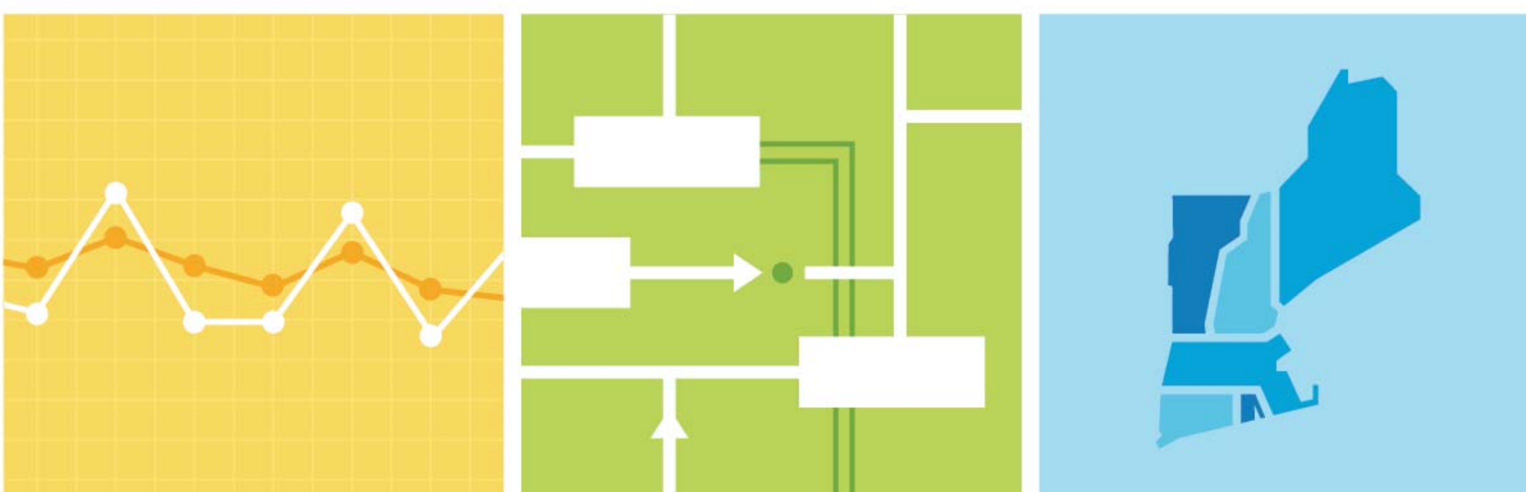
2016 ISO New England Electric Generator Air Emissions Report

System Planning

JANUARY 2018



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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 and marginal emissions (kilotons [ktons])[1]
- 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 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 2007 through 2016, total system emissions have decreased overall: NO_X by 54%, 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 offsetting decreases in coal- and oil-fired generation (see Figure 1-1).

[1]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.

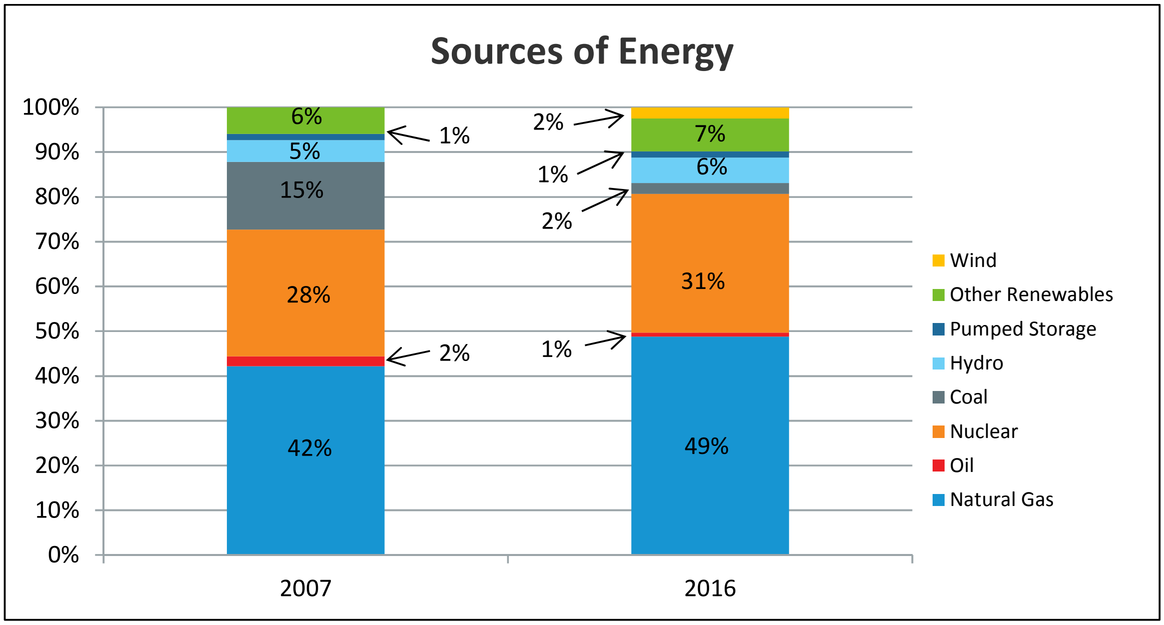

Figure 1-1: Percentage energy generation by fuel type, 2007 compared with 2016.

Compared with the 20-year average for heating and cooling days (i.e., an indicator of weather), 2016 had a 9% hotter summer and a 5% warmer winter. From 2015 to 2016, the net energy for load and system generation decreased by 2.0% and 2.2%, respectively. The amount of energy that New England received from neighboring areas in 2016 was approximately 1% lower than the previous year. The energy generation by non-emitting generators (not including behind-the-meter generators) (e.g., pumped storage hydroelectric generation, nuclear, and wind and solar renewables) increased from 39% to 41% of the total. Additionally, all fossil generation decreased: coal-fired generation by 34%, oil-fired generation by 51%, and natural gas-fired generation by 1% from 2015 to 2016.

Table 1-1 shows the total 2015 and 2016 New England system emissions (ktons) and average system emission rates (lb/MWh) of NO_X, SO_2 and CO_2. Both system emissions and emission rates decreased for NO_X, SO_2, and CO_2 from 2015 to 2016.

Table 1-1
2015 and 2016 New England System Emissions (ktons)
and Emission Rates (lb/MWh)

Annual System Emissions						
	2015 Emissions (kTons)	2016 Emissions (kTons)	Total Emissions % Change	2015 Emission Rate (lb/MWh)	2016 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	18.86	16.26	-13.8	0.35	0.31	-11.4
SO_2	9.11	4.47	-50.9	0.17	0.08	-52.9
CO_2	40,312	37,468	-7.1	747	710	-5.0

Table 1-2 shows the 2015 and 2016 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 New England region, subject to a set of constraints reflecting physical 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
2015 and 2016 Average LMU Marginal Emission Rates (lb/MWh)

LMU Marginal Emissions						
	All LMUs			Emitting LMUs		
	2015 Annual Rate (lb/MWh)	2016 Annual Rate (lb/MWh)	Percent Change 2015 to 2016 (%)	2015 Annual Rate (lb/MWh)	2016 Annual Rate (lb/MWh)	Percent Change 2015 to 2016 (%)
NO_X	0. 28	0.21	-27.2	0.36	0.25	-29.2
SO_2	0. 33	0.16	-53.0	0.41	0.19	-53.0
CO_2	857	842	-1.7	1,036	1,007	-2.7

Figure 1-2 summarizes the 2016 emission rates in New England. 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 significantly higher than on average during the year.

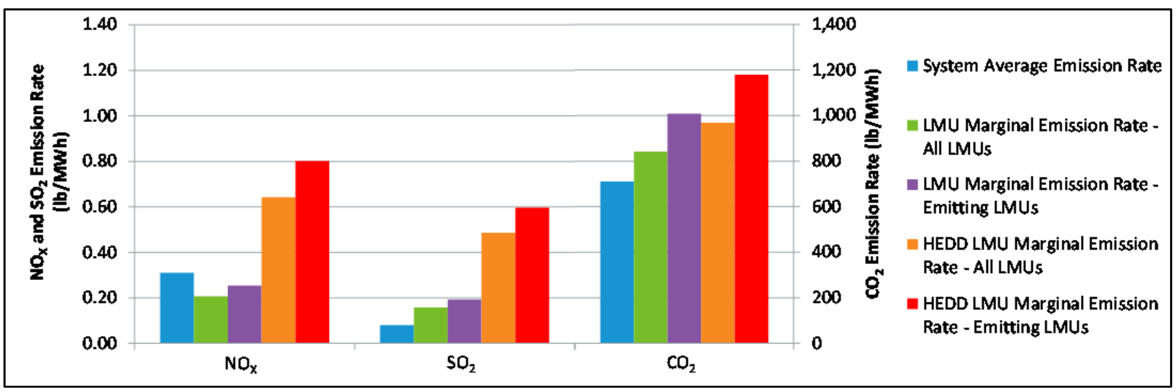

Figure 1-2: Comparison of 2016 New England emission rates (lb/MWh).

A generator's heat rate (MMBtu/MWh) is a measurement of its efficiency in converting fuel into electricity. The 2016 calculated all-LMU marginal heat rate of 6.625 MMBtu/MWh was 1% lower than the 2015 value of 6.707 MMBtu/MWh. When considering the emitting units only, the LMU marginal heat rate decreased 2%, from 8.096 MMBtu/MWh in 2015 to 7.925 MMBtu/MWh in 2016.

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.[2] 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.[3] 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.[4] The revised report was renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of emissions from the entire 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 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 New England's NO_X, SO_2, and CO_2 power plant air emissions. The *2016 Emissions Report* focuses on analysis and observations over the past decade (2007 to 2016). The Appendix includes data for years before 2007 and values for the figures presented.

