3	1.0%	2.6%	4.7%	30.8%	38.1%	84.8%	89.2%	92.3%
4	1.1%	2.8%	4.9%	29.5%	37.0%	84.6%	89.2%	92.3%
5	1.2%	2.8%	4.8%	28.1%	35.7%	82.9%	89.0%	92.3%
6	1.3%	2.7%	4.2%	27.6%	34.9%	83.1%	89.2%	92.4%
7	1.4%	2.7%	4.2%	26.4%	34.5%	84.0%	89.3%	92.4%
8	1.2%	2.6%	4.1%	25.3%	34.2%	83.5%	89.0%	92.3%
9	0.9%	2.1%	3.6%	22.8%	32.8%	82.8%	88.6%	92.1%
10	0.9%	1.9%	3.1%	21.5%	31.6%	82.3%	88.4%	91.9%
11	0.8%	1.9%	3.0%	21.6%	31.7%	82.8%	88.4%	91.9%
12	0.7%	1.6%	2.6%	21.0%	31.6%	82.9%	88.6%	92.0%
13	0.6%	1.3%	2.2%	20.9%	31.9%	82.1%	88.3%	92.0%
14	0.6%	1.2%	2.0%	21.9%	32.0%	82.0%	88.6%	92.1%
15	0.5%	1.1%	1.9%	23.1%	33.1%	83.6%	89.1%	92.3%
16	0.7%	1.4%	2.2%	24.9%	34.6%	84.6%	89.3%	92.4%
17	0.9%	1.8%	2.9%	26.8%	35.9%	85.5%	89.7%	92.6%
18	1.1%	2.3%	3.5%	28.0%	36.7%	85.8%	89.7%	92.6%
19	1.4%	2.7%	4.1%	29.2%	38.0%	86.6%	89.9%	92.6%
20	1.6%	3.0%	4.5%	31.6%	39.1%	87.0%	90.1%	92.8%
21	1.5%	3.0%	4.6%	34.5%	39.7%	86.9%	90.1%	92.7%
22	1.4%	2.9%	4.5%	35.2%	39.9%	87.3%	90.2%	92.7%
23	1.4%	2.8%	4.4%	35.1%	39.8%	86.9%	90.0%	92.6%
24	1.3%	2.7%	4.3%	34.3%	39.2%	86.2%	89.7%	92.5%

Table A-10 Probability of exceedance for offshore wind generation during P5 net load days – Corresponds to Figure 6-5

Hour ending	Offshore wind during P5 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.4%	2.7%	4.4%	32.7%	38.6%	86.0%	89.6%	92.4%
2	1.1%	2.5%	4.3%	31.2%	38.1%	85.0%	89.2%	92.3%
3	1.0%	2.6%	4.7%	30.6%	38.0%	84.7%	89.2%	92.3%
4	1.1%	2.8%	4.8%	29.4%	37.0%	84.6%	89.2%	92.3%
5	1.2%	2.8%	4.8%	28.0%	35.7%	83.0%	89.0%	92.3%
6	1.3%	2.6%	4.2%	27.5%	34.9%	83.3%	89.2%	92.4%
7	1.3%	2.7%	4.2%	26.4%	34.5%	84.2%	89.3%	92.4%
8	1.1%	2.5%	4.1%	25.4%	34.3%	83.6%	89.1%	92.3%
9	0.8%	2.0%	3.5%	22.9%	33.0%	83.0%	88.7%	92.1%
10	0.9%	1.9%	3.1%	21.6%	31.8%	82.7%	88.5%	92.0%
11	0.8%	1.8%	2.9%	21.7%	32.0%	83.2%	88.5%	91.9%
12	0.7%	1.6%	2.6%	21.2%	31.9%	83.4%	88.7%	92.0%
13	0.6%	1.3%	2.2%	21.1%	32.3%	82.6%	88.5%	92.0%
14	0.6%	1.2%	2.0%	22.2%	32.3%	82.7%	88.8%	92.2%
15	0.5%	1.1%	1.9%	23.5%	33.5%	84.3%	89.2%	92.3%
16	0.7%	1.4%	2.2%	25.4%	35.0%	85.1%	89.5%	92.4%
17	0.9%	1.8%	2.9%	27.2%	36.3%	86.0%	89.8%	92.6%
18	1.1%	2.3%	3.6%	28.3%	37.0%	86.2%	89.8%	92.6%
19	1.4%	2.8%	4.1%	29.6%	38.3%	86.9%	90.0%	92.7%
20	1.6%	3.0%	4.5%	31.9%	39.4%	87.2%	90.2%	92.8%
21	1.5%	3.0%	4.6%	34.9%	39.9%	87.1%	90.1%	92.7%
22	1.4%	2.9%	4.5%	35.6%	40.2%	87.4%	90.2%	92.7%
23	1.4%	2.8%	4.4%	35.4%	40.1%	87.1%	90.1%	92.7%
24	1.3%	2.7%	4.3%	34.6%	39.4%	86.4%	89.8%	92.5%

Table A-11 Probability of exceedance for offshore wind generation during P1 gross load days – Corresponds to Figure 6-6

Hour ending	Offshore wind during P1 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.4%	2.7%	4.4%	32.9%	38.7%	86.1%	89.6%	92.4%
2	1.1%	2.5%	4.3%	31.3%	38.2%	85.1%	89.3%	92.3%
3	1.0%	2.6%	4.7%	30.7%	38.1%	84.8%	89.2%	92.3%
4	1.1%	2.8%	4.8%	29.5%	37.1%	84.6%	89.3%	92.3%
5	1.2%	2.8%	4.8%	28.1%	35.8%	83.1%	89.0%	92.3%
6	1.3%	2.6%	4.2%	27.6%	35.0%	83.3%	89.2%	92.4%
7	1.3%	2.7%	4.2%	26.5%	34.5%	84.2%	89.3%	92.4%
8	1.1%	2.5%	4.1%	25.4%	34.3%	83.6%	89.1%	92.3%
9	0.8%	2.1%	3.6%	22.9%	32.9%	82.9%	88.7%	92.1%
10	0.9%	1.9%	3.1%	21.6%	31.8%	82.5%	88.5%	92.0%
11	0.8%	1.9%	3.0%	21.7%	31.9%	83.0%	88.4%	91.9%
12	0.7%	1.6%	2.6%	21.1%	31.7%	83.1%	88.6%	92.0%
13	0.6%	1.3%	2.2%	20.9%	32.0%	82.3%	88.4%	92.0%
14	0.6%	1.2%	2.0%	21.9%	32.0%	82.2%	88.7%	92.2%
15	0.5%	1.1%	1.9%	23.1%	33.2%	83.9%	89.1%	92.3%
16	0.7%	1.4%	2.2%	25.0%	34.6%	84.8%	89.4%	92.4%
17	0.9%	1.8%	2.9%	26.7%	36.0%	85.7%	89.7%	92.6%
18	1.1%	2.3%	3.5%	28.0%	36.8%	86.0%	89.7%	92.6%
19	1.4%	2.7%	4.1%	29.3%	38.0%	86.7%	89.9%	92.6%
20	1.6%	3.0%	4.5%	31.6%	39.1%	87.1%	90.1%	92.8%
21	1.5%	2.9%	4.6%	34.4%	39.7%	87.0%	90.1%	92.7%
22	1.4%	2.9%	4.5%	35.2%	40.0%	87.3%	90.2%	92.7%
23	1.4%	2.8%	4.4%	35.0%	39.8%	87.0%	90.0%	92.6%
24	1.3%	2.7%	4.3%	34.2%	39.2%	86.3%	89.8%	92.5%

Table A-12 Probability of exceedance for offshore wind generation during P1 net load days – Corresponds to Figure 6-6

Hour ending	Offshore wind during P1 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	1.4%	2.7%	4.4%	32.8%	38.7%	86.1%	89.6%	92.4%
2	1.1%	2.5%	4.3%	31.3%	38.2%	85.1%	89.3%	92.3%
3	1.0%	2.6%	4.7%	30.7%	38.1%	84.9%	89.2%	92.3%
4	1.1%	2.8%	4.8%	29.5%	37.1%	84.7%	89.3%	92.3%
5	1.2%	2.7%	4.7%	28.1%	35.8%	83.1%	89.0%	92.3%
6	1.3%	2.6%	4.2%	27.7%	35.0%	83.4%	89.2%	92.4%
7	1.3%	2.7%	4.2%	26.5%	34.6%	84.2%	89.3%	92.4%
8	1.1%	2.5%	4.1%	25.5%	34.3%	83.7%	89.1%	92.3%
9	0.8%	2.1%	3.5%	23.0%	33.0%	83.0%	88.7%	92.1%
10	0.9%	1.9%	3.1%	21.7%	31.8%	82.6%	88.5%	92.0%
11	0.8%	1.9%	3.0%	21.7%	31.9%	83.1%	88.4%	91.9%
12	0.7%	1.6%	2.6%	21.2%	31.8%	83.2%	88.6%	92.0%
13	0.6%	1.3%	2.2%	21.0%	32.1%	82.4%	88.4%	92.0%
14	0.6%	1.2%	2.0%	21.9%	32.1%	82.4%	88.7%	92.2%
15	0.5%	1.1%	1.9%	23.2%	33.3%	84.0%	89.2%	92.3%
16	0.7%	1.4%	2.2%	25.0%	34.7%	84.9%	89.4%	92.4%
17	0.9%	1.8%	2.9%	26.7%	36.0%	85.8%	89.7%	92.6%
18	1.1%	2.3%	3.5%	28.0%	36.8%	86.1%	89.8%	92.6%
19	1.4%	2.7%	4.1%	29.3%	38.0%	86.7%	90.0%	92.7%
20	1.6%	3.0%	4.5%	31.6%	39.2%	87.2%	90.2%	92.8%
21	1.5%	2.9%	4.6%	34.4%	39.8%	87.0%	90.1%	92.7%
22	1.4%	2.9%	4.5%	35.2%	40.0%	87.4%	90.2%	92.7%
23	1.4%	2.8%	4.4%	34.9%	39.8%	87.0%	90.0%	92.7%
24	1.3%	2.7%	4.3%	34.2%	39.2%	86.4%	89.8%	92.5%

