



2013 ISO New England

## Electric Generator Air Emissions Report

ISO New England Inc.  
System Planning  
December 2014

*{ This page left intentionally blank }*

# Contents

<b>Figures</b> .....	<b>iv</b>
<b>Tables</b> .....	<b>v</b>
<b>Section 1 Executive Summary</b> .....	<b>1</b>
<b>Section 2 Background</b> .....	<b>5</b>
2.1 History of Marginal Emissions Methodologies .....	5
<b>Section 3 Methodologies</b> .....	<b>7</b>
3.1 Calculating Total System Emission Rate.....	7
3.2 Calculating Marginal Emission Rate.....	7
3.2.1 Fuel Type Assumed (FTA) Marginal Units .....	7
3.2.2 Locational Marginal Units (LMU).....	8
3.2.3 Definition of Time Periods.....	8
<b>Section 4 Data and Assumptions</b> .....	<b>10</b>
4.1 2013 New England Weather.....	10
4.2 Emission Data Sources.....	10
4.3 ISO New England System Installed Capacity .....	11
4.4 ISO New England System Energy Production .....	13
4.5 Locational Marginal Units (LMUs) .....	14
4.5.1 All LMUs.....	15
4.5.2 Emitting LMUs .....	17
4.5.3 Oil- & Natural Gas-Fired LMUs.....	18
<b>Section 5 Results</b> .....	<b>19</b>
5.1 2013 New England System Emissions .....	19
5.1.1 Observations.....	22
5.2 2013 New England Marginal Heat Rate.....	22
5.2.1 Fuel Type Assumed (FTA) Marginal Heat Rate .....	23
5.2.2 Locational Marginal Unit (LMU) Marginal Heat Rate .....	24
5.2.3 Observations.....	25
5.3 2013 New England Marginal Emission Rates.....	25
5.3.1 Fuel Type Assumed (FTA) Marginal Emission Rates.....	25
5.3.2 Locational Marginal Unit (LMU) Marginal Emission Rates .....	29
5.3.3 High Electric Demand Day (HEDD) Marginal Emission Rate .....	35
5.3.4 Observations.....	36
<b>Section 6 Appendix</b> .....	<b>37</b>

## Figures

Figure 1-1: 2004 vs. 2013 Energy Generation by Fuel Type.....	2
Figure 1-2: Comparison of 2013 New England Emission Rates (lb/MWh).....	4
Figure 4-1: 2013 New England Summer Capacity by State .....	11
Figure 4-2 : 2004 – 2013 ISO New England Generator Additions.....	12
Figure 4-3: 2013 Monthly Generation by Fuel Type.....	13
Figure 4-4 : 2009 - 2013 Annual Generation by Fuel Type.....	14
Figure 4-5: 2013 Percent of Time Fuel Types Marginal – All LMUs.....	15
Figure 4-6: 2009 - 2013 Percent of Time Fuel Types Marginal – All LMUs.....	16
Figure 4-7: 2013 Percent of Time Fuel Types Marginal – Emitting LMUs.....	17
Figure 4-8: 2009 - 2013 Percent of Time Fuel Types Marginal – Emitting LMUs.....	17
Figure 4-9: 2013 Percent of Time Fuel Types Marginal – O&NG LMUs.....	18
Figure 4-10: 2009 - 2013 Percent of Time Fuel Types Marginal – O&NG LMUs.....	18
Figure 5-1: 2013 New England System Annual Emission of NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> (kTons) .....	19
Figure 5-2: 2004 - 2013 New England System Annual Emissions of NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> (kTons).....	20
Figure 5-3: 2013 New England System Monthly Average NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> Emission Rates (lb/MWh) .....	21
Figure 5-4: 2004-2013 New England System Annual Average NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> Emission Rates (lb/MWh) .....	21
Figure 5-5: 2004 - 2013 New England System Annual FTA Marginal Heat Rate (MMBtu/MWh).....	23
Figure 5-6: 2013 LMU Monthly Marginal Heat Rate (MMBtu/MWh).....	24
Figure 5-7: 2009-2013 LMU Annual Marginal Heat Rate (MMBtu/MWh).....	24
Figure 5-8: 2004 - 2013 New England NO <sub>x</sub> FTA Marginal Emission Rates (lb/MWh).....	27
Figure 5-9: 2004 - 2013 New England SO <sub>2</sub> FTA Marginal Emission Rates (lb/MWh) .....	28
Figure 5-10: 2004 - 2013 New England CO <sub>2</sub> FTA Marginal Emission Rates (lb/MWh) .....	28
Figure 5-11: 2013 Monthly LMU Marginal Emission Rates – All LMUs (lb/MWh).....	30
Figure 5-12: 2013 Monthly LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	31
Figure 5-13: 2013 Monthly LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	32
Figure 5-14: 2009 - 2013 LMU Marginal Emission Rates – All LMUs (lb/MWh).....	33
Figure 5-15: 2009 - 2013 LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	34
Figure 5-16: 2009 - 2013 LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	34

## Tables

Table 1-1: 2012 & 2013 New England System Emissions (kTons) and Emission Rates (lb/MWh)....	2
Table 1-2: 2012 & 2013 FTA Marginal Emission Rates (lb/MWh).....	3
Table 1-3: 2012 & 2013 LMU Marginal Emission Rates (lb/MWh).....	3
Table 1-4: Differences between LMU O&NG and FTA Marginal Emissions Rates (lb/MWh).....	3
Table 5-1: 2013 New England System Annual Average NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> Emission Rates (lb/MWh) .....	20
Table 5-2: 2013 New England FTA Marginal Emission Rates (lb/MWh).....	25
Table 5-3: 2013 New England NO <sub>x</sub> FTA Marginal Emission Rates by State (lb/MWh).....	26
Table 5-4: 2013 New England SO <sub>2</sub> FTA Marginal Emission Rates by State (lb/MWh).....	26
Table 5-5: 2013 New England CO <sub>2</sub> FTA Marginal Emission Rates by State (lb/MWh).....	27
Table 5-6: 2013 LMU Marginal Emission Rates – All LMUs (lb/MWh).....	29
Table 5-7: 2013 LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	31
Table 5-8: 2013 LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	32
Table 5-9: High Electric Demand Day LMU Marginal Emission Rates (lb/MWh).....	35
Appendix Table 1: 1994 - 2013 New England Total Cooling and Heating Degree Days.....	37
Appendix Table 2: 2013 New England Summer Capacity.....	37
Appendix Table 3: 2013 New England Winter Capacity <sup>12, 13</sup> .....	38
Appendix Table 4: 2001 - 2013 ISO New England System Annual Emissions of NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> (kTons).....	38
Appendix Table 5: 1999 - 2013 New England System Annual Average NO <sub>x</sub> , SO <sub>2</sub> , and CO <sub>2</sub> Emission Rates (lb/MWh).....	39
Appendix Table 6: 2009 - 2013 LMU Marginal Heat Rate (MMBtu/MWh).....	40
Appendix Table 7: 2013 New England FTA Marginal Emission Rates (lb/MMBtu).....	40
Appendix Table 8: 1993 - 2013 New England NO <sub>x</sub> FTA Marginal Emission Rates (lb/MWh).....	41
Appendix Table 9: 1993 - 2013 New England SO <sub>2</sub> FTA Marginal Emission Rates (lb/MWh).....	42
Appendix Table 10: 1993 - 2013 New England CO <sub>2</sub> FTA Marginal Emission Rates (lb/MWh).....	43
Appendix Table 11: 2013 LMU Marginal Emission Rates – All LMUs (lb/MMBtu).....	43
Appendix Table 12: 2013 Monthly LMU Marginal Emission Rates – All LMUs (lb/MWh).....	44
Appendix Table 13: 2013 LMU Marginal Emission Rates – Emitting LMUs (lb/MMBtu).....	44
Appendix Table 14: 2013 Monthly LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	44
Appendix Table 15: 2013 LMU Marginal Emission Rates – O&NG LMUs (lb/MMBtu).....	45
Appendix Table 16: 2013 Monthly LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	45
Appendix Table 17: 2009 - 2013 NO <sub>x</sub> LMU Marginal Emission Rates – All LMUs (lb/MWh).....	45
Appendix Table 18: 2009 - 2013 NO <sub>x</sub> LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	46
Appendix Table 19: 2009 - 2013 NO <sub>x</sub> LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	46
Appendix Table 20: 2009 - 2013 SO <sub>2</sub> LMU Marginal Emission Rates – All LMUs (lb/MWh).....	46
Appendix Table 21: 2009 - 2013 SO <sub>2</sub> LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	47
Appendix Table 22: 2009 - 2013 SO <sub>2</sub> LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	47
Appendix Table 23: 2009 - 2013 CO <sub>2</sub> LMU Marginal Emission Rates – All LMUs (lb/MWh).....	47
Appendix Table 24: 2009 - 2013 CO <sub>2</sub> LMU Marginal Emission Rates – Emitting LMUs (lb/MWh).....	48
Appendix Table 25: 2009 - 2013 CO <sub>2</sub> LMU Marginal Emission Rates – O&NG LMUs (lb/MWh).....	48

***{ This page left intentionally blank }***

## Section 1

### Executive Summary

This ISO New England (ISO-NE) report provides a comprehensive analysis of New England electric generator air emissions (NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub>) and review of relating system conditions. The following is a highlight of analysis results available in this report.

- System and marginal emissions (kTons)<sup>1</sup>
- System and marginal emission rates (lb/MWh & lb/MMBtu)
- System and marginal heat rate (MMBtu/MWh)

The information is also provided in different time periods of interest.

- On-Peak vs. Off-Peak hours
- Ozone Season vs. Non-Ozone Season
- Monthly variations [New]
- High Electric Demand Days (HEDDs) [New]

The ISO New England Electric Generator Air Emissions Report (Emissions Report), first developed in 1993, has evolved through the years in response to stakeholder needs. It was initially motivated by the need to determine the emission reductions that demand-side management (DSM) programs have had upon New England's aggregate NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> generating unit air emissions. The use of these emission rates was subsequently broadened to include the benefits of energy efficiency programs and renewable resource projects within the region.

There has been an overall decrease in NO<sub>x</sub> (60%), SO<sub>2</sub> (88%), and CO<sub>2</sub> (28%) emissions from 2004 through 2013. A shift in the fuel mix powering the region has direct contribution to the changing total system emissions. Figure 1-1 shows an increase of natural gas generation and a decrease of coal- and oil-fired generation.

Compared to the 20-year average for cooling and heating days (indicator of weather), 2013 had a 25% warmer summer and an average winter. From 2012 to 2013, net energy for load was 1% higher, but system generation was lower by 4%. New England received more imported energy from neighboring areas in 2013. The energy generation by non-emitting generators increased from 39% to 42%. However, the energy generation by air-emitting generators had a decrease in natural gas (lower emission rates) to more coal- and oil-fired generators (higher emission rates).

---

<sup>1</sup>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: 2004 vs. 2013 Energy Generation by Fuel Type**

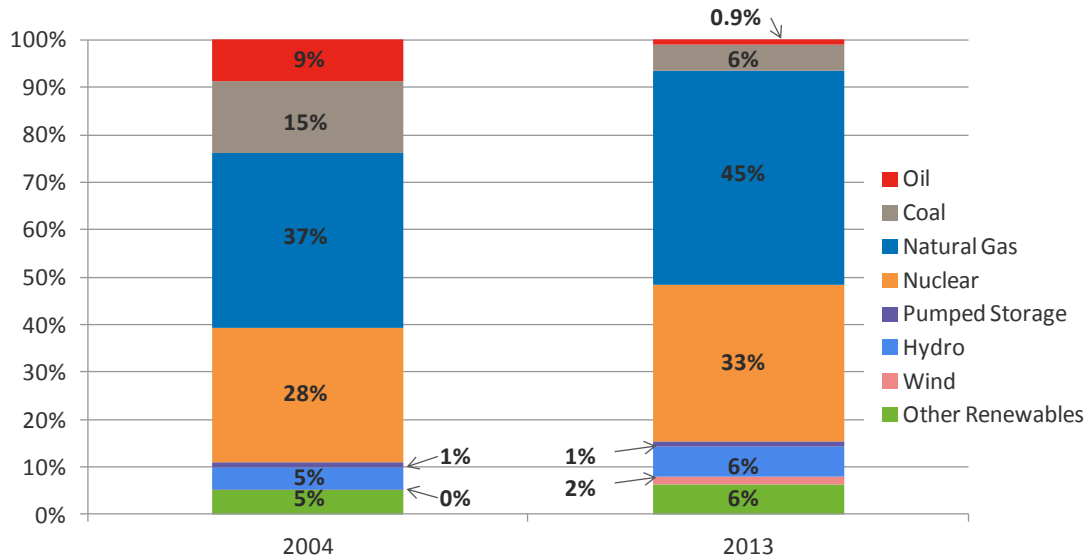


Table 1-1 shows the total New England system emissions (kTons) and average system emission rates (lb/MWh) of NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub>. There was an increase in emission rates observed from 2012 to 2013.

**Table 1-1: 2012 & 2013 New England System Emissions (kTons) and Emission Rates (lb/MWh)**

Annual System Emissions						
	2012 Emissions (kTons)	2013 Emissions (kTons)	Total Emissions % Change	2012 Emission Rate (lb/MWh)	2013 Emission Rate (lb/MWh)	Emission Rate % Change
NO <sub>x</sub>	20.32	20.32	0.0	0.35	0.36	2.9
SO <sub>2</sub>	16.61	18.04	8.6	0.28	0.32	14.3
CO <sub>2</sub>	41,975	40,901	-2.6	719	730	1.5

Table 1-2 and Table 1-3 show the 2012 and 2013 annual average marginal emission rates as calculated by the two marginal emissions analysis methodologies. The Fuel Type Assumed (FTA) Marginal Emission Analysis method has been used to calculate marginal emission rates since 2004. The FTA marginal units are assumed to be those that are fueled with oil (including residual, distillate, diesel, kerosene, and jet fuel), and/or natural gas.<sup>2</sup> FTA marginal emission rates are calculated using the energy-weighted, average emission rates of all oil- and natural gas-fired generating units, which are assumed to increase their output in response to higher regional energy demand.