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[2] Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2017), http://www.mass.gov/eea/agencies/massdep/service/approvals/bwp-aq-18.html.

[3] 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.

[4] 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.[5] 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 New England region 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, and its level of electrical power output.

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.[6] In the 1999 to 2003 MEA studies, the marginal heat rate was calculated using the results of production

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[5] 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.

[6] 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 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.[7] The database contains actual 2016 air emissions (tons) reported by generators under EPA's Acid Rain Program and NO_X Clean Air Interstate Rule (CAIR) and the Regional Greenhouse Gas Initiative (RGGI).[8]

For those units not required to file emissions data under the Acid Rain Program, CAIR, or RGGI, 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 eGRID2014 were used.[9] 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:

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

[7] EPA's Clean Air Markets Program data (2017) are available at http://ampd.epa.gov/ampd/, and the Clean Air Markets emissions data (2016) 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, as well as CAIR, which includes generators 15 MW or larger in the affected states of Connecticut and Massachusetts (the predecessors of CAIR were the 1999-2002 Ozone Transport Commission NOx Budget Program, and EPA's 2003-2008 NO_X Budget Trading Program). Generators subject to RGGI also report CO_2 emissions to EPA.

[8] 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.

[9] The U.S. EPA's eGRID2014 database (2017) is available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

3.3 Marginal Emission Rate Calculation

The cost of the generation dispatched to meet the next increment of load at a pricing location is called the marginal unit, which sets the locational marginal price. LMPs minimize total energy costs for the entire New England region, 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

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

LMU Off-Peak Marginal Emission Rate

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

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 2016 marginal air emission rates for on- and off-peak periods for 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:[10]

- 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

[10] 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 (http://www.iso-ne.com/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf).

Section 4
Data and Assumptions

This section highlights the key parameters and assumptions modeled in the 2016 ISO New England Emissions Report, including weather, emissions data, installed capacity, and system generation.

4.1 2016 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2016 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 2016 was 31°F, which was significantly warmer than average over the past 20 years, and also much warmer than the previous year's average temperature of 20°F during those months. Summer 2016, and in particular the month of August, was warmer than average. Spring and fall were relatively mild, but December was slightly colder than average.

The 2016 summer peak electricity demand of 25,596 MW was 4.7% higher than the 2015 summer peak of 24,437 MW. There were 351 cooling degree days in 2016, which is 9.2% higher than the 20-year average.[11] The net energy for load was 2.0% lower in 2016 than 2015. With respect to the winter months, there were 5,705 heating degree days, which is 5.2% lower than the 20-year average.

New England's historical cooling degree days and heating degree days for 1997 through 2016 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 68% of the SO_2 emissions and 75% of the CO_2 emissions were based on EPA's Clean Air Markets data. For NO_X, Clean Air Markets data were used for 36% of total emissions.

The emission rates were multiplied by the 2016 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

[11] Over the 20-year span from 1997 to 2016, the average number of cooling degree days was 319, and the average number of heating degree days was 6,021.

- Fuel and emission allowance costs
- 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 2016 summer capacity for ISO New England generation as obtained from *ISO New England's 2017–2026 Forecast Report of Capacity, Energy, Loads and Transmission* (CELT).[12] Appendix Table 2 and Appendix Table 3 summarize the total summer and winter capacity for ISO New England generation by state and fuel type.

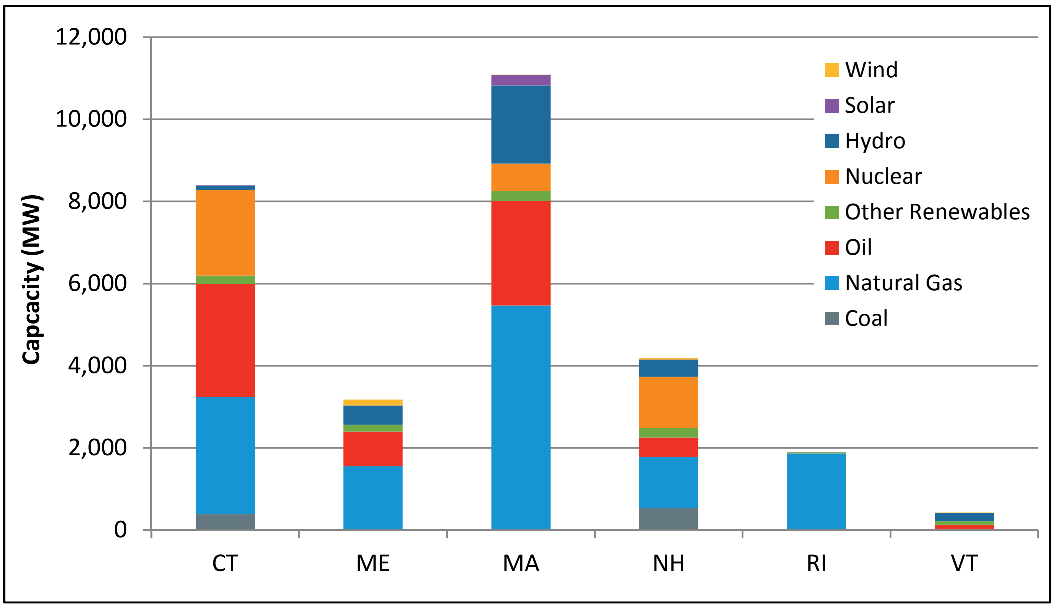

Figure 4-1: 2016 New England summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2007 through 2016. A total of 2,715 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 65% of this new capacity. The remaining additions consist primarily of renewable generation, including 16% of total capacity from wind and solar resources.

[12] The ISO New England *CELT Report* is typically issued in April of each year. The *2017 CELT Report* (using the January 1, 2017 ratings) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2016. The capacity also includes generators that retired in 2016. The CELT reports are available at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

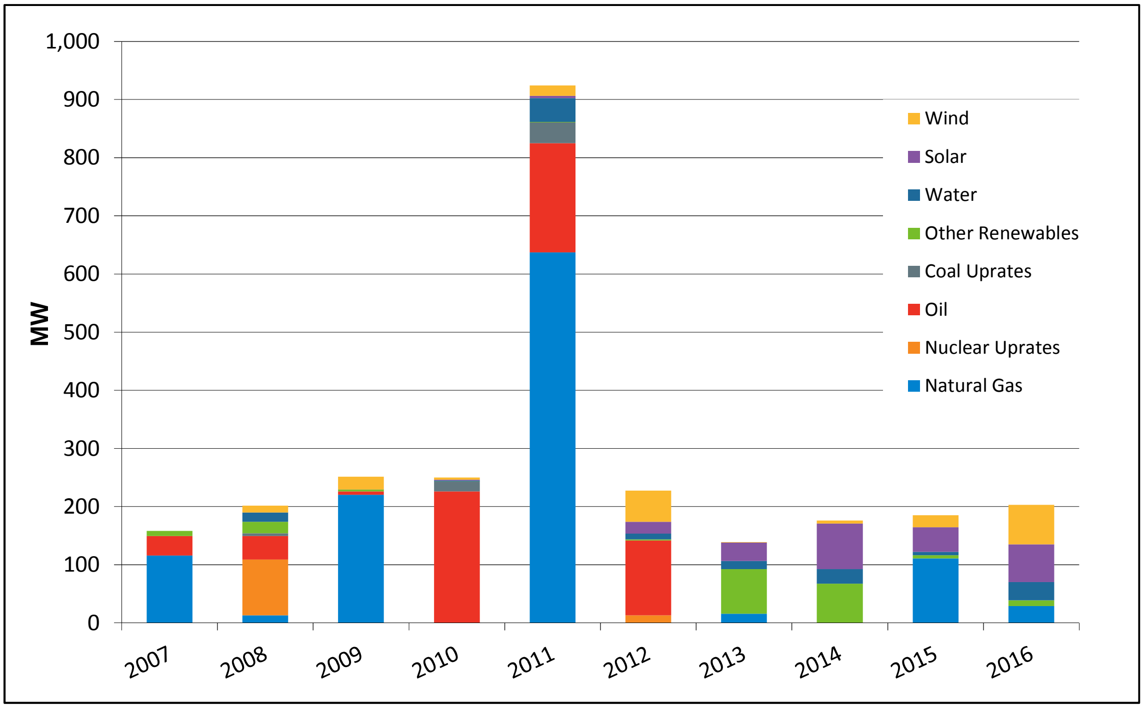

Figure 4-2 : ISO New England generator additions, 2007 to 2016 (MW).
Note: The generator additions and uprate values are based on the summer Seasonal Claimed Capabilities, as reported in the 2017 CELT Report.

Several recent large generators in New England have retired in recent years. The retirements, as shown in Figure 4-3, total 1,081 MW of coal, 567 MW of residual oil, and 604 MW of nuclear generation since late 2011.