Table A-13 Probability of exceedance for onshore wind generation during P5 gross load days – Corresponds to Figure 6-7

Hour ending	Onshore wind during P5 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	7.1%	9.6%	11.7%	24.6%	26.4%	43.2%	49.5%	62.8%
2	6.8%	9.1%	11.2%	23.9%	25.8%	42.6%	48.9%	61.9%
3	6.2%	8.6%	10.5%	23.1%	25.1%	42.0%	48.7%	61.1%
4	5.6%	8.0%	10.0%	22.3%	24.4%	41.4%	48.1%	60.8%
5	5.1%	7.7%	9.6%	21.7%	23.9%	41.1%	47.8%	60.9%
6	4.7%	7.2%	9.1%	21.1%	23.3%	40.7%	47.7%	61.2%
7	4.1%	6.5%	8.2%	19.9%	22.3%	40.1%	47.2%	61.4%
8	3.3%	5.3%	6.7%	17.2%	20.1%	37.9%	45.9%	62.1%
9	2.2%	3.5%	4.6%	13.7%	17.5%	35.9%	44.9%	62.3%
10	1.5%	2.5%	3.4%	12.0%	16.4%	36.0%	45.5%	63.3%
11	1.4%	2.4%	3.2%	12.1%	16.8%	37.2%	46.9%	64.2%
12	1.6%	2.5%	3.5%	13.2%	18.0%	39.6%	49.4%	65.7%
13	1.7%	2.7%	3.8%	14.5%	19.2%	42.2%	51.6%	67.3%
14	1.9%	3.0%	4.2%	15.8%	20.5%	44.4%	53.5%	69.3%
15	1.9%	3.1%	4.5%	17.0%	21.6%	46.0%	55.2%	71.5%
16	2.0%	3.5%	5.0%	18.0%	22.7%	47.6%	57.1%	72.8%
17	2.2%	3.9%	5.4%	18.7%	23.1%	48.0%	57.6%	73.2%
18	2.6%	4.3%	5.8%	18.8%	22.9%	46.5%	56.4%	72.0%
19	3.2%	5.2%	6.7%	19.0%	22.6%	44.1%	53.8%	70.1%
20	4.5%	6.5%	8.1%	20.1%	23.0%	42.0%	50.5%	67.0%
21	6.6%	9.0%	10.7%	22.7%	25.0%	42.5%	50.1%	64.9%
22	7.2%	9.7%	11.7%	24.4%	26.3%	43.5%	50.4%	64.5%
23	7.5%	10.2%	12.2%	25.2%	26.8%	43.7%	49.9%	63.5%
24	7.5%	10.1%	12.2%	25.2%	26.8%	43.7%	49.7%	62.8%

Table A-14 Probability of exceedance for onshore wind generation during P5 net load days – Corresponds to Figure 6-7

Hour ending	Onshore wind during P5 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	7.1%	9.6%	11.6%	24.5%	26.2%	42.9%	49.0%	61.9%
2	6.8%	9.1%	11.1%	23.8%	25.6%	42.2%	48.4%	61.2%
3	6.2%	8.5%	10.5%	23.0%	24.9%	41.6%	48.3%	60.5%
4	5.6%	8.0%	10.0%	22.1%	24.2%	40.9%	47.6%	60.4%
5	5.1%	7.6%	9.6%	21.6%	23.7%	40.6%	47.3%	60.4%
6	4.7%	7.2%	9.1%	20.9%	23.1%	40.3%	47.1%	60.7%
7	4.1%	6.5%	8.2%	19.7%	22.1%	39.6%	46.7%	60.7%
8	3.3%	5.3%	6.7%	17.1%	19.9%	37.5%	45.3%	61.2%
9	2.2%	3.5%	4.6%	13.6%	17.3%	35.3%	44.1%	61.2%
10	1.5%	2.5%	3.4%	11.9%	16.2%	35.3%	44.6%	61.8%
11	1.4%	2.4%	3.2%	12.0%	16.6%	36.5%	45.9%	62.9%
12	1.6%	2.5%	3.5%	13.1%	17.8%	38.9%	48.3%	64.7%
13	1.7%	2.7%	3.8%	14.5%	19.0%	41.5%	50.5%	66.4%
14	1.9%	3.0%	4.2%	15.8%	20.3%	43.8%	52.5%	68.2%
15	1.9%	3.1%	4.5%	17.0%	21.4%	45.4%	54.3%	70.2%
16	2.0%	3.5%	5.0%	18.0%	22.5%	46.9%	56.2%	71.6%
17	2.2%	3.9%	5.5%	18.7%	23.0%	47.4%	56.7%	71.8%
18	2.6%	4.3%	5.9%	18.9%	22.8%	46.0%	55.5%	70.6%
19	3.3%	5.2%	6.7%	19.0%	22.5%	43.7%	53.0%	68.9%
20	4.5%	6.5%	8.1%	20.1%	23.0%	41.8%	50.1%	66.4%
21	6.6%	9.0%	10.8%	22.7%	25.0%	42.4%	50.1%	64.9%
22	7.2%	9.7%	11.7%	24.3%	26.2%	43.5%	50.4%	64.6%
23	7.5%	10.2%	12.2%	25.1%	26.8%	43.7%	49.9%	63.6%
24	7.4%	10.1%	12.2%	25.1%	26.7%	43.6%	49.8%	62.8%

Table A-15 Probability of exceedance for onshore wind generation during P1 gross load days – Corresponds to Figure 6-8

Hour ending	Onshore wind during P1 gross load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	7.1%	9.6%	11.7%	24.7%	26.5%	43.4%	49.8%	63.0%
2	6.9%	9.1%	11.2%	24.0%	25.8%	42.8%	49.2%	62.3%
3	6.2%	8.6%	10.5%	23.2%	25.1%	42.2%	49.0%	61.4%
4	5.6%	8.0%	10.0%	22.3%	24.5%	41.6%	48.4%	61.3%
5	5.2%	7.7%	9.6%	21.8%	24.0%	41.4%	48.2%	61.4%
6	4.7%	7.2%	9.1%	21.2%	23.4%	41.1%	48.1%	61.8%
7	4.1%	6.5%	8.2%	20.0%	22.4%	40.4%	47.7%	62.2%
8	3.3%	5.3%	6.7%	17.3%	20.3%	38.4%	46.4%	62.9%
9	2.2%	3.5%	4.6%	13.8%	17.6%	36.3%	45.5%	63.2%
10	1.5%	2.5%	3.4%	12.1%	16.6%	36.5%	46.1%	64.2%
11	1.4%	2.4%	3.2%	12.1%	16.9%	37.8%	47.7%	65.0%
12	1.6%	2.5%	3.5%	13.3%	18.1%	40.1%	50.2%	66.4%
13	1.7%	2.7%	3.8%	14.6%	19.4%	42.7%	52.3%	68.0%
14	1.9%	3.0%	4.2%	15.9%	20.6%	44.9%	54.2%	69.9%
15	1.9%	3.2%	4.5%	17.1%	21.8%	46.5%	55.9%	72.0%
16	2.0%	3.5%	5.0%	18.1%	22.8%	48.0%	57.7%	73.3%
17	2.2%	3.9%	5.4%	18.8%	23.3%	48.5%	58.1%	73.7%
18	2.6%	4.3%	5.8%	18.9%	23.1%	46.9%	56.9%	72.5%
19	3.3%	5.2%	6.7%	19.1%	22.8%	44.5%	54.3%	70.7%
20	4.5%	6.5%	8.1%	20.2%	23.1%	42.3%	50.9%	67.5%
21	6.6%	9.0%	10.8%	22.8%	25.1%	42.7%	50.5%	65.4%
22	7.2%	9.7%	11.7%	24.5%	26.4%	43.7%	50.7%	64.9%
23	7.5%	10.2%	12.3%	25.2%	26.9%	43.9%	50.1%	63.9%
24	7.5%	10.1%	12.2%	25.3%	26.9%	43.8%	50.0%	63.1%

Table A-16 Probability of exceedance for onshore wind generation during P1 net load days – Corresponds to Figure 6-8

Hour ending	Onshore wind during P1 net load days (% capacity)							
	P1	P5	P10	Median	Mean	P90	P95	P99
1	7.1%	9.6%	11.7%	24.7%	26.4%	43.3%	49.6%	63.0%
2	6.9%	9.1%	11.2%	24.0%	25.8%	42.7%	49.0%	62.2%
3	6.2%	8.6%	10.5%	23.2%	25.1%	42.2%	48.8%	61.5%
4	5.6%	8.0%	10.0%	22.3%	24.5%	41.5%	48.3%	61.3%
5	5.2%	7.7%	9.6%	21.8%	24.0%	41.3%	48.1%	61.4%
6	4.7%	7.2%	9.1%	21.2%	23.4%	41.0%	47.9%	61.8%
7	4.1%	6.5%	8.2%	20.0%	22.4%	40.3%	47.5%	62.2%
8	3.3%	5.3%	6.7%	17.2%	20.2%	38.2%	46.2%	62.8%
9	2.2%	3.5%	4.6%	13.8%	17.6%	36.2%	45.3%	62.9%
10	1.5%	2.5%	3.4%	12.1%	16.5%	36.3%	45.9%	63.8%
11	1.4%	2.4%	3.2%	12.1%	16.9%	37.5%	47.4%	64.6%
12	1.6%	2.5%	3.5%	13.3%	18.1%	39.9%	49.8%	66.0%
13	1.7%	2.7%	3.8%	14.6%	19.4%	42.5%	52.0%	67.7%
14	1.9%	3.0%	4.2%	15.9%	20.6%	44.6%	53.8%	69.6%
15	1.9%	3.2%	4.5%	17.1%	21.7%	46.3%	55.5%	71.7%
16	2.0%	3.5%	5.0%	18.1%	22.8%	47.8%	57.3%	73.0%
17	2.2%	3.9%	5.5%	18.8%	23.2%	48.3%	57.7%	73.4%
18	2.6%	4.3%	5.9%	18.9%	23.0%	46.8%	56.6%	72.2%
19	3.3%	5.2%	6.7%	19.1%	22.7%	44.3%	54.0%	70.4%
20	4.5%	6.5%	8.1%	20.2%	23.1%	42.2%	50.8%	67.4%
21	6.6%	9.0%	10.8%	22.8%	25.1%	42.7%	50.5%	65.3%
22	7.2%	9.7%	11.7%	24.4%	26.4%	43.7%	50.7%	64.9%
23	7.5%	10.2%	12.3%	25.2%	26.9%	43.9%	50.2%	63.9%
24	7.5%	10.1%	12.2%	25.2%	26.9%	43.9%	50.1%	63.1%