The Locational Marginal Unit (LMU) Marginal Emission Analysis uses the emissions rates from the ISO-NE identified marginal unit(s) that set the Energy Market hourly Locational Marginal Price(s) (LMP). The LMP results from a process that minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitations of the power system.

<sup>2</sup> All fuel types refer to the generating unit's primary fuel type, as reported within the 2013 CELT Report.



Three sets of emission rate results are presented in this report utilizing this methodology. They are: 1) All LMUs; 2) Emitting LMUs; and 3) Oil- and Natural Gas-Fired (O&NG) LMUs.

**Table 1-2: 2012 & 2013 FTA Marginal Emission Rates (lb/MWh)**

Fuel Type Assumed Marginal Emissions			
	2012 Annual Rate (lb/MWh)	2013 Annual Rate (lb/MWh)	Percent Change 2012 to 2013 (%)
NO <sub>x</sub>	0.14	0.16	14.3
SO <sub>2</sub>	0.03	0.11	266.7
CO <sub>2</sub>	899	914	1.7

**Table 1-3: 2012 & 2013 LMU Marginal Emission Rates (lb/MWh)**

LMU Marginal Emissions						
	All LMUs			Emitting LMUs		
	2012 Annual Rate (lb/MWh)	2013 Annual Rate (lb/MWh)	Percent Change 2012 to 2013 (%)	2012 Annual Rate (lb/MWh)	2013 Annual Rate (lb/MWh)	Percent Change 2012 to 2013 (%)
NO <sub>x</sub>	0.22	0.34	56.7	0.26	0.42	62.8
SO <sub>2</sub>	0.35	0.55	55.8	0.42	0.69	64.3
CO <sub>2</sub>	854	930	8.9	1,010	1,125	11.4

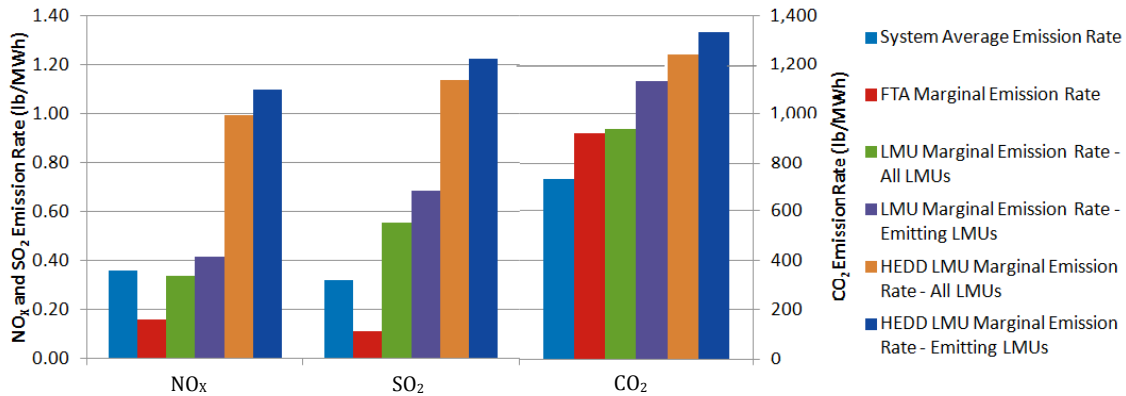
Table 1-4 compares the two marginal emission analysis methods that have the same fuel type based assumption, which only accounts for oil- and natural gas-fired generators as marginal units. The difference for CO<sub>2</sub> marginal emission rates has been within 3.5% in the last four years. Although SO<sub>2</sub> and NO<sub>x</sub> marginal emission rates have a larger percentage of difference, the magnitudes of the marginal emission rates are similar.

**Table 1-4: Differences between LMU O&NG and FTA Marginal Emissions Rates (lb/MWh)**

	LMU O&NG vs. FTA Marginal Emissions								
	NO <sub>x</sub>			SO <sub>2</sub>			CO <sub>2</sub>		
	LMU Annual Rate (lb/MWh)	FTA Annual Rate (lb/MWh)	Difference Between Methods (%)	LMU Annual Rate (lb/MWh)	FTA Annual Rate (lb/MWh)	Difference Between Methods (%)	LMU Annual Rate (lb/MWh)	FTA Annual Rate (lb/MWh)	Difference Between Methods (%)
2009	0.18	0.17	-7.1	0.15	0.22	46.7	928	930	0.2
2010	0.26	0.18	-30.8	0.13	0.09	-30.8	965	943	-2.3
2011	0.19	0.14	-27.8	0.09	0.05	-46.2	877	907	3.4
2012	0.16	0.14	-11.9	0.04	0.03	-28.6	915	899	-1.7
2013	0.20	0.16	-20.0	0.21	0.11	-47.6	928	914	-1.5

The 2013 Emissions Report presents a variety of emission rates and is summarized in Figure 1-2. The HEDD LMU Marginal Emission Rates characterize the emissions profile of the top five HEDDs and the marginal units responding to system demand during these days.

**Figure 1-2: Comparison of 2013 New England Emission Rates (lb/MWh)**



The 2013 calculated FTA marginal heat rate was determined to be 7.598 MMBtu/MWh, increasing approximately 8% from the 2012 marginal heat rate of 7.407 MMBtu/MWh. The 2013 calculated All LMU marginal heat rate was 6.841 MMBtu/MWh compared to 6.678 MMBtu/MWh or 2% higher than in 2012. When considering emitting units only, the LMU marginal heat rate increased 5%, from 7.870 MMBtu/MWh to 8.271 MMBtu/MWh.

## Section 2

### Background

In early 1994, the NEPOOL Environmental Planning Committee (EPC) conducted a study to analyze the impact that demand-side management (DSM) programs had on NEPOOL's generating unit NO<sub>x</sub> air emissions in the calendar year 1992. The results were presented in a report entitled *1992 Marginal NO<sub>x</sub> Emission Rate Analysis*. This report was subsequently used to support applications for obtaining NO<sub>x</sub> Emission Reduction Credits (ERC) resulting from the impacts of those DSM programs. 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<sub>x</sub>, VOC, and CO in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Later in 1994, the *1993 Marginal Emission Rate Analysis* (MEA Report) was published, which provided expanded analysis of the impact of DSM programs on power plant NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> air emissions for the calendar year 1993. MEA Reports were published annually from 1994 to 2007, to provide similar annual environmental analyses for those years. For the 2008 emissions analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the MEA Report be restructured and renamed to reflect the importance of emissions from the entire New England electric generation system.<sup>3</sup> The name of the MEA Report was changed to the *ISO New England Electric Generator Air Emissions Report* (Emissions Report), and the new report includes calculated system and marginal emissions for the entire ISO New England generation system, rather than focusing primarily on marginal emissions. The calculated marginal emissions can be used to estimate the impact DSM programs and non-emitting renewable energy projects have had on reducing New England's NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> power plant air emissions.

Currently, the Emissions Report includes system emissions analysis and two methodologies to calculate marginal emissions analysis. The Fuel Type Assumed (FTA) methodology, started in 2004, assumes that all natural gas- and oil-fired units are the marginal fossil units. The Locational Marginal Unit (LMU) methodology, begun as a pilot program in 2011, uses marginal units identified by the Locational Marginal Price. Each methodology provides a different perspective of marginal emissions. The 2013 Emissions Report focuses on analysis and observations over the past decade (2004 - 2013). The Appendix includes data of years prior to 2004 and values of the figures presented.

The Emissions Report has been used by a variety of stakeholders to track air emissions from New England's electric generation system, and to estimate the avoided emissions resulting from DSM programs and renewable energy projects.

#### 2.1 History of Marginal Emissions Methodologies

---

In MEA studies performed prior to 2004, production simulation models were used to replicate, as closely as possible, the actual system operations for the study year (reference case). Then an incremental load scenario was modeled in which the system load was increased by 500 MW in each hour (marginal case). The marginal air emission rates were calculated based on the differences in

---

<sup>3</sup> The EAG is a stakeholder working group that assists the Planning Advisory Committee (PAC), the Reliability Committee (RC) and the associated Power Supply Planning Committee (PSPC). The EAG's web site is located at: <http://www.iso-ne.com/eag>

generator air emissions between these two scenarios. However, this methodology had some drawbacks. The reference case simulation could not exactly match the actual unit-specific energy production levels of the study year due to a number of limitations in the production simulation model, including the inability to accurately represent historical overall dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit specific outages and deratings, and effects of the daily volatility of regional (power plant) fuel prices.

Beginning in 2004, the Fuel Type Assumed (FTA) methodology was used to calculate the average marginal emission rates. This method was based on all natural gas and oil-fired generators; assumed to respond 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; they historically (2000s) operated as base-load or were non-dispatchable units and would typically not be dispatched to balance supply with demand on the system.<sup>4</sup> Other non-emitting resources, such as hydro-electric, pumped storage, wind, solar, and nuclear units that do not vary in output to follow load, are also assumed not to be marginal units; they were excluded from the calculation of FTA marginal emission rates.

In 2011, ISO-NE began developing a methodology for calculating the marginal emission rate based on the Locational Marginal Unit (LMU), 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 New England while accounting for transmission and other constraints. By using this method, the Locational Marginal Unit (LMU), or the last unit dispatched to balance the system, can be identified. Results are presented starting in 2009, as this is the earliest year of available data.

---

<sup>4</sup> In determining whether to consider coal units as marginal units, it was observed that higher or lower loads change the number of committed natural gas and/or oil units, while coal units would be dispatched when available. During the low-load troughs of the daily cycle, coal units were seen to be 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 Locational Marginal Prices during those off-peak hours.

## Section 3

### Methodologies

The New England power system emissions and marginal emission rate calculations for NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub> were based primarily on the tons of air emissions reported in the U.S. EPA Clean Air Markets Division (CAMD) database.<sup>5</sup> When unit specific emissions data were not available from the CAMD database, emission rates from the New England Power Pool Generation Information System (NEPOOL GIS) or the U.S. eGRID database, or, alternatively, emission rates that were assumed based on a similar generator type were used. These unit-specific emission rates were used in conjunction with the actual megawatt-hours (MWh) of generation, from the ISO-NE database used for energy market settlement purposes, to calculate tons of emissions.<sup>6</sup>

All electric generators dispatched by ISO New England are included in these 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.

#### 3.1 Calculating Total System Emission Rate

---

The total annual system emission rate (lb/MWh) is based on the emissions produced by all ISO New England generators during a calendar year. The formula for calculating the total annual system emission rate is:

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

#### 3.2 Calculating Marginal Emission Rate

---

##### 3.2.1 Fuel Type Assumed (FTA) Marginal Units

In calculating the FTA marginal emission rates, the hourly emissions (lb) for those units in the U.S. EPA CAMD were grouped into on-peak and off-peak periods. When only monthly NEPOOL GIS or annual eGRID data were available, those emission rates (lb/MWh) were multiplied by the associated monthly on-peak and off-peak generation. The amount of emissions (lb) from each individual marginal fossil generator was added together to obtain the annual total FTA marginal emissions. This quantity was then divided by the total on-peak or off-peak generation to get the corresponding FTA marginal emission rates (lb/MWh) for that time period. In the case of NO<sub>x</sub> emission rates, the monthly totals (lb) were grouped into ozone and non-ozone season emissions and divided by the respective ozone and non-ozone season generation.

The average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> emission rates of the assumed marginal fossil units in each time period analyzed are referred to as the FTA marginal emission rates. These emission rates are calculated as:

$$\text{FTA Marginal Emission Rate (lb/MWh)} = \frac{\text{Total Emissions (lb) in Time Period}_{\text{Marginal Fossil Units}}}{\text{Total Energy (MWh) in Time Period}_{\text{Marginal Fossil Units}}}$$

---

<sup>5</sup> EPA Clean Air Markets Program Data can be found at <http://ampd.epa.gov/ampd/>.

<sup>6</sup> U.S. EPA's eGRID Ninth Edition Version 1.0 at: <http://www.epa.gov/cleanenergy/energy-resources/egrid/>.

### 3.2.2 Locational Marginal Units (LMU)

LMUs are identified through the Locational Marginal Price (LMP) process, which minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitation of the power system.

For each five minute-period, at least one marginal unit (LMU) is identified by the LMP. In some time periods, there may be physical limitations on the power system, such as a transmission constraint. For each binding constraint, this will add an additional marginal unit. This results in  $n + 1$  marginal unit (LMUs) for every  $n$  binding constraints, in each five minute period.

The percent of time each generator is marginal in each month is calculated and linked to the generator's month-specific on-/off-peak average emissions rate. The month and generator-specific average emission rates are obtained from the process of calculating system emission rates. The LMU Marginal Emission Rates are calculated as described below, where generator  $k$  is identified to be marginal during hour  $h$ , and has a specific monthly emission rate during month  $m$ . This calculation is used for on-peak and off-peak hours.

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 is then calculated by combining the on-peak and off-peak in a weighted calculation.

