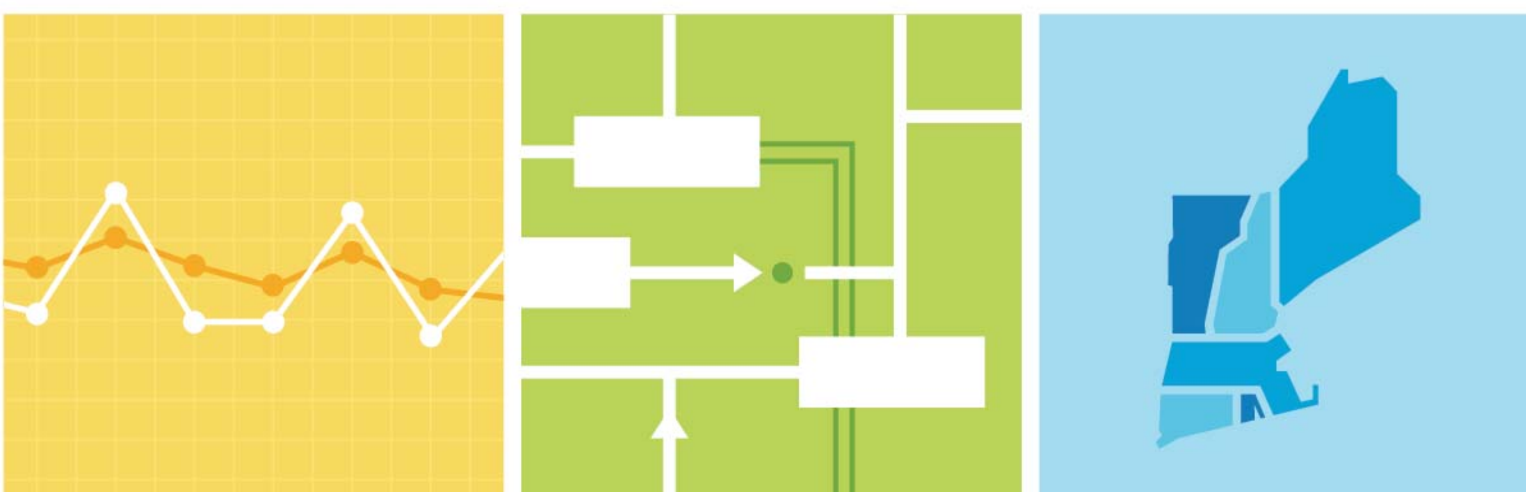
2017 ISO New England Electric Generator Air Emissions Report

System Planning

APRIL 2019



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Section 1
Executive Summary

This ISO New England (ISO) *Electric Generator Air Emissions Report* (*Emissions Report*) provides a comprehensive analysis of New England electric generator air emissions (nitrogen oxides [NO_X], sulfur dioxide [SO_2], and carbon dioxide [CO_2]) and a review of relevant system conditions. The main factors analyzed are as follows:

- System[1] and marginal emissions (in thousand short tons [ktons])[2]
- System and marginal emission rates (pounds per megawatt-hour [lb/MWh] and pounds per million British thermal unit [lb/MMBtu])
- Marginal heat rate (MMBtu/MWh)

The report presents information for different time periods of interest:

- On-peak compared with off-peak hours
- Ozone season compared with non-ozone season
- Monthly variations
- High electric demand days (HEDDs)

The *Emissions Report*, first developed in 1993, has evolved in response to stakeholder needs. It was initially motivated by the need to determine the reductions of ISO New England's aggregate NO_X, SO_2, and CO_2 generating unit air emissions resulting from demand-side management (DSM) programs. The use of these emission rates was subsequently broadened to reflect the emission-reduction benefits of energy-efficiency programs and renewable resource projects within the region.

During the ten-year period from 2008 through 2017, total system emissions have decreased overall: NO_X by 53%, SO_2 by 96%, and CO_2 by 37%. The decline in emissions during this period reflects shifts in the regional fuel mix, with increasing natural gas generation as well as wind generation offsetting decreases in coal- and oil-fired generation (see Figure 1-1).

[1] For purposes of this report, "System" refers to native generation located within the New England Control Area.

[2] The mass value of "tons" is equivalent to a US short ton, or 2,000 lb and "ktons" is equivalent to 2,000,000 lb.

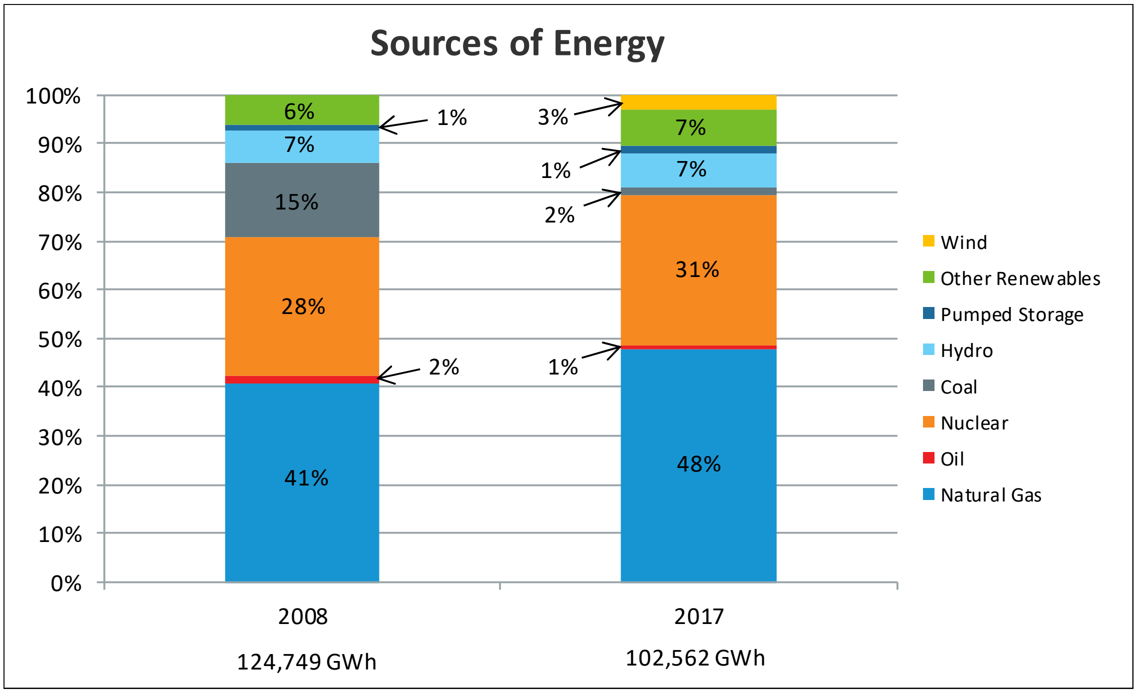

Figure 1-1: Percentage energy generation by fuel type, 2008 compared with 2017.

Compared with the 20-year average for heating and cooling days (i.e., an indicator of weather), 2017 had a 5% cooler summer and a 3% warmer winter. From 2016 to 2017, the net energy for load and system generation decreased by 2.6% and 2.8%, respectively. The amount of energy that ISO New England received from neighboring areas in 2017 was approximately 2% lower than the previous year. Generation by hydro, wind, and solar resources increased by 20%, while nuclear generation declined by 4%. All fossil generation decreased from 2016 to 2017: coal-fired generation by 34%, oil-fired generation by 16%, and natural gas-fired generation by 5%.

Table 1-1 shows the total 2016 and 2017 ISO New England system emissions (ktons) and average system emission rates (lb/MWh) of NO_X, SO_2 and CO_2. System emissions decreased for NO_X, SO_2, and CO_2 from 2016 to 2017. The NO_X and CO_2 emission rates decreased as well, but there was no change in the SO_2 rate.

Table 1-1
2016 and 2017 ISO New England System Emissions (ktons) and Emission Rates (lb/MWh)

Annual System Emissions						
	2016 Emissions (kTons)	2017 Emissions (kTons)	Total Emissions % Change	2016 Emission Rate (lb/MWh)	2017 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	16.26	15.30	-5.9	0.31	0.30	-3.2
SO_2	4.47	4.00	-10.5	0.08	0.08	0.0
CO_2	37,468	34,969	-6.7	710	682	-3.9

Table 1-2 shows the 2016 and 2017 annual average marginal emission rates as calculated by the locational marginal unit (LMU) marginal emission analysis. This analysis uses the emission rates from the ISO's identified marginal unit(s) that set the energy market hourly locational marginal price(s) (LMP). The LMP results from economic dispatch, which minimizes total energy costs for the entire ISO New England system, subject to a set of constraints reflecting physical (transmission) limitations of the power system. This report presents the results for two scenarios of emission rates calculated using this methodology: 1) all LMUs; and 2) emitting LMUs.

Table 1-2
2016 and 2017 Annual LMU Marginal Emission Rates (lb/MWh)

LMU Marginal Emissions						
	All LMUs			Emitting LMUs		
	2016 Annual Rate (lb/MWh)	2017 Annual Rate (lb/MWh)	% Change 2016 to 2017	2016 Annual Rate (lb/MWh)	2017 Annual Rate (lb/MWh)	% Change 2016 to 2017
NO_X	0.21	0.15	-28.6	0.25	0.23	-8.0
SO_2	0.16	0.08	-50.0	0.19	0.12	-36.8
CO_2	842	654	-22.3	1,007	971	-3.6

Figure 1-2 summarizes the 2017 ISO New England emission rates. The all-LMU and emitting-LMU marginal emission rates for the top-five high electric demand days (HEDDs) characterize the emissions profiles of the marginal units responding to system demand during these days. On those HEDD days, the percentage of coal and oil units on the margin was higher than on average during the year.

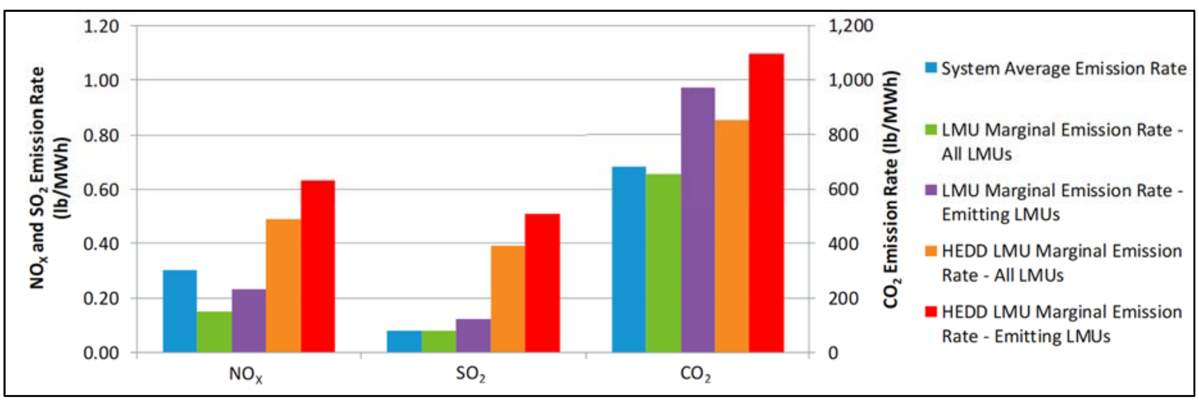

Figure 1-2: Comparison of 2017 ISO New England emission rates (lb/MWh).

A generator's heat rate (MMBtu/MWh) is a measurement of its efficiency in converting fuel into electricity. The 2017 calculated all-LMU marginal heat rate of 5.428 MMBtu/MWh was 18% lower than the 2016 value of 6.625 MMBtu/MWh. When considering the emitting units only, the LMU marginal heat rate increased 1%, from 7.925 MMBtu/MWh in 2016 to 8.043 MMBtu/MWh in 2017.

Section 2
Background

In 1994, the New England Power Pool (NEPOOL) Environmental Planning Committee (EPC) analyzed the impact that demand-side management (DSM) programs had on 1992 nitrogen oxide (NO_X) air emissions of NEPOOL generating units. The results were presented in a report, *1992 Marginal NO_X Emission Rate Analysis*. This report was used to support applications to obtain NO_X Emission-Reduction Credits (ERC) in Massachusetts resulting from the impacts of DSM programs.[3] Such applications were filed under the Massachusetts ERC banking and trading program, which became effective on January 1, 1994. The ERC program allows inventoried sources of NO_X, volatile organic compounds (VOC), and carbon monoxide (CO) in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Also in 1994, the *1993 Marginal Emission Rate Analysis* (*1993 MEA Report*) was published, which provided expanded analysis of the impact of DSM programs on power plant NO_X, sulfur dioxide (SO_2), and carbon dioxide (CO_2) air emissions for 1993. MEA reports were published annually from 1994 to 2007 to provide similar annual environmental analyses for these years.[4] For the 2008 emissions analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the *MEA Report* be restructured to include calculated system and marginal emissions for the entire ISO New England generation system, rather than focusing primarily on marginal emissions.[5] In response, the report was revised and renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of emissions from the entire ISO New England electric generation system.