APPENDIX B – TABLES OF HOURLY RAMP RATE QUANTILES

B.1 Tables for Section 7 Figures

Table B-1 Probability of exceedance for 1-hour offshore wind generation up ramps

Hour ending	Offshore wind generation up ramp (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	4.5%	2.7%	11.3%	15.0%	23.3%	59.7%
2	4.6%	2.8%	11.5%	15.2%	23.9%	68.9%
3	4.7%	2.8%	11.8%	15.5%	23.4%	57.9%
4	4.3%	2.5%	11.0%	14.6%	22.7%	56.2%
5	4.5%	2.7%	11.4%	14.9%	22.7%	59.9%
6	4.6%	2.7%	11.8%	15.5%	23.7%	55.1%
7	4.7%	2.7%	12.1%	16.1%	24.5%	57.4%
8	4.9%	2.9%	12.4%	16.4%	25.2%	63.7%
9	4.8%	2.8%	12.0%	16.0%	25.1%	75.8%
10	4.7%	2.7%	12.0%	15.9%	24.4%	61.8%
11	4.9%	2.9%	12.6%	16.5%	25.1%	65.8%
12	4.8%	2.8%	12.4%	16.5%	25.5%	63.8%
13	4.9%	2.9%	12.6%	16.7%	25.3%	58.0%
14	4.8%	2.9%	12.1%	16.0%	24.8%	60.0%
15	5.1%	3.2%	12.7%	16.6%	25.2%	63.7%
16	5.0%	3.1%	12.7%	16.7%	25.4%	82.3%
17	5.0%	3.0%	12.4%	16.4%	25.1%	85.1%
18	4.8%	3.0%	11.8%	15.6%	24.3%	77.7%
19	4.9%	3.0%	12.3%	16.1%	24.6%	62.6%
20	5.1%	3.2%	12.7%	16.5%	24.8%	59.8%
21	5.2%	3.3%	12.9%	16.7%	25.1%	60.7%
22	4.8%	3.0%	12.2%	15.8%	23.9%	54.5%
23	4.7%	2.8%	11.9%	15.6%	23.9%	67.7%
24	4.6%	2.7%	11.6%	15.4%	23.9%	57.6%

Table B-2 Probability of exceedance for 1-hour offshore wind generation down ramps

Hour ending	Offshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-5.0%	-3.2%	-12.4%	-15.9%	-23.3%	-50.5%
2	-4.9%	-3.1%	-12.2%	-15.7%	-23.0%	-53.3%
3	-5.0%	-3.2%	-12.5%	-16.0%	-23.2%	-54.0%
4	-5.3%	-3.5%	-13.1%	-16.6%	-24.0%	-55.7%
5	-5.4%	-3.6%	-13.3%	-16.8%	-24.0%	-52.8%
6	-5.0%	-3.3%	-12.3%	-15.8%	-23.0%	-50.3%
7	-4.9%	-3.2%	-12.0%	-15.6%	-23.3%	-59.6%
8	-4.5%	-2.9%	-11.2%	-14.6%	-21.8%	-54.2%
9	-4.7%	-3.0%	-11.7%	-15.3%	-23.1%	-56.5%
10	-4.9%	-3.0%	-12.1%	-16.0%	-24.2%	-54.2%
11	-4.8%	-2.9%	-12.1%	-16.0%	-24.7%	-57.7%
12	-4.9%	-3.0%	-12.4%	-16.3%	-24.3%	-55.1%
13	-4.8%	-2.9%	-12.1%	-16.0%	-24.3%	-61.6%
14	-4.9%	-2.9%	-12.5%	-16.4%	-24.2%	-62.6%
15	-4.3%	-2.5%	-11.2%	-14.8%	-22.6%	-83.9%
16	-4.2%	-2.5%	-10.8%	-14.3%	-21.8%	-80.9%
17	-4.3%	-2.6%	-10.9%	-14.4%	-21.5%	-76.2%
18	-4.4%	-2.6%	-11.4%	-15.0%	-22.7%	-54.2%
19	-4.2%	-2.5%	-10.7%	-14.2%	-22.1%	-55.8%
20	-4.1%	-2.4%	-10.6%	-14.2%	-21.8%	-54.0%
21	-4.2%	-2.4%	-10.7%	-14.2%	-21.7%	-59.6%
22	-4.3%	-2.5%	-11.0%	-14.5%	-22.2%	-58.0%
23	-4.5%	-2.8%	-11.3%	-14.6%	-22.0%	-54.1%
24	-4.8%	-3.0%	-12.1%	-15.6%	-23.2%	-56.8%

Table B-3 Probability of exceedance for 1-hour onshore wind generation up ramps

Hour ending	Onshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	2.1%	1.6%	4.5%	5.7%	8.4%	20.2%
2	2.0%	1.5%	4.4%	5.6%	8.5%	23.2%
3	2.1%	1.5%	4.5%	5.7%	8.5%	23.3%
4	2.1%	1.6%	4.6%	5.8%	8.3%	18.7%
5	2.0%	1.6%	4.5%	5.7%	8.1%	17.2%
6	2.1%	1.6%	4.7%	5.9%	8.5%	18.0%
7	2.2%	1.6%	4.8%	6.0%	8.6%	20.1%
8	2.3%	1.7%	5.1%	6.5%	9.4%	22.7%
9	2.4%	1.8%	5.3%	6.6%	9.4%	20.3%
10	2.4%	1.7%	5.4%	6.7%	9.8%	26.9%
11	2.4%	1.7%	5.5%	7.0%	10.5%	27.7%
12	2.6%	1.9%	5.8%	7.4%	10.7%	25.5%
13	2.6%	1.9%	5.8%	7.4%	10.6%	27.4%
14	2.6%	1.9%	5.7%	7.1%	10.6%	29.9%
15	2.5%	1.9%	5.4%	6.8%	9.9%	24.1%
16	2.4%	1.8%	5.3%	6.6%	9.6%	23.5%
17	2.3%	1.7%	5.0%	6.3%	9.1%	24.7%
18	2.5%	1.9%	5.6%	7.1%	10.3%	25.5%
19	2.8%	2.2%	6.1%	7.5%	10.6%	22.4%
20	3.0%	2.5%	6.3%	7.8%	10.9%	22.1%
21	3.2%	2.8%	6.3%	7.6%	10.5%	23.6%
22	2.6%	2.2%	5.5%	6.7%	9.2%	21.2%
23	2.3%	1.9%	4.9%	6.0%	8.6%	20.2%
24	2.2%	1.7%	4.8%	6.0%	8.5%	20.7%

Table B-4 Probability of exceedance for 1-hour onshore wind generation down ramps

Hour ending	Onshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-2.4%	-1.9%	-5.0%	-6.2%	-8.9%	-22.2%
2	-2.4%	-1.9%	-5.0%	-6.2%	-8.6%	-19.3%
3	-2.3%	-1.8%	-4.8%	-6.0%	-8.6%	-19.9%
4	-2.2%	-1.8%	-4.7%	-5.8%	-8.1%	-18.6%
5	-2.2%	-1.7%	-4.7%	-5.9%	-8.5%	-21.5%
6	-2.2%	-1.8%	-4.7%	-5.8%	-8.4%	-21.7%
7	-2.4%	-2.0%	-5.1%	-6.3%	-8.7%	-20.0%
8	-3.0%	-2.5%	-6.2%	-7.4%	-10.0%	-22.5%
9	-3.3%	-2.8%	-6.7%	-8.0%	-10.5%	-21.3%
10	-2.8%	-2.2%	-5.9%	-7.3%	-10.2%	-21.6%
11	-2.4%	-1.7%	-5.4%	-6.9%	-10.0%	-22.0%
12	-2.2%	-1.6%	-5.0%	-6.4%	-9.3%	-20.2%
13	-2.0%	-1.4%	-4.6%	-6.0%	-8.8%	-22.7%
14	-2.0%	-1.3%	-4.6%	-5.9%	-8.8%	-20.2%
15	-1.9%	-1.3%	-4.6%	-5.9%	-8.6%	-21.5%
16	-2.1%	-1.4%	-4.8%	-6.1%	-9.1%	-23.8%
17	-2.2%	-1.6%	-5.1%	-6.6%	-10.3%	-23.6%
18	-2.5%	-1.8%	-5.7%	-7.2%	-10.5%	-24.1%
19	-2.8%	-2.0%	-6.3%	-8.0%	-11.4%	-26.4%
20	-3.1%	-2.2%	-7.2%	-9.2%	-13.4%	-27.8%
21	-2.7%	-2.0%	-6.0%	-7.6%	-11.5%	-28.4%
22	-2.3%	-1.7%	-5.0%	-6.3%	-9.2%	-20.6%
23	-2.3%	-1.8%	-5.1%	-6.4%	-9.1%	-21.2%
24	-2.3%	-1.8%	-4.9%	-6.2%	-9.0%	-21.1%