### 3.2.3 Definition of Time Periods

The 2013 marginal air emission rates for on and off-peak periods for New England have been calculated for this report. The on-peak period, which excludes nights and weekends, is provided to enable typical industrial and commercial users that can provide load response during a traditional weekday to explicitly account for their emissions reductions during those hours. The marginal emission rates for NO<sub>x</sub> are calculated for five time periods:<sup>7</sup>

- On-Peak Ozone Season consisting of all weekdays between 8 A.M. and 10 P.M. from May 1 to September 30
- Off-Peak Ozone Season consisting of all weekdays between 10 P.M. and 8 A.M. and all weekend hours from May 1 to September 30

---

<sup>7</sup> There was a special report, developed by ISO-NE, titled *Analysis of New England Electric Generator's NO<sub>x</sub> Emissions on 25 Peak-load Days in 2005-2009* released in 2011 that summarized ISO-NE's effort in conducting an analysis of NO<sub>x</sub> emissions during peak days. This report is located at: [http://www.iso-ne.com/genrtion\\_resrcs/reports/emission/peak\\_nox\\_analysis.pdf](http://www.iso-ne.com/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf)

- On-Peak Non-Ozone Season consisting of all weekdays between 8 A.M. and 10 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 P.M. and 8 A.M. and all weekend hours from January 1 to April 30 and from October 1 to December 31
- Annual average

Since the ozone and non-ozone seasons are only relevant to NO<sub>x</sub> emissions, the SO<sub>2</sub> and CO<sub>2</sub> emission rates were only calculated for the following time periods:

- On-Peak Annual consisting of all weekdays between 8 A.M. and 10 P.M.
- Off-Peak Annual consisting of all weekdays between 10 P.M. and 8 A.M. and all weekend hours
- Annual average

## Section 4

### Data and Assumptions

The key parameters and assumptions modeled in the 2013 ISO New England Emissions Report are highlighted in this section. They include weather, emissions data sources, installed capacity and system generation.

#### 4.1 2013 New England Weather

---

Since the demand for energy and peak loads are significantly affected by the weather, it is useful to provide perspective for the changes in emission rates by comparing 2013 total energy use and both cooling and heating degree days to previous years.

The 2013 summer peak electricity demand of 27,379 MW was 1,499 MW higher than the 2012 summer peak of 25,880 MW. There were 401 cooling degree days, which is 25% higher than the 20-year average.<sup>8</sup> The net energy for load was 1% higher in 2013 than 2012. With respect to the winter months, there were 6,156 heating degree days, which is an 18% increase compared to 2012, while staying near the 20-year average at 1.4% difference.

New England's historical cooling degree days and heating degree days for 1994 through 2013 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 Emission Data Sources

---

Individual generating unit emissions were calculated primarily from the 2013 actual emissions (tons) as reported under the U.S. EPA's Acid Rain Program, NO<sub>x</sub> Clean Air Interstate Rule and the Regional Greenhouse Gas Initiative (Clean Air Markets data).<sup>9 10</sup> Prior to 2005, the MEA reports used annual data obtained primarily from the U.S. EPA Emissions Scorecard. In the 2005 and 2006 MEA Reports, monthly U.S. EPA data rather than hourly data were used for calculating marginal rates.

For those units that were not required to file emissions data under the Acid Rain Program, Clean Air Interstate Rule or the Regional Greenhouse Gas Initiative, monthly emission rates (lb/MWh) from the NEPOOL Generation Information System (GIS) were used instead. If the data could not be obtained from either of those sources, annual emission rates (lb/MWh) from the U.S. EPA's eGRID Ninth edition Version 1.0 (Year 2010 data) were used.<sup>11</sup> If that information was not available,

---

<sup>8</sup> Over the 20-year span of 1994 to 2013, the average number of cooling degree days is 322 and the average number of heating degree days is 6,070.

<sup>9</sup> The U.S. EPA's Clean Air Markets emissions data can be accessed from <http://www.epa.gov/airmarkets/>.

<sup>10</sup> Generators report emissions to the U.S. EPA under the Acid Rain Program, which covers generators 25 MW or larger, and the NO<sub>x</sub> Budget Trading Program, which includes generators 15 MW or greater in the affected states of Connecticut and Massachusetts. (Starting in 2009, the Clean Air Interstate Rule (CAIR) took the place of the NO<sub>x</sub> Budget Trading Program.) Generators subject to the Regional Greenhouse Gas Initiative also report CO<sub>2</sub> emissions to the U.S. EPA.

<sup>11</sup> The U.S. EPA's eGRID Ninth edition Version 1.0 (Year 2010 data) is located at:

<http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.



emission rates based on eGRID data were obtained for similar type units. The emission rates were then multiplied by the 2013 energy generation reported to ISO-NE to obtain the emissions (tons) by each generator.

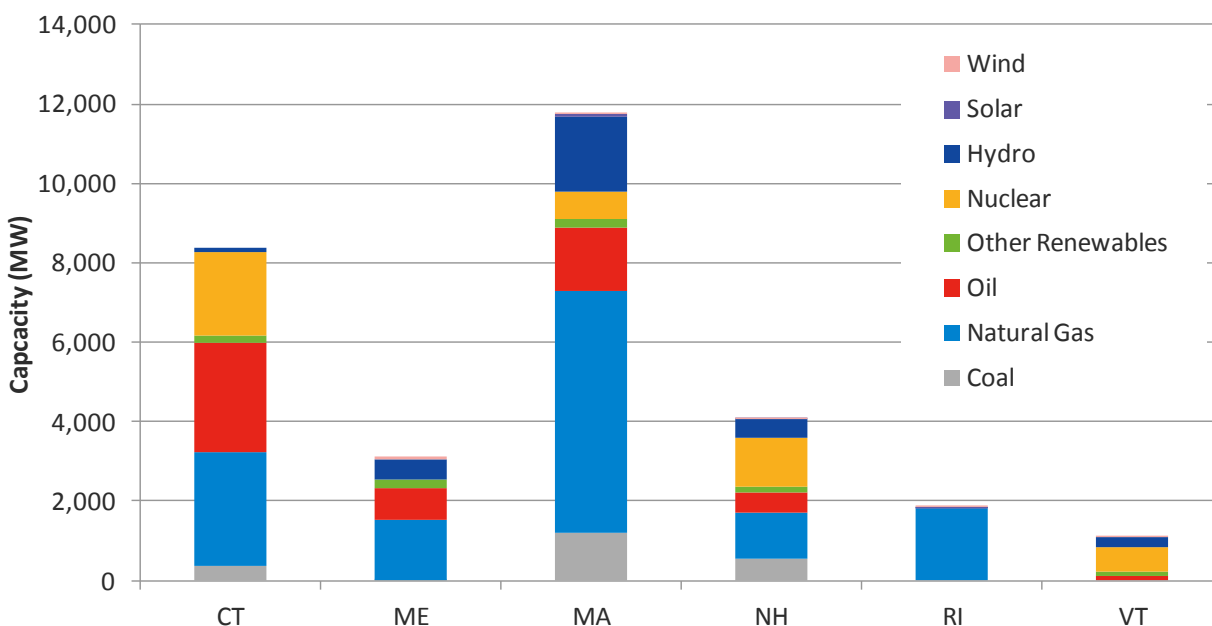
The U.S. EPA Clean Air Markets data were the primary source of emissions data used for this report. For calculating total system emissions, approximately 89% of the SO<sub>2</sub> emissions and 75% of the CO<sub>2</sub> emissions were based on Clean Air Markets data. For NO<sub>x</sub>, Clean Air Markets data were used for 47% of total emissions. For the total FTA marginal emissions, approximately 96% of the SO<sub>2</sub>, 98% of the CO<sub>2</sub> and 92% of the NO<sub>x</sub> emissions were based on Clean Air Markets data.

### 4.3 ISO New England System Installed Capacity

The ISO-NE 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 forced and scheduled maintenance outages of resources and transmission system elements, 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, and a variety of other factors.

Figure 4-1 shows the total ISO New England generation 2013 summer capacity as obtained from ISO New England’s 2014 – 2023 Forecast Report of Capacity, Energy, Loads and Transmission (CELT).<sup>12</sup> Appendix Table 2 and Appendix Table 3 show a summary of the total ISO New England generation summer and winter capacity by state and fuel type.

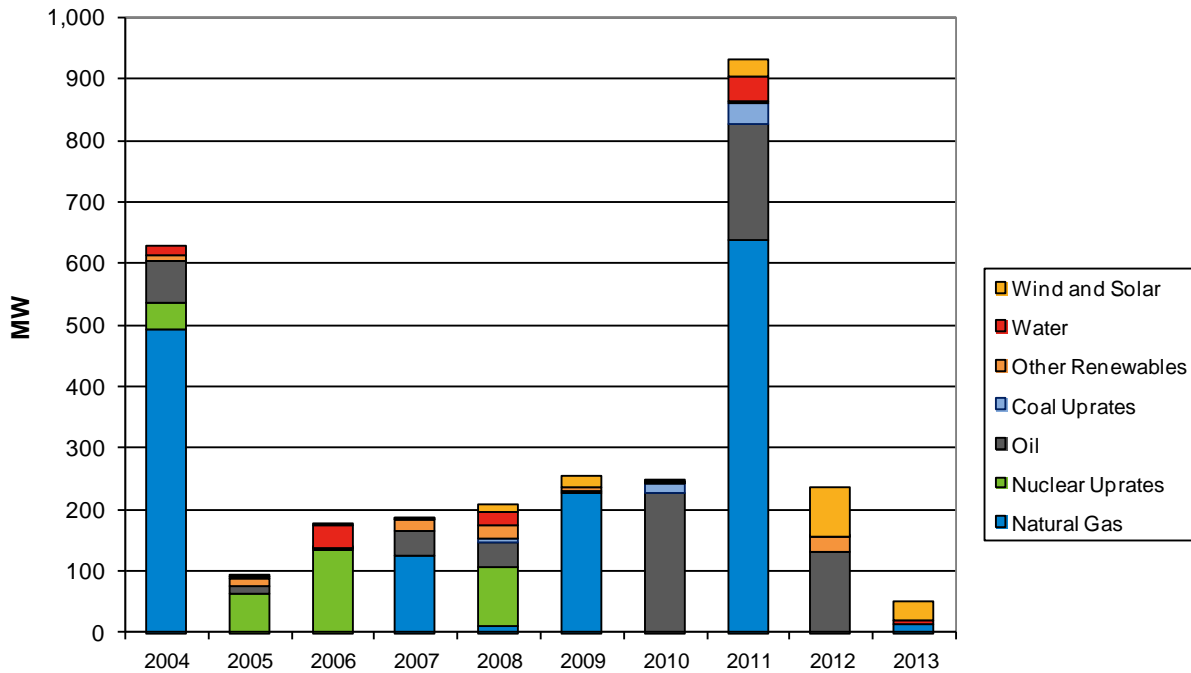
**Figure 4-1: 2013 New England Summer Capacity by State**



<sup>12</sup> The ISO-NE CELT Report is typically issued in April of each year. The 2014 CELT Report (using the January 1, 2014 ratings) was used in order to completely capture all the new capacity additions that occurred during the prior calendar year 2013. It can be accessed from <http://www.iso-ne.com/system-planning/system-plans-studies/celt>.

Figure 4-2 illustrates the new generating capacity that was added to the ISO New England system during 2004 through 2013. A total of 2,998 MW was added, with combustion turbines and combined cycle plants capable of burning natural gas or distillate oil making up nearly 50% of this new capacity. The remaining additions consist of nuclear uprates and renewable generation.

**Figure 4-2 : 2004 – 2013 ISO New England Generator Additions<sup>13</sup>**



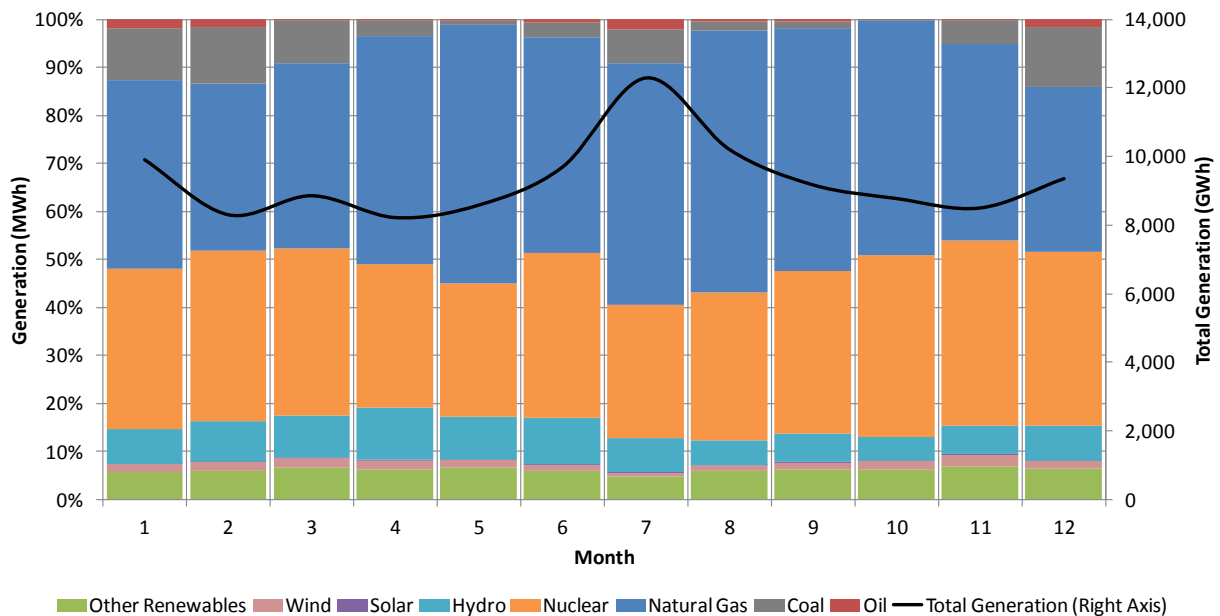
<sup>13</sup> The generator additions and uprate values are based on the Seasonal Claimed Capabilities as reported in the ISO-NE CELT Report of the year following the addition.