The *Emissions Report* includes a marginal emissions analysis that is based on the Locational Marginal Unit (LMU) methodology. This methodology, which was begun as a pilot program in 2011, uses marginal units identified by the Locational Marginal Price (LMP) to calculate the marginal emissions for LMUs.

Stakeholders can use the calculated marginal emissions to track air emissions from ISO New England's electric generation system and to estimate the impact that DSM programs and non-emitting renewable energy projects (i.e., wind and solar units) have on reducing ISO New England's NO_X, SO_2, and CO_2 power plant air emissions. The *2017 Emissions Report* focuses on analysis and observations over the past decade (2008 to 2017). The Appendix includes data for years before 2008, as well as the values behind the figures presented.

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[3] Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2018), http://www.mass.gov/eea/agencies/massdep/service/approvals/bwp-aq-18.html.

[4] ISO New England emissions analyses and reports from 1999 to the present are available at http://www.iso-ne.com/system-planning/system-plans-studies/emissions.

[5] The EAG is a stakeholder working group that assists the ISO's Planning Advisory Committee (PAC), the Reliability Committee (RC), and the associated Power Supply Planning Committee (PSPC); http://www.iso-ne.com/eag.

2.1 History of Marginal Emissions Methodologies

MEA studies performed before 2004 used production simulation models to replicate, as closely as possible, the actual system operations for the study year (reference case). An incremental load scenario was then modeled in which the system load was increased by 500 MW in each hour (marginal case). The calculation for the marginal air emission rates was based on the differences in generator air emissions between the reference and marginal scenarios. However, the reference case simulation could not exactly match the actual unit-specific energy production levels of the study year because the production simulation model had a number of limitations. For example, the model could not accurately represent the historical overall dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit-specific outages and deratings, and the effects of the daily volatility of regional (power plant) fuel prices.

From 2004 to 2013, the Fuel Type Assumed (FTA) methodology was used to calculate the average marginal emission rates. This method was based on the assumption that all natural-gas-fired and oil-fired generators responded to changing system load by increasing or decreasing their loading. Units fueled with other sources, such as coal, wood, biomass, refuse, or landfill gas, were excluded from the calculation; historically (in the 2000s), these types of units operated as base load or were non-dispatchable and not typically dispatched to balance supply with demand on the system.[6] Other non-emitting resources, such as hydroelectric, pumped storage, wind, solar, and nuclear units that do not vary in output to follow load were also assumed not to be marginal units and were excluded from the FTA calculation of marginal emission rates.

In 2011, the ISO began developing a methodology for calculating the marginal emission rate based on the locational marginal unit, which stemmed from recommendations of the Environmental Advisory Group. This methodology identifies marginal units using the locational marginal price (LMP), a process that minimizes total cost of energy production for the entire ISO New England system while accounting for transmission and other constraints reflecting physical limitations of the power system. This method identifies the last unit dispatched to balance the system, called the *locational marginal unit* (refer to Section 3.3). Results are presented starting in 2009, the earliest year of available data.

2.2 History of Heat Rate Methodologies

A thermal power plant's heat rate is a measure of its efficiency in converting fuel (British thermal units, Btus) to electricity (kWh); the lower the heat rate, the more efficient the facility. A plant's heat rate depends on the individual plant design, its operating conditions, its level of electrical power output, etc.

Before 1999, MEA studies assumed a fixed marginal heat rate of 10.0 million BTUs per megawatt-hour (MMBtu/MWh), which was used to convert from pounds (lb)/MWh to lb/MMBtu.[7] In the 1999 to 2003 MEA studies, the marginal heat rate was calculated using the results of production

[6] One observation for determining whether to consider coal units as marginal units was that higher or lower loads change the number of committed natural gas and oil units, while coal units would be dispatched when available. During the low-load troughs of the daily cycle, coal units were load following. It is reasonable to expect that the coal units would continue to be available for load following during such low-load periods of the night and would likely continue to be marginal for establishing LMPs during these off-peak hours.

[7] 10 MMBtu/MWh is equivalent to 10,000,000 Btu/kWh.

simulation runs. Beginning with the 2004 MEA study, the marginal heat rate was based on the actual generation of marginal fossil units only.

Beginning with the *2007 MEA Report*, the marginal heat rate has been calculated using a combination of both US Environmental Protection Agency (EPA) heat input data and the heat-rate information collected and maintained by the ISO. For the marginal fossil units with EPA data, the heat inputs reported to EPA were used. For units without EPA data, the heat inputs were calculated by multiplying each unit's monthly generation by the ISO's heat-rate data. The individual heat input values (in MMBtu) using the two methods were then added and the sum divided by the total generation of the marginal fossil units.

In the current methodology (see Section 3.4), the calculation for the marginal heat rate is based on the heat rates for each individual LMU. The percentage of time each generator is marginal per year leads to the contribution of that unit's heat rate to the LMU marginal heat rate.

Section 3
Data Sources and Methodologies

This section discusses the data sources and methodologies used for the emissions analysis. The calculations for total system emission rate, marginal emission rate, and marginal heat rate are shown. The time periods studied are also described.

3.1 Data Sources

The primary source of data for the ISO New England power system emissions and marginal emission rate calculations for NO_X, SO_2, and CO_2 was the US EPA Clean Air Markets Division (CAMD) database.[8] The database contains measured 2017 air emissions (tons) reported by generators under EPA's monitoring and recordkeeping requirements for the Acid Rain Program and NO_X mass emissions and the Regional Greenhouse Gas Initiative (RGGI).[9]

For those units not required to report emissions data to EPA under 40 CFR Part 75for a federal or state regulation, monthly emission rates (lb/MWh) from the New England Power Pool Generation Information System (NEPOOL GIS) were used. If this information was not available, annual emission rates (lb/MWh) from EPA's eGRID2016 were used.[10] In the case of no other sources of data, emission rates based on eGRID data were obtained for similar type units. These unit-specific emission rates were used in conjunction with the actual megawatt-hours of generation, from the ISO's database used for energy market settlement purposes, to calculate tons of emissions.

All electric generators dispatched by ISO New England are included in the emissions calculations. Emissions from "behind-the-meter" generators or those generators not within the ISO New England balancing authority area are not part of this analysis.

3.2 Total System Emission Rate Calculation

The total annual system emission rate is based on the emissions produced by all ISO New England generators during a calendar year. The rates are calculated by dividing the total air emissions by the total generation from all units. The formula for calculating the total annual system emission rate is:

$$\text{Annual System Emission Rate (lb/MWh)} = \frac{\text{Total Annual Emissions (lb)}_{\text{All Generators}}}{\text{Total Annual Energy (MWh)}_{\text{All Generators}}}$$

[8] EPA's Clean Air Markets Program data (2018) are available at http://ampd.epa.gov/ampd/, and the Clean Air Markets emissions data (2018) are available at http://www.epa.gov/airmarkets/. Generators report emissions to EPA under the Acid Rain Program, which covers generators 25 MW or larger. Generators subject to RGGI also report CO_2 emissions to EPA. Additional details for the monitoring, recordkeeping, and reporting requirements of SO_2, NO_X, and CO_2 emissions, volumetric flow, and opacity data from affected units under 40 CFR Part 75 are available at https://www.epa.gov/airmarkets/clean-air-markets-emissions-monitoring.

[9] Before 2005, the MEA reports used annual data obtained primarily from the EPA Emissions Scorecard. In the 2005 and 2006 MEA Reports, monthly EPA data, rather than hourly data, were used for calculating marginal rates.

[10] The U.S. EPA's eGRID2016 database (2018) is available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

3.3 Marginal Emission Rate Calculation

The Locational Marginal Unit (LMU) is identified by the LMP, which is set by the cost of the generation dispatched to meet the next increment of load at the pricing location. The resource that sets price is called the marginal unit. LMPs minimize total energy costs for the entire ISO New England system, subject to a set of constraints reflecting physical limitations of the power system.

The process to determine the LMP identifies at least one locational marginal unit for each five-minute period, which is associated with meeting the energy requirements on the system during that pricing interval. When transmission is not constrained, the marginal unit is classified as the unconstrained marginal unit. Each binding transmission constraint adds an additional marginal unit, resulting in *n + 1 marginal units* (LMUs) for every *n* binding constraints, in each five-minute period. To calculate the marginal emission rates, the hourly emissions (lb) for those units in the EPA CAMD database were grouped into on-peak and off-peak periods (defined in Section 3.5) for each month. When only monthly NEPOOL GIS or annual eGRID data were available, these emission rates were multiplied by the associated monthly on-peak and off-peak generation. The amount of monthly emissions (lb) from each individual marginal fossil generator was then divided by that generator's monthly on-peak or off-peak generation to obtain the corresponding emission rate (lb/MWh) for that time period. For NO_X emission rates, the monthly totals (lb) for each generator were grouped into ozone and non-ozone season emissions and divided by the respective ozone and non-ozone season generation.

The percentage of time each generator was marginal in each month was calculated and then multiplied by the generator's month-specific on-peak or off-peak average emission rate described above. That amount was summed for each marginal unit and then divided by the total on-peak or off-peak hours in the year. The LMU marginal emission rate calculations are as follows, where generator *k* is identified to be marginal during hour *h* and has a specific monthly emission rate during month *m*:

LMU On-Peak Marginal Emission Rate

$$= \frac{\sum_{\text{k}=1}^{\text{LMP marginal units}} \sum_{\text{h}=1}^{\text{on-peak hours in year}} (\text{\% of LMP Unit Marginal}_{\text{k,h}} \times \text{On-Peak Emission Rate}_{\text{k,m}})}{\text{On-Peak Hours in Year}}$$

LMU Off-Peak Marginal Emission Rate

$$= \frac{\sum_{\text{k}=1}^{\text{LMP marginal units}} \sum_{\text{h}=1}^{\text{off-peak hours in year}} (\text{\% of LMP Unit Marginal}_{\text{k,h}} \times \text{Off-Peak Emission Rate}_{\text{k,m}})}{\text{Off-Peak Hours in Year}}$$

The annual LMU marginal emission rate was then calculated by combining the on-peak and off-peak rates in a weighted calculation.

The analysis of LMU marginal emission rates was conducted for two different scenarios. Each scenario includes or excludes certain generators depending on their characteristics. The two scenarios are as follows:

- **All LMUs**—includes all locational marginal units identified by the LMP

- **Emitting LMUs**—excludes all non-emitting units with no associated air emissions, such as pumped storage, hydroelectric generation, nuclear, external transactions, and wind and solar renewables

3.4 Marginal Heat Rate Calculation

The marginal heat rate was calculated by first calculating a heat rate for each individual generator. The heat input values for the individual LMUs were then multiplied by the percentage of time each generator was marginal during the year. These values were then added together and divided by the total generation of the marginal units.

Since a unit's heat rate is equal to its heat input, or fuel consumption, divided by its generation, the calculated marginal heat rate is defined as follows:

$$\text{Calculated Marginal Heat Rate} = \frac{\text{Calculated Fuel Consumption of } \mathit{Marginal\ Fossil} \text{ Units (MBtu)}}{\text{Actual Generation of } \mathit{Marginal\ Fossil} \text{ Units (MWh)}}$$

3.5 Time Periods Analyzed

The 2017 marginal air emission rates for on- and off-peak periods for ISO New England were calculated for this report. Data for the on-peak period are presented so that a typical industrial and commercial user that can provide load response during a traditional weekday can explicitly account for its emissions reductions during the on-peak hours. The marginal emission rates for NO_X were calculated for five time periods:[11]

- On-peak ozone season, consisting of all weekdays between 8:00 a.m. and 10:00 p.m. from May 1 to September 30
- Off-peak ozone season, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours from May 1 to September 30
- On-peak non-ozone season, consisting of all weekdays between 8:00 a.m. and 10:00 p.m. from January 1 to April 30 and from October 1 to December 31
- Off-peak non-ozone season, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours from January 1 to April 30 and from October 1 to December 31
- Annual average

Because the ozone and non-ozone seasons are only relevant to NO_X emissions, the SO_2 and CO_2 emission rates were only calculated for the following time periods:

- On-peak annual, consisting of all weekdays between 8:00 a.m. and 10:00 p.m.
- Off-peak annual, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours
- Annual average

[11] The ISO developed a special report, *Analysis of New England Electric Generators' NO_X Emissions on 25 Peak-Load Days in 2005–2009*, released September 23, 2011, which summarized its analysis of NO_X emissions during peak days (https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf

Section 4
Data and Assumptions

This section highlights the key parameters and assumptions modeled in the *2017 Emissions Report*, including weather, emissions data, installed capacity, and system generation.

4.1 2017 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2017 temperatures, total energy use and both cooling and heating degree days to previous years can provide some perspective.

The average temperature in January and February 2017 was 33°F, which was significantly warmer than the 20-year average of 28°F, and also warmer than the previous year's average temperature of 31°F during those months. The month of December 2017, with an average temperature of 28°F, was significantly colder than average. Summer 2017 was somewhat cooler than average.