Table B-5 Probability of exceedance for 2-hour offshore wind generation up ramps

Hour ending	Offshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	10.2%	7.4%	23.4%	29.8%	43.9%	76.7%
2	10.2%	7.4%	23.0%	29.5%	45.7%	84.6%
3	10.4%	7.7%	23.4%	29.3%	43.6%	79.7%
4	9.8%	7.3%	22.5%	28.3%	40.5%	76.9%
5	9.6%	7.1%	22.2%	28.0%	40.7%	77.4%
6	10.2%	7.6%	23.4%	29.3%	42.5%	75.0%
7	10.4%	7.7%	24.2%	30.4%	41.9%	68.6%
8	10.9%	8.2%	24.6%	30.5%	42.8%	77.6%
9	11.3%	8.6%	24.9%	30.9%	44.5%	82.0%
10	11.0%	8.2%	24.7%	31.0%	44.1%	83.7%
11	10.9%	8.2%	24.8%	31.0%	43.3%	76.3%
12	11.2%	8.3%	25.5%	32.0%	44.5%	77.2%
13	11.1%	8.3%	25.1%	31.4%	44.0%	81.4%
14	10.7%	8.1%	24.2%	30.4%	42.6%	78.8%
15	10.8%	8.3%	24.2%	30.6%	43.5%	79.9%
16	10.9%	8.4%	24.3%	30.7%	44.2%	79.8%
17	10.4%	7.7%	23.7%	30.0%	42.7%	83.2%
18	10.0%	7.5%	22.6%	28.8%	41.4%	85.3%
19	10.0%	7.5%	22.4%	28.5%	42.0%	76.6%
20	10.6%	8.3%	23.5%	29.2%	40.6%	75.8%
21	11.3%	9.0%	24.5%	30.6%	43.6%	78.2%
22	11.1%	8.7%	24.3%	30.2%	42.1%	73.4%
23	10.4%	8.0%	23.3%	29.3%	42.1%	81.4%
24	10.3%	7.7%	23.4%	29.4%	42.0%	82.3%

Table B-6 Probability of exceedance for 2-hour offshore wind generation down ramps

Hour ending	Offshore Wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-10.5%	-8.5%	-23.0%	-28.6%	-40.3%	-74.8%
2	-10.6%	-8.5%	-23.0%	-28.3%	-39.2%	-77.1%
3	-10.8%	-8.8%	-23.4%	-28.3%	-38.3%	-70.1%
4	-11.4%	-9.3%	-24.3%	-29.4%	-39.7%	-73.0%
5	-11.8%	-9.8%	-24.9%	-29.9%	-39.4%	-75.2%
6	-11.4%	-9.3%	-24.3%	-29.4%	-39.2%	-69.9%
7	-10.8%	-8.6%	-23.0%	-28.4%	-39.9%	-71.7%
8	-10.0%	-8.0%	-21.5%	-26.5%	-37.5%	-76.0%
9	-9.4%	-7.4%	-20.8%	-25.8%	-35.8%	-73.8%
10	-10.0%	-7.6%	-22.1%	-28.0%	-40.0%	-68.6%
11	-10.2%	-7.7%	-22.8%	-28.8%	-41.2%	-70.0%
12	-10.3%	-7.6%	-23.4%	-29.4%	-41.7%	-72.6%
13	-10.3%	-7.6%	-23.2%	-29.1%	-40.4%	-75.6%
14	-10.4%	-7.8%	-23.7%	-29.3%	-40.3%	-70.6%
15	-9.9%	-7.3%	-22.8%	-28.4%	-39.8%	-81.9%
16	-9.3%	-6.8%	-21.3%	-26.9%	-38.4%	-82.2%
17	-9.1%	-6.8%	-20.7%	-25.6%	-35.5%	-77.5%
18	-9.6%	-7.3%	-21.6%	-26.6%	-36.4%	-70.0%
19	-9.8%	-7.4%	-22.0%	-27.4%	-39.4%	-68.2%
20	-9.2%	-7.0%	-20.7%	-26.1%	-37.4%	-68.1%
21	-8.6%	-6.3%	-20.1%	-25.3%	-36.2%	-71.6%
22	-8.7%	-6.4%	-20.5%	-26.0%	-37.0%	-79.1%
23	-9.1%	-7.0%	-20.5%	-25.8%	-37.3%	-71.5%
24	-9.8%	-7.8%	-21.7%	-27.0%	-37.9%	-75.3%

Table B-7 Probability of exceedance for 2-hour onshore wind generation up ramps

Hour ending	Onshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	4.8%	4.1%	9.1%	11.0%	14.9%	29.1%
2	4.6%	3.9%	8.7%	10.8%	16.1%	32.0%
3	4.7%	3.9%	8.9%	11.0%	16.6%	32.9%
4	4.7%	4.0%	8.9%	10.9%	15.4%	32.5%
5	4.6%	3.9%	8.9%	10.8%	14.8%	24.5%
6	4.7%	4.1%	9.0%	10.8%	14.5%	27.3%
7	4.9%	4.2%	9.3%	11.2%	15.4%	28.4%
8	5.1%	4.4%	9.7%	11.8%	16.8%	29.2%
9	5.5%	4.6%	10.5%	12.7%	17.0%	30.7%
10	5.5%	4.8%	10.5%	12.6%	16.9%	33.5%
11	5.8%	4.9%	11.3%	13.6%	19.1%	40.6%
12	5.6%	4.6%	11.3%	13.8%	19.2%	37.8%
13	5.6%	4.6%	11.4%	13.9%	19.1%	37.5%
14	5.6%	4.6%	11.0%	13.6%	19.0%	40.4%
15	5.4%	4.5%	10.6%	12.9%	18.5%	38.5%
16	5.1%	4.3%	10.1%	12.3%	17.5%	34.2%
17	4.9%	4.1%	9.7%	11.7%	16.1%	32.9%
18	5.1%	4.2%	10.2%	12.3%	16.9%	36.8%
19	5.8%	4.9%	11.4%	13.9%	19.0%	38.3%
20	6.3%	5.4%	11.8%	14.2%	18.9%	32.9%
21	6.6%	5.9%	11.7%	13.9%	18.5%	37.2%
22	6.3%	5.6%	11.2%	13.4%	17.8%	31.0%
23	5.3%	4.7%	9.7%	11.6%	15.5%	29.2%
24	5.0%	4.4%	9.2%	11.0%	15.5%	27.4%

Table B-8 Probability of exceedance for 2-hour onshore wind generation down ramps

Hour ending	Onshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-5.1%	-4.4%	-9.5%	-11.5%	-15.9%	-32.2%
2	-5.0%	-4.4%	-9.4%	-11.2%	-14.9%	-29.9%
3	-4.9%	-4.3%	-9.1%	-10.9%	-14.8%	-28.5%
4	-4.7%	-4.1%	-8.7%	-10.6%	-14.4%	-26.9%
5	-4.6%	-4.0%	-8.6%	-10.5%	-14.4%	-26.3%
6	-4.7%	-4.1%	-8.7%	-10.5%	-14.5%	-30.6%
7	-4.9%	-4.3%	-9.0%	-10.8%	-14.5%	-30.2%
8	-5.7%	-5.0%	-10.4%	-12.4%	-16.3%	-27.9%
9	-6.6%	-6.0%	-12.0%	-13.9%	-18.0%	-31.5%
10	-6.4%	-5.7%	-11.8%	-13.9%	-17.9%	-31.3%
11	-5.6%	-4.6%	-10.9%	-13.3%	-18.0%	-32.4%
12	-5.1%	-4.1%	-10.3%	-12.5%	-17.4%	-31.5%
13	-4.6%	-3.8%	-9.4%	-11.5%	-16.1%	-29.4%
14	-4.4%	-3.5%	-9.2%	-11.4%	-16.0%	-29.7%
15	-4.4%	-3.6%	-9.0%	-11.0%	-15.5%	-30.5%
16	-4.6%	-3.8%	-9.2%	-11.2%	-15.7%	-29.4%
17	-5.0%	-4.1%	-9.9%	-12.3%	-18.6%	-34.5%
18	-5.4%	-4.5%	-10.7%	-13.4%	-19.5%	-33.7%
19	-6.2%	-5.2%	-12.2%	-14.6%	-19.6%	-36.5%
20	-7.1%	-5.9%	-14.1%	-17.0%	-23.1%	-39.7%
21	-7.0%	-5.8%	-14.0%	-17.4%	-24.7%	-43.8%
22	-5.7%	-4.8%	-10.8%	-13.0%	-18.0%	-33.9%
23	-5.2%	-4.6%	-9.8%	-11.8%	-16.4%	-30.3%
24	-5.1%	-4.4%	-9.7%	-11.6%	-16.0%	-30.7%