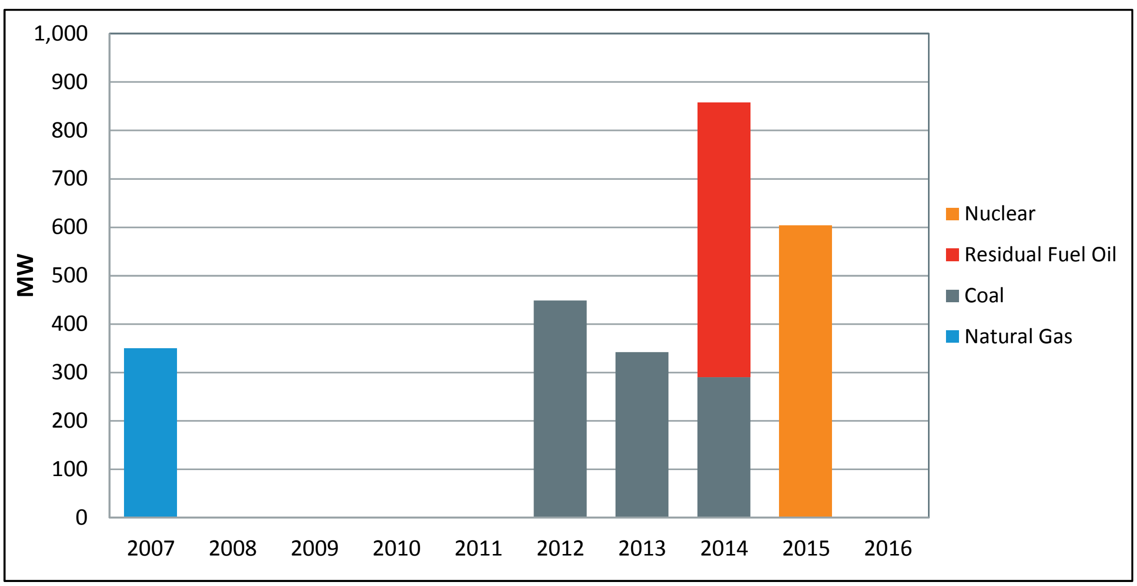

Figure 4-3: Major retirements in ISO New England, 2007 to 2016 (MW).
Note: The retirement date shown is not necessarily the year in which the retirement occurred. In the case of units that retired late in the year, the retirement is included in the following year because that is when the impact would 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 2016 monthly generation by fuel type. The overlaid black line represents the total generation in each month and corresponds with the right axis. Throughout the year, natural-gas-fired generation accounted for 41% to 59% of the total generation. In the past few years in general, the overall lower prices of natural gas, combined with the use of highly efficient generating units, have led to the growing contribution of natural gas to generate electric energy in New England. However, during months with higher energy demand and coupled with limitations in natural gas availability, other fuel types have increased their contribution to support the New England system. During the winter months, the use of natural gas supplies and transportation by the regional gas sector's firm local distribution company (LDC) customers take priority over the use of gas to generate electricity.[13] Most natural-gas-fired generating units lack both firm supply and transportation contracts.

The lowest monthly percentages of natural-gas-fired generation in 2016 were in January, February, March, and December. During the months of January, February, and December, the contribution from coal-fired generation was higher than during the remainder of the year. Oil-fired generation remained consistently low throughout the year, with a high of only 1.2% in February. Although both natural gas and oil prices were significantly lower than in 2015, the difference between average natural gas prices and both coal and oil increased in 2016, resulting in lower contributions from coal and oil generation in 2016.

Hydroelectric and wind generation exhibit seasonal differences in their generation due to fuel availability; there is less rain (water) and onshore wind during the summer months.

[13] Firm customers of regional gas LDCs include residential, commercial, and industrial (RCI) customers.

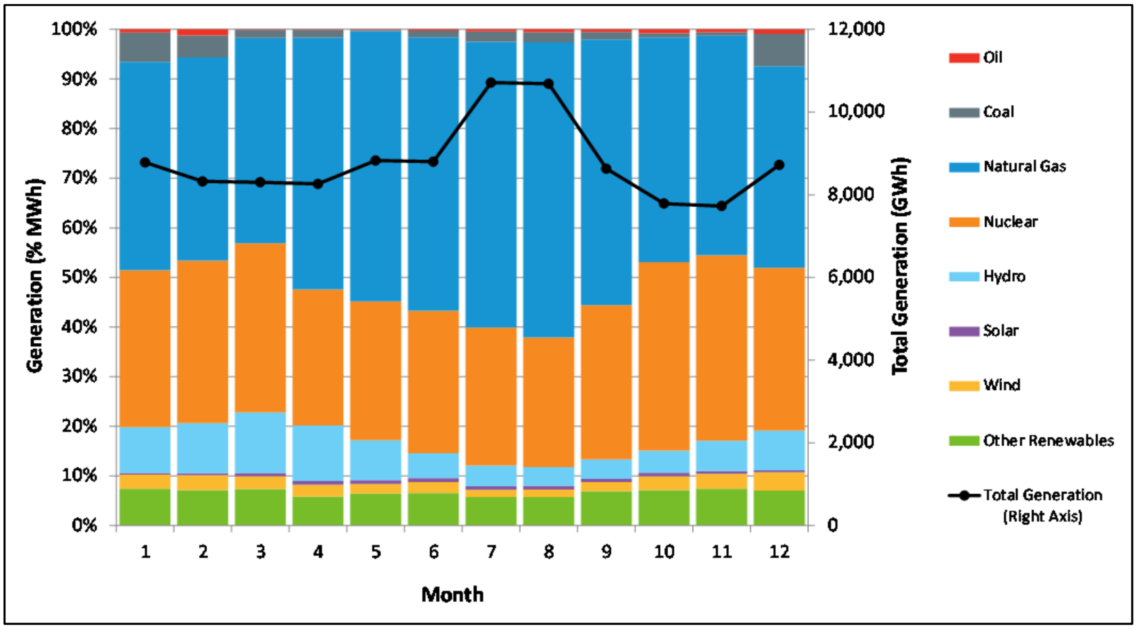

Figure 4-4: 2016 ISO New England monthly generation by fuel type (% MWh, MWh).

Figure 4-5 shows the generation (MWh) by fuel type from 2012 to 2016 based on the resource's primary fuel type listed in the *2017 CELT Report*. In 2016, coal-fired generation was about 1,300 GWh lower than in 2015, and oil-fired generation was 1,000 GWh lower. Natural-gas-fired generation in 2016 was similar to 2015, decreasing by about 1%. The only categories that increased in 2016 were nuclear generation, with a 2.7% increase, and solar and wind, which together increased by 546 GWh, or 21% over 2015. The overall system generation of 105,570 GWh in 2016 was 2% below the 2015 level.

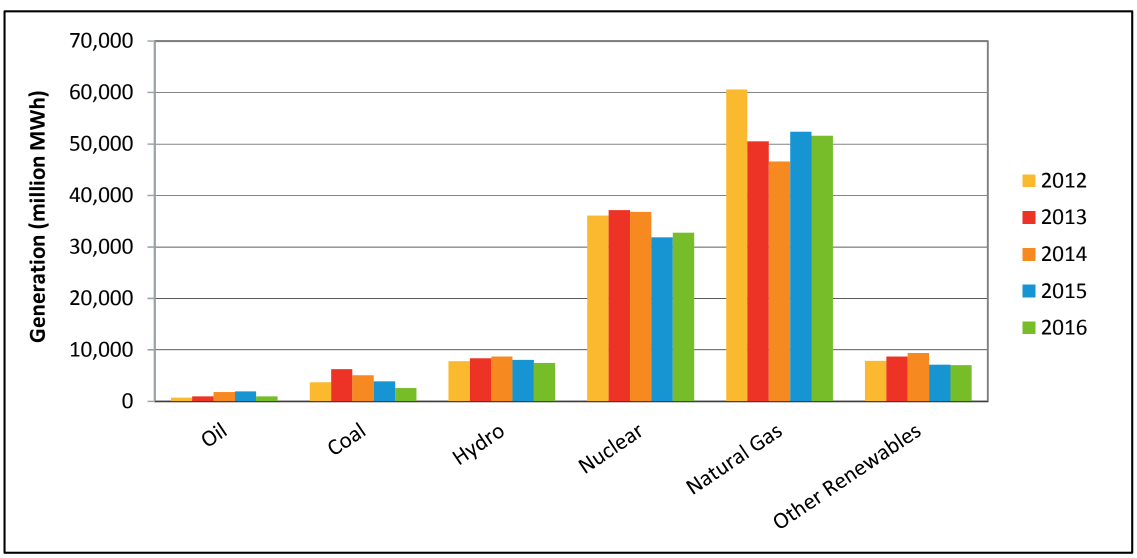

Figure 4-5: ISO New England annual generation by fuel type, 2012 to 2016 (million MWh).

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.

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 68% to 83% of the time. More natural gas units were on the margin from February through May, in the 81% to 83% range. During the winter months of January and December, coal-fired generation was on the margin more than other months, at 10% and 8%, respectively. Oil-fired generation was on the margin an average of only 1% during the year, with the highest percentage of the time on the margin (approximately 3%) occurring in February and September. Since intermittent resources became eligible to be dispatched and set price beginning in May 2016,[14] wind units were also on the margin during the subsequent months. The time that wind was marginal ranged from 3% during the summer to a maximum of nearly 20% in October.

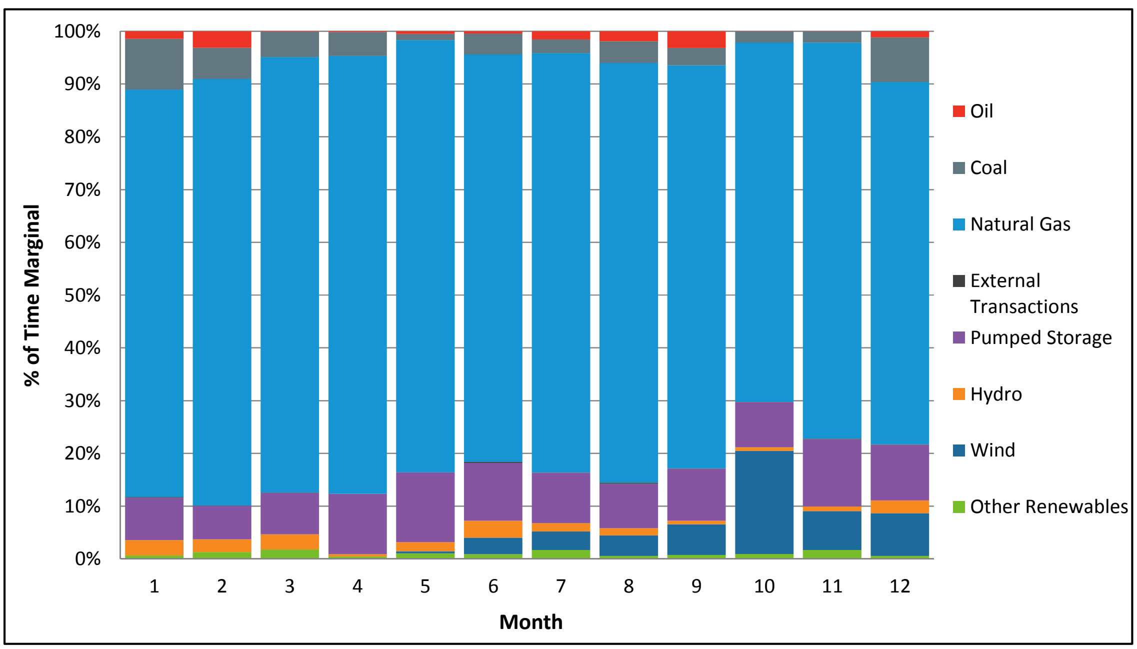

Figure 4-6: 2016 percentage of time various fuel types were marginal—all LMUs.