## 4.4 ISO New England System Energy Production

Emissions characteristics of an electric generator are directly contributed by the type of fuel that powers it. Direct correlation can be drawn between the different fuel burned and the magnitude of a unit's emissions. Section 4.4 compares the generation changes across months and years to explore one of the main factors that contribute to changing system emission rates and heat rates.

Figure 4-3 shows the 2013 monthly generation by fuel type. The overlaid black line represents the total generation. Natural gas-fired generation accounts for 34% - 55% of the total generation. The lower monthly percentage of natural gas-fired generation is observed when the amount of system generation and energy demand is higher, such as January, February, July and December. Correspondingly, these are also the months where coal- and oil-fired generation have a larger contribution. In the past few years, natural gas has been observed to have overall lower prices coupled with highly efficient generating units leading to the growing contribution of energy generation. However, during higher energy demand months and when tied with natural gas availability limitations, other fuel types have increased their contribution to support the New England system. During winter months, natural gas supplies are targeted for use by firm customers of the regional gas LDCs.<sup>14</sup> Hydro-electric and wind generation have seasonal differences which reflect their fuel availability, as there is less rain (water) and on-shore wind during summer months.

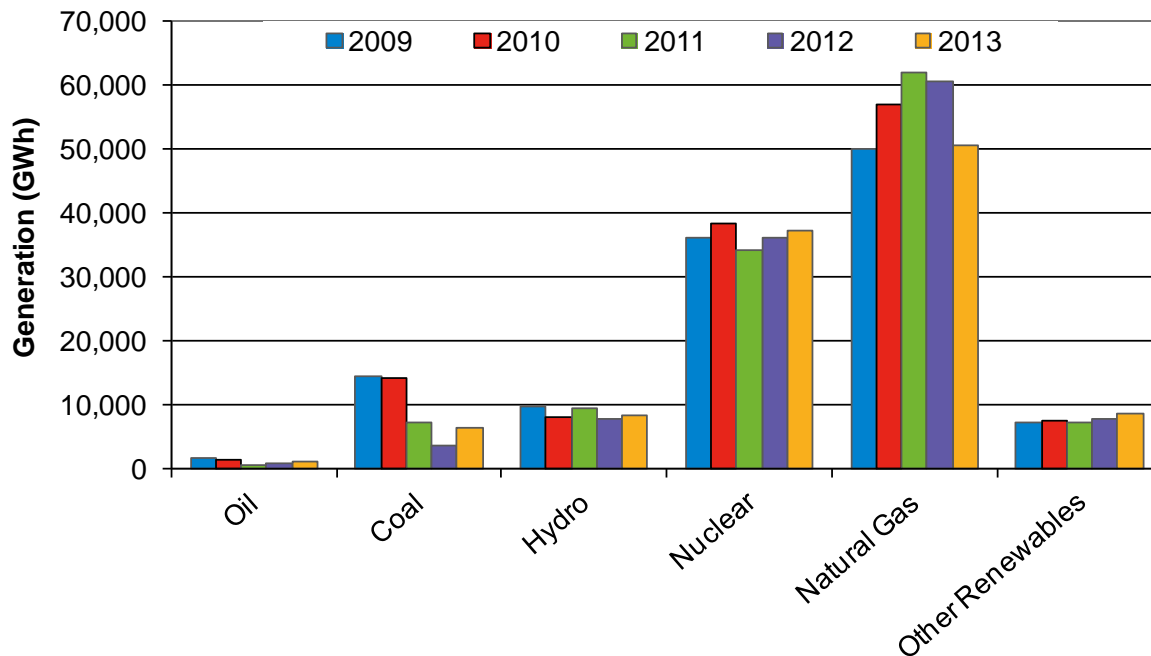
**Figure 4-3: 2013 Monthly Generation by Fuel Type**



<sup>14</sup> Firm customers of regional gas local distribution companies (LDCs) include residential, commercial and industrial (RCI) customers.

Figure 4-4 shows the generation (MWh) by fuel types from 2009-2013, based on the resource's primary fuel type listed in the 2014 CELT Report. In 2013, coal- and oil-fired generation was about 2,558 GWh and 244 GWh higher, respectively, than in 2012. In contrast, natural gas-fired generation decreased by about 10,061 GWh, or about 17%. Overall system generation was about 4,902 GWh lower in 2013 than 2012; 2013 total energy generation was 112,040 GWh.

**Figure 4-4 : 2009 - 2013 Annual Generation by Fuel Type**



#### 4.5 Locational Marginal Units (LMUs)

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. Because the price of electricity changes as the determination and price of the marginal unit changes, the price of the marginal unit largely is determined by its fuel type and heat rate. Thus, examining marginal units by fuel type can explain changes in electricity prices. The system has at least one marginal unit associated with meeting the energy requirements on the system during each pricing interval. If transmission is not constrained, the marginal unit is classified as the unconstrained marginal unit. In intervals with binding transmission constraints, there is one additional marginal unit for each constraint.

The analysis of LMU marginal emission rates was conducted in three different scenarios. Each scenario provides a different perspective by including or excluding certain generators depending on their characteristics. The three scenarios are described as followed:

- **All LMUs** – includes all Locational Marginal Units identified by the LMP
- **Emitting LMUs** - excludes all non-emitting units, such as pumped storage, hydro-electric generation, external transactions and other renewables with no associated air emissions
- **Oil- and Natural Gas-fired (O&NG) LMUs** – includes only oil- and natural gas-fired units identified by LMP

#### 4.5.1 All LMUs

In this scenario, all identified locational marginal units (LMUs) are used to develop the marginal emission rates. Non-emitting generators such as hydro-electric generation and external transactions are associated with a zero emission rate. Each fuel type's time on the margin and month-to-month variations is shown in Figure 4-5. Natural gas is marginal 47% to 81% of the time. August, September and October was higher in the 80% range, while January, February and December were at the lower range of 47% - 59%. During January, February and December, coal- and oil-fired generation was on the margin more than other months at 10% - 21% (coal) and 6% (oil).

**Figure 4-5: 2013 Percent of Time Fuel Types Marginal – All LMUs**

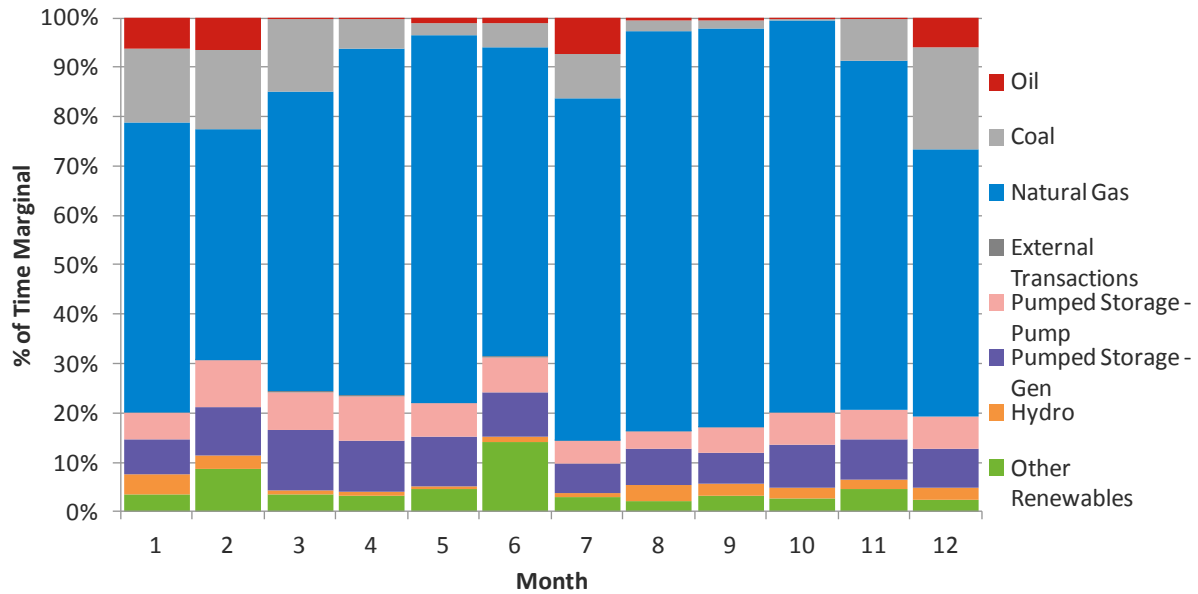
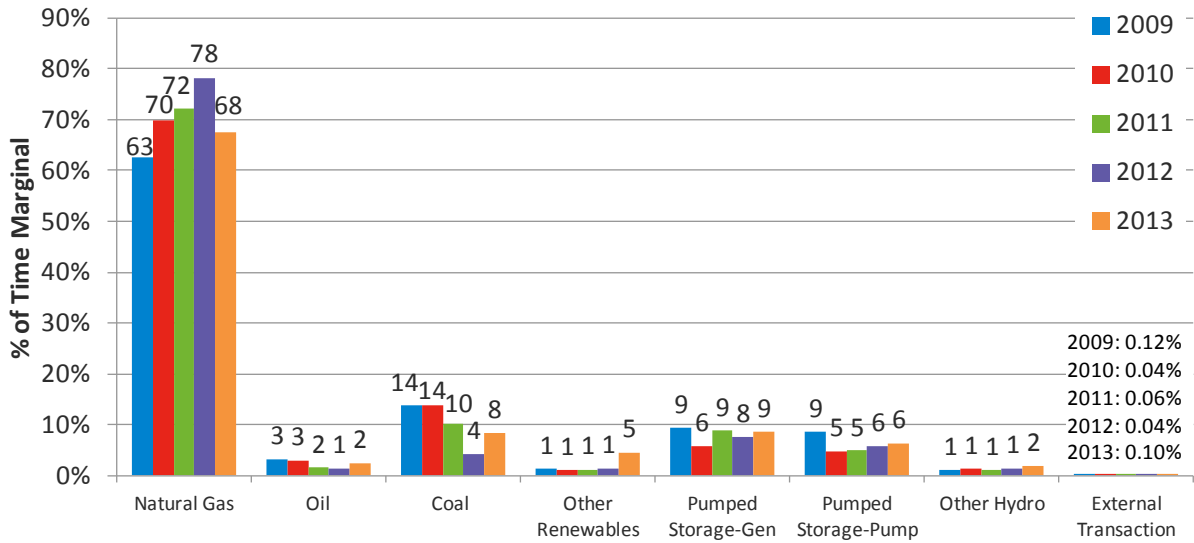


Figure 4-6 shows the historical percentages that each fuel type is marginal within a calendar year. It can be observed that natural gas has been the primary fuel type marginal in the last five years. But from 2012 to 2013, natural gas had a decrease, while coal and other renewables increased.

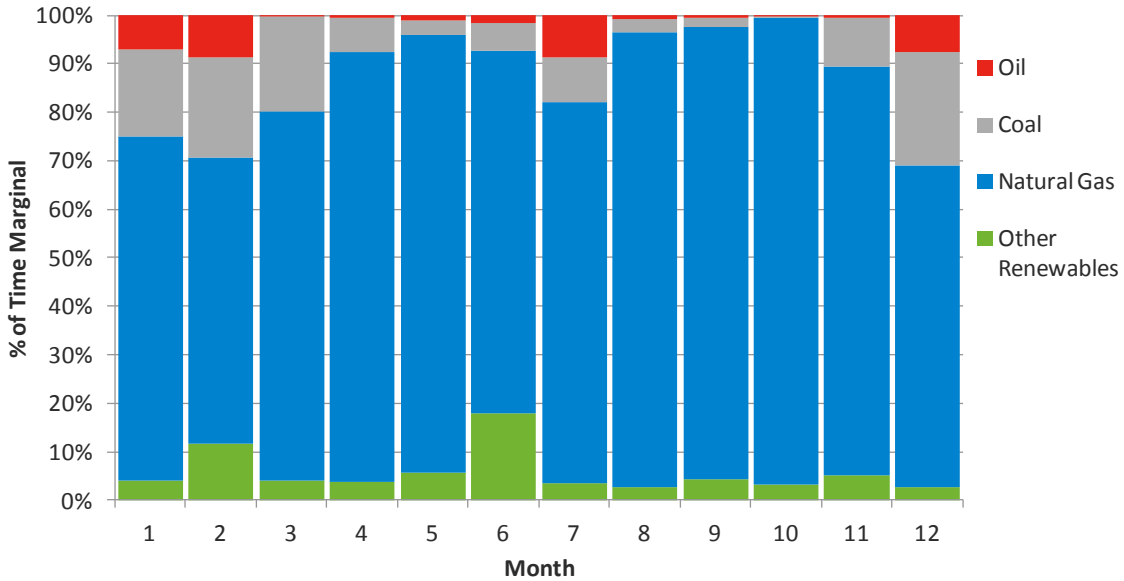
**Figure 4-6: 2009 - 2013 Percent of Time Fuel Types Marginal - All LMUs**



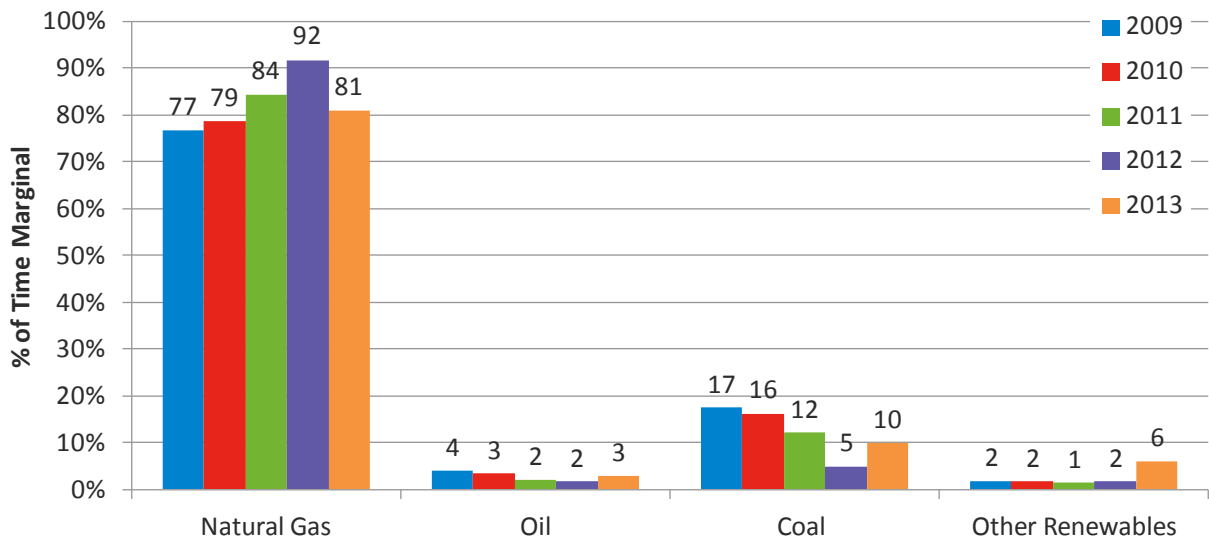
#### 4.5.2 Emitting LMUs

Generating resources with no air emissions are excluded in this scenario. Therefore, hydro, pumped storage, external transaction and other renewables with no air emissions are not taken into account, while all other LMUs are.