The 2017 summer peak electricity demand of 23,968 MW was 6.4% lower than the 2016 summer peak of 25,596 MW. There were 309 cooling degree days in 2017, which is 4.5% lower than the 20-year average.[12] The net energy for load was 2.6% lower in 2017 than 2016. With respect to the winter months, there were 5,838 heating degree days, which is 2.6% lower than the 20-year average.

New England's historical cooling degree days and heating degree days for 1998 through 2017 are shown in Appendix Table 1. The difference between the cooling and heating degree days for a particular year and the average is also provided.

4.2 Emissions Data

For calculating total system emissions, approximately 61% of the SO_2 emissions and 74% of the CO_2 emissions were based on EPA's Clean Air Markets data. For NO_X, Clean Air Markets data were used for 34% of total emissions.

The emission rates were multiplied by the 2017 energy generation reported to the ISO to obtain the emissions (tons) by each generator.

4.3 ISO New England System Installed Capacity

The ISO New England power grid operates as a unified system serving all loads in the region. The amount of generation by fuel type and its associated emissions are affected by a number of factors, including the following:

- Forced and scheduled maintenance outages of resources and transmission system elements
- Fuel and emission allowance costs

[12] Over the 20-year span from 1998 to 2017, the average number of cooling degree days was 324, and the average number of heating degree days was 5,991.

- Imports from and exports to neighboring regions
- System peak load and energy consumption
- Water availability to hydro facilities and for thermal system cooling
- A variety of other factors

Figure 4-1 shows the total 2017 summer capacity for ISO New England generation as obtained from *ISO New England's 2018–2027 Forecast Report of Capacity, Energy, Loads and Transmission* (CELT).[13] Appendix Table 2 and Appendix Table 3 summarize the total summer and winter capacity for ISO New England generation by state and fuel type.

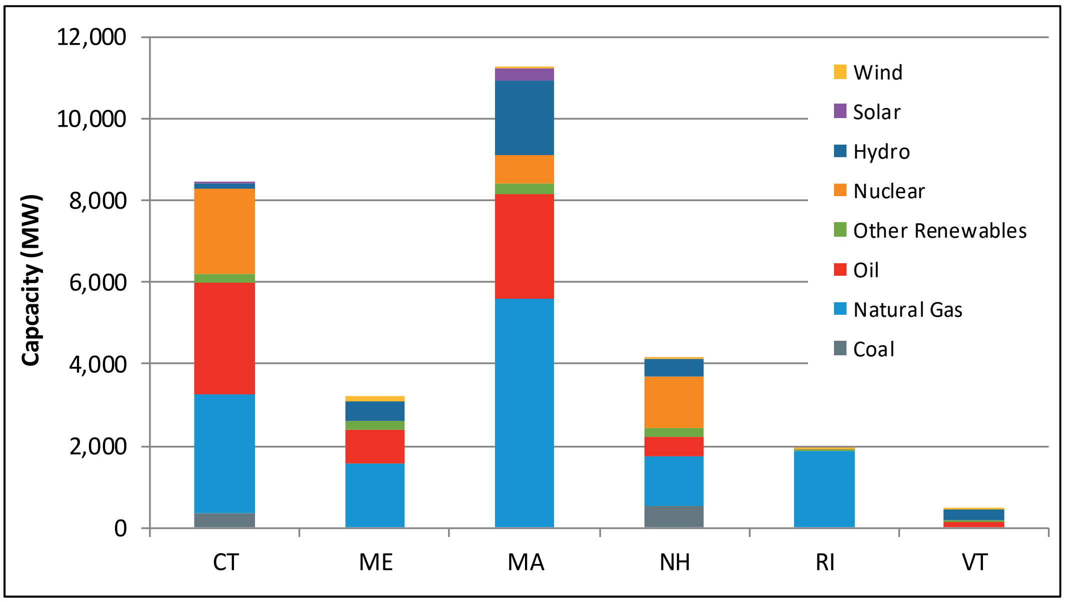

Figure 4-1: 2017 ISO New England summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2008 through 2017. A total of 2,635 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 62% of this new capacity. The remaining additions consist primarily of renewable generation, including 20% of total capacity from wind and solar resources.

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[13] The ISO New England *CELT Report* is typically issued in May of each year. The *2018 CELT Report* (using the January 1, 2018 ratings) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2017. The capacity may also include generators that retired in 2017. The CELT reports are available at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

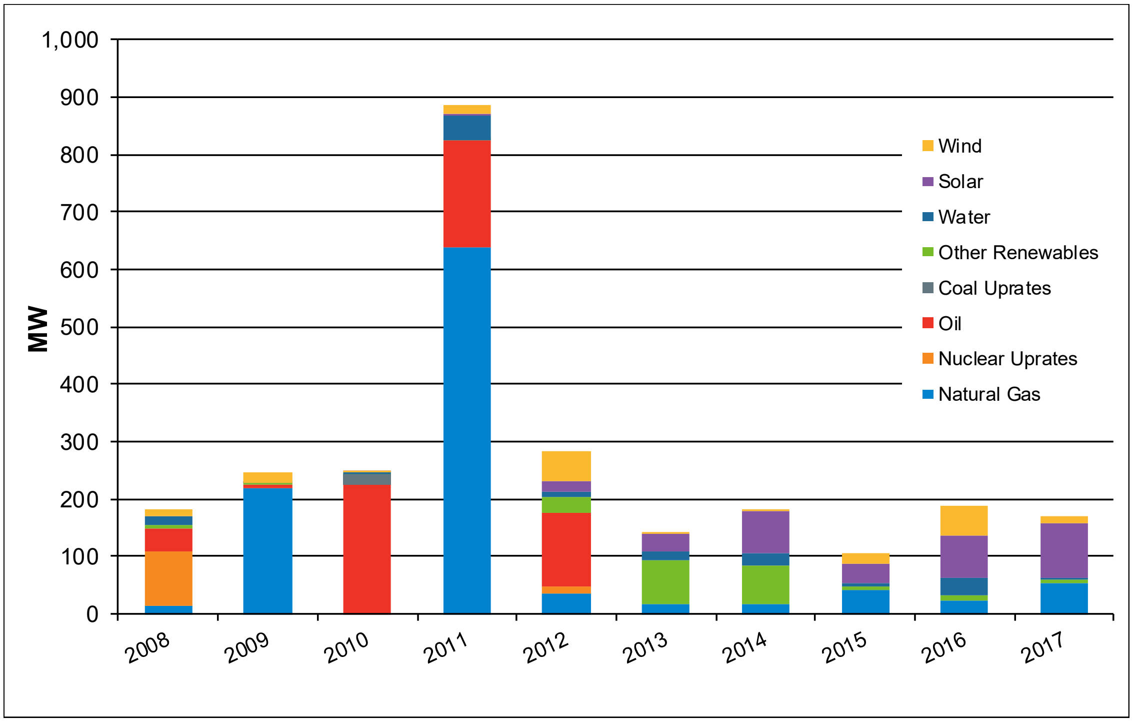

Figure 4-2 : ISO New England generator additions, 2008 to 2017 (MW).
Note: The generator additions and uprate values are based on the summer Seasonal Claimed Capabilities, as reported in the 2018 CELT Report.

Several large generators in New England have retired in recent years. The retirements, as shown in Figure 4-3, total 1,829 MW of coal, 1,332 MW of residual oil, and 604 MW of nuclear generation since late 2011.

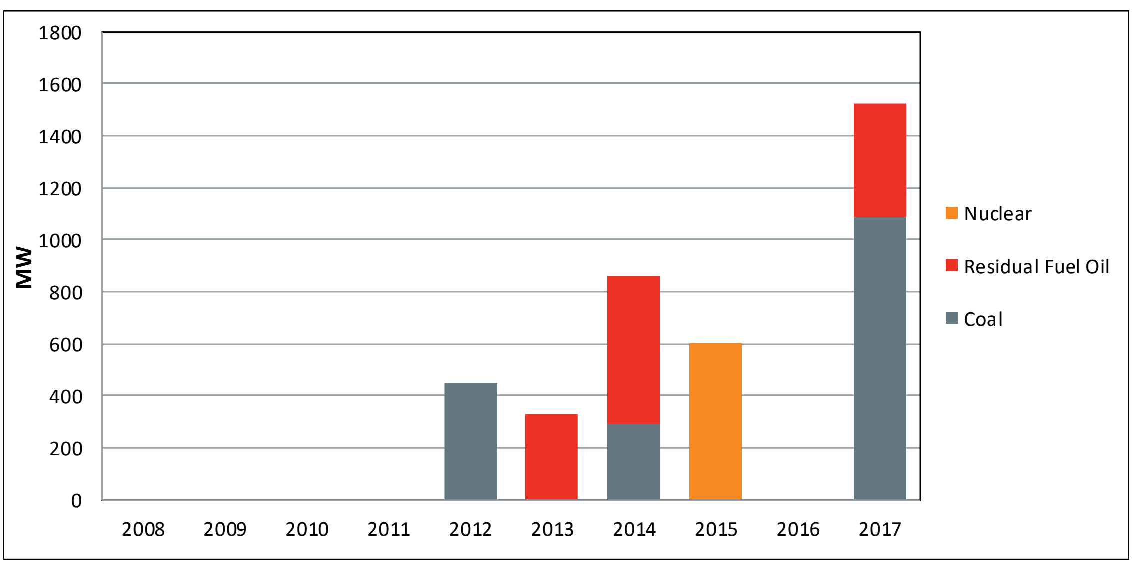

Figure 4-3: Major retirements in ISO New England, 2008 to 2017 (MW).
Note: The retirement date shown is not necessarily the year in which the retirement occurred. In the case of units that retired late in the year, the retirement is included in the following year because that is when the impact would primarily have been observed.

4.4 ISO New England System Energy Production

The ISO relies on generating units of all operating characteristics and fuel types, and a generator's fuel type directly correlates with the magnitude and characteristics of the unit's emissions.

Figure 4-4 shows the 2017 monthly generation by fuel type. The overlaid black line represents the total generation in each month and corresponds with the right axis. Natural-gas-fired generation accounted for 38% to 60% of the total generation in each month.[14]. During winter months with higher energy demand and occasional limitations in natural gas availability, other fuel types have increased their energy contribution to support the New England system.[15] During the winter months, the use of firmly contracted gas pipeline transportation by the regional gas sector's local distribution company (LDC) customers takes priority over the use of the interruptible and/or secondary pipeline capacity which is primarily used by gas-fired generators to generate electricity.[16] Almost all gas-fired generating units lack both firm supply and transportation contracts.

The lowest monthly percentages of natural-gas-fired generation in 2017 were in January, February, March, and December. During the months of January, February, and March, the contribution from coal-fired generation was higher than during the remainder of the year. Oil-fired generation remained below 0.5% of total generation during every month of the year except December. A cold snap during the second half of the month required extensive generation by oil-fired units, as well as increased generation by coal-fired units.

[14] Annual energy production share for natural gas-fired generation was 48% in 2017, compared to 49% in 2016.
[15] Annual energy production share by fuel type remained generally consistent between 2016 and 2017, although wind generation increased to 3% of annual real-time energy production. This was the first time wind exceeded oil- and coal-fired generation in the New England control area, due in part to oil- and coal-fired retirements and increased wind generation.
[16] Firm customers of regional gas LDCs include residential, commercial, and industrial (RCI) customers.

Hydroelectric, solar, and wind generation accounted for 8% to 18% of the total generation. These fuel types exhibit seasonal differences in their generation due to fuel availability; typically hydroelectric and wind generation decline over the summer months due to less rainfall replenishing reservoirs and rivers and less favorable onshore wind conditions, while solar generation peaks between March and September.

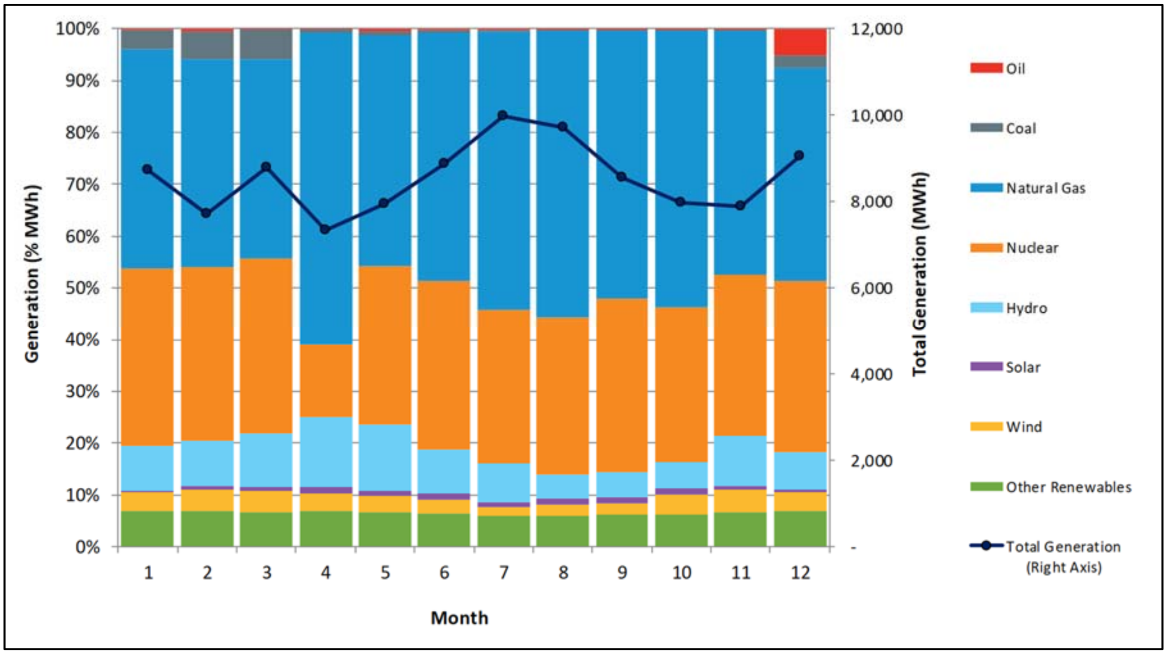

Figure 4-4: 2017 ISO New England monthly generation by fuel type (% MWh, MWh).