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

[14] 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.

2015 to 2016, the percentage of time that natural gas was marginal increased by 2%, while the time that oil was the marginal fuel decreased from 4% to 1%. Coal was marginal slightly more in 2016 than in 2015. The percentage of time that the Other Renewables category was marginal increased from 1% to 5% due to the inclusion of wind units in that category for the first time in 2016.

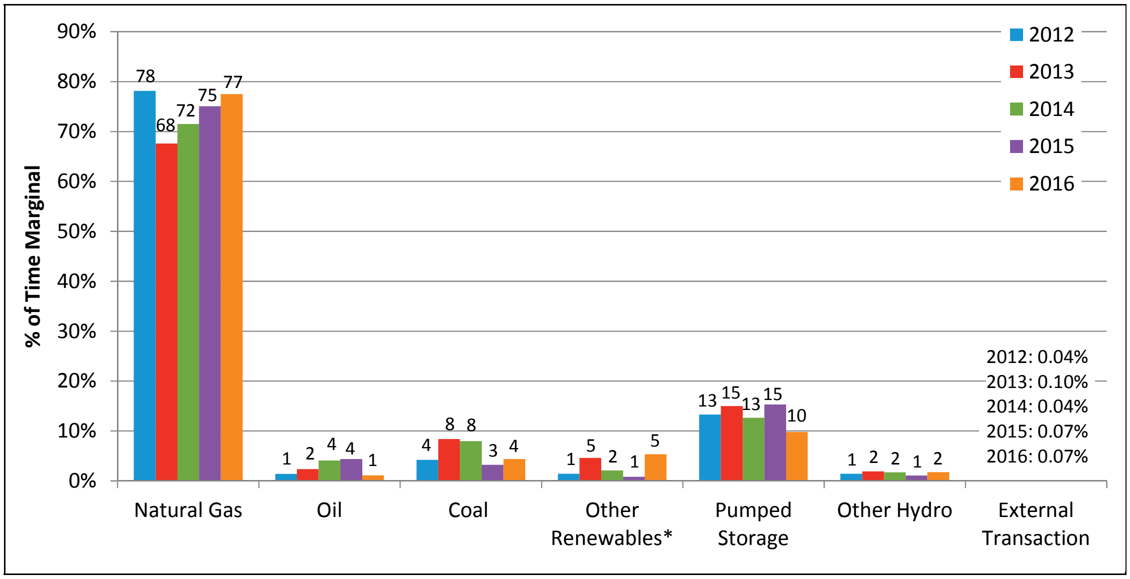

Figure 4-7: Annual percentage of time various fuel types were marginal—all LMUs, 2012 to 2016.

4.5.2 Emitting LMUs

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

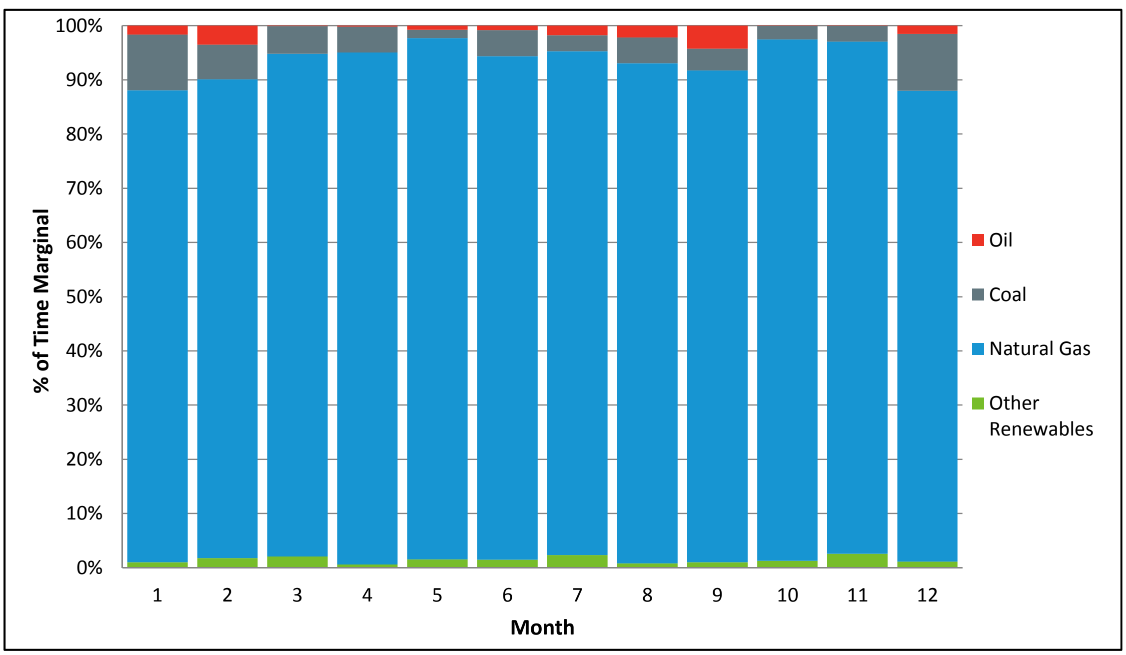

Figure 4-8: 2016 percentage of time various fuel types were marginal—emitting LMUs.

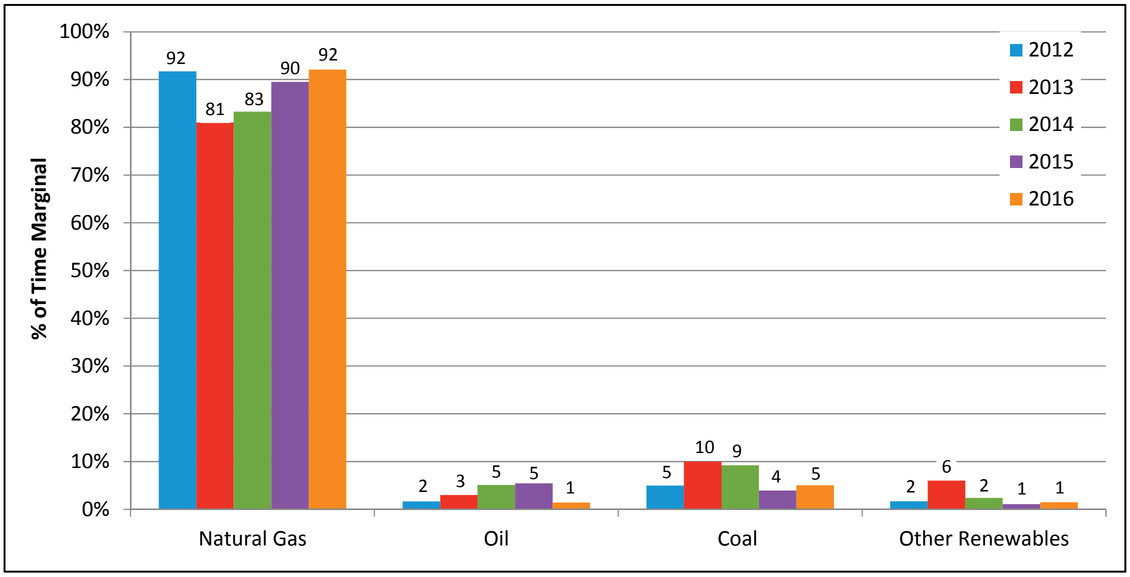

Figure 4-9: Annual percentage of time various fuel types were marginal—emitting LMUs, 2012 to 2016.

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 system demand.

Section 5
Results and Observations

This section presents the results for ISO New England's 2016 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 2016 New England System Emissions

Results are presented for the following metrics:

- Aggregate NO_X, SO_2, and CO_2 emissions for each state for 2016
- A comparison of aggregate NO_X, SO_2, and CO_2 emissions for 2007 to 2016
- 2016 annual average NO_X, SO_2, and CO_2 emission rates, by state and for New England
- Monthly variations in the emission rates for 2016
- A comparison of annual average NO_X, SO_2, and CO_2 emission rates for 2007 to 2016

5.1.1 Results

Figure 5-1 shows the annual aggregate 2016 NO_X, SO_2, and CO_2 air emissions for each state. The New England system total emissions for NO_X, SO_2, and CO_2 were 16.26 ktons, 4.47 ktons, and 37,468 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.[15] The reason for the divergent total emissions for each state is that the emissions are based on the physical locations of the generating units in each state (refer to Figure 4-1 showing summer capacity by state). However, ISO New England operates the New England power system as one unified grid, dispatching a unit physically located in one state to serve the entire system, not only the unit's own state.

[15] 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.