Table B-9 Probability of exceedance for 3-hour offshore wind generation up ramps

Hour ending	Offshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	17.4%	14.3%	36.9%	44.9%	61.5%	87.2%
2	17.7%	14.3%	37.6%	47.0%	66.9%	88.8%
3	17.5%	14.1%	37.1%	45.8%	65.3%	87.7%
4	17.0%	14.1%	35.9%	43.6%	57.9%	85.4%
5	16.5%	13.7%	35.1%	42.4%	57.4%	84.6%
6	16.9%	14.0%	35.9%	43.9%	59.9%	82.1%
7	17.7%	14.7%	38.5%	45.8%	58.1%	83.8%
8	18.2%	15.6%	37.7%	44.7%	57.9%	81.6%
9	18.8%	16.1%	38.1%	45.2%	59.2%	85.8%
10	19.2%	16.3%	38.8%	46.5%	62.8%	85.9%
11	19.0%	16.0%	39.0%	46.4%	59.8%	84.6%
12	18.7%	15.5%	39.4%	47.0%	60.0%	83.6%
13	18.9%	15.8%	39.3%	46.7%	60.5%	87.1%
14	18.3%	15.0%	38.4%	46.0%	58.5%	85.1%
15	18.1%	15.1%	37.8%	45.1%	57.7%	88.7%
16	18.1%	15.1%	37.9%	45.6%	60.0%	86.4%
17	17.6%	14.5%	37.2%	45.2%	58.9%	86.2%
18	16.2%	13.1%	35.2%	42.8%	56.1%	82.7%
19	16.1%	13.2%	34.7%	42.5%	56.6%	84.5%
20	16.7%	14.1%	34.8%	42.2%	55.7%	82.9%
21	18.0%	15.6%	36.6%	44.0%	56.3%	82.3%
22	18.4%	15.9%	37.5%	45.1%	57.5%	83.3%
23	18.0%	15.5%	37.1%	44.3%	58.1%	83.3%
24	17.4%	14.6%	36.8%	44.3%	57.9%	88.4%

Table B-10 Probability of exceedance for 3-hour offshore wind generation down ramps

Hour ending	Offshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-16.7%	-14.5%	-34.1%	-41.3%	-54.8%	-84.2%
2	-17.2%	-15.0%	-34.9%	-42.3%	-56.0%	-84.9%
3	-17.7%	-15.8%	-35.1%	-41.3%	-53.6%	-88.0%
4	-18.5%	-16.7%	-36.0%	-42.1%	-53.7%	-79.3%
5	-19.2%	-17.3%	-37.0%	-42.9%	-53.8%	-80.0%
6	-18.9%	-16.9%	-36.6%	-42.2%	-52.3%	-83.0%
7	-18.5%	-16.1%	-36.4%	-42.8%	-54.5%	-81.5%
8	-16.8%	-14.5%	-33.5%	-40.0%	-52.8%	-83.8%
9	-15.7%	-13.6%	-31.7%	-37.7%	-49.0%	-83.9%
10	-15.4%	-12.9%	-32.1%	-39.1%	-51.4%	-82.5%
11	-16.0%	-13.0%	-33.8%	-41.5%	-55.1%	-78.3%
12	-16.4%	-13.1%	-34.9%	-42.5%	-56.7%	-81.6%
13	-16.5%	-13.2%	-35.5%	-43.1%	-56.1%	-82.7%
14	-16.7%	-13.7%	-35.5%	-42.5%	-54.3%	-83.3%
15	-16.5%	-13.5%	-35.2%	-42.0%	-54.3%	-83.4%
16	-16.5%	-13.5%	-34.9%	-42.0%	-54.4%	-85.0%
17	-15.5%	-12.8%	-32.7%	-38.9%	-50.8%	-75.6%
18	-15.7%	-13.3%	-32.5%	-38.4%	-48.9%	-75.0%
19	-16.5%	-14.0%	-33.7%	-40.1%	-51.9%	-74.7%
20	-16.2%	-13.8%	-33.3%	-39.7%	-53.1%	-83.1%
21	-14.8%	-12.4%	-30.7%	-37.7%	-52.8%	-82.7%
22	-14.3%	-11.7%	-31.3%	-37.9%	-50.5%	-82.7%
23	-14.3%	-11.6%	-31.1%	-38.2%	-52.0%	-80.0%
24	-15.4%	-13.1%	-32.0%	-38.6%	-53.2%	-86.8%

Table B-11 Probability of exceedance for 3-hour onshore wind generation up ramps

Hour ending	Onshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	7.9%	7.1%	13.7%	16.3%	22.0%	37.6%
2	7.8%	6.8%	13.9%	16.5%	23.8%	40.9%
3	7.8%	6.8%	14.0%	17.1%	25.2%	41.8%
4	7.8%	6.8%	13.9%	17.1%	24.2%	38.5%
5	7.7%	6.8%	13.9%	16.8%	22.1%	42.6%
6	7.8%	7.0%	13.9%	16.4%	21.0%	33.3%
7	8.0%	7.3%	14.1%	16.4%	21.9%	36.6%
8	8.4%	7.6%	14.8%	17.7%	23.5%	37.7%
9	8.8%	7.9%	15.5%	18.6%	24.4%	41.1%
10	9.2%	8.1%	16.5%	19.2%	24.6%	41.9%
11	9.5%	8.5%	16.8%	19.5%	24.5%	43.6%
12	9.8%	8.7%	17.8%	20.9%	27.4%	50.4%
13	9.2%	7.9%	17.4%	20.7%	27.1%	45.7%
14	8.9%	7.7%	17.0%	20.4%	27.2%	49.7%
15	8.7%	7.6%	16.2%	19.5%	26.6%	48.4%
16	8.4%	7.2%	15.6%	18.7%	26.5%	49.9%
17	7.9%	6.8%	14.7%	17.6%	24.1%	42.4%
18	7.9%	6.7%	15.0%	17.6%	22.9%	43.8%
19	8.6%	7.4%	16.3%	19.2%	25.0%	48.4%
20	9.5%	8.4%	17.2%	20.3%	26.4%	48.5%
21	9.9%	9.0%	17.0%	20.1%	26.3%	49.0%
22	9.8%	8.9%	16.8%	19.4%	25.4%	44.5%
23	9.2%	8.4%	15.8%	18.4%	23.5%	42.4%
24	8.3%	7.6%	14.2%	16.6%	22.1%	33.2%

Table B-12 Probability of exceedance for 3-hour onshore wind generation down ramps

Hour ending	Onshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-8.3%	-7.4%	-14.7%	-17.3%	-23.0%	-43.4%
2	-8.1%	-7.1%	-14.2%	-16.9%	-22.3%	-36.7%
3	-7.8%	-7.0%	-13.8%	-16.3%	-21.2%	-38.4%
4	-7.6%	-6.8%	-13.3%	-15.7%	-20.9%	-36.7%
5	-7.4%	-6.5%	-13.1%	-15.6%	-20.8%	-34.9%
6	-7.3%	-6.5%	-12.9%	-15.5%	-20.5%	-39.4%
7	-7.6%	-6.8%	-13.2%	-15.7%	-20.7%	-40.3%
8	-8.4%	-7.6%	-14.5%	-17.0%	-21.7%	-38.7%
9	-9.5%	-8.7%	-16.3%	-18.9%	-23.6%	-40.1%
10	-9.8%	-9.0%	-17.0%	-19.6%	-24.6%	-40.2%
11	-9.3%	-8.4%	-16.7%	-19.7%	-25.2%	-42.1%
12	-8.7%	-7.5%	-16.3%	-19.2%	-25.1%	-45.0%
13	-8.0%	-6.8%	-15.1%	-18.2%	-24.9%	-41.0%
14	-7.5%	-6.4%	-14.6%	-17.6%	-23.3%	-38.4%
15	-7.4%	-6.4%	-14.2%	-17.2%	-23.5%	-38.0%
16	-7.6%	-6.7%	-14.1%	-16.8%	-23.0%	-37.2%
17	-8.0%	-7.1%	-14.6%	-17.9%	-25.3%	-43.8%
18	-8.7%	-7.5%	-16.1%	-19.9%	-27.4%	-41.1%
19	-9.5%	-8.4%	-17.4%	-20.7%	-27.3%	-44.9%
20	-11.0%	-9.8%	-19.9%	-23.3%	-30.0%	-45.2%
21	-11.8%	-10.4%	-21.6%	-25.6%	-33.8%	-48.1%
22	-10.3%	-9.1%	-18.6%	-22.1%	-29.5%	-46.9%
23	-9.1%	-8.1%	-15.9%	-18.7%	-24.3%	-38.9%
24	-8.5%	-7.6%	-14.8%	-17.5%	-23.3%	-36.9%

Table B-13 Probability of exceedance for 4-hour offshore wind generation up ramps

Hour ending	Offshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	25.2%	22.6%	49.3%	57.4%	72.6%	91.8%
2	25.7%	22.6%	50.8%	61.3%	76.9%	90.8%
3	26.1%	22.5%	52.6%	64.9%	79.4%	91.8%
4	24.9%	21.9%	49.8%	59.1%	73.5%	88.5%
5	24.3%	21.8%	48.0%	56.1%	69.3%	91.0%
6	24.6%	22.2%	48.3%	57.1%	71.7%	88.6%
7	25.3%	22.5%	51.0%	58.7%	70.0%	91.2%
8	26.5%	24.4%	51.5%	58.7%	69.7%	86.0%
9	26.7%	24.8%	49.7%	56.7%	68.6%	86.8%
10	27.0%	24.9%	50.4%	57.8%	72.1%	89.0%
11	27.8%	25.3%	52.2%	59.6%	73.6%	88.3%
12	27.5%	25.0%	52.3%	59.6%	71.3%	87.0%
13	27.0%	24.3%	51.7%	59.6%	72.8%	88.5%
14	26.6%	23.6%	51.7%	58.9%	70.5%	90.1%
15	26.3%	23.4%	50.9%	58.0%	69.0%	89.0%
16	26.2%	23.4%	50.6%	57.7%	70.1%	91.6%
17	25.6%	22.7%	50.4%	58.3%	70.4%	89.7%
18	24.0%	20.7%	48.4%	56.1%	68.6%	88.9%
19	22.7%	19.5%	46.5%	54.3%	66.9%	88.2%
20	23.2%	20.5%	46.3%	54.3%	66.4%	89.9%
21	24.6%	22.3%	47.7%	55.5%	66.7%	86.5%
22	25.5%	23.4%	48.8%	55.9%	66.5%	87.7%
23	25.8%	23.5%	49.2%	56.5%	69.0%	87.5%
24	25.7%	23.4%	49.4%	56.5%	69.4%	90.6%

Table B-14 Probability of exceedance for 4-hour offshore wind generation down ramps