**Figure 4-7: 2013 Percent of Time Fuel Types Marginal – Emitting LMUs**



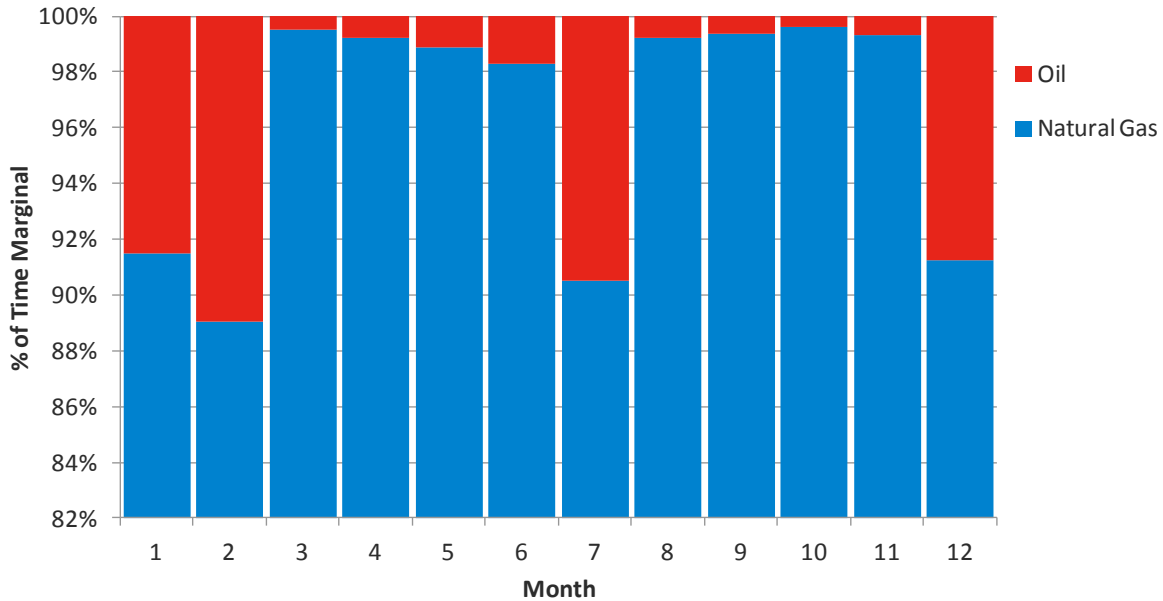
**Figure 4-8: 2009 - 2013 Percent of Time Fuel Types Marginal – Emitting LMUs**



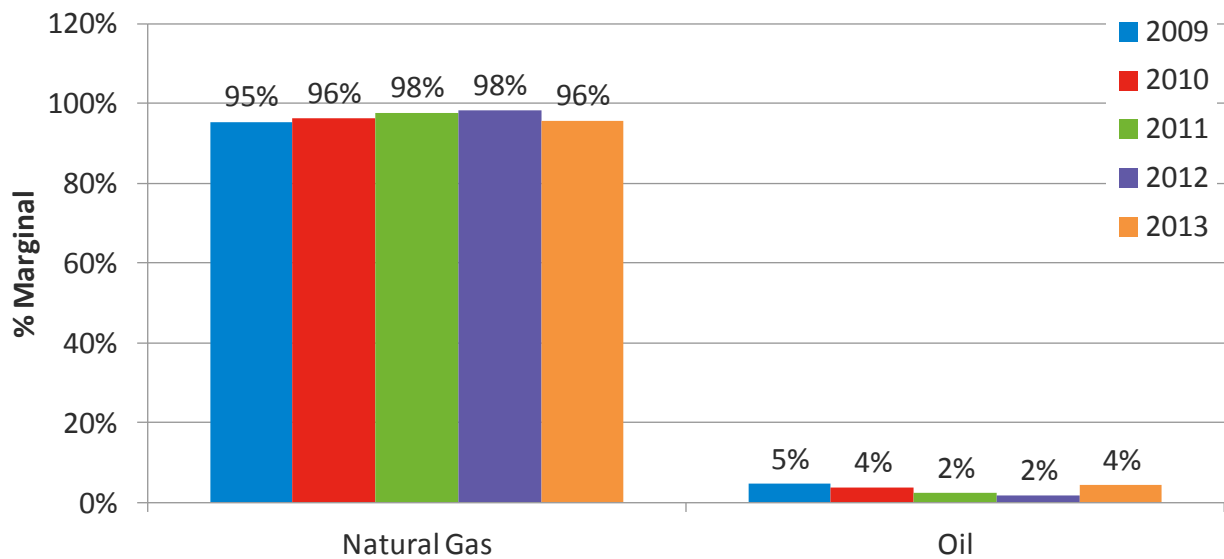
### 4.5.3 Oil- & Natural Gas-Fired LMUs

This scenario only includes natural gas and oil-fired generators from all LMUs identified by the LMP, and was created to provide a benchmark comparison with the previous method of Fuel Type Assumed (FTA) Marginal Emission Analysis.

**Figure 4-9: 2013 Percent of Time Fuel Types Marginal – O&NG LMUs**



**Figure 4-10: 2009 - 2013 Percent of Time Fuel Types Marginal – O&NG LMUs**





## Section 5 Results

### 5.1 2013 New England System Emissions

Section 5.1 provides analysis results that represent all ISO New England generators. Figure 5-1 shows the annual aggregate 2013 NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> air emissions for each state. The New England system total emissions for NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> were 20.32 kTons, 18.04 kTons and 40,901 kTons, respectively. These emissions were calculated based on the actual generation of all generating units in ISO-NE's balancing authority area and the actual or assumed unit-specific emission rates.<sup>15</sup> While it can be observed that some states have more total emissions than others, it is relevant to consider that these figures are based on the physical location of the generating units as shown in Figure 4-1. ISO New England operates the New England power system as one unified grid. Therefore, a unit physically located in one state is dispatched to serve the entire system, not only its own state.

**Figure 5-1: 2013 New England System Annual Emission of NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (kTons)** <sup>16</sup>

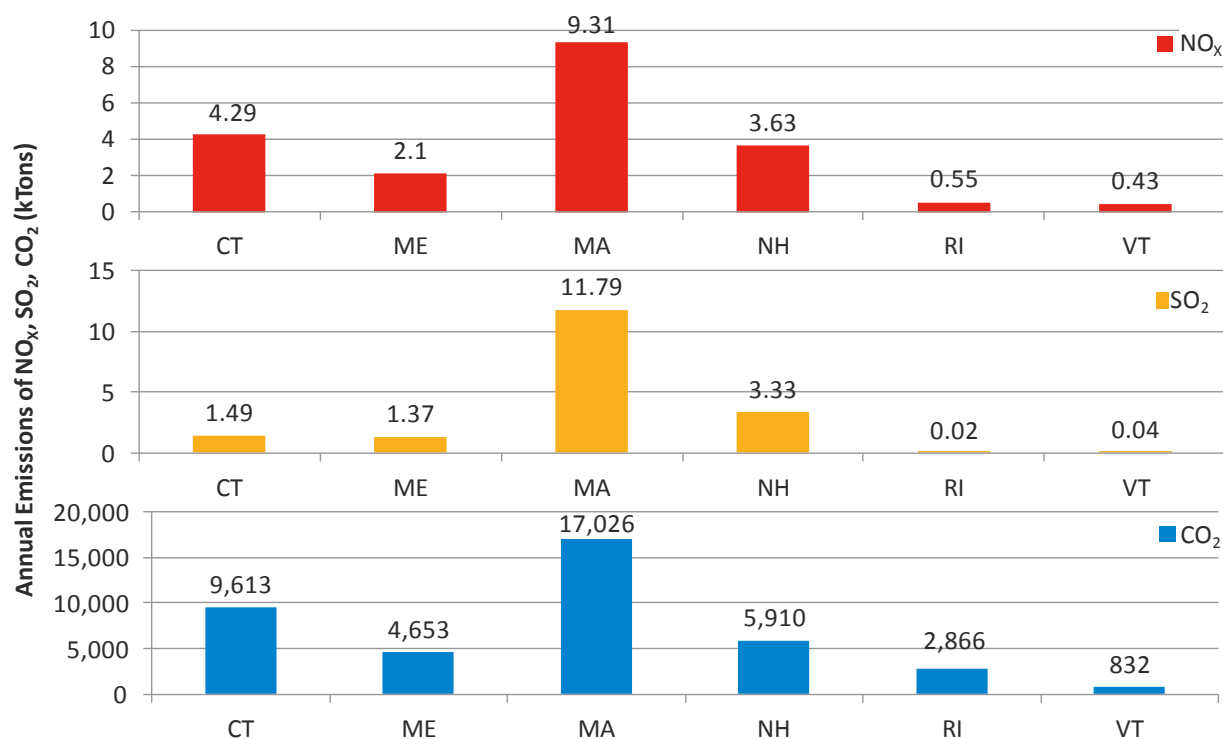


Figure 5-2 shows the annual aggregate NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> air emissions for the years 2004 through 2013. Since 2004, NO<sub>x</sub> emissions have dropped by 60% and SO<sub>2</sub> by 88%, while CO<sub>2</sub> has decreased by about 28%. Refer to Appendix Table 4 for historical system emissions by kTons.

<sup>15</sup> This does not include Northern Maine and the Citizens Block Load (Northern Vermont), which is typically served by New Brunswick and Quebec. These areas are not electrically connected to the ISO-NE Control Area.

<sup>16</sup> Sum may not equal New England system total due to rounding.

**Figure 5-2: 2004 - 2013 New England System Annual Emissions of NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (kTons)**

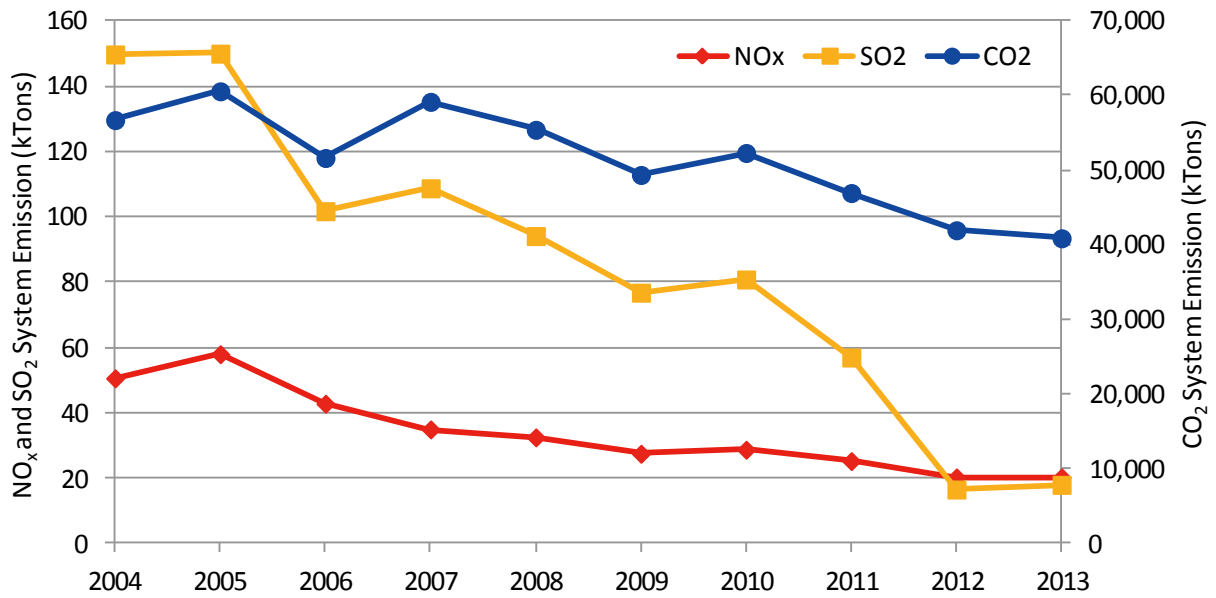


Table 5-1 shows the 2013 annual average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> air emission rates (lb/MWh), by state and for New England, calculated based on the actual hourly unit generation of ISO-NE generating units located within that specific state and the actual or assumed unit-specific emission rates.