Figure 4-5 shows the generation (MWh) by fuel type from 2013 to 2017 based on the resource's primary fuel type listed in the *2018 CELT Report*. In 2017, coal-fired generation was about 870 GWh lower than in 2016, and oil-fired generation was 150 GWh lower. Natural-gas-fired generation in 2017 was about 2,500 GWh lower than in 2016, decreasing by about 5%. Nuclear generation decreased by 4%. The only categories that increased in 2017 were hydroelectric generation, which grew 15%, and solar and wind, which together increased by 995 GWh, or 31% over 2016. The overall system generation of 102,562 GWh in 2017 was 3% below the 2016 level.

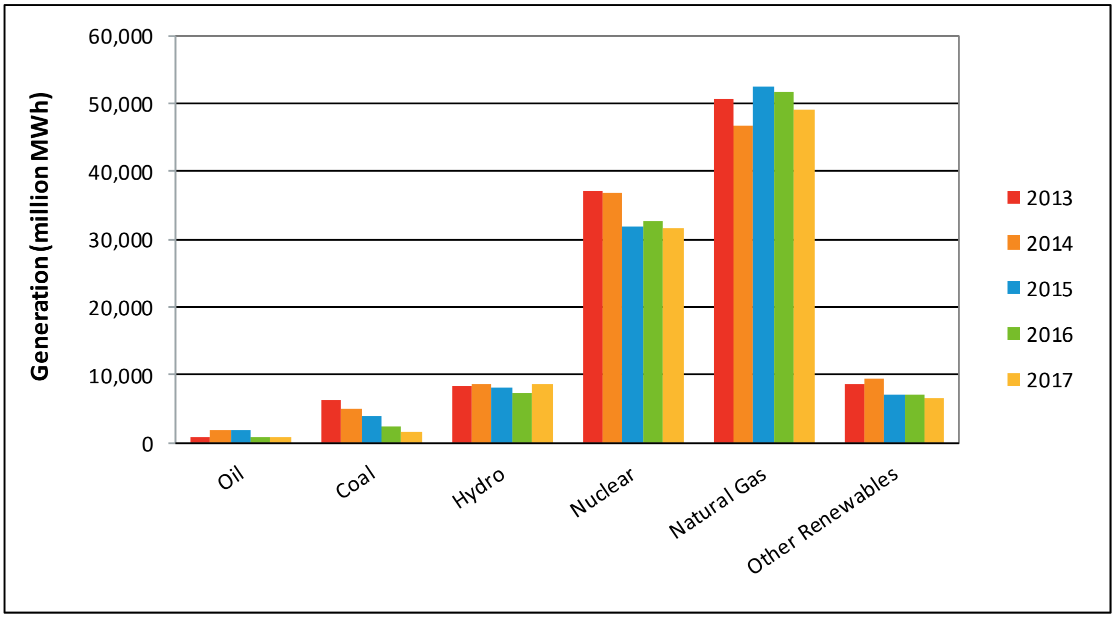

Figure 4-5: ISO New England annual generation by fuel type, 2013 to 2017 (million MWh).

4.5 Locational Marginal Unit Scenarios

The data and assumptions applied for the all-LMU and emitting-LMU scenarios are presented in this section, including the percentage of time various fuel types were marginal. Because the price of the marginal unit (and thus the price of electricity) is largely determined by the unit's fuel type and heat rate, examining the marginal units by fuel type can explain changes in electricity prices and emissions.

4.5.1 All LMUs

In this scenario, all identified locational marginal units were used to develop the marginal emission rates. Non-emitting generators were associated with a zero emission rate. Figure 4-6 shows each fuel type's time on the margin and month-to-month variations. Natural gas was marginal 50% to 78% of the time. The months when natural gas units were marginal the most, in the range of 74% to 78% of the time, were January and July through September. During the months of January through March, coal-fired generation was on the margin more than other months, at 5% to 6% of the time. Oil-fired generation was on the margin an average of only 1% during the year, with the highest percentage of time on the margin (approximately 4%) occurring in December, when the cold snap occurred. Intermittent resources became eligible to be dispatched and set price beginning in May 2016,[17] and in 2017 the time that wind was marginal ranged from 7% in July to a maximum of 35% in October.

[17] The Do Not Exceed (DNE) dispatch rules, which went into effect on May 25, 2016, incorporate wind and hydro intermittent units into the unit dispatch and pricing process, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price.

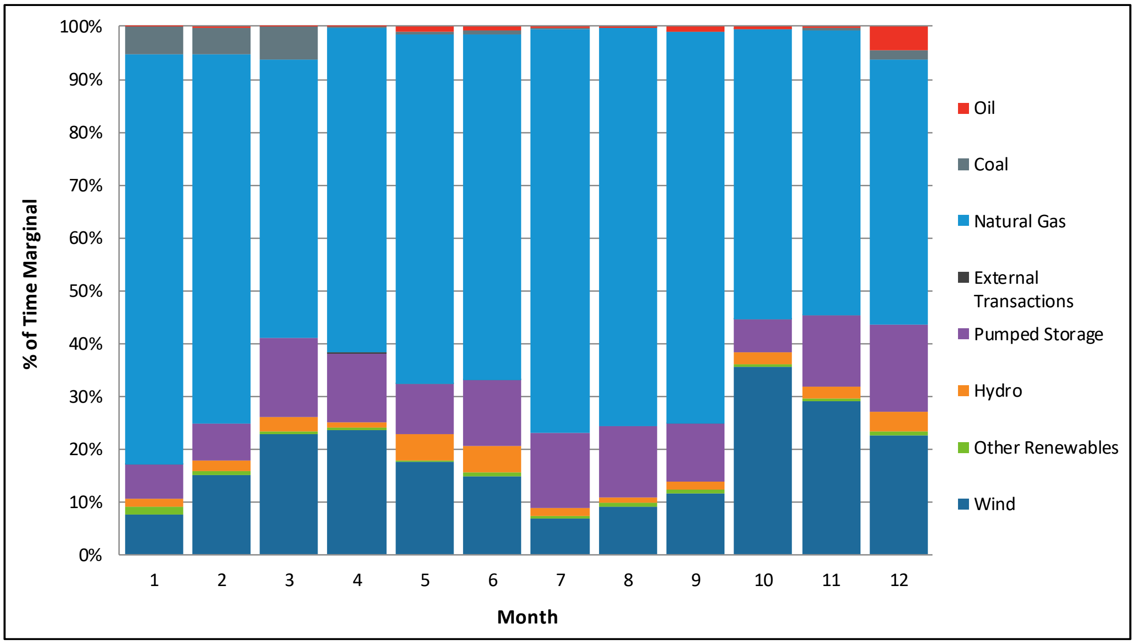

Figure 4-6: 2017 percentage of time various fuel types were marginal—all LMUs.

Figure 4-7 shows the historical percentage of time that each fuel type was marginal within a calendar year. Natural gas has been the primary marginal fuel type during the past five years. From 2016 to 2017, the percentage of time that natural gas was marginal decreased by 12%. The amount of time that oil was the marginal fuel remained at 1% in 2017, and coal was marginal 2% of the time, or about half that in 2016. The percentage of time that the Other Renewables category was marginal increased by 14%. This was due to the higher frequency of marginal wind generators. In 2017, wind often displaced gas as the price-setting fuel. However, it is important to note that wind predominantly set price in small, local export-constrained areas of the system, as opposed to setting price for large parts of the system. Though wind was marginal 18% of the time in 2017, it was generally marginal in a very local congested area and did not directly impact system price. At the system level, wind was the marginal fuel type less than 1% of the time.[18]

[18] Beginning with the 2018 Spring Quarterly Markets Report (July 2018), the ISO-NE Internal Market Monitor (IMM) recalculated the percentage of time marginal units by fuel type by quarter, using a load-weighted analysis for 2016 through the first half of 2018. The IMM switched to the load-weighted marginal resources methodology to better reflect the impact of system constraints since resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. The IMM reports are available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/.

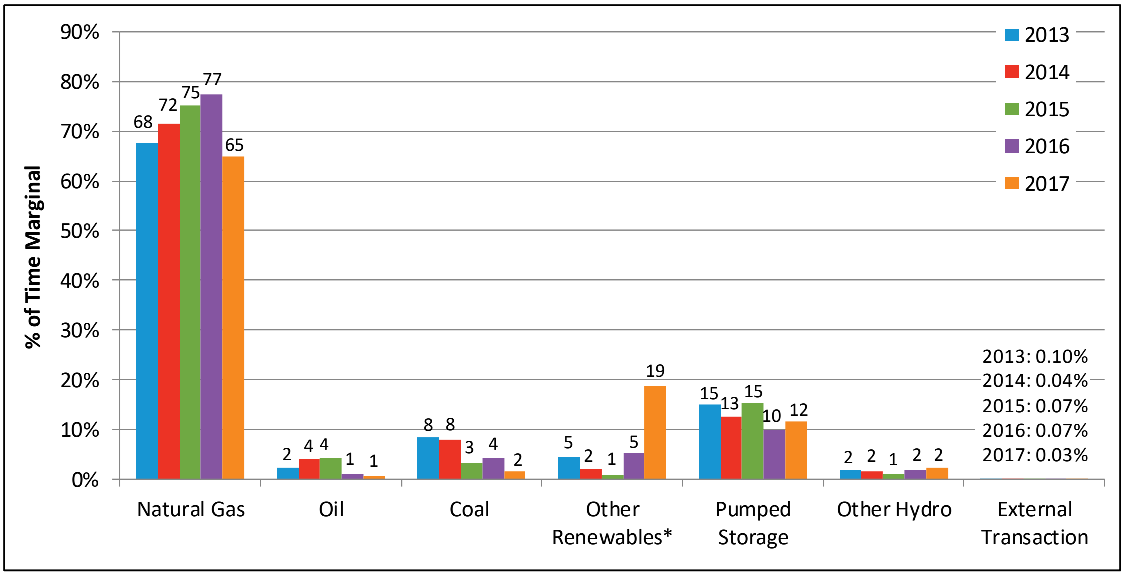

Figure 4-7: Annual percentage of time various fuel types were marginal—all LMUs, 2013 to 2017.

4.5.2 Emitting LMUs

Marginal generating resources with no air emissions were excluded in this scenario. Therefore, hydroelectric, pumped storage, external transactions, and other renewables with no air emissions were not taken into account, while all other LMUs were.

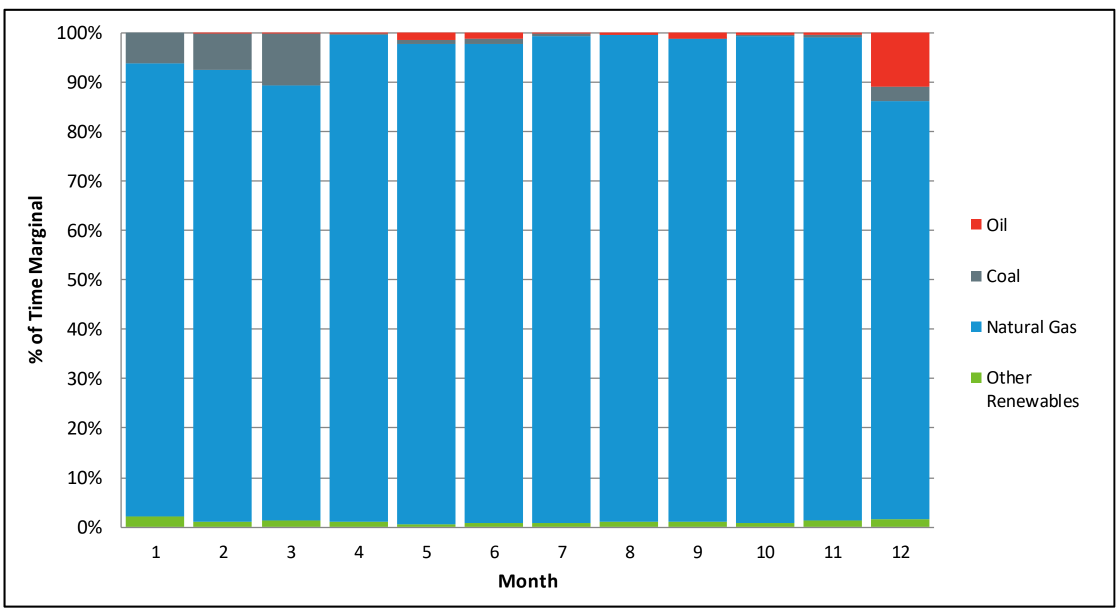

Figure 4-8: 2017 percentage of time various fuel types were marginal—emitting LMUs.