Hour ending	Offshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-22.8%	-20.7%	-44.5%	-52.2%	-65.9%	-91.4%
2	-23.9%	-21.5%	-46.7%	-55.3%	-67.7%	-87.3%
3	-25.1%	-23.3%	-47.0%	-54.6%	-66.7%	-92.0%
4	-25.9%	-24.4%	-46.8%	-53.4%	-65.2%	-87.5%
5	-27.0%	-25.7%	-48.0%	-54.3%	-64.7%	-84.1%
6	-26.7%	-25.4%	-47.6%	-53.4%	-63.0%	-85.1%
7	-26.5%	-24.8%	-47.7%	-53.7%	-64.6%	-85.3%
8	-25.1%	-23.1%	-46.3%	-53.5%	-66.1%	-85.1%
9	-22.9%	-20.8%	-43.0%	-49.7%	-61.3%	-89.2%
10	-22.0%	-19.7%	-42.0%	-49.0%	-60.7%	-84.9%
11	-21.7%	-18.8%	-43.6%	-51.9%	-63.6%	-85.6%
12	-22.5%	-19.0%	-45.8%	-54.5%	-67.1%	-85.0%
13	-22.8%	-19.0%	-46.7%	-55.2%	-67.4%	-87.3%
14	-23.2%	-19.8%	-47.3%	-54.7%	-66.0%	-88.1%
15	-23.2%	-20.0%	-47.1%	-54.1%	-65.5%	-89.4%
16	-24.0%	-21.1%	-47.1%	-54.3%	-65.8%	-87.9%
17	-23.7%	-21.3%	-45.7%	-52.5%	-64.3%	-87.1%
18	-22.9%	-20.9%	-43.8%	-50.0%	-60.1%	-81.2%
19	-23.4%	-21.6%	-44.3%	-50.6%	-60.3%	-83.0%
20	-23.5%	-21.8%	-43.6%	-50.0%	-62.4%	-86.0%
21	-22.4%	-20.2%	-42.4%	-50.0%	-66.8%	-88.4%
22	-21.2%	-18.9%	-41.3%	-49.4%	-65.7%	-87.5%
23	-20.3%	-17.7%	-41.7%	-49.2%	-62.6%	-88.2%
24	-21.0%	-18.4%	-42.4%	-50.8%	-66.4%	-87.7%

Table B-15 Probability of exceedance for 4-hour onshore wind generation up ramps

Hour ending	Onshore wind generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	11.4%	10.6%	18.7%	21.8%	27.4%	44.8%
2	11.1%	10.0%	18.7%	21.8%	29.5%	48.5%
3	11.3%	10.2%	19.1%	22.7%	33.5%	51.0%
4	11.2%	10.0%	19.4%	23.3%	32.6%	46.6%
5	11.1%	9.8%	19.8%	23.4%	30.0%	43.9%
6	11.2%	10.2%	19.3%	22.5%	28.0%	46.4%
7	11.4%	10.5%	19.2%	22.3%	28.3%	43.4%
8	11.9%	11.0%	19.9%	22.9%	29.8%	44.2%
9	12.4%	11.4%	21.0%	24.4%	30.5%	44.0%
10	12.7%	11.6%	21.5%	25.0%	31.3%	47.6%
11	13.3%	12.2%	22.5%	25.5%	31.5%	48.8%
12	13.8%	12.9%	23.0%	25.9%	31.3%	50.1%
13	14.0%	12.8%	24.0%	27.7%	34.6%	56.6%
14	12.7%	11.4%	23.1%	27.0%	34.4%	54.3%
15	12.1%	10.8%	22.1%	26.2%	34.1%	56.2%
16	11.8%	10.4%	21.3%	25.2%	34.5%	58.0%
17	11.2%	9.8%	20.2%	24.1%	32.7%	54.9%
18	10.9%	9.6%	19.8%	23.1%	30.1%	51.6%
19	11.4%	10.0%	20.7%	23.9%	30.9%	54.1%
20	12.3%	11.0%	21.7%	25.3%	32.4%	53.5%
21	13.2%	12.0%	22.2%	26.1%	33.3%	55.7%
22	13.2%	12.1%	22.0%	25.5%	32.3%	55.1%
23	12.8%	11.8%	21.0%	24.2%	30.2%	50.9%
24	12.3%	11.5%	20.4%	23.6%	29.1%	43.1%

Table B-16 Probability of exceedance for 4-hour onshore wind generation down ramps

Hour ending	Onshore wind generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-12.0%	-11.1%	-20.0%	-23.2%	-29.5%	-45.4%
2	-11.6%	-10.5%	-19.7%	-23.0%	-29.0%	-47.5%
3	-11.1%	-10.0%	-19.1%	-22.3%	-28.2%	-43.1%
4	-10.7%	-9.6%	-18.1%	-21.1%	-27.1%	-47.8%
5	-10.4%	-9.3%	-17.7%	-20.9%	-27.4%	-42.5%
6	-10.2%	-9.1%	-17.6%	-20.9%	-26.9%	-46.5%
7	-10.3%	-9.3%	-17.5%	-20.5%	-26.4%	-49.3%
8	-11.1%	-10.2%	-18.7%	-21.7%	-27.5%	-44.8%
9	-12.2%	-11.4%	-20.4%	-23.4%	-28.5%	-50.9%
10	-12.7%	-11.7%	-21.4%	-24.4%	-30.2%	-48.1%
11	-12.7%	-11.7%	-21.8%	-25.1%	-31.3%	-48.5%
12	-12.5%	-11.3%	-22.0%	-25.3%	-31.8%	-52.6%
13	-11.7%	-10.5%	-21.0%	-24.6%	-32.3%	-51.9%
14	-11.2%	-9.9%	-20.7%	-24.6%	-31.7%	-48.0%
15	-10.9%	-9.7%	-19.9%	-23.6%	-30.6%	-46.2%
16	-10.9%	-9.9%	-19.6%	-23.3%	-29.9%	-46.8%
17	-11.2%	-10.2%	-19.7%	-23.7%	-32.0%	-49.9%
18	-11.9%	-10.8%	-21.0%	-25.2%	-33.2%	-48.0%
19	-12.8%	-11.5%	-22.5%	-26.5%	-33.5%	-48.7%
20	-14.2%	-13.1%	-24.4%	-27.8%	-34.9%	-48.7%
21	-16.0%	-14.7%	-26.9%	-31.3%	-39.0%	-52.0%
22	-15.1%	-13.8%	-25.3%	-29.2%	-37.7%	-52.2%
23	-13.8%	-12.7%	-23.4%	-26.9%	-33.8%	-51.6%
24	-12.5%	-11.5%	-20.9%	-24.0%	-30.5%	-43.8%

Table B-17 Probability of exceedance for 1-hour combined wind and solar generation up ramps

Hour ending	Wind + solar generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	1.2%	0.7%	2.9%	3.9%	6.1%	15.0%
2	1.2%	0.8%	3.0%	4.0%	6.2%	17.7%
3	1.3%	0.8%	3.1%	4.1%	6.1%	15.0%
4	1.2%	0.7%	2.9%	3.8%	5.9%	14.4%
5	1.2%	0.7%	3.0%	3.9%	5.9%	15.6%
6	1.3%	0.8%	3.1%	4.1%	6.2%	14.7%
7	1.3%	0.8%	3.2%	4.2%	6.4%	14.7%
8	1.8%	1.5%	3.9%	4.9%	7.0%	16.9%
9	3.6%	3.3%	6.8%	7.8%	10.4%	19.7%
10	6.9%	7.0%	11.4%	12.6%	15.0%	26.2%
11	8.7%	9.2%	13.7%	14.7%	16.9%	27.7%
12	7.4%	7.7%	12.2%	13.4%	16.0%	29.5%
13	5.1%	4.9%	9.2%	10.7%	14.0%	34.4%
14	3.3%	2.7%	6.7%	8.3%	11.8%	32.3%
15	2.7%	1.9%	5.9%	7.5%	11.6%	36.1%
16	2.3%	1.6%	5.2%	6.5%	9.6%	27.7%
17	1.9%	1.4%	4.5%	5.8%	8.8%	22.6%
18	1.7%	1.1%	3.9%	5.1%	7.9%	20.2%
19	1.5%	1.0%	3.5%	4.6%	6.8%	14.6%
20	1.5%	0.9%	3.6%	4.6%	6.9%	15.8%
21	1.4%	0.9%	3.4%	4.5%	6.8%	15.9%
22	1.3%	0.8%	3.2%	4.2%	6.4%	14.2%
23	1.2%	0.8%	3.1%	4.0%	6.2%	17.8%
24	1.2%	0.7%	3.0%	4.0%	6.2%	15.0%

Table B-18 Probability of exceedance for 1-hour combined wind and solar generation down ramps