**Table 5-1: 2013 New England System Annual Average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> Emission Rates (lb/MWh)**

State	NO <sub>x</sub>	SO <sub>2</sub>	CO <sub>2</sub>
Connecticut	0.25	0.09	552
Maine	0.41	0.27	917
Massachusetts	0.54	0.69	996
New Hampshire	0.37	0.34	602
Rhode Island	0.18	0.01	918
Vermont	0.12	0.01	239
<b>New England</b>	<b>0.36</b>	<b>0.32</b>	<b>730</b>

Monthly variations shown in Figure 5-3 reflect the different system fuel mixes from Figure 4-3. Emission rates are at a higher magnitude during January, February, July and December, which had lower natural gas generation and higher coal- and oil-fired generation. Values can be found in Appendix Table 5.

**Figure 5-3: 2013 New England System  
Monthly Average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> Emission Rates (lb/MWh)**

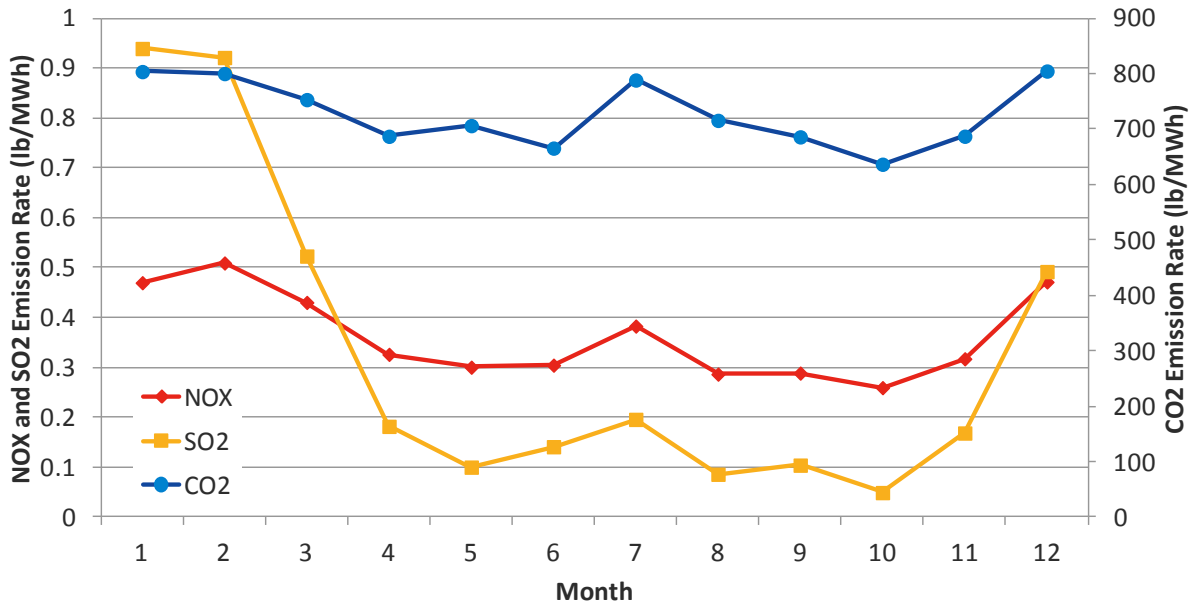
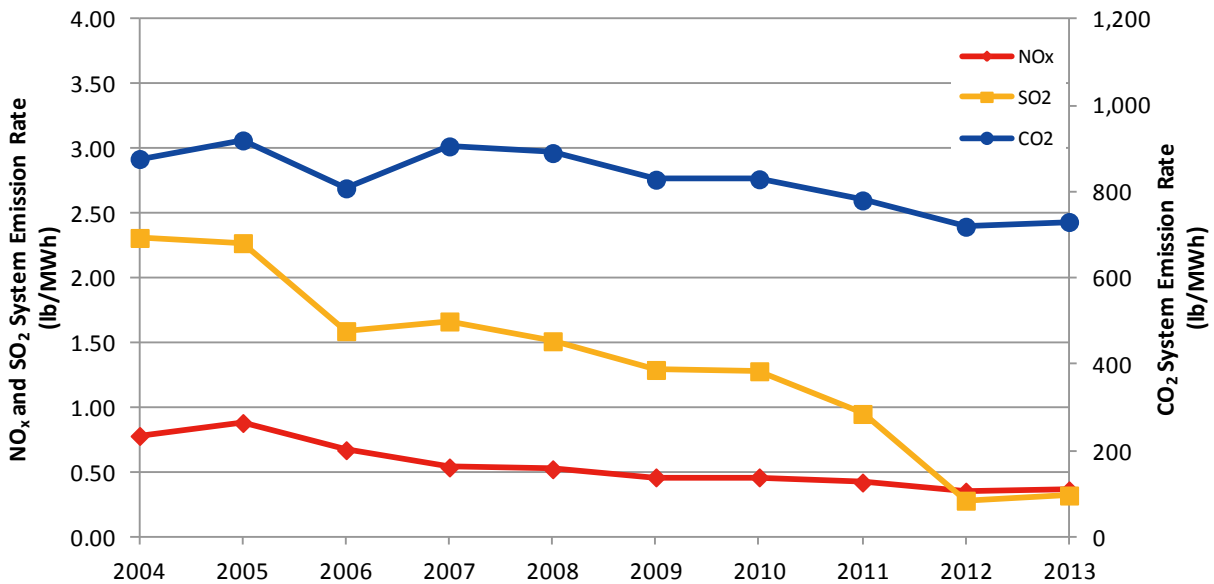


Figure 5-4 illustrates the annual average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> air emission rate values (lb/MWh), for the 2004 – 2013 time period. These annual emission rates were calculated by dividing the total air emissions by the total generation from all units. Since 2004, the annual average NO<sub>x</sub> emission rate has decreased by 54%, SO<sub>2</sub> by 86%, and CO<sub>2</sub> by 17%. All historical emission rates can be seen in Appendix Table 6.

**Figure 5-4: 2004-2013 New England System  
Annual Average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> Emission Rates (lb/MWh)**



### 5.1.1 Observations

While total energy generation declined 4% in 2013 from 2012, there was little to no change in system emissions. There was less natural gas generation and more coal- and oil-fired generation in 2013 than in the 2012. Total NO<sub>x</sub> system emissions had no change, while SO<sub>2</sub> system emissions increased 9% and CO<sub>2</sub> system emissions decreased 3%. The system emission rates for 2013 were higher than 2012 values. The 2013 NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub> emission rates have increased by 3%, 14%, and 2%, respectively from 2012 values. Table 1-1 summarizes the above system emission changes.

There remains a decreasing trend in emissions during the last ten years, which can be attributed to the increased use of new, more efficient natural-gas-fired power plants, a decline in the cost of natural gas, and the implementation of new emission controls on some of the region's oil- and coal-fired power plants.

### 5.2 2013 New England Marginal Heat Rate

---

Prior to 1999, MEA studies assumed a fixed marginal heat rate of 10.0 MMBtu/MWh which was used to convert from lb/MWh to lb/MMBtu.<sup>17</sup> In the 1999-2003 MEA studies, the marginal heat rate was calculated using the results of production simulation runs. Beginning with the 2004 MEA study, the marginal heat rate was based on the actual generation of marginal fossil units only. Since a unit's heat rate is equal to its fuel consumption divided by its generation, the calculated marginal heat rate is defined as follows:<sup>18</sup>

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

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

The calculated annual marginal heat rate reflects the average annual efficiency of all of the marginal fossil units dispatched throughout 2013. The lower the marginal heat rate value, the more efficient the system or marginal generator(s) is with respect to converting raw fuel into electric energy. Section 5.2 presents two methodologies of Marginal Heat Rates.

---

<sup>17</sup> 10 MMBtu/MWh is equivalent to 10,000,000 Btu/kWh.

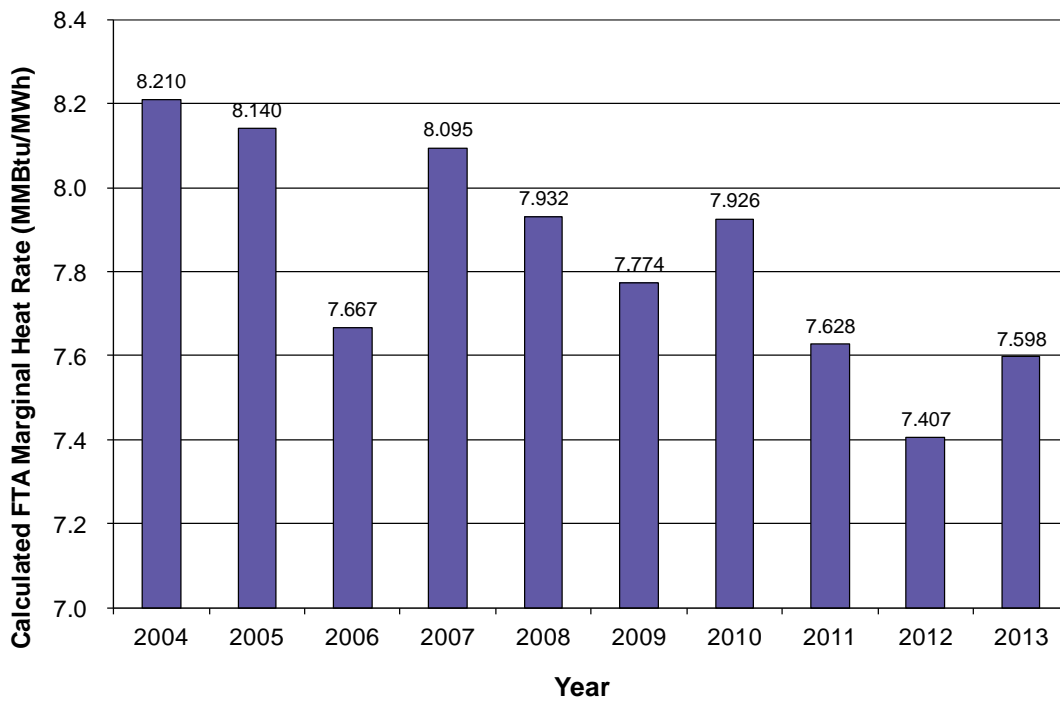
<sup>18</sup> Heat rate is the measure of efficiency in converting fuel input to electricity. The heat rate for a power plant depends on the individual plant design, its operating conditions, and its level of electrical power output. The lower the heat rate, the more efficient the power plant.

### 5.2.1 Fuel Type Assumed (FTA) Marginal Heat Rate

Assuming natural gas and oil-fired generators as marginal units, the FTA Marginal Heat Rate is calculated with their heat input (MMBtu) and generation.

The 2013 calculated FTA marginal heat rate is 7.598 MMBtu/MWh. It was used as the conversion factor to convert from lb/MWh to lb/MMBtu for the marginal emission rates in this report. The FTA heat rate has declined 7% since 2004. Figure 5-5 illustrates the calculated annual marginal heat rate spanning the 2004 to 2013.

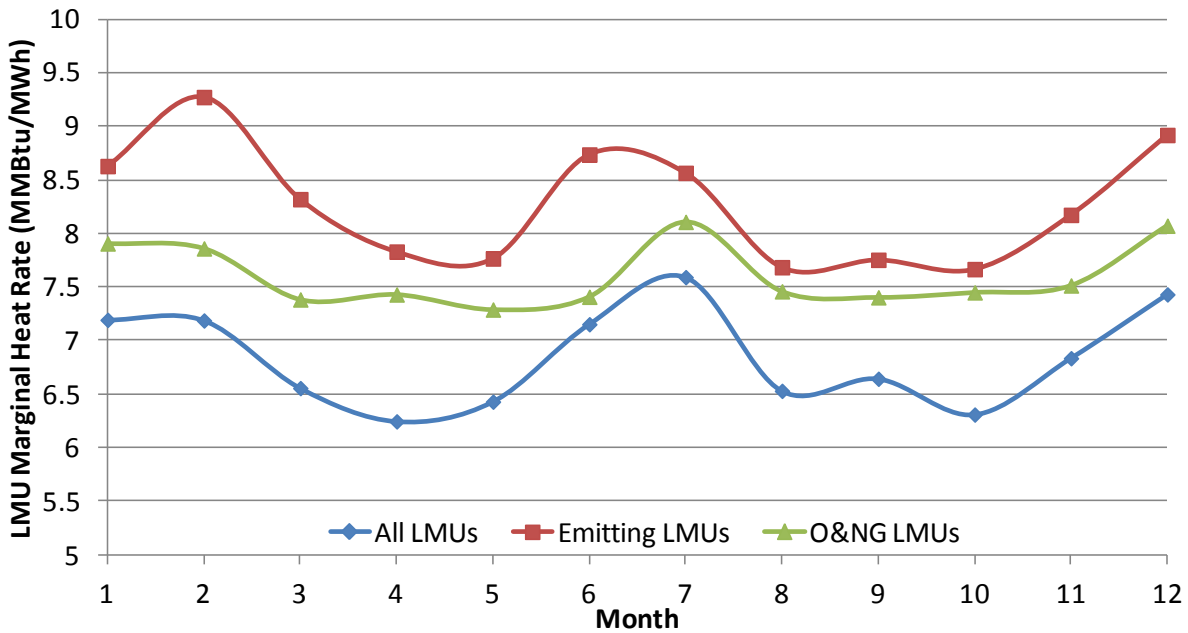
**Figure 5-5: 2004 - 2013 New England System Annual FTA Marginal Heat Rate (MMBtu/MWh)**