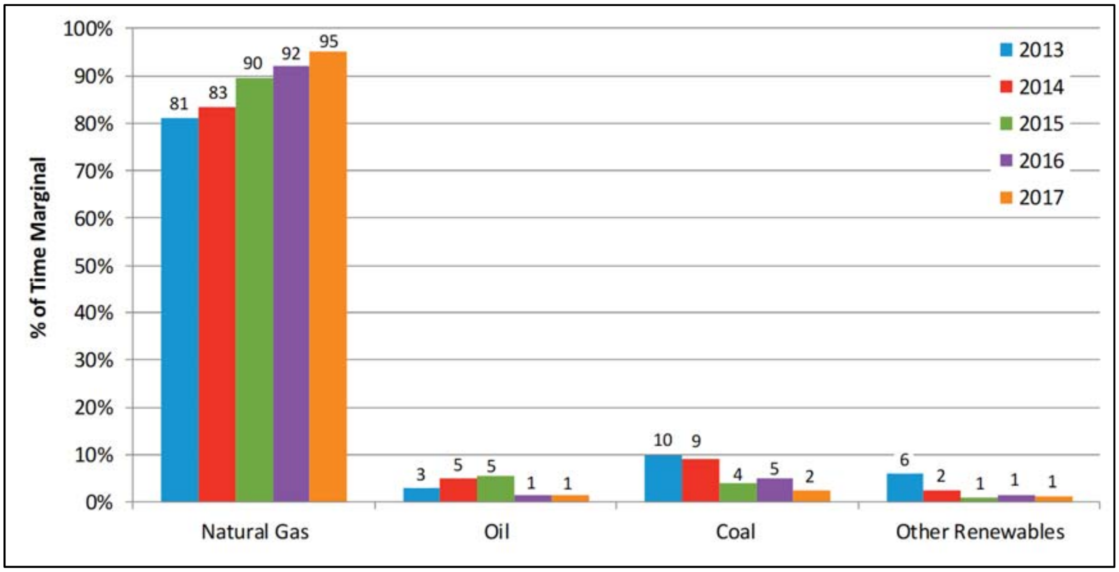

Figure 4-9: Annual percentage of time various fuel types were marginal—emitting LMUs, 2013 to 2017.

4.6 High Electric Demand Days

In New England, high electric demand days (HEDDs) are typically characterized by high temperatures leading to elevated cooling (energy) demand. During peak energy demand periods, such as HEDDs, the ISO relies on peaking units, which are less utilized during the rest of the year but respond quickly to meet system demand. These peaking units are often jet (aero-derivative) or combustion turbines with higher emission rates. Therefore, examining the marginal emission rates on HEDDs (see Section 5.3.4) reveals the emission rates associated with the units responding to higher system demand.

Section 5
Results and Observations

This section presents the results for ISO New England's 2017 system emissions representing all generators. It also provides the results for the annual marginal heat rates and the locational marginal unit emission rates for the all-LMU and emitting-LMU scenarios.

5.1 2017 ISO New England System Emissions

Results are presented for the following metrics:

- Aggregate NO_X, SO_2, and CO_2 emissions for each state for 2017
- A comparison of aggregate NO_X, SO_2, and CO_2 emissions for 2008 to 2017
- 2017 annual average NO_X, SO_2, and CO_2 emission rates, by state and for the ISO New England system as a whole
- Monthly variations in the emission rates for 2017
- A comparison of annual average NO_X, SO_2, and CO_2 emission rates for 2008 to 2017

5.1.1 Results

Figure 5-1 shows the 2017 annual aggregate NO_X, SO_2, and CO_2 air emissions for each state. The ISO New England system total emissions for NO_X, SO_2, and CO_2 were 15.30 ktons, 4.00 ktons, and 34,969 ktons, respectively. The calculations for these emission levels were based on the actual generation of all generating units in ISO New England's balancing authority area and the actual or assumed unit-specific emission rates.[19] The reason for the divergent total emissions for each state is that the total emissions reflect the generation of units physically located in that state (refer to Figure 4-1 showing summer capacity by state) rather than emissions associated with the generation needed to meet that state's energy demand..

[19] This does not include northern Maine and the Citizens Block Load (in Northern Vermont), which is typically served by New Brunswick and Quebec. These areas are not electrically connected to the ISO New England Control Area.

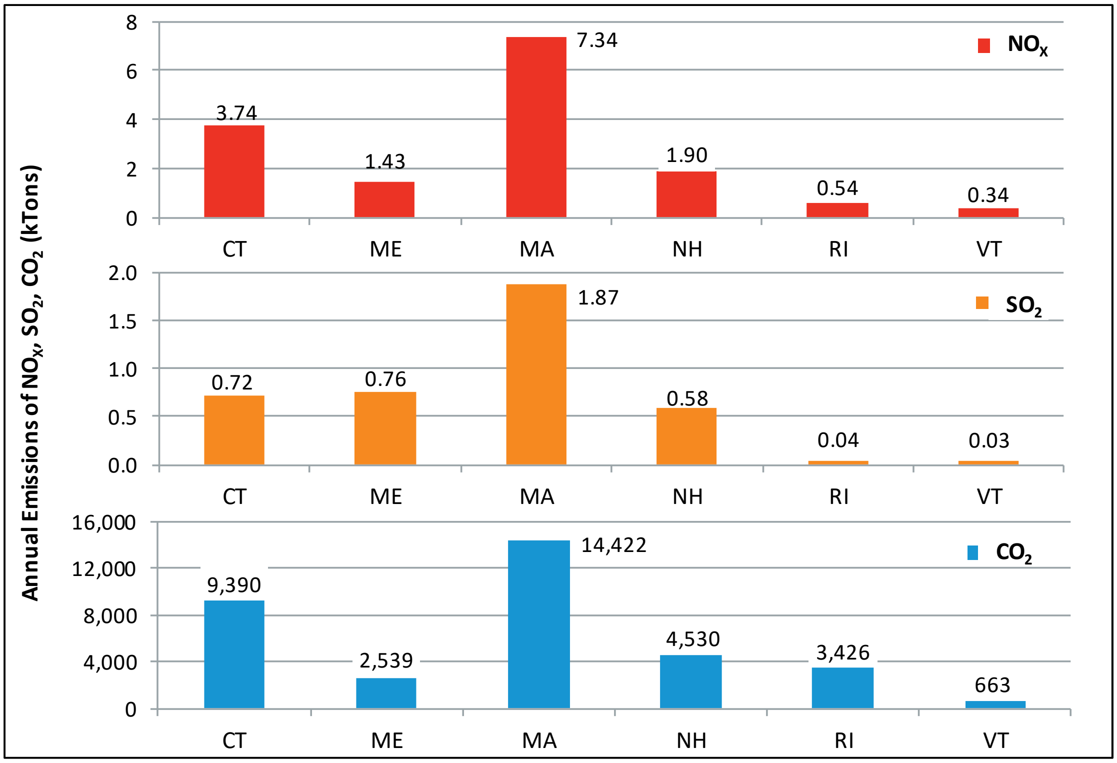

Figure 5-1: 2017 ISO New England system annual emissions of NO_X, SO_2, and CO_2 (ktons).
Note: System annual emissions based on physical location of the generating resources.
Sum may not equal New England system total due to rounding.

Figure 5-2 shows the annual aggregate NO_X, SO_2, and CO_2 air emissions for 2008 through 2017. Since 2008, NO_X emissions have dropped by 53% and SO_2 by 96%, while CO_2 has decreased by about 37%. Refer to Appendix Table 4 for historical system emissions by ktons.

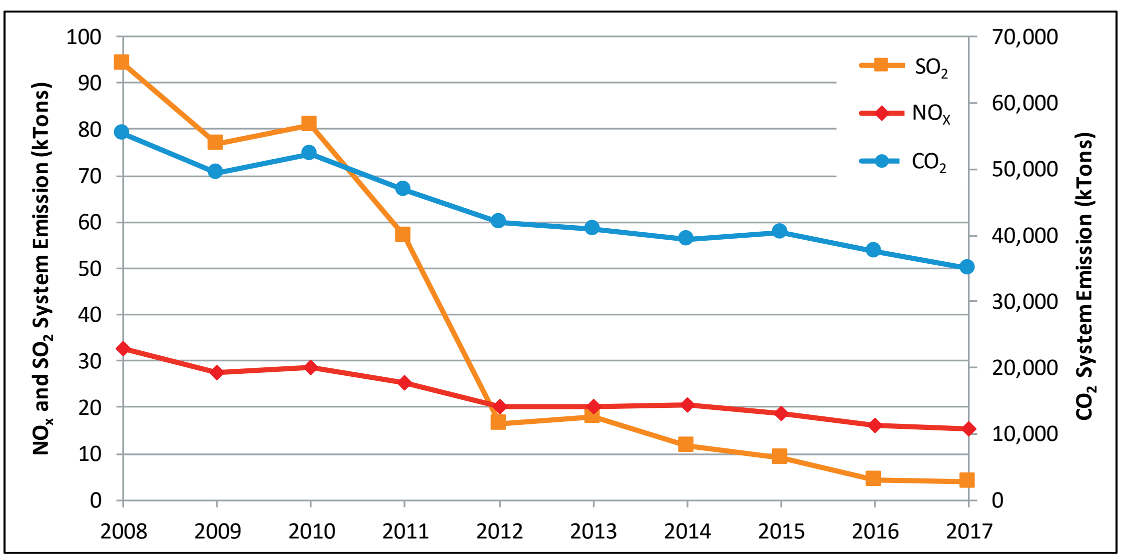

Figure 5-2: ISO New England system annual generator emissions, 2008 to 2017 (ktons).

Table 5-1 shows the 2017 annual average NO_X, SO_2, and CO_2 air emission rates (lb/MWh), by state and for the New England system as a whole. The rate calculations were based on the actual hourly unit generation of ISO New England generating units located within each state and the actual or assumed unit-specific emission rates.

Table 5-1
2017 ISO New England System
Annual Average Generator Emission Rates (lb/MWh)

State	NO_x	SO_2	CO_2
Connecticut	0.22	0.04	561
Maine	0.33	0.17	586
Massachusetts	0.44	0.11	861
New Hampshire	0.22	0.07	521
Rhode Island	0.15	0.01	919
Vermont	0.33	0.03	634
New England	0.30	0.08	682

Monthly variations in the emission rates shown in Figure 5-3 reflect the generation by different fuel types shown in Figure 4-4. In 2017, emission rates were at a higher magnitude during January through March, when natural gas generation was lower and coal-fired generation was higher. An increase in emission rates occurred in April, when higher natural gas generation compensated for a reduction in nuclear generation. In December, there was a substantial rise in emission rates due to increased generation by oil- and coal-fired units. Appendix Table 5 shows the values for this figure.

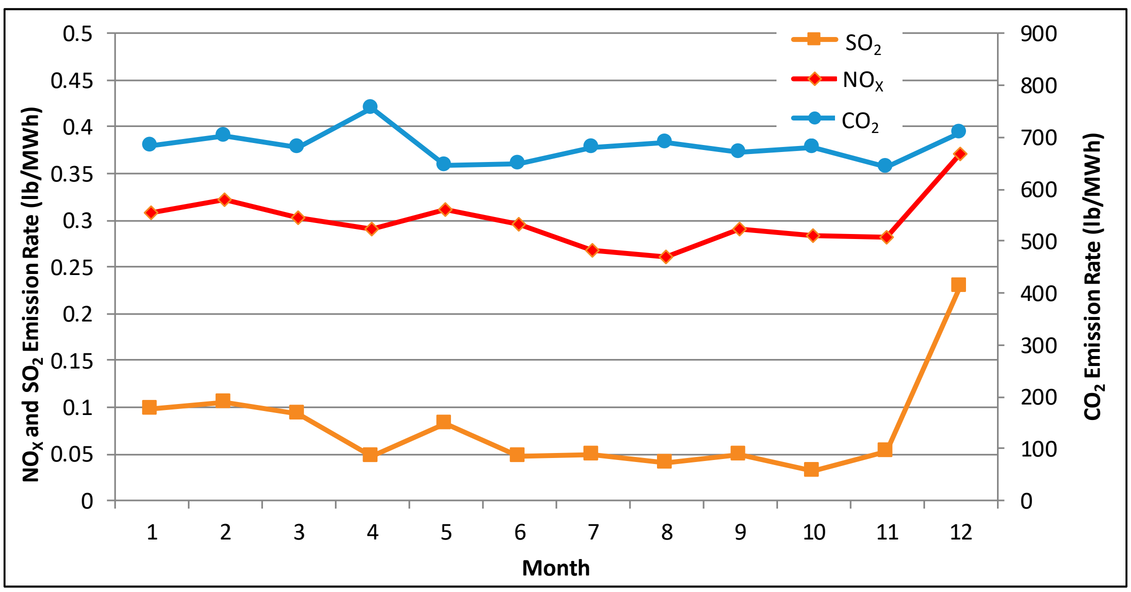

Figure 5-3: 2017 ISO New England system monthly average generator emission rates (lb/MWh).