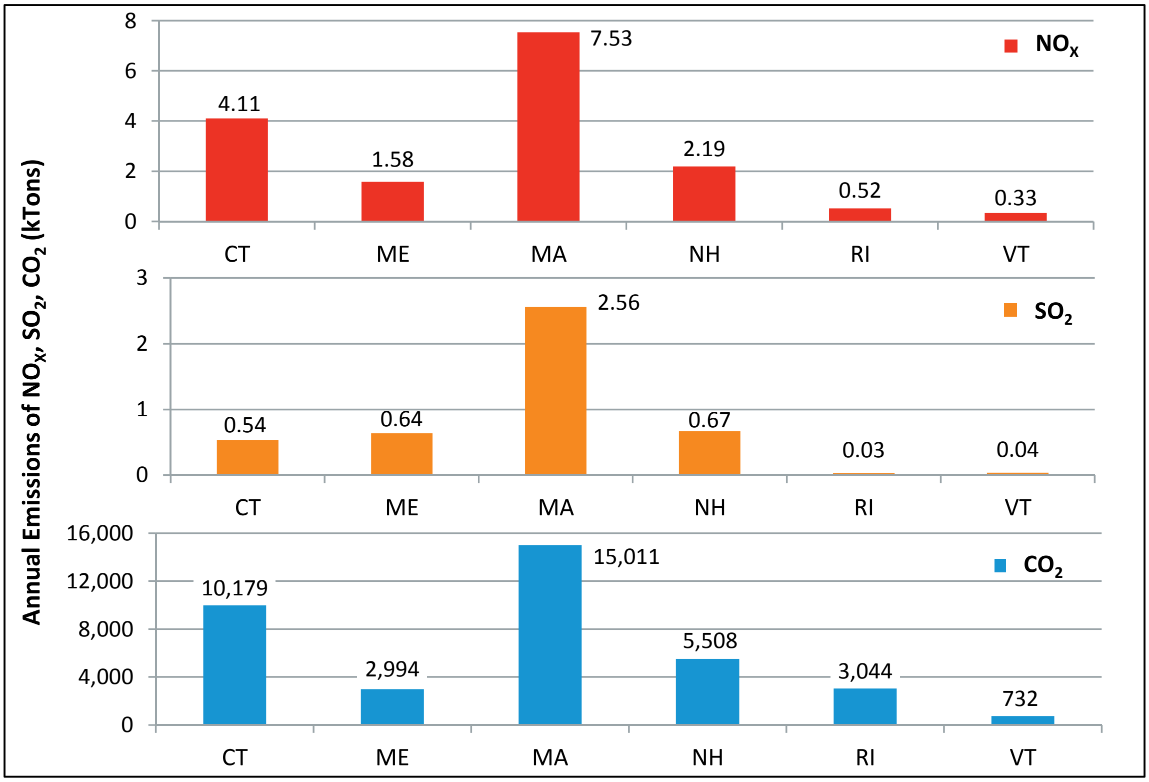

Figure 5-1: 2016 New England system annual emissions of NO_X, SO_2, and CO_2 (ktons).
Note: Sum may not equal New England system total due to rounding.

Figure 5-2 shows the annual aggregate NO_X, SO_2, and CO_2 air emissions for 2007 through 2016. Since 2007, NO_X emissions have dropped by 54% and SO_2 by 96%, while CO_2 has decreased by about 37%. Refer to Appendix Table 4 for historical system emissions by ktons.

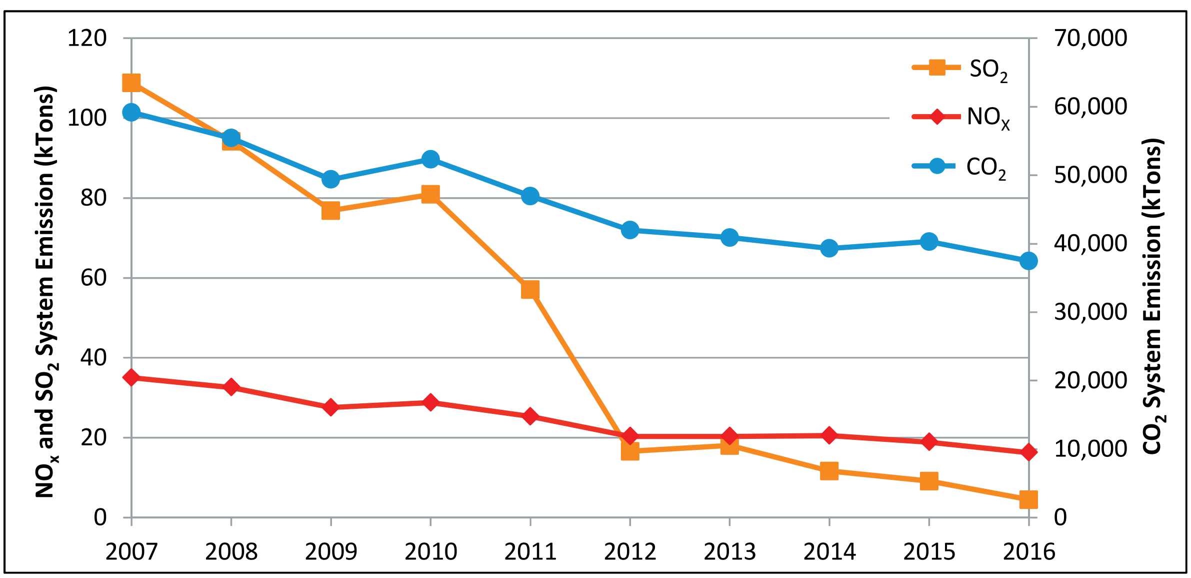

Figure 5-2: New England system annual emissions of NO_X, SO_2, and CO_2, 2007 to 2016 (ktons).

Table 5-1 shows the 2016 annual average NO_X, SO_2, and CO_2 air emission rates (lb/MWh), by state and for New England. 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
2016 New England System
Annual Average NO_X, SO_2, and CO_2 Emission Rates (lb/MWh)

State	NO_x	SO_2	CO_2
Connecticut	0.23	0.03	572
Maine	0.36	0.14	678
Massachusetts	0.45	0.15	897
New Hampshire	0.23	0.07	573
Rhode Island	0.16	0.01	930
Vermont	0.35	0.04	775
New England	0.31	0.08	710

Monthly variations in the emission rates shown in Figure 5-3 reflect the different system fuel mixes shown in Figure 4-4. In 2016, emission rates were at a higher magnitude during January, February, and December, when natural gas generation was lower and coal-fired generation was higher. During the summer peak-load months, a lower percentage of generation from non-emitting sources, together with an increased amount of natural gas-fired generation and small amounts of coal- and oil-fired generation led to increased emission rates. Appendix Table 5 shows the values for this figure.

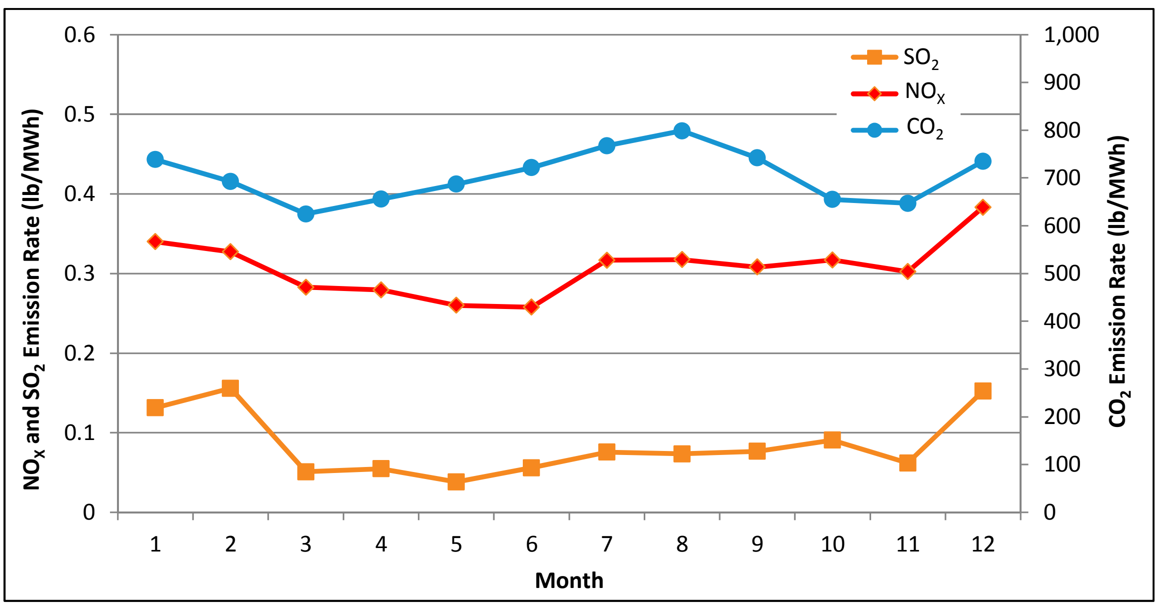

Figure 5-3: 2016 New England system monthly average NO_X, SO_2, and CO_2 emission rates (lb/MWh).

Figure 5-4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rates (lb/MWh) for 2007 to 2016 using the calculation method presented in Section 3.2. Since 2007, the annual average NO_X emission rate has decreased by 43%, SO_2 by 95%, and CO_2 by 22%. Appendix Table 6 shows all historical emission rates.