Hour ending	Wind + solar generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-1.4%	-0.9%	-3.3%	-4.3%	-6.2%	-13.8%
2	-1.4%	-0.9%	-3.3%	-4.2%	-6.1%	-14.0%
3	-1.4%	-0.9%	-3.3%	-4.3%	-6.1%	-14.2%
4	-1.4%	-1.0%	-3.5%	-4.4%	-6.3%	-15.0%
5	-1.5%	-1.0%	-3.5%	-4.4%	-6.3%	-13.4%
6	-1.4%	-0.9%	-3.3%	-4.2%	-6.1%	-14.3%
7	-1.4%	-0.9%	-3.2%	-4.1%	-6.1%	-15.5%
8	-1.3%	-0.9%	-3.1%	-4.0%	-5.9%	-14.2%
9	-1.4%	-1.0%	-3.2%	-4.0%	-5.8%	-11.6%
10	-1.5%	-1.0%	-3.4%	-4.3%	-6.2%	-11.2%
11	-1.5%	-1.1%	-3.6%	-4.6%	-6.7%	-12.0%
12	-1.7%	-1.2%	-4.0%	-5.0%	-7.0%	-18.5%
13	-2.1%	-1.6%	-4.8%	-6.1%	-8.9%	-20.6%
14	-2.8%	-2.2%	-6.2%	-7.7%	-10.9%	-25.3%
15	-3.7%	-3.0%	-8.0%	-9.5%	-12.8%	-28.1%
16	-5.2%	-4.6%	-10.2%	-11.7%	-14.5%	-32.3%
17	-6.7%	-6.6%	-11.8%	-13.1%	-15.7%	-32.6%
18	-7.2%	-7.2%	-12.7%	-14.1%	-16.6%	-28.8%
19	-6.9%	-7.0%	-12.6%	-13.8%	-16.4%	-28.4%
20	-5.1%	-5.0%	-9.9%	-10.9%	-13.2%	-22.7%
21	-2.8%	-2.6%	-5.6%	-6.5%	-8.6%	-17.6%
22	-1.6%	-1.2%	-3.4%	-4.3%	-6.4%	-16.1%
23	-1.3%	-0.8%	-3.0%	-3.9%	-5.9%	-13.9%
24	-1.3%	-0.9%	-3.2%	-4.1%	-6.2%	-14.3%

Table B-19 Probability of exceedance for 2-hour combined wind and solar generation up ramps

Hour ending	Wind + solar generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	2.6%	1.8%	6.0%	7.6%	11.2%	20.3%
2	2.7%	1.9%	5.9%	7.6%	11.8%	21.4%
3	2.7%	2.0%	6.1%	7.6%	11.4%	20.6%
4	2.6%	1.9%	5.9%	7.4%	10.6%	20.1%
5	2.6%	1.8%	5.8%	7.3%	10.6%	20.4%
6	2.7%	1.9%	6.0%	7.6%	11.2%	20.4%
7	2.7%	1.9%	6.3%	7.9%	11.0%	18.9%
8	3.2%	2.7%	6.6%	8.1%	11.3%	19.8%
9	5.8%	5.6%	10.0%	11.4%	14.9%	26.0%
10	10.8%	10.7%	17.6%	19.5%	23.6%	38.2%
11	15.8%	16.5%	24.3%	25.9%	29.1%	43.1%
12	16.4%	17.4%	24.8%	26.4%	29.6%	44.4%
13	12.9%	13.2%	19.9%	21.8%	25.9%	43.4%
14	8.8%	8.4%	14.3%	16.6%	21.6%	46.0%
15	6.4%	5.4%	11.9%	14.5%	20.9%	51.4%
16	5.8%	4.9%	11.1%	13.5%	19.4%	37.8%
17	5.0%	4.2%	9.8%	11.7%	15.4%	28.1%
18	4.4%	3.7%	8.9%	10.7%	14.0%	21.9%
19	4.0%	3.3%	8.3%	9.8%	12.7%	20.5%
20	3.2%	2.5%	6.8%	8.3%	11.0%	20.5%
21	3.1%	2.3%	6.8%	8.7%	12.5%	21.3%
22	2.9%	2.1%	6.6%	8.2%	11.4%	18.5%
23	2.8%	2.0%	6.2%	7.8%	11.2%	21.6%
24	2.6%	1.8%	5.9%	7.5%	10.8%	21.4%

Table B-20 Probability of exceedance for 2-hour combined wind and solar generation down ramps

Hour ending	Wind + solar generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-2.9%	-2.3%	-6.1%	-7.6%	-10.7%	-19.9%
2	-2.9%	-2.3%	-6.1%	-7.6%	-10.4%	-19.8%
3	-2.9%	-2.3%	-6.2%	-7.5%	-10.1%	-18.2%
4	-3.0%	-2.4%	-6.4%	-7.8%	-10.5%	-19.3%
5	-3.1%	-2.6%	-6.6%	-7.9%	-10.5%	-19.2%
6	-3.0%	-2.5%	-6.4%	-7.7%	-10.3%	-18.4%
7	-2.9%	-2.3%	-6.1%	-7.5%	-10.5%	-18.7%
8	-2.9%	-2.4%	-5.9%	-7.2%	-10.1%	-19.5%
9	-3.1%	-2.6%	-6.0%	-7.2%	-9.7%	-16.4%
10	-3.5%	-3.1%	-6.7%	-7.8%	-9.9%	-14.3%
11	-3.8%	-3.3%	-7.2%	-9.0%	-12.6%	-16.0%
12	-4.1%	-3.7%	-7.7%	-9.0%	-11.2%	-19.4%
13	-4.4%	-3.8%	-8.6%	-10.0%	-13.4%	-27.4%
14	-5.5%	-4.8%	-10.5%	-12.7%	-17.4%	-30.9%
15	-7.4%	-6.8%	-13.4%	-15.6%	-19.9%	-33.7%
16	-9.5%	-8.4%	-17.3%	-19.7%	-23.8%	-43.6%
17	-12.4%	-11.8%	-20.8%	-23.2%	-27.4%	-55.1%
18	-14.3%	-14.5%	-22.9%	-25.3%	-29.4%	-47.4%
19	-14.9%	-15.4%	-24.5%	-26.5%	-30.5%	-43.5%
20	-13.2%	-13.8%	-22.1%	-24.3%	-28.4%	-43.7%
21	-9.1%	-9.4%	-15.1%	-16.6%	-19.9%	-32.4%
22	-4.9%	-4.8%	-8.5%	-9.8%	-12.9%	-24.7%
23	-2.9%	-2.4%	-5.8%	-7.1%	-10.1%	-20.5%
24	-2.7%	-2.2%	-5.8%	-7.2%	-10.2%	-20.1%

Table B-21 Probability of exceedance for 3-hour combined wind and solar generation up ramps

Hour ending	Wind + solar generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	4.2%	3.1%	9.2%	11.2%	15.5%	23.1%
2	4.3%	3.2%	9.4%	11.8%	17.0%	23.0%
3	4.4%	3.3%	9.5%	11.8%	16.9%	22.9%
4	4.3%	3.3%	9.2%	11.2%	14.9%	22.0%
5	4.2%	3.3%	9.1%	11.0%	15.0%	22.8%
6	4.3%	3.3%	9.2%	11.3%	15.8%	22.6%
7	4.4%	3.4%	9.8%	11.9%	15.3%	22.4%
8	4.8%	4.0%	9.8%	11.6%	15.2%	22.7%
9	7.1%	6.8%	12.3%	14.3%	17.7%	28.1%
10	13.3%	13.4%	20.7%	22.7%	27.8%	45.9%
11	20.0%	20.7%	30.3%	32.6%	37.1%	53.6%
12	23.6%	25.1%	34.9%	36.9%	41.0%	55.7%
13	22.2%	23.2%	32.3%	34.3%	38.5%	54.3%
14	16.9%	17.3%	24.6%	27.0%	32.8%	49.5%
15	12.0%	11.2%	19.4%	22.4%	29.5%	53.9%
16	9.8%	8.8%	17.1%	20.1%	28.6%	44.8%
17	8.6%	7.8%	15.2%	17.6%	23.2%	37.1%
18	7.3%	6.8%	12.8%	14.3%	17.0%	24.3%
19	7.0%	6.5%	12.6%	14.4%	17.0%	21.1%
20	6.3%	5.9%	11.5%	12.9%	15.7%	20.9%
21	5.0%	4.2%	10.4%	12.2%	15.3%	22.8%
22	4.8%	3.8%	10.3%	12.5%	16.1%	23.9%
23	4.6%	3.6%	9.9%	11.9%	15.6%	22.2%
24	4.4%	3.3%	9.6%	11.6%	15.3%	24.1%

Table B-22 Probability of exceedance for 3-hour combined wind and solar generation down ramps

Hour ending	Wind + solar generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-4.5%	-3.8%	-9.1%	-11.0%	-14.7%	-23.0%
2	-4.6%	-3.9%	-9.3%	-11.3%	-14.9%	-23.6%
3	-4.7%	-4.1%	-9.3%	-11.0%	-14.2%	-22.9%
4	-4.8%	-4.2%	-9.4%	-11.1%	-14.3%	-22.1%
5	-5.0%	-4.4%	-9.7%	-11.3%	-14.4%	-23.4%
6	-4.9%	-4.4%	-9.6%	-11.2%	-14.0%	-23.0%
7	-4.8%	-4.1%	-9.5%	-11.2%	-14.4%	-21.9%
8	-4.7%	-4.1%	-9.1%	-10.8%	-14.3%	-21.9%
9	-4.9%	-4.5%	-8.9%	-10.4%	-13.4%	-21.7%
10	-5.5%	-5.2%	-9.5%	-10.7%	-13.0%	-17.4%
11	-6.1%	-5.6%	-10.4%	-12.4%	-15.7%	-18.2%
12	-6.6%	-6.4%	-11.0%	-12.6%	-14.7%	-17.2%
13	-6.9%	-6.6%	-11.5%	-12.7%	-17.8%	-25.8%
14	-7.3%	-6.8%	-12.4%	-14.1%	-18.4%	-28.9%
15	-9.9%	-9.3%	-17.1%	-19.9%	-24.0%	-37.0%
16	-14.0%	-13.5%	-22.9%	-25.3%	-30.0%	-49.3%
17	-17.0%	-16.1%	-27.9%	-30.8%	-36.0%	-55.0%
18	-20.1%	-20.3%	-30.8%	-33.5%	-38.8%	-60.3%
19	-22.1%	-22.9%	-34.2%	-36.9%	-41.6%	-55.8%
20	-21.7%	-23.0%	-33.6%	-36.5%	-42.1%	-56.0%
21	-17.7%	-18.7%	-27.3%	-29.8%	-34.8%	-53.7%
22	-11.5%	-12.2%	-17.9%	-19.8%	-23.9%	-38.3%
23	-6.2%	-5.9%	-10.7%	-12.5%	-16.4%	-26.0%
24	-4.5%	-3.8%	-8.8%	-10.5%	-14.2%	-24.9%