Figure 5-4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rates (lb/MWh) for 2008 to 2017 using the calculation method presented in Section 3.2. Since 2008, the annual average NO_X emission rate has decreased by 43%, SO_2 by 95%, and CO_2 by 23%. Appendix Table 6 shows historical emission rates since 1999.

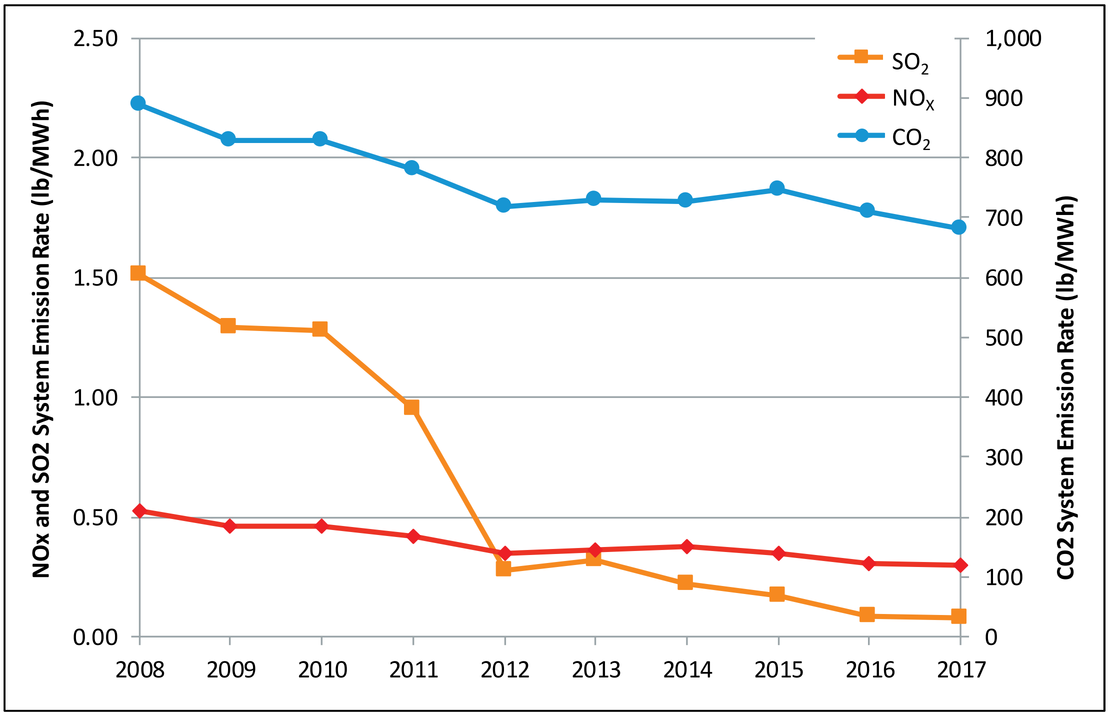

Figure 5-4: ISO New England system annual average generator emission rates, 2008 to 2017 (lb/MWh).

5.1.2 Additional Observations

Total energy generation decreased by 2.8% in 2017 from 2016. The amount of energy from coal-fired generation continued its decline in 2017, decreasing by 34% to 1.6% of total generation. Energy from oil-fired generators decreased by about 16%, and natural gas-fired generation decreased by 5%. In contrast, there was a 2% increase in total energy produced by non-emitting sources, which includes nuclear generation. Although nuclear generation itself decreased by 4%, photovoltaic and wind generation grew by 31%, and generation by hydroelectric facilities rose 15%. The impacts on system emissions resulting from these changes in the generation mix can be seen in Table 5-2. The reduction in coal and oil-fired generation from 2016 to 2017 contributed to decreases of 5.9%, 10.5%, and 6.7% in system emissions for NO_X, SO_2, and CO_2, respectively. Similar changes were also observed in the 2017 NO_X and CO_2 emission rates, which decreased by 3.2% and 3.9%, respectively, from 2016 values. The SO_2 rate, which has already fallen by 98% since 1999, remained flat between 2016 and 2017.

Table 5-2
2016 and 2017 ISO New England System Emissions (ktons)
and Emission Rates (lb/MWh)

Annual System Emissions						
	2016 Emissions (kTons)	2017 Emissions (kTons)	Total Emissions % Change	2016 Emission Rate (lb/MWh)	2017 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	16.26	15.30	-5.9	0.31	0.30	-3.2
SO_2	4.47	4.00	-10.5	0.08	0.08	0.0
CO_2	37,468	34,969	-6.7	710	682	-3.9

Overall, total system emissions have declined over the last 10 years, which can be attributed to several factors:

- Increased use of highly efficient natural-gas-fired generators
- Decline in the cost of natural gas
- Mandated use of lower-sulfur fuels
- Retirement of oil and coal-fired generation, and retrofits of NO_X and SO_2 emission controls on some of the remaining oil- and coal-fired generators

5.2 2017 ISO New England Marginal Heat Rate

The calculated annual marginal heat rate reflects the average annual efficiency of all the marginal fossil units dispatched throughout 2017. The 2017 monthly marginal heat rates for both the all-LMU and emitting-LMU scenarios are shown in Figure 5-5, and the historical marginal heat rates for 2010 to 2017 are presented in Figure 5-6. The values behind Figure 5-6 are provided in Appendix Table 7.

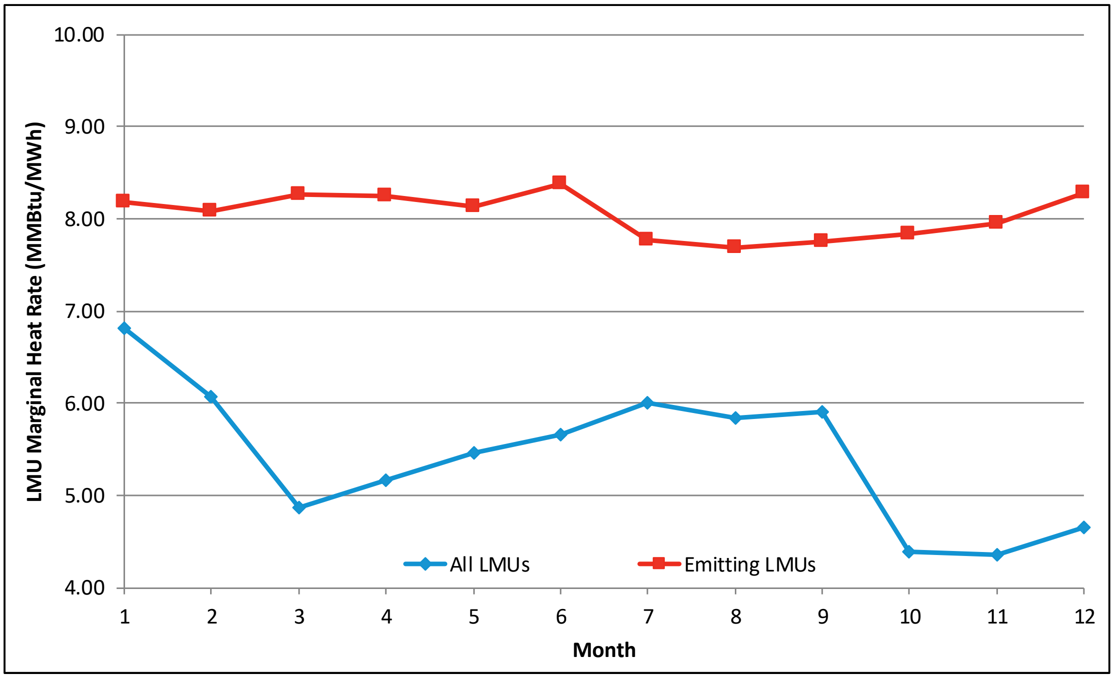

Figure 5-5: 2017 LMU monthly marginal heat rate (MMBtu/MWh).

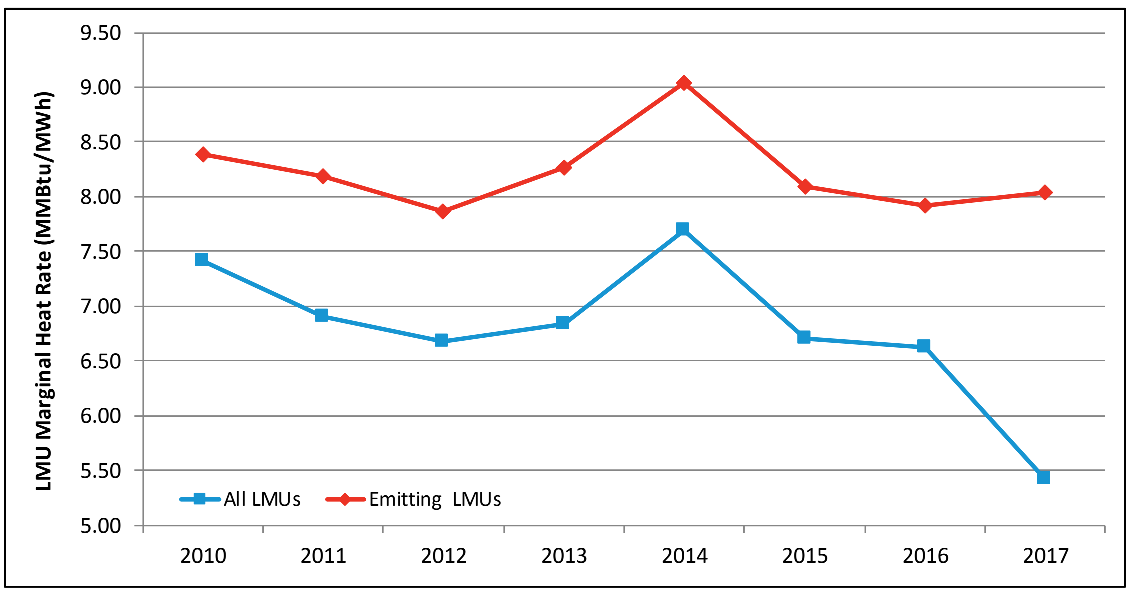

Figure 5-6: LMU annual marginal heat rate, 2010-2017 (MMBtu/MWh).

Marginal heat rates declined through 2012 but increased in 2013 and then again in 2014. In 2015, the marginal heat rate for the emitting LMUs dropped to below the 2013 level, and the 2016 rate decreased slightly beyond that. In 2017, there was a steep drop in the heat rate in the all-LMU scenario due to the large amount of wind units on the margin, while the rate for the emitting-LMU case increased slightly.

5.3 2017 ISO New England Marginal Emission Rates

This section presents the 2017 calculated LMU-based marginal emission rates for the all-LMU and emitting-LMU scenarios, as defined in Section 4.5.

The NO_X data for both these scenarios are provided for each of the five time periods studied. Since the ozone and non-ozone seasons are not relevant to SO_2 and CO_2, only the on-peak, off-peak, and annual rates are provided for these emissions.

5.3.1 Marginal Emission Rates for the All-LMU Scenario

The all-LMU marginal emission rates were calculated with all LMUs (units the LMP identified as marginal). Table 5-3 shows the rates in lb/MWh. Appendix Table 8 shows these rates in lb/MMBtu, with the associated marginal heat rate of 5.428 MMBtu/MWh used as the conversion factor. It is helpful to compare Figure 5-7, which shows the monthly LMU marginal emission rates, with Figure 4-6 (showing the 2017 percentage of time various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2017 ISO New England system monthly average NO_X, SO_2, and CO_2 emission rates). Appendix Table 9 lists the values behind Figure 5-7.

Table 5-3
2017 LMU Marginal Emission Rates—All LMUs (lb/MWh)[a, b]

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.23	0.11	0.14	0.15	0.15
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.12	0.05		0.08
CO_2		681	635		654

(a) The ozone season occurs between May 1 and September 30, while the non-ozone season occurs from January 1 to April 30 and from October 1 to December 31.

(b) On-peak hours consist of all weekdays between 8:00 a.m. and 10:00 p.m. Off-peak hours consist of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours.