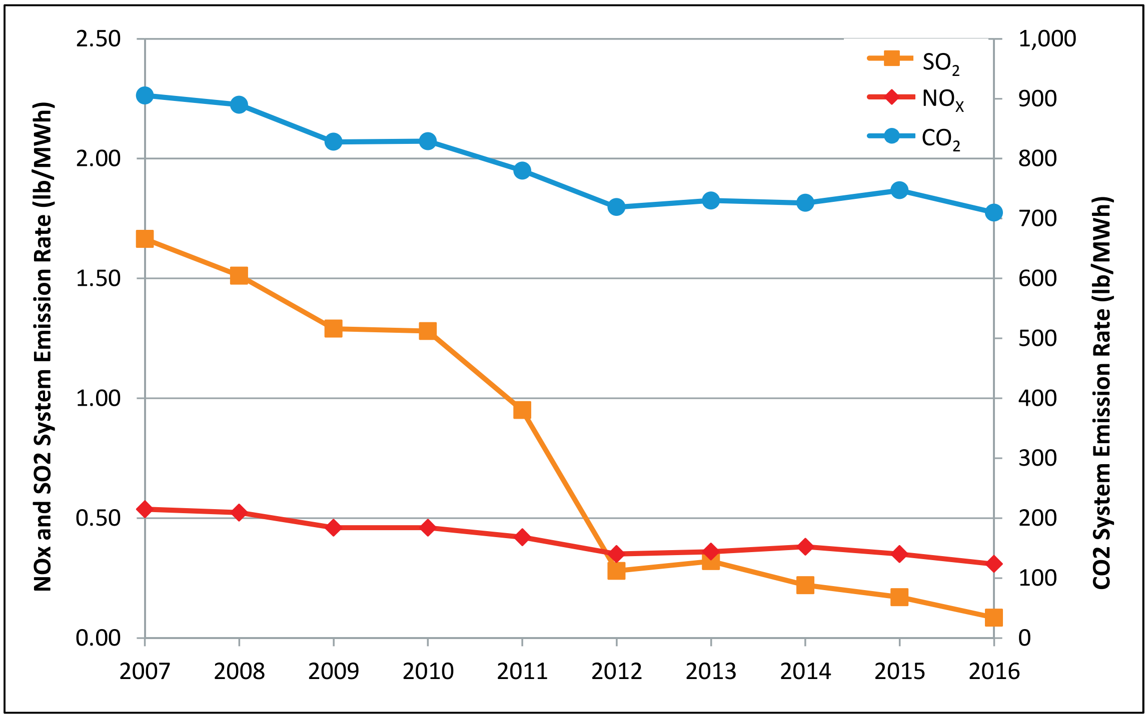

Figure 5-4: New England system annual average NO_X, SO_2, and CO_2 emission rates, 2007 to 2016 (lb/MWh).

5.1.2 Additional Observations

Total energy generation declined by 2.2% in 2016 from 2015. This was accompanied by a slight change in the percentage of energy produced by non-emitting generators, which increased from 39.5% of the total energy in 2015 to 41.1% in 2016. There was a large change in the amount of energy from coal-fired generation, which decreased by 34% in 2016. Energy from oil-fired generators decreased to about half of the 2015 amount, and natural gas-fired generation decreased slightly as well. In contrast, there was an increase in energy produced by non-emitting sources, including nuclear generation, which increased 2.7%, and photovoltaic and wind generation, which grew by 21%. 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 2015 to 2016 contributed to decreases of 13.8%, 50.9%, and 7.1% in system emissions for NO_X, SO_2, and CO_2, respectively. The changes in emission rates mirror the changes in total emissions: the 2016 NO_X, SO_2, and CO_2emission rates decreased by 11.4%, 52.9%, and 5.0%, respectively, from 2015 values.

Table 5-2
2015 and 2016 New England System Emissions (ktons)
and Emission Rates (lb/MWh)

Annual System Emissions						
	2015 Emissions (kTons)	2016 Emissions (kTons)	Total Emissions % Change	2015 Emission Rate (lb/MWh)	2016 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	18.86	16.26	-13.8	0.35	0.31	-11.4
SO_2	9.11	4.47	-50.9	0.17	0.08	-52.9
CO_2	40,312	37,468	-7.1	747	710	-5.0

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
- 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 2016 New England Marginal Heat Rate

The calculated annual marginal heat rate reflects the average annual efficiency of all the marginal fossil units dispatched throughout 2016. The 2016 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 2009 to 2016 are presented in Figure 5-6. The values behind Figure 5-6 are provided in Appendix Table 7.

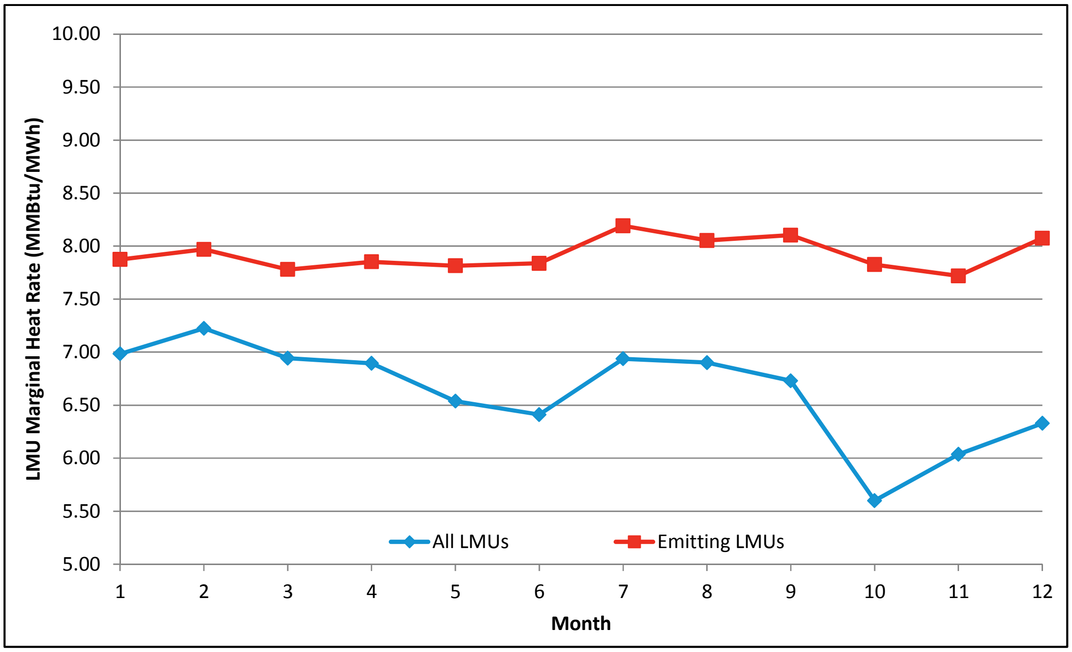

Figure 5-5: 2016 LMU monthly marginal heat rate (MMBtu/MWh).

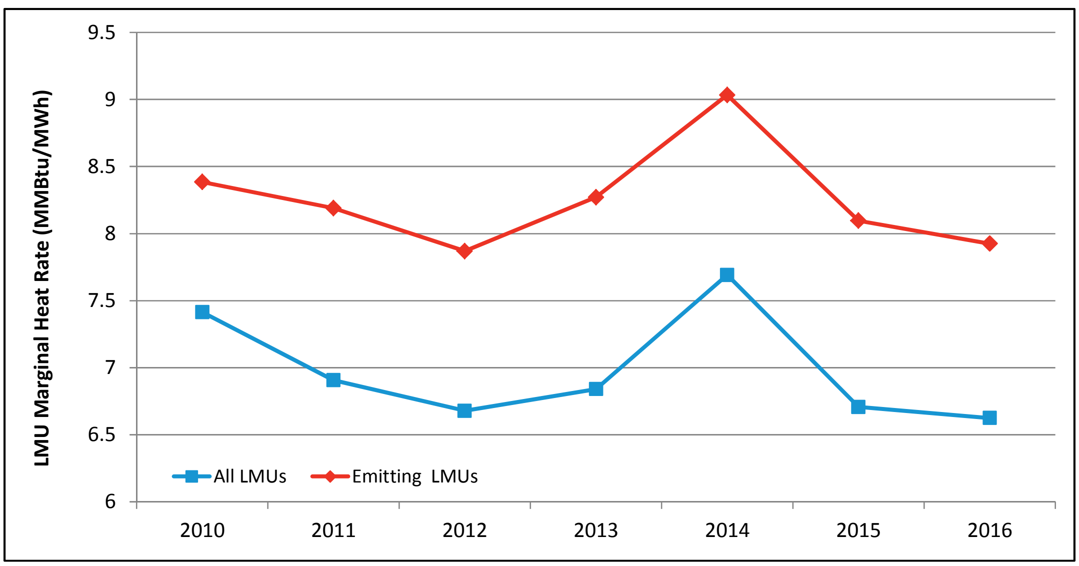

Figure 5-6: LMU annual marginal heat rate, 2010-2016 (MMBtu/MWh).

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. This is likely due to the increased amount of time that gas units were marginal and the decreased time that coal units were on the margin.

5.3 2016 New England Marginal Emission Rates

This section presents the 2016 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 6.625 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 2016 percentage of time various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2016 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
2016 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	0.26	0.14	0.25	0.19	0.21
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.22	0.11		0.16
CO_2		892	807		842

(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.