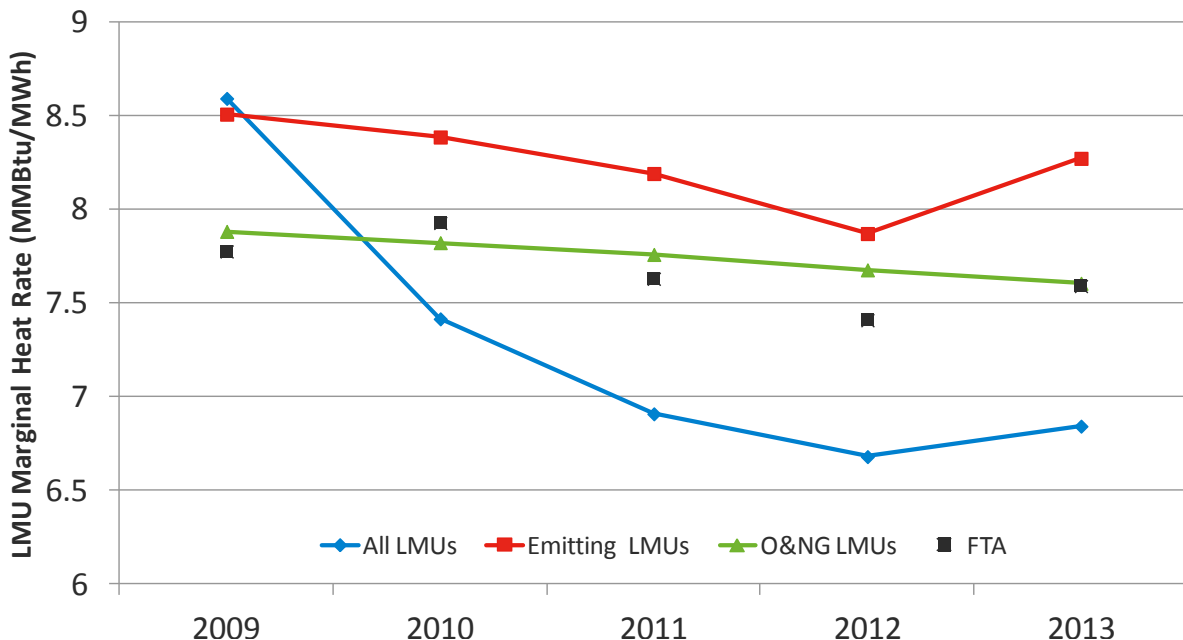
### 5.2.2 Locational Marginal Unit (LMU) Marginal Heat Rate

In the LMU methodology, a heat rate is calculated for each individual generator. The percentage of time each generator is marginal per year leads to the amount of contribution of that unit's heat rate to the LMU Marginal Heat Rate. The historical LMU marginal heat rates for the years 2009-2013 can be found in Appendix Table 7. Figure 5-7 displays Appendix Table 7 in graphical form while also adding the FTA Marginal Heat Rate for comparing against the O&NG LMU Marginal Heat Rate.

**Figure 5-6: 2013 LMU Monthly Marginal Heat Rate (MMBtu/MWh)**



**Figure 5-7: 2009-2013 LMU Annual Marginal Heat Rate (MMBtu/MWh)**



### 5.2.3 Observations

Overall, the trend of decreasing marginal heat rates has been continuing, with rates declining from 10.013 MMBtu/MWh to 7.598 MMBtu/MWh over the past ten years according to the FTA methodology. There has also been a downward trend with the LMU-based Marginal Heat Rate methodology. Both methodologies reflect a system that is mostly powered by natural gas units (lower heat rates).

When only studying natural gas- and oil-fired units for marginal heat rate, the FTA and LMU O&NG results can be compared. They track similarly to each other, concluding that both methodologies lead to similar results when considering the same unit types.

## 5.3 2013 New England Marginal Emission Rates

### 5.3.1 Fuel Type Assumed (FTA) Marginal Emission Rates

Table 5-2 shows the NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> calculated marginal emission rates in lb/MWh for ISO New England's generation system. The NO<sub>x</sub> data are provided for each of the five time periods studied. Since the ozone and non-ozone seasons are not relevant to SO<sub>2</sub> and CO<sub>2</sub>, only the on-peak, off-peak, and annual rates are provided for those emissions. Appendix Table 8 shows the same information expressed in lb/MMBtu. As noted earlier, the 2013 calculated marginal heat rate of 7.598 MMBtu/MWh was used as the conversion factor.

**Table 5-2: 2013 New England FTA Marginal Emission Rates (lb/MWh)<sup>19,20</sup>**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.17	0.14	0.15	0.18	0.16
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.12	0.11		0.11
CO <sub>2</sub>		904	924		914

FTA Marginal Emission Rates by State in Table 5-3, Table 5-4, and Table 5-5 show the 2013 calculated NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub> FTA marginal air emission rates for each state based on the generation that operated in that state. The NO<sub>x</sub> emission rates are shown for ozone and non-ozone seasons, and the SO<sub>2</sub> and CO<sub>2</sub> rates are shown for the annual on-peak and off-peak hours.

<sup>19</sup> The Ozone Season is defined as occurring between May 1 and September 30, while the Non-Ozone Season is defined as occurring from January 1 to April 30 and from October 1 to December 31.

<sup>20</sup> On-Peak hours consist of all weekdays between 8 A.M. and 10 P.M. Off-Peak hours consist of all weekdays between 10 P.M. and 8 A.M. and all weekend hours.

The type of capacity located within each state is the major factor in the calculated state marginal emission rates. For example, Rhode Island, where 99% of the in-state capacity is gas-fired combined cycle, has much lower marginal emission rates than Vermont, which has the highest (primarily due to the large amount of oil-fired peaking capacity). The total amount of emissions (lb) in Vermont is the lowest in New England; representing 0.02% of the total New England FTA marginal emissions. However, the marginal emission rates are high because the generating units in the marginal fossil category are mostly older, oil-fired, internal combustion engines and gas turbines (peaking units).

**Table 5-3: 2013 New England NO<sub>x</sub> FTA Marginal Emission Rates by State (lb/MWh)**

State	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
Connecticut	0.13	0.10	0.11	0.13	0.12
Maine	0.20	0.22	0.24	0.32	0.25
Massachusetts	0.20	0.14	0.17	0.17	0.17
New Hampshire	0.12	0.08	0.13	0.14	0.12
Rhode Island	0.15	0.18	0.15	0.23	0.17
Vermont	18.43	7.93	8.94	5.59	12.10
<b>New England Average</b>	0.17	0.14	0.15	0.18	0.16

**Table 5-4: 2013 New England SO<sub>2</sub> FTA Marginal Emission Rates by State (lb/MWh)<sup>21</sup>**

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.05	0.04	0.04
Maine	0.37	0.35	0.36
Massachusetts	0.14	0.12	0.13
New Hampshire	0.18	0.15	0.17
Rhode Island	0.01	0.01	0.01
Vermont	1.16	0.47	0.92
<b>New England Average</b>	0.12	0.11	0.11

<sup>21</sup> Actual values may differ from values due to rounding.



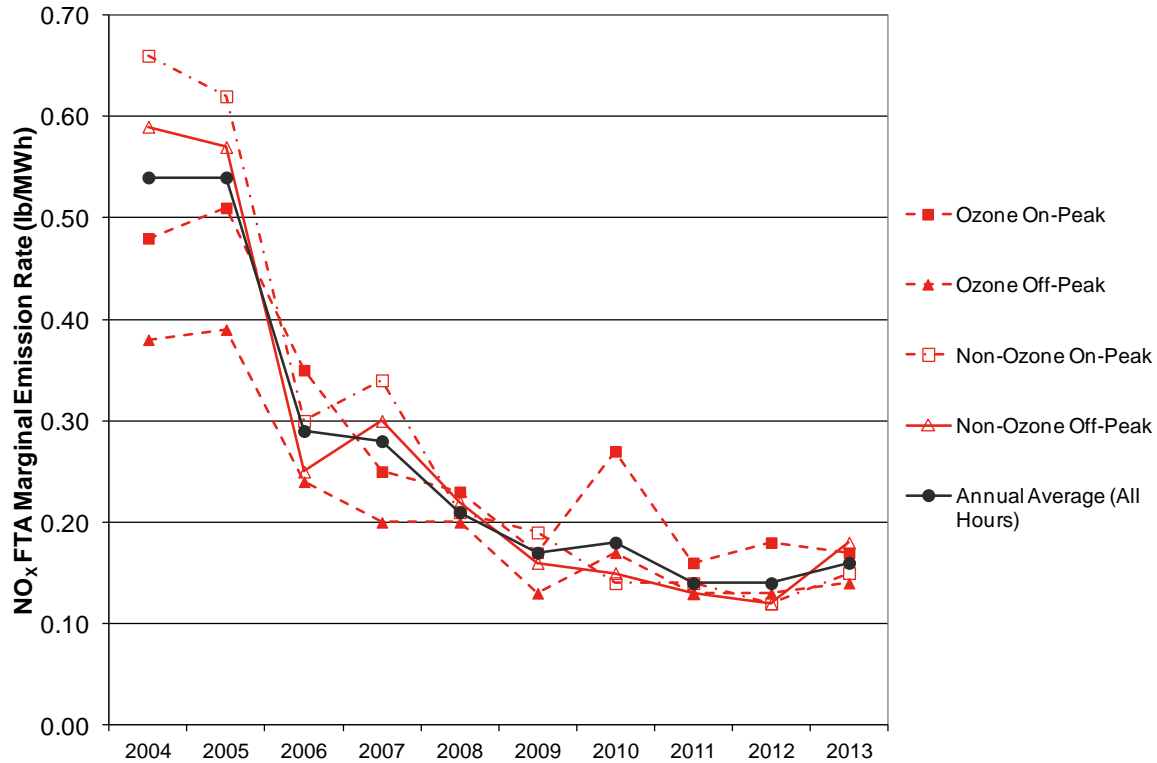
**Table 5-5: 2013 New England CO<sub>2</sub> FTA Marginal Emission Rates by State (lb/MWh)**

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	849	858	853
Maine	1,028	1,150	1,084
Massachusetts	912	924	918
New Hampshire	914	941	925
Rhode Island	894	919	904
Vermont	4,033	1,809	3,264
<b>New England Average</b>	<b>904</b>	<b>924</b>	<b>914</b>

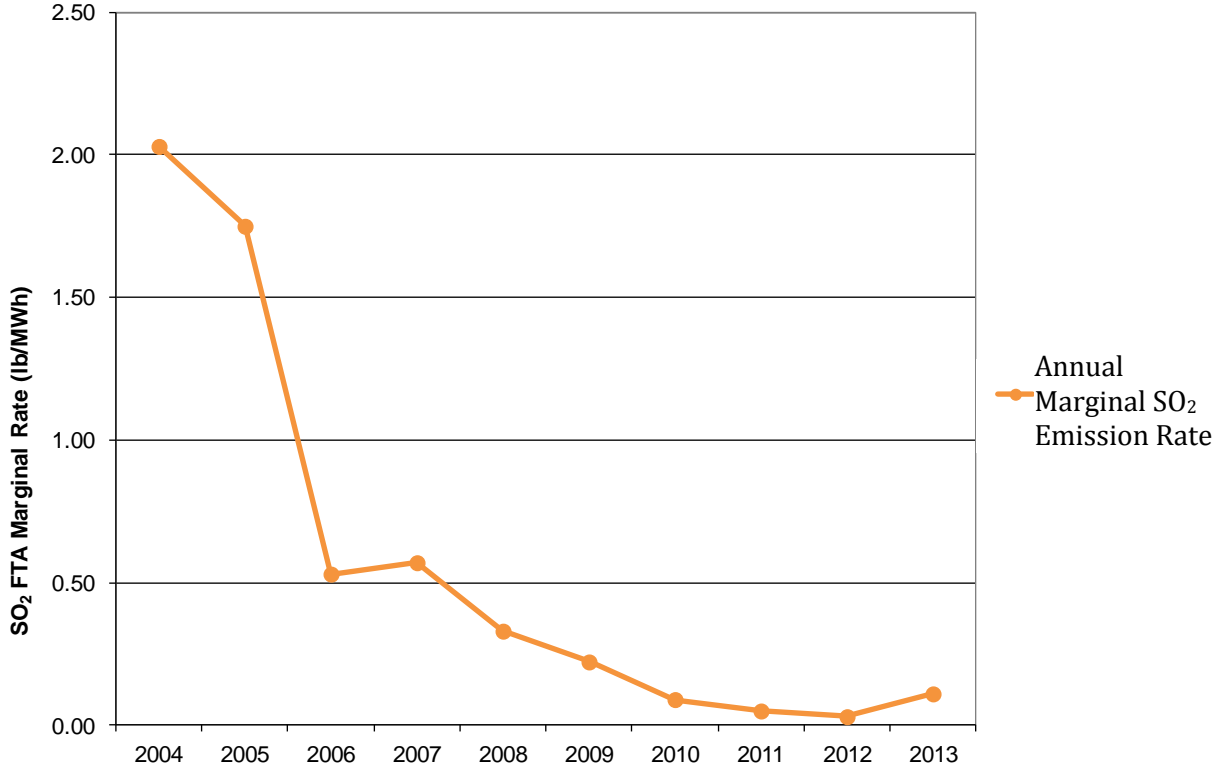
5.3.1.1 2004 - 2013 FTA Marginal Emission Rates

Figure 5-8 , Figure 5-9 and Figure 5-10 show the historical calculated FTA marginal emission rates for NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub>, respectively, in lb/MWh for the years 2004 through 2013. Figure 5-8 shows the ozone and non-ozone season rates, while the SO<sub>2</sub> and CO<sub>2</sub> figures include only the annual average emission rates. Appendix Table 9, Appendix Table 10 and Appendix Table 11 show the historical emission rates in detail. All three tables show the annual average percentage change from the previous year.