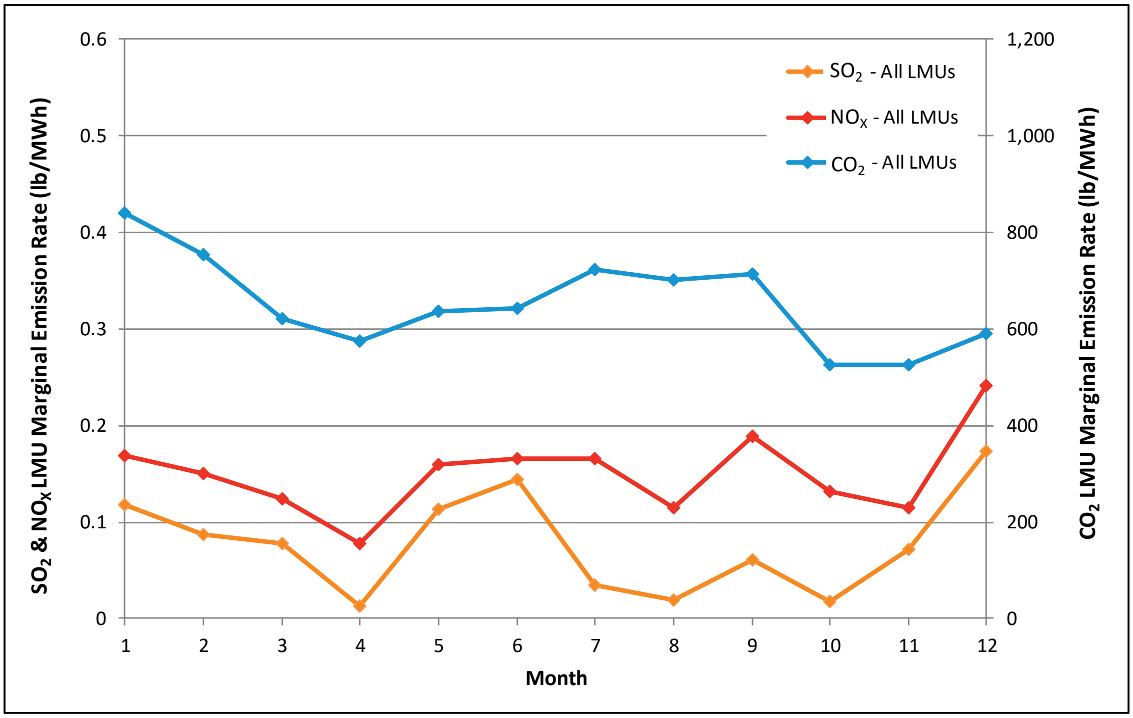

Figure 5-7: 2017 monthly LMU marginal emission rates—all LMUs (lb/MWh).

5.3.2 Marginal Emission Rates for the Emitting-LMU Scenario

Table 5-4 and Appendix Table 10 present the marginal emission rates for emitting LMUs. The marginal heat rate for this scenario is 8.043 MMBtu/MWh. The values for the monthly rates shown in Figure 5-8 are shown in Appendix Table 11.

Table 5-4
2017 LMU Marginal Emission Rates—Emitting LMUs (lb/MWh)

Ozone / Non-Ozone Season Emissions (NOX)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.31	0.14	0.25	0.24	0.23
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.18	0.08		0.12
CO_2		981	964		971

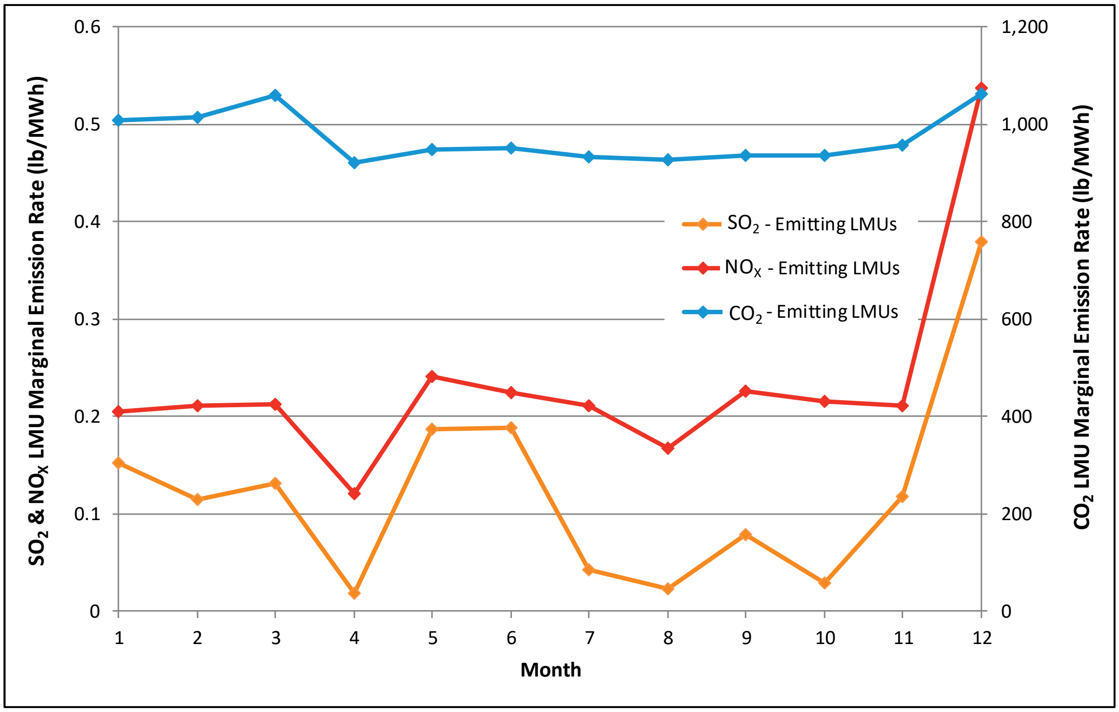

Figure 5-8: 2017 monthly LMU marginal emission rates—emitting LMUs (lb/MWh).

5.3.3 2009 to 2017 LMU Marginal Emission Rates

The LMUs actively exhibit the changes in ISO New England's energy production. Compared with the emitting-LMU scenario, the all-LMU scenario has lower marginal emission rates because it includes zero-air-emission resources that lower the average emission rate. Figure 5-9 and Figure 5-10 summarize the results for the two LMU scenarios for marginal emission rates, which are detailed in Appendix Table 12 through Appendix Table 17 in lb/MWh.

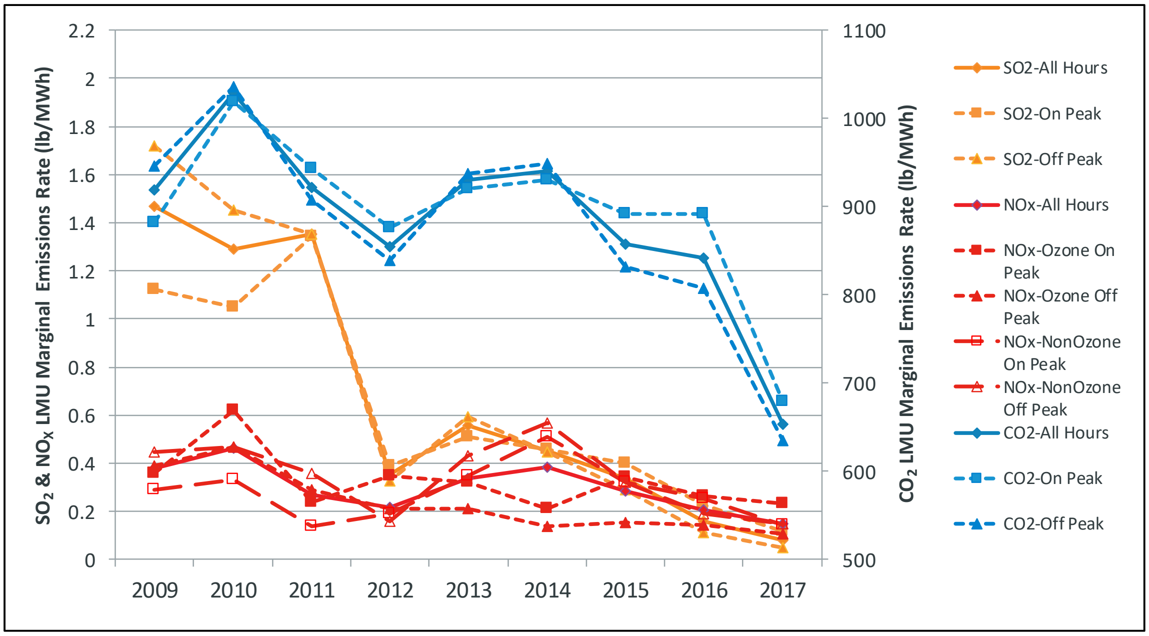

Figure 5-9: LMU marginal emission rates, 2009 to 2017—all LMUs (lb/MWh).

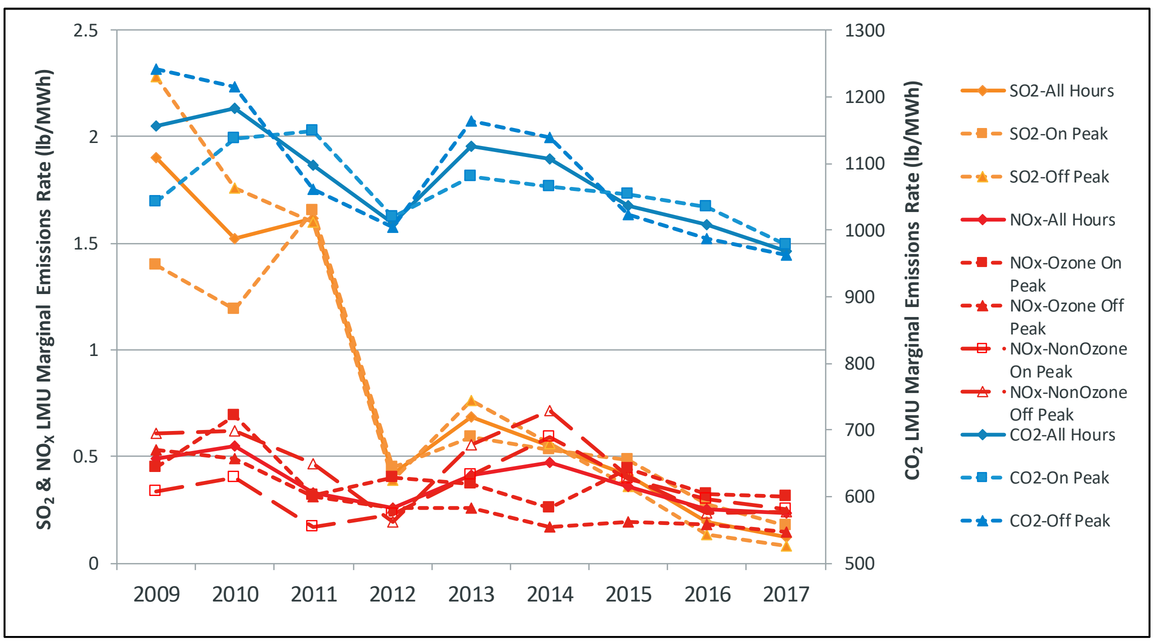

Figure 5-10: LMU marginal emission rates, 2009 to 2017—emitting LMUs (lb/MWh).

5.3.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five high electric demand days in 2017 were examined. In 2017, the top five HEDDs were June 12 and 13, and July 19, 20, and 21. The temperatures in New England during these days ranged from 88° to 92°F. Peak daily loads ranged from 22,942 MW on Friday, July 21, to a high of 23,968 MW on Tuesday, June 13. Table 5-5 shows the average LMU marginal emission rate during these five days.

Table 5-5
High Electric Demand Day LMU Marginal Emission Rates (lb/MWh)

HEDD LMU Marginal Emission Rate (lb/MWh)		
	All LMUs	**Emitting LMUs**
NO_X	0.49	0.63
SO_2	0.39	0.51
CO_2	853	1096

5.3.5 Observations

ISO New England's power plant air emissions are directly dependent on the specific units available and dispatched to serve load for each hour of the year. Therefore, seasonal emissions can vary widely, primarily due to changes in economic and reliability dispatch, unit availability, fuel price and consumption, fuel switching, transmission topology, and load levels. The amount of imports, the use of pumped storage, and significant generator outages, such as a nuclear unit outage, also affect emissions. The LMU marginal emission rates reflect the dynamics of the ISO New England power system.

The 2017 LMU annual marginal rates for SO_2, NO_X, and CO_2 are the lowest rates of the 2009 through 2017 period. Compared with 2009, the 2017 LMU SO_2 annual marginal rates have declined by approximately 94% for both the all-LMU and emitting-LMU scenarios. As illustrated in Figure 5-9 and Figure 5-10, most of this decline took place in 2012, when there was an increase in natural gas units on the margin combined with a significant decrease in marginal coal-fired units. In the case of marginal NO_X emissions, there has been a 60% and 53% decline in the rates for the all-LMU and emitting-LMU scenarios, respectively, since 2009. During that period, the CO_2 rates have declined by 29% for the all-LMU scenario and 16% for the emitting-LMU scenario. The greater decrease in the CO_2 rate for the all-LMU scenario is due to a large amount of wind on the margin in 2017, which resulted in a 23% drop in the marginal rate from 2016 to 2017.

In 2017, the on-peak marginal rates for SO_2 and CO_2, as well as for NO_X during the ozone season, were higher than the off-peak rates. This is likely due to the operation of older, less-efficient peaking units (jets or combustion turbines) dispatched to meet peak load.