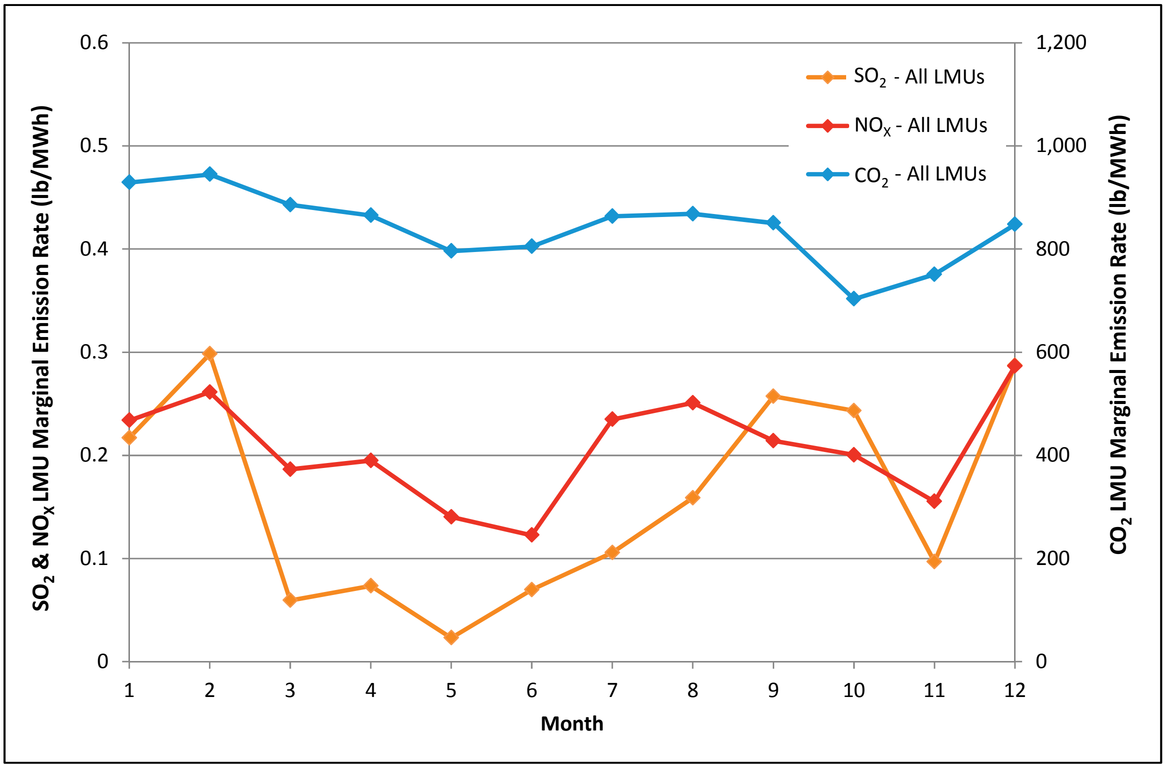

Figure 5-7: 2016 monthly LMU marginal emission rates—all LMUs (lb/MWh).

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 7.925 MMBtu/MWh. The values for the monthly rates shown in Figure 5-8 are shown in Appendix Table 11.

Table 5-4
2016 LMU Marginal Emission Rates—Emitting LMUs (lb/MWh)

Ozone / Non-Ozone Season Emissions (NO_X)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.33	0.18	0.30	0.24	0.25
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.28	0.13		0.19
CO_2		1,035	987		1,007

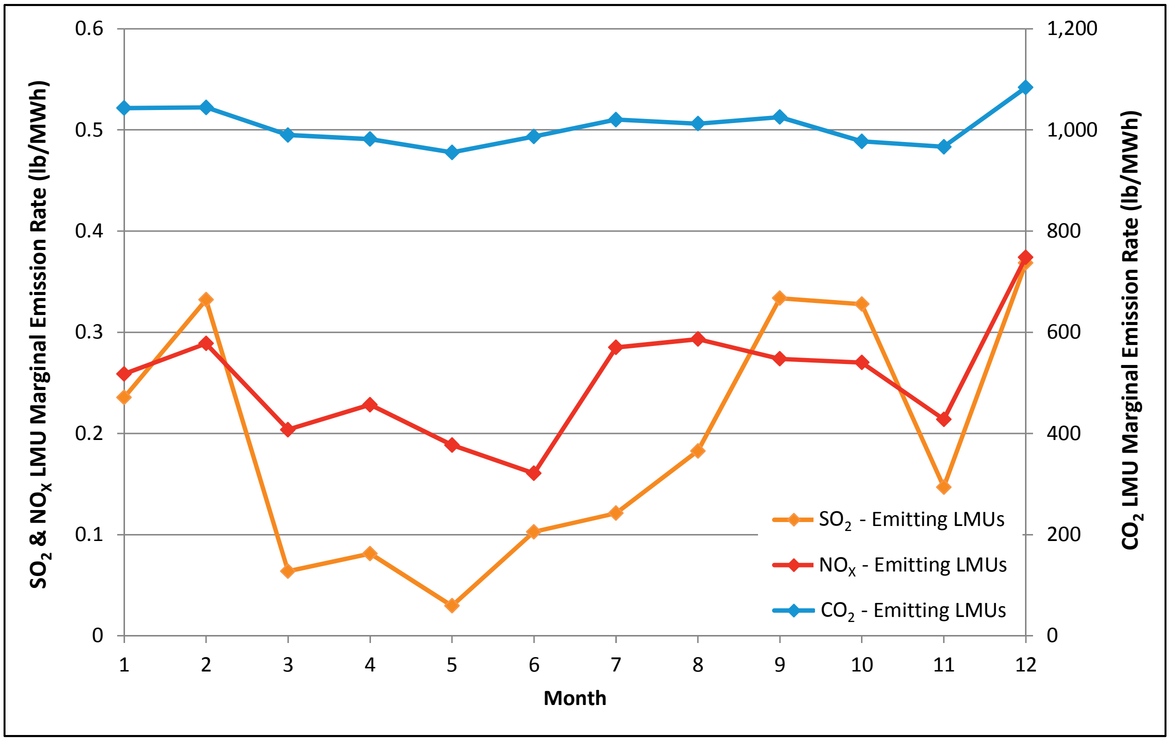

Figure 5-8: 2016 monthly LMU marginal emission rates—emitting LMUs (lb/MWh).

5.3.3 2009 to 2016 LMU Marginal Emission Rates

The LMUs actively exhibit the changes in 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.

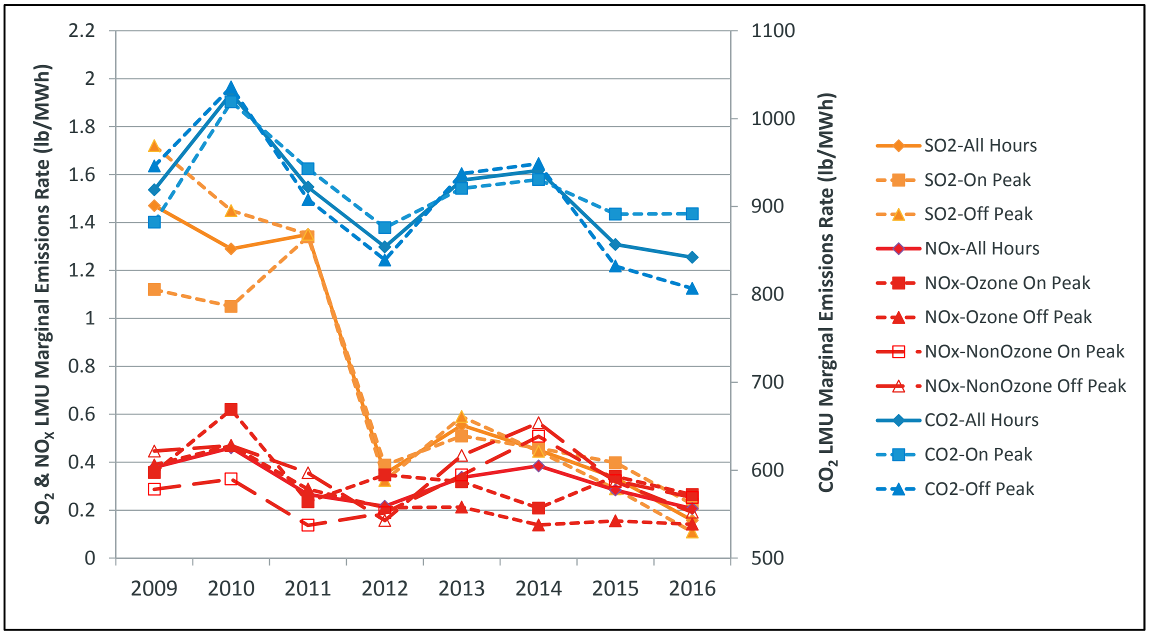

Figure 5-9: LMU marginal emission rates, 2009 to 2016—all LMUs (lb/MWh).

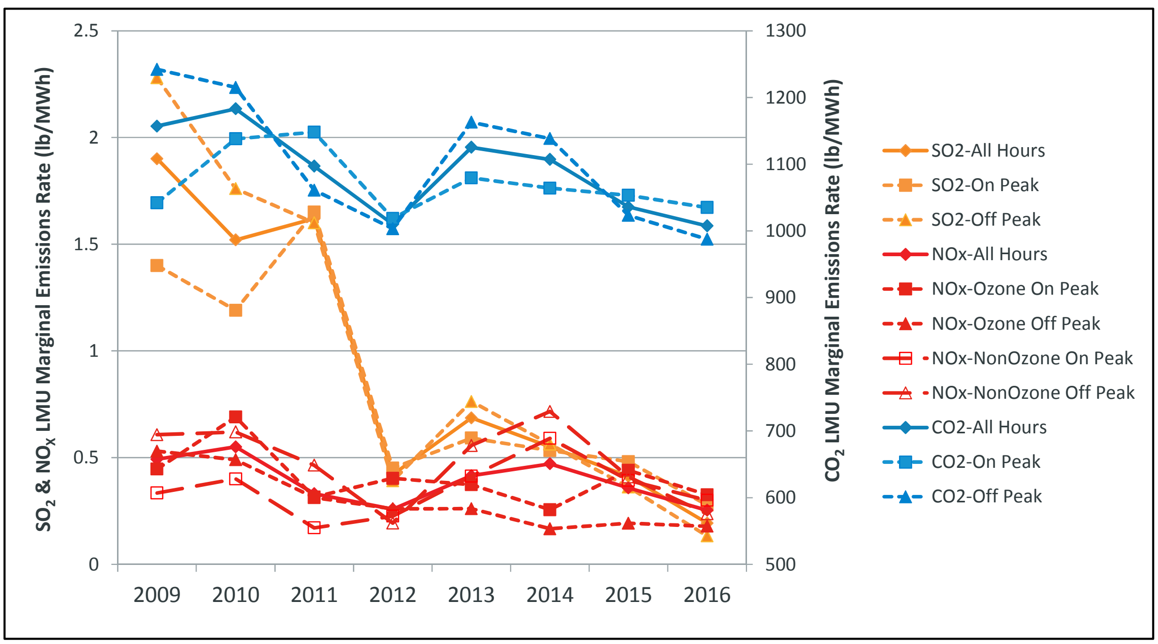

Figure 5-10: LMU marginal emission rates, 2009 to 2016—emitting LMUs (lb/MWh).