Table B-23 Probability of exceedance for 4-hour combined wind and solar generation up ramps

Hour ending	Wind + solar generation up ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	6.0%	4.8%	12.7%	14.9%	19.0%	25.2%
2	5.9%	4.7%	12.4%	15.2%	19.7%	23.9%
3	6.2%	4.9%	13.1%	16.3%	20.5%	24.6%
4	6.0%	4.9%	12.6%	15.0%	18.8%	24.1%
5	6.0%	5.0%	12.3%	14.6%	18.3%	24.8%
6	6.0%	5.1%	12.3%	14.7%	19.1%	24.3%
7	6.1%	4.9%	13.0%	15.3%	18.9%	24.3%
8	6.5%	5.5%	13.1%	15.2%	18.6%	25.4%
9	8.4%	8.1%	14.8%	16.8%	20.2%	30.8%
10	14.2%	14.0%	22.3%	24.7%	30.0%	46.2%
11	22.4%	23.3%	33.3%	35.8%	41.0%	60.6%
12	27.9%	29.6%	40.5%	43.1%	47.9%	65.7%
13	29.5%	31.3%	41.9%	44.4%	49.0%	66.9%
14	26.3%	27.7%	36.7%	39.1%	44.0%	60.1%
15	19.4%	19.5%	28.8%	32.0%	39.1%	56.9%
16	14.6%	13.7%	23.8%	27.4%	35.6%	48.2%
17	11.7%	11.0%	19.4%	22.1%	30.2%	42.1%
18	9.6%	9.5%	15.3%	16.6%	18.7%	22.3%
19	9.5%	9.5%	15.1%	16.2%	18.1%	20.8%
20	9.2%	9.3%	15.0%	16.3%	18.7%	23.0%
21	8.2%	8.1%	14.2%	15.5%	17.9%	22.6%
22	6.8%	6.0%	13.5%	15.3%	18.6%	25.8%
23	6.5%	5.4%	13.4%	15.5%	19.0%	25.5%
24	6.3%	5.2%	13.2%	15.1%	18.2%	24.7%

Table B-24 Probability of exceedance for 4-hour combined wind and solar generation down ramps

Hour ending	Wind + solar generation down ramps (% capacity)					
	Mean	P50	P90	P95	P99	Max
1	-6.3%	-5.5%	-12.0%	-14.0%	-17.9%	-26.2%
2	-6.3%	-5.6%	-12.4%	-14.7%	-18.3%	-24.1%
3	-6.5%	-5.9%	-12.5%	-14.6%	-17.9%	-24.2%
4	-6.7%	-6.2%	-12.5%	-14.3%	-17.6%	-23.7%
5	-6.9%	-6.4%	-12.7%	-14.4%	-17.5%	-25.5%
6	-6.9%	-6.4%	-12.6%	-14.2%	-17.2%	-25.1%
7	-6.8%	-6.3%	-12.6%	-14.2%	-17.4%	-24.6%
8	-6.8%	-6.2%	-12.4%	-14.3%	-17.8%	-23.7%
9	-6.9%	-6.5%	-12.0%	-13.8%	-17.1%	-23.5%
10	-7.4%	-7.2%	-12.1%	-13.5%	-15.6%	-19.3%
11	-7.7%	-7.5%	-11.9%	-14.9%	-17.1%	-19.5%
12	-8.8%	-8.6%	-13.4%	-15.8%	-17.6%	-20.0%
13	-8.5%	-8.5%	-12.4%	-13.3%	-14.7%	-16.5%
14	-8.8%	-9.0%	-13.4%	-14.4%	-16.3%	-24.2%
15	-10.0%	-9.6%	-15.8%	-18.2%	-22.6%	-29.4%
16	-15.7%	-15.1%	-25.6%	-28.4%	-32.9%	-43.6%
17	-21.5%	-21.3%	-33.5%	-36.4%	-41.7%	-55.5%
18	-24.6%	-24.5%	-36.4%	-39.5%	-45.3%	-63.4%
19	-27.8%	-28.7%	-40.5%	-43.5%	-49.0%	-69.1%
20	-28.9%	-30.5%	-42.3%	-45.6%	-51.8%	-64.1%
21	-26.2%	-27.9%	-38.5%	-41.7%	-48.2%	-65.2%
22	-20.1%	-21.5%	-29.8%	-32.5%	-38.2%	-56.0%
23	-12.6%	-13.1%	-20.0%	-22.4%	-26.9%	-40.3%
24	-7.7%	-7.3%	-13.3%	-15.4%	-19.9%	-29.1%

APPENDIX C – DNV GL STOCHASTIC ENGINE BROCHURE

C.1 Brochure for stochastic modeling and variable energy analysis

SAFER, SMARTER, GREENER

DNV·GL

ENERGY

ENERGY VARIABILITY ASSESSMENTS

Revolutionizing How We Approach Long-term Variability

Best-in-class probabilistic modeling can provide insight into risk and relationships across independent variables–from expected solar and wind generation to electric load, merchant pricing revenue, and more.

DNV GL's Energy Variability Assessment (EVA) services focus on a growing need in the current utility-scale assessment landscape. The full range of long-term resource distributions–and associated risks–are not adequately captured in standardized approaches such as estimating a representative annual time series of energy production–presented in the form of an 8760 hourly time series. DNV GL's Energy Analytics Team uses a novel stochastic approach to analyze long-term variability, providing holistic data products and services for various users. We aim to…

Fully address what's missing in the annualized approach.

Whether you are in the project screening or financing process stage, our EVAs can help you assess a variety of metrics and access an indicative estimate of the likelihood of a wide range of development criteria. Our energy experts offer a range of scenario-based data products and services to help you improve the site-selection process, reduce the likelihood of misalignment between development- and operational-phase assumptions, and mitigate commercial risks.

Re-defining resource planning for the utility sector, our Analytics Team offers a sophisticated, next-generation approach to time series modeling. As traditional operations comprise of more and more renewable generation, our experts have quantified the risk associated with resource perturbations across a wide range of commercial variables such as offshore wind, merchant pricing revenue, curtailment planning, and multi-site co-variability trends. Relevant examples include–but are not limited to–understanding risks associated with low generation and high demand, revenue risk including basis and generation-weighted realized price where time of day or seasonal characteristics are important, and robust probabilistic estimates of events, such as low wind years, high-wind shutdown events, large wind ramp events, or periods of solar resource constraints.

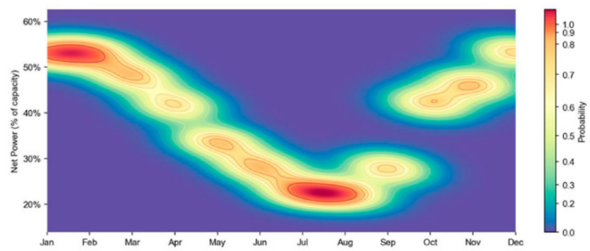
Our experience

Industry-leading modeling and analytics expertise provided by pre-construction resource assessment and operational assessment teams across the renewable energy development chain –including extensive offshore and solar + storage specialists–integrate with our experts from transmission planning to grid integration advisory services.

DNV GL has performed independent energy assessments on more than 15,000 MW of proposed solar farms, more than 170,000 MW of proposed onshore wind farms, 5,000 MW proposed offshore wind farms, and approximately 70% of the installed wind capacity in North America.

Time series expertise tailored to your needs

Applying our extensive and unparalleled understanding of meteorology, renewable energy systems, advanced machine-learning models, and data analytics, our Energy Variability Assessment (EVA) services provide full realization of input variation and robust probabilistic distributions across co-variable dependencies. We offer a variety of service packages, scaled to your needs and value expectations.



Offering	8760	EVA Lite	EVA Plus
Hourly time series for typical year of power generation	●	●	●
Historical 1- to 20-year time series of weather, power generation, or load		●	●
Upside/downside risk profile assuming historical behavior (e.g. P90)		●	●
Historical dataset which maintains co-variability (e.g. solar and load)		●	●
10,000+ realizations, 20+ year dataset of 2-10+ variables			●
Upside/downside risk profile encapsulating future possibilities			●

Case Study: EVA Plus

Customer: ISO New England Inc.

Challenges: Available datasets no longer matched needs for economic, energy security, and transmission planning studies. Solar, wind, and load time series had limited overlap and poor representation of offshore wind. The high penetration of distributed energy resources and increasing development of offshore wind called for a unified dataset of solar, wind, and load to allow for a robust probabilistic analysis of coincident solar, wind, and load variability.

EVA Plus: Used to stochastically model 20,000 years of realistically-plausible time series of hourly behind-the-meter solar PV generation, onshore and offshore wind generation, weather, gross load, and net load.

Value: Captured the frequency of less common meteorological events—such as overlapping cold snaps and wind lulls—and provided robust statistical results. Provided 8760s representing probabilistic solar-, wind-, or load-years for ISO to select new weather-basis years—such as a P10 wind-year. **The true value of the EVA service is its ability to represent the full spectrum of possible weather conditions that drive solar and wind power production, along with the coincident grid/transmission system and regional load, thereby allowing a comprehensive assessment of all possible scenarios across the entire portfolio.** Each individual synthetic time series closely mimicked the characteristics of the weather that could occur at each project location, based on the historical record. The spatial coherency of weather conditions across the entire portfolio of sites (inter-site correlations) was also fully preserved.

For more information, please contact:

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About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil & gas and energy industries. We also provide certification services to customers across a wide range of industries. Combining leading technical and operational expertise, risk methodology and in-depth industry knowledge, we empower our customers' decisions and actions with trust and confidence. We continuously invest in research and collaborative innovation to provide customers and society with operational and technological foresight. Operating in more than 100 countries, our professionals are dedicated to helping customers make the world safer, smarter and greener.