As mentioned above, the increased amount of wind on the margin in 2017 had a significant impact on marginal CO_2 rates in the all-LMU scenario. Although the rates for each of the emission types decreased in 2017, in all cases the reduction for the all-LMU scenario was considerably greater than for the emitting-LMU scenario. The CO_2 rates, which were impacted the most, decreased by 23% in the all-LMU scenario and only 4% for the emitting-LMU scenario. The SO_2 marginal emission rates decreased by 51% for the all-LMU scenario and 37% for the emitting-LMU scenario. For NO_X, the decrease in the all-LMU scenario was 27% in contrast with 9% in the emitting-LMU scenario.

Although both the marginal and system emission rates decreased in 2017, the magnitude of the changes was not consistent. In comparing the change in the emitting-LMU rates with the system emission rates between 2016 and 2017, the decrease in the NO_X and SO_2 marginal rates was greater than the decrease in the system rate. However, in the case of CO_2, the marginal and system rates both decreased approximately 4%. The decline in both the marginal and system emission rates in 2017 can be attributed to a decrease in coal- and oil-fired generation.

Section 6
Appendix

Appendix Table 1
ISO New England Total Cooling and Heating Degree Days, 1998 to 2017

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1998	312	-3.6%	5,483	-8.5%
1999	360	11.2%	5,774	-3.6%
2000	217	-32.9%	6,397	6.8%
2001	323	-0.2%	5,893	-1.6%
2002	354	9.4%	5,959	-0.5%
2003	355	9.7%	6,651	11.0%
2004	251	-22.4%	6,352	6.0%
2005	418	29.2%	6,353	6.0%
2006	335	3.5%	5,552	-7.3%
2007	288	-11.0%	6,175	3.1%
2008	281	-13.2%	6,049	1.0%
2009	224	-30.8%	6,291	5.0%
2010	406	25.5%	5,653	-5.6%
2011	357	10.3%	5,826	-2.8%
2012	353	9.1%	5,304	-11.5%
2013	401	23.9%	6,156	2.7%
2014	240	-25.8%	6,318	5.5%
2015	337	4.1%	6,100	1.8%
2016	351	8.5%	5,705	-4.8%
2017	309	-4.5%	5,838	-2.6%

Appendix Table 2
2017 ISO New England Summer Generating Capacity (MW, %)[a, b]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	383.4	4.6	-	-	-	-	533.3	12.9	-	-	-	-
Natural Gas	2,877.9	34.2	5,620.5	49.9	1,557.6	48.3	1,220.3	29.4	1,890.0	97.6	-	-
Nuclear	2,084.1	24.8	677.3	6.0	-	-	1,251.4	30.2	-	-	-	-
Oil	2,745.1	32.7	2,541.8	22.6	842.5	26.1	468.9	11.3	-	-	129.8	28.1
Hydro	92.2	1.1	179.7	1.6	494.6	15.3	435.2	10.5	0.8	0.0	231.7	50.2
Pumped Storage	28.5	0.3	1,657.9	14.7	-	-	-	-	-	-	-	-
Solar	1.0	0.0	316.2	2.8	2.9	0.1	1.4	0.0	10.2	0.5	-	-
Wind	-	-	13.2	0.1	119.6	3.7	25.7	0.6	10.0	0.5	19.7	4.3
Other Renewables	192.6	-	246.3	-	210.2	-	214.1	-	25.5	-	80.4	17.4
Total	8,404.8	97.7	11,252.9	97.8	3,227.3	93.5	4,150.3	94.8	1,936.4	98.7	461.5	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2018.

Appendix Table 3
2017 ISO New England Winter Generating Capacity (MW, %)[a, b]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	385.0	4.3	-	-	-	-	534.7	12.0	-	-	-	-
Natural Gas	3,173.1	35.8	6,398.6	53.2	1,762.0	48.4	1,404.5	31.6	2,119.3	98.2	-	-
Nuclear	2,092.7	23.6	683.4	5.7	-	-	1,250.2	28.2	-	-	-	-
Oil	2,898.7	32.7	2,706.5	22.5	863.7	23.7	501.7	11.3	-	-	172.5	32.2
Hydro	99.6	1.1	203.7	1.7	553.9	15.2	474.6	10.7	2.2	0.1	252.1	47.1
Pumped Storage	27.8	0.3	1,756.9	14.6	-	-	-	-	-	-	-	-
Solar	0.0	0.0	3.5	0.0	-	-	0.0	0.0	0.0	0.0	-	-
Wind	-	-	25.1	0.2	239.9	6.6	46.9	1.1	11.4	0.5	27.9	5.2
Other Renewables	198.3	2.2	259.3	2.2	218.0	6.0	227.6	5.1	25.2	1.2	82.9	15.5
Total	8,875.2	100.0	12,037.1	100.0	3,637.6	100.0	4,440.3	100.0	2,158.1	100.0	535.4	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2018.

Appendix Table 4
ISO New England System
Annual Generator Emissions, 2001 to 2017 (kilotons)[a]

Year	NOx	SO_2	CO_2	
	kilotons (short)	kilotons (short)	kilotons (short)	kilotons (metric)
2001	59.73	200.01	52,991	48,073
2002	56.40	161.10	54,497	49,439
2003	54.23	159.41	56,278	51,055
2004	50.64	149.75	56,723	51,458
2005	58.01	150.00	60,580	54,957
2006	42.86	101.78	51,649	46,855
2007	35.00	108.80	59,169	53,677
2008	32.57	94.18	55,427	50,283
2009	27.55	76.85	49,380	44,797
2010	28.79	80.88	52,321	47,465
2011	25.30	57.01	46,959	42,601
2012	20.32	16.61	41,975	38,079
2013	20.32	18.04	40,901	37,105
2014	20.49	11.67	39,319	35,670
2015	18.86	9.11	40,312	36,570
2016	16.27	4.47	37,467	33,990
2017	15.30	4.00	34,969	31,723
Percent Reduction, 2001-2017	74	98	34	34

(a) Since greenhouse gas data is often expressed in metric tons, an additional column showing CO_2 emissions in metric kilotons is included in this table. A metric ton is approximately 2,205 lb.

Appendix Table 5
2017 ISO New England System
Average Monthly Generator Emission Rates (lb/MWh)

Monthly System Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.31	0.10	684
2	0.32	0.11	702
3	0.30	0.09	681
4	0.29	0.05	757
5	0.31	0.08	645
6	0.30	0.05	649
7	0.27	0.05	679
8	0.26	0.04	690
9	0.29	0.05	670
10	0.28	0.03	682
11	0.28	0.05	642
12	0.37	0.23	709

Appendix Table 6
ISO New England System
Annual Average Generator Emission Rates, 1999 to 2017 (lb/MWh)

Year	Total Generation (GWh)	NO_x	SO_2	CO_2
1999	104,409	1.36	4.52	1,009
2000	110,199	1.12	3.88	913
2001	114,626	1.05	3.51	930
2002	120,539	0.94	2.69	909
2003	127,195	0.93	2.75	970
2004	129,459	0.78	2.31	876
2005	131,874	0.88	2.27	919
2006	128,046	0.67	1.59	808
2007	130,723	0.54	1.66	905
2008	124,749	0.52	1.51	890
2009	119,282	0.46	1.29	828
2010	126,383	0.46	1.28	829
2011	120,612	0.42	0.95	780
2012	116,942	0.35	0.28	719
2013	112,040	0.36	0.32	730
2014	108,356	0.38	0.22	726
2015	107,916	0.35	0.17	747
2016	105,570	0.31	0.08	710
2017	102,562	0.30	0.08	682
Percent Reduction, 1999 - 2017		78	98	32

Appendix Table 7
LMU Marginal Heat Rate, 2009 to 2017 (MMBtu/MWh)

LMU Marginal Heat Rate (MMBtu/MWh)		
Year	All Marginal LMUs	Emitting LMUs
2009	8.591	8.507
2010	7.414	8.385
2011	6.907	8.190
2012	6.678	7.870
2013	6.841	8.271
2014	7.692	9.034
2015	6.707	8.096
2016	6.625	7.925
2017	5.428	8.043

Appendix Table 8
2017 LMU Marginal Emission Rates—All LMUs (lb/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.043	0.020	0.026	0.027	0.028
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.022	0.009		0.014
CO_2		126	117		121

Appendix Table 9
2017 Monthly LMU Marginal Emission Rates—All LMUs (lb/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.17	0.12	841
2	0.15	0.09	755
3	0.12	0.08	620
4	0.08	0.01	575
5	0.16	0.11	637
6	0.17	0.14	643
7	0.17	0.04	723
8	0.12	0.02	702
9	0.19	0.06	714
10	0.13	0.02	526
11	0.11	0.07	527
12	0.24	0.17	592

Appendix Table 10
2017 LMU Marginal Emission Rates—Emitting LMUs (lb/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.039	0.018	0.031	0.030	0.029
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.022	0.010		0.015
CO_2		122	120		121

Appendix Table 11
2017 Monthly LMU Marginal Emission Rates—Emitting LMUs (lb/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.21	0.15	1,008
2	0.21	0.12	1,014
3	0.21	0.13	1,058
4	0.12	0.02	921
5	0.24	0.19	948
6	0.23	0.19	953
7	0.21	0.04	934
8	0.17	0.02	929
9	0.23	0.08	937
10	0.22	0.03	937
11	0.21	0.12	958
12	0.54	0.38	1,063

Appendix Table 12
NO_X LMU Marginal Emission Rates, 2009 to 2017 —All LMUs (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.36	0.39	0.29	0.45	0.38	-
2010	0.62	0.47	0.33	0.47	0.46	21.7
2011	0.24	0.29	0.14	0.36	0.27	-42.2
2012	0.35	0.21	0.19	0.16	0.22	-18.4
2013	0.32	0.21	0.35	0.43	0.34	56.7
2014	0.21	0.14	0.51	0.56	0.38	13.1
2015	0.34	0.16	0.32	0.32	0.28	-26.2
2016	0.26	0.14	0.25	0.19	0.21	-27.2
2017	0.23	0.11	0.14	0.15	0.15	-27.2
% Change 2009 - 2017	**-34.9**	**-72.8**	**-51.2**	**-67.2**	**-60.2**	

Appendix Table 13
NO_X LMU Marginal Emission Rates, 2009 to 2017—Emitting LMUs (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.45	0.53	0.33	0.61	0.49	-
2010	0.69	0.49	0.40	0.62	0.55	11.8
2011	0.32	0.31	0.17	0.46	0.33	-39.8
2012	0.40	0.26	0.23	0.19	0.26	-22.0
2013	0.37	0.26	0.42	0.56	0.42	62.7
2014	0.26	0.17	0.59	0.72	0.47	12.1
2015	0.44	0.19	0.39	0.41	0.36	-24.0
2016	0.33	0.18	0.30	0.24	0.25	-29.2
2017	0.31	0.14	0.25	0.24	0.23	-8.4
% Change 2009 - 2017	**-30.1**	**-73.0**	**-24.6**	**-60.4**	**-52.8**	

Appendix Table 14
SO_2 LMU Marginal Emission Rates, 2009 to 2017—All LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1.12	1.72	1.47	-
2010	1.05	1.45	1.29	-12.2
2011	1.34	1.35	1.35	4.7
2012	0.39	0.32	0.35	-73.9
2013	0.51	0.59	0.55	56.0
2014	0.46	0.45	0.45	-18.0
2015	0.40	0.29	0.33	-25.8
2016	0.22	0.11	0.16	-53.0
2017	0.12	0.05	0.08	-50.5
% Change 2009 - 2017	**-89.5**	**-97.1**	**-94.7**	

Appendix Table 15
SO_2 LMU Marginal Emission Rates, 2009 to 2017—Emitting LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1.40	2.28	1.90	-
2010	1.19	1.76	1.52	-20.0
2011	1.65	1.60	1.62	6.6
2012	0.45	0.39	0.42	-74.3
2013	0.59	0.76	0.69	65.9
2014	0.53	0.56	0.55	-20.2
2015	0.48	0.36	0.41	-25.2
2016	0.28	0.13	0.19	-53.0
2017	0.18	0.08	0.12	-37.2
% Change 2009 - 2017	**-87.4**	**-96.4**	**-93.6**	

Appendix Table 16
CO_2 LMU Marginal Emission Rates, 2009 to 2017—All LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	882	946	919	-
2010	1,019	1,036	1,029	12.0
2011	943	908	922	-10.4
2012	876	839	854	-7.4
2013	921	937	930	8.9
2014	931	949	941	1.2
2015	891	832	857	-9.0
2016	892	807	842	-1.7
2017	681	635	654	-22.3
% Change 2009 - 2017	**-22.8**	**-32.8**	**-28.8**	

Appendix Table 17
CO_2 LMU Marginal Emission Rates, 2009 to 2017—Emitting LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1,042	1,242	1,157	-
2010	1,138	1,215	1,183	2.2
2011	1,148	1,061	1,097	-7.3
2012	1,019	1,003	1,010	-7.9
2013	1,079	1,163	1,125	11.4
2014	1,064	1,138	1,107	-1.6
2015	1,053	1,023	1,036	-6.4
2016	1,035	987	1,007	-2.7
2017	981	964	971	-3.6
% Change 2009 - 2017	**-5.9**	**-22.3**	**-16.0**	