5.3.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five energy demand days in 2016 were examined. In 2016, the top five HEDDs were July 22 and 26, and August 11, 12, and 14. The temperatures in New England during these days ranged from 88° to 94°F. Peak daily loads ranged from 23,970 MW on Tuesday, July 26, to a high of 25,596 MW on Friday, August 12. 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	0.64	0.80
SO_2	0.49	0.60
CO_2	968	1179

5.3.5 Observations

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 New England power system.

The 2016 LMU annual marginal rates for SO_2, NO_X and CO_2 are the lowest rates of the 2009 through 2016 period. Compared with 2009, the 2016 LMU SO_2 annual marginal rates have declined by approximately 89% 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 units. Since 2009, there has been a 45% to 48% decline in the NO_X LMU rates for the all-LMU and emitting-LMU scenarios, while the CO_2 rates have declined by 8% to 13% during that period.

In prior emissions reports, where long-term trends of fuel-type-assumed (FTA) marginal emission rates were calculated, the FTA marginal emission rates for NO_X decreased noticeably in 1995. This was primarily due to the implementation of reasonable available control technology (RACT) regulations for NO_X required under Title I of the 1990 *Clean Air Act Amendments*. Most of the decrease in emission rates that took place through 2004 can be attributed to the commercial installation of many highly efficient, low-emitting, natural-gas-fired combined-cycle plants before that time in New England, as well as a decrease in the price of natural gas. Meeting the requirements of the 1999-2002 Ozone Transport Commission NO_X Budget Program, followed by EPA's NO_X Budget Trading Program, reduced emissions further. Because few new natural-gas-fired power plants have been added since 2004, the decline in marginal NO_X emission rates has tapered off.

In 2016, the on-peak marginal rates for SO_2 and CO_2, as well as for NO_X during both the ozone and non-ozone seasons, were higher than the off-peak rates. This is likely due to the operation of older, less-efficient jets or combustion turbines dispatched to meet peak load.

Between 2015 and 2016, the SO_2 and NO_X marginal emission rates decreased approximately 53% and 28%, respectively, while the CO_2 rates decreased by 2% and 3% for the all-LMU and emitting LMU scenarios. Although both the marginal and system emission rates decreased in 2016, the magnitude of the changes was not consistent. The decrease in the SO_2 marginal emission rate was similar to the decrease in the SO_2 system emission rate. However, the system emission rate for NO_X only decreased 11%, and the CO_2 system rate decreased by 5%, or about twice the amount of the marginal rate. The greater decrease in CO_2 system emission rates is likely due to significant decreases in both coal- and oil-fired generation in 2016, as well an increase in nuclear generation. In contrast, the amount of time that coal-fired generation was on the margin actually increased from 2015 to 2016.

Section 6
Appendix

Appendix Table 1
New England Total Cooling and Heating Degree Days, 1997 to 2016

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1997	211	-34.4%	6,432	6.9%
1998	312	-3.0%	5,483	-8.9%
1999	360	12.0%	5,774	-4.0%
2000	217	-32.5%	6,399	6.3%
2001	323	0.5%	5,895	-2.0%
2002	354	10.1%	5,959	-1.0%
2003	355	10.4%	6,651	10.5%
2004	251	-21.9%	6,354	5.6%
2005	418	30.0%	6,353	5.6%
2006	335	4.2%	5,552	-7.7%
2007	288	-10.4%	6,175	2.6%
2008	281	-12.6%	6,049	0.5%
2009	224	-30.3%	6,278	4.3%
2010	406	26.3%	5,653	-6.1%
2011	357	11.0%	5,826	-3.2%
2012	409	27.2%	5,235	-13.0%
2013	401	24.7%	6,156	2.3%
2014	240	-25.3%	6,318	5.0%
2015	337	4.8%	6,100	1.4%
2016	351	9.2%	5,705	-5.2%

Appendix Table 2
2016 New England Summer 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	12.8	-	-	-	-
Natural Gas	2,852.5	34.0	5,470.6	49.3	1,556.7	49.0	1,241.4	29.7	1,863.6	97.8	-	-
Nuclear	2,081.5	24.8	670.5	6.0	-	-	1,249.1	29.9	-	-	-	-
Oil	2,750.3	32.8	2,535.0	22.9	843.6	26.6	482.9	11.5	-	-	132.8	30.8
Hydro	85.9	1.0	139.2	1.3	469.9	14.8	418.2	10.0	-	-	200.9	46.6
Pumped Storage	27.9	0.3	1,757.9	15.9	-	-	-	-	-	-	-	-
Solar	1.2	0.0	251.8	2.3	-	-	2.2	0.1	9.0	0.5	-	-
Wind	-	-	11.3	0.1	142.2	4.5	25.2	0.6	7.1	0.4	16.4	3.8
Other Renewables	209.7	2.5	251.6	2.3	163.1	5.1	229.0	5.5	26.3	1.4	80.9	18.8
Total	8,392.4	100.0	11,087.9	100.0	3,175.4	100.0	4,181.3	100.0	1,906.0	100.0	431.0	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2017.

Appendix Table 3
2016 New England Winter 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	1,082.4	8.0	-	-	534.5	12.1	-	-	-	-
Natural Gas	3,125.5	35.1	6,962.4	51.2	1,750.0	50.9	1,364.8	31.0	2,091.4	98.6	-	-
Nuclear	2,110.9	23.7	683.4	5.0	-	-	1,246.7	28.3	-	-	-	-
Oil	2,955.1	33.2	2,643.4	19.4	876.4	25.5	502.1	11.4	-	-	168.8	31.2
Hydro	104.6	1.2	209.5	1.5	523.1	15.2	471.7	10.7	1.6	0.1	244.5	45.1
Pumped Storage	28.1	0.3	1,733.4	12.7	-	-	-	-	-	-	-	-
Solar	-	-	0.2	0.0	-	-	-	-	0.0	0.0	-	-
Wind	-	-	23.6	0.2	114.6	3.3	55.3	1.3	0.3	0.0	44.5	8.2
Other Renewables	202.7	2.3	258.0	1.9	176.9	5.1	227.6	5.2	27.9	1.3	84.1	15.5
Total	8,911.9	100.0	13,596.4	100.0	3,441.0	100.0	4,402.7	100.0	2,121.2	100.0	542.0	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2017.

Appendix Table 4
ISO New England System
Annual Emissions of NO_X, SO_2, and CO_2, 2001 to 2016 (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
Percent Reduction, 2001-2016	73	98	29	29

(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
2016 Monthly System Emission Rates of NO_X, SO_2, and CO_2 (lb/MWh)

Monthly System Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.34	0.13	738
2	0.33	0.16	692
3	0.28	0.05	625
4	0.28	0.05	656
5	0.26	0.04	687
6	0.26	0.06	722
7	0.32	0.08	767
8	0.32	0.07	799
9	0.31	0.08	742
10	0.32	0.09	655
11	0.30	0.06	647
12	0.38	0.15	735

Appendix Table 6
New England System
Annual Average NO_X, SO_2, and CO_2 Emission Rates, 1999 to 2016 (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
Percent Reduction, 1999 - 2016		77	98	30

Appendix Table 7
LMU Marginal Heat Rate, 2009 to 2016 (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

Appendix Table 8
2016 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	0.040	0.021	0.038	0.029	0.031
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.034	0.016		0.024
CO_2		135	122		127

Appendix Table 9
2016 Monthly LMU Marginal Emission Rates—All LMUs (lb/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.23	0.22	929
2	0.26	0.30	945
3	0.19	0.06	886
4	0.19	0.07	865
5	0.14	0.02	796
6	0.12	0.07	805
7	0.23	0.11	863
8	0.25	0.16	868
9	0.21	0.26	850
10	0.20	0.24	703
11	0.16	0.10	751
12	0.29	0.29	848

Appendix Table 10
2016 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	0.041	0.022	0.038	0.030	0.032
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.035	0.017		0.024
CO_2		131	125		127

Appendix Table 11
2016 Monthly LMU Marginal Emission Rates—Emitting LMUs (lb/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.26	0.24	1,043
2	0.29	0.33	1,045
3	0.20	0.06	990
4	0.23	0.08	982
5	0.19	0.03	956
6	0.16	0.10	987
7	0.29	0.12	1,020
8	0.29	0.18	1,012
9	0.27	0.33	1,025
10	0.27	0.33	977
11	0.21	0.15	967
12	0.37	0.37	1,084

Appendix Table 12
NO_X LMU Marginal Emission Rates, 2009 to 2016 —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
% Change 2009 - 2016	**-25.8**	**-63.7**	**-12.8**	**-57.1**	**-45.3**	

Appendix Table 13
NO_X LMU Marginal Emission Rates, 2009 to 2016—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
% Change 2009 - 2016	**-26.9**	**-66.4**	**-10.2**	**-61.1**	**-48.5**	

Appendix Table 14
SO_2 LMU Marginal Emission Rates, 2009 to 2016—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
% Change 2009 - 2016	**-79.9**	**-93.7**	**-89.3**	

Appendix Table 15
SO_2 LMU Marginal Emission Rates, 2009 to 2016—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
% Change 2009 - 2016	**-80.2**	**-94.2**	**-89.8**	

Appendix Table 16
CO_2 LMU Marginal Emission Rates, 2009 to 2016—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
% Change 2009 - 2016	**1.1**	**-14.7**	**-8.4**	

Appendix Table 17
CO_2 LMU Marginal Emission Rates, 2009 to 2016—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
% Change 2009 - 2016	**-0.7**	**-20.5**	**-12.9**	