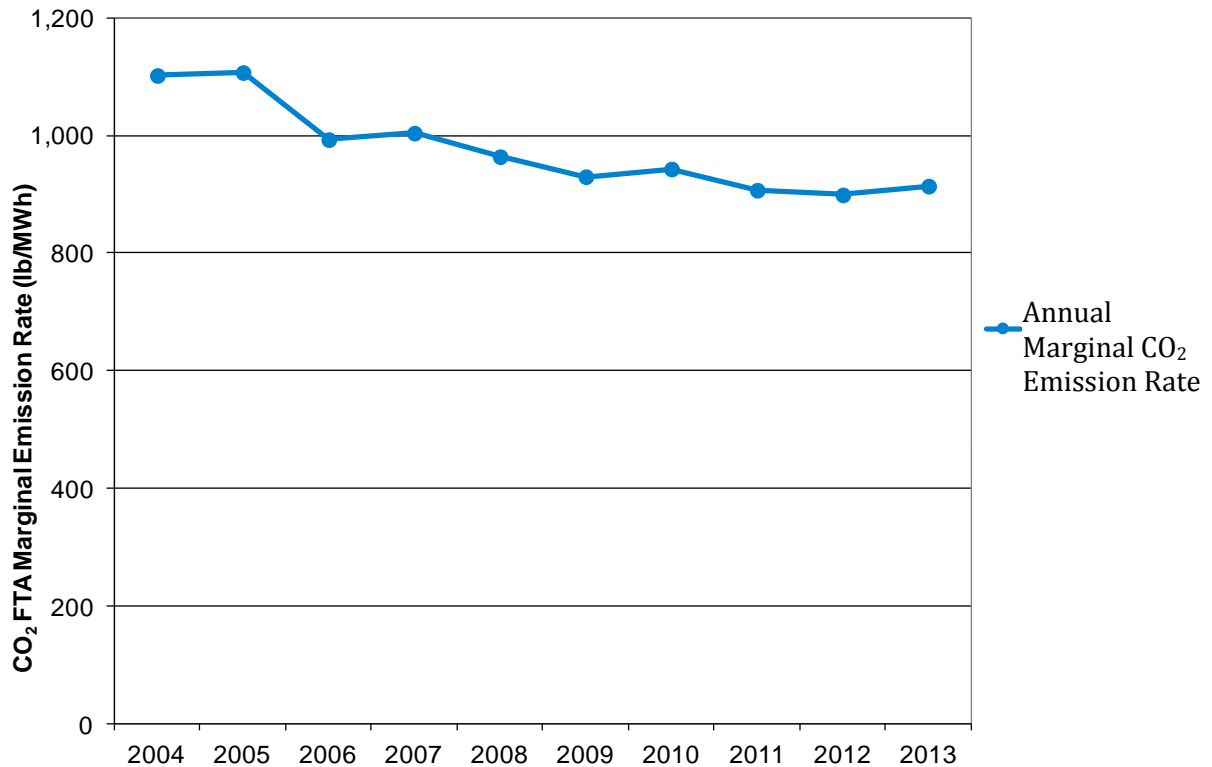
**Figure 5-8: 2004 - 2013 New England NO<sub>x</sub> FTA Marginal Emission Rates (lb/MWh)**



**Figure 5-9: 2004 - 2013 New England SO<sub>2</sub> FTA Marginal Emission Rates (lb/MWh)**



**Figure 5-10: 2004 - 2013 New England CO<sub>2</sub> FTA Marginal Emission Rates (lb/MWh)**



### 5.3.2 Locational Marginal Unit (LMU) Marginal Emission Rates

This section presents the 2013 calculated LMU-based Marginal Emission Rates for three different scenarios.

- **All LMUs** – includes all Locational Marginal Units identified by the LMP
- **Emitting LMUs** - excludes all non-emitting units, such as pumped storage, hydro-electric generation, external transactions and other renewables with no associated air emissions
- **Oil- and Natural Gas-fired (O&NG) LMUs** – includes only oil- and natural gas-fired units identified by LMP

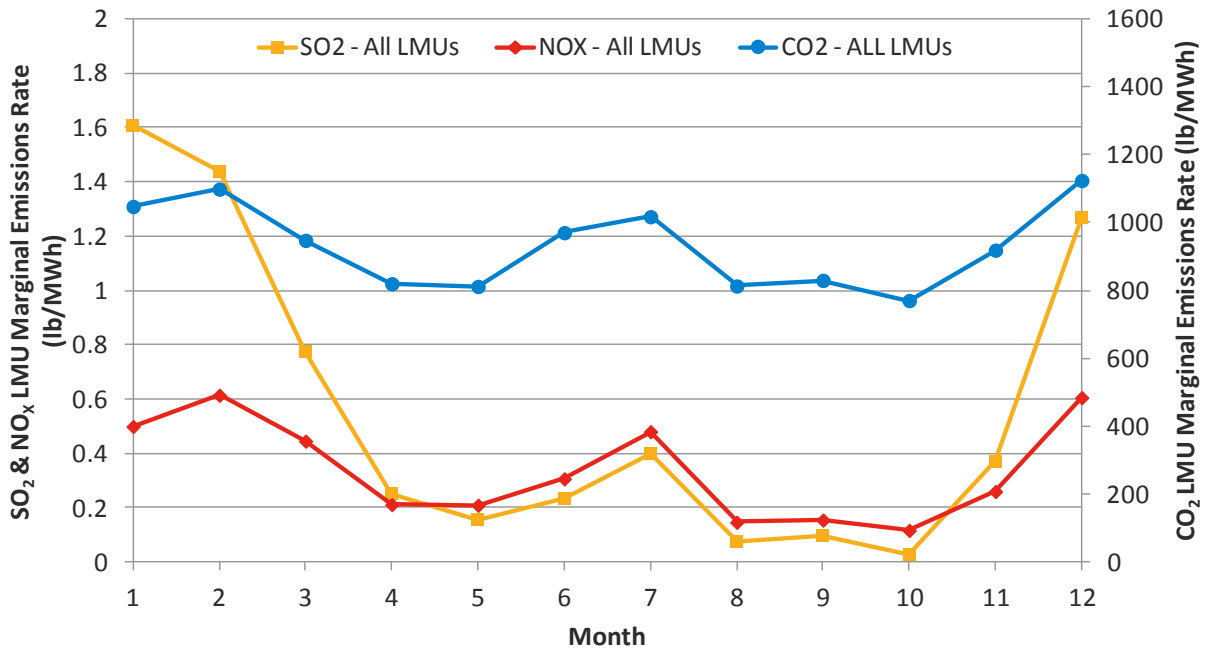
#### 5.3.2.1 All LMUs Marginal Emission Rates

These marginal emission rates are calculated with all LMUs (units that are identified by the LMP to be marginal). Table 5-6 shows rates in lb/MWh, which is calculated from Appendix Table 12 (lb/MMBtu) and the associated marginal heat rate of 6.841 MMBtu/MWh. Figure 5-11 show the monthly LMU marginal emission rates and is helpful to compare with Figure 4-5 and Figure 5-3. Appendix Table 13 lists these monthly values.

**Table 5-6: 2013 LMU Marginal Emission Rates – All LMUs (lb/MWh)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.32	0.21	0.35	0.43	0.34
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.51	0.59		0.55
CO <sub>2</sub>		921	937		930

**Figure 5-11: 2013 Monthly LMU Marginal Emission Rates - All LMUs (lb/MWh)**



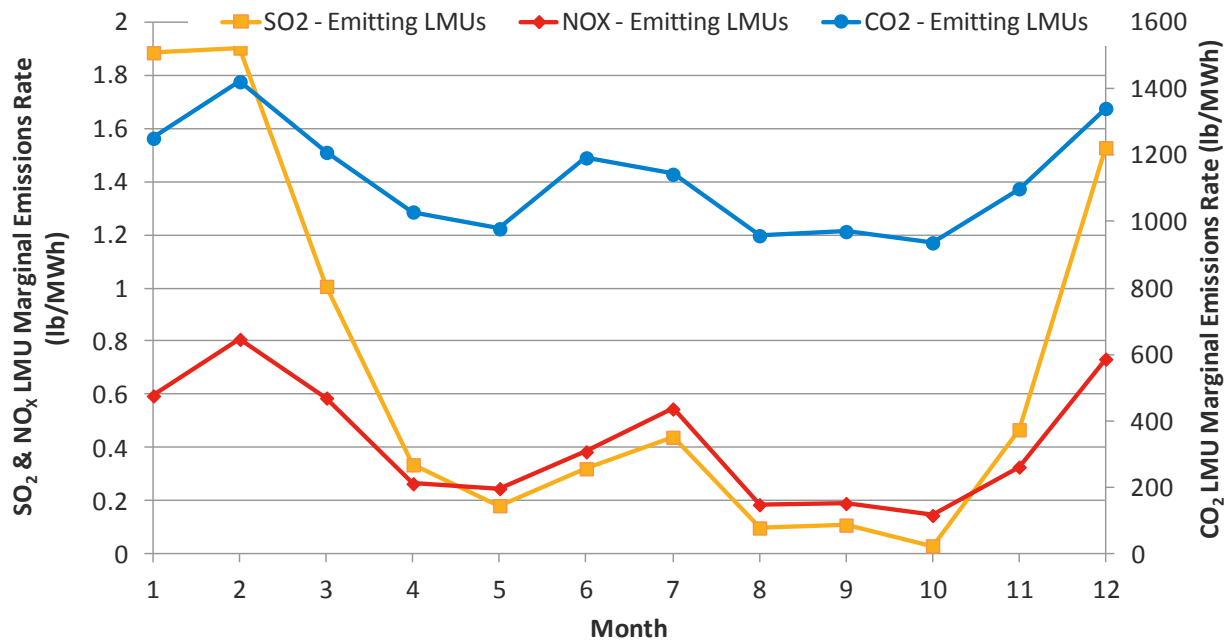
5.3.2.2 Emitting LMUs Marginal Emission Rates

Presented in Table 5-7 and Appendix Table 14 are the marginal emissions rates from emitting LMUs. The marginal heat rate for this scenario is 8.271 MMBtu/MWh. The monthly rates seen in Figure 5-12 can be found in Appendix Table 15.

**Table 5-7: 2013 LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.37	0.26	0.41	0.56	0.42
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.59	0.76		0.69
CO <sub>2</sub>		1,079	1,163		1,125

**Figure 5-12: 2013 Monthly LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)**



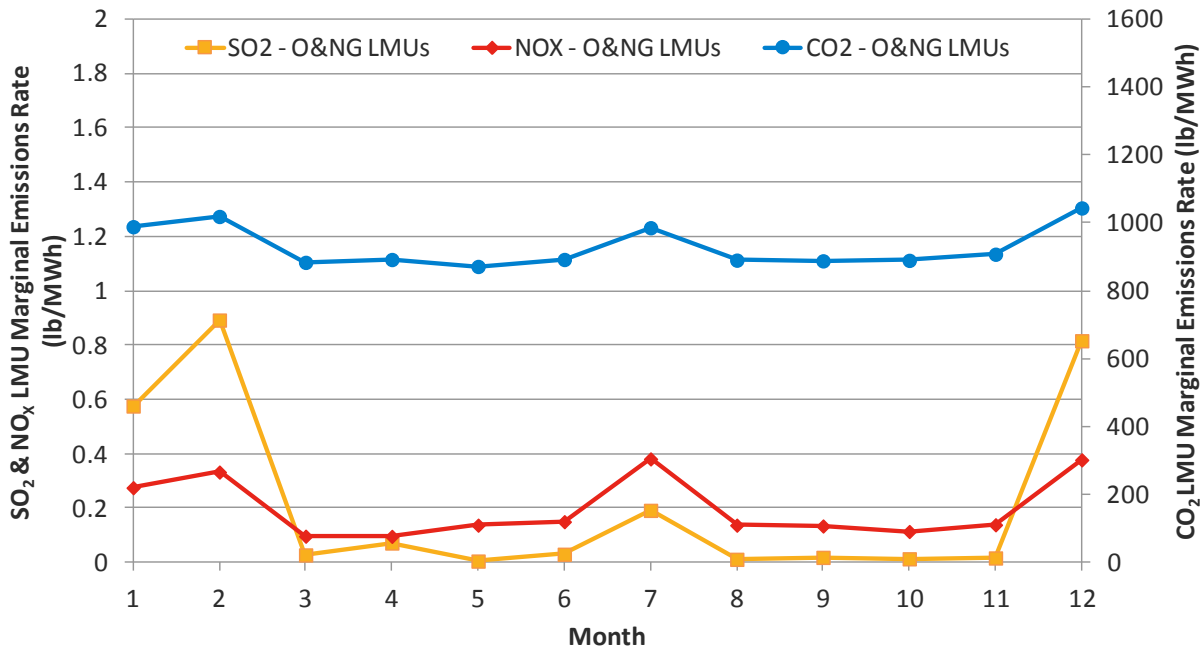
5.3.2.3 O&NG Marginal Emission Rates

Table 5-8 and Appendix Table 16 include the O&NG marginal emission rates. These rates are calculated for benchmarking purposes to give a framework for how the FTA and O&NG LMU Marginal Emission Rates compare when only looking at natural gas and oil-fueled units. Since natural gas has low sulfur content and O&NG LMU reflect natural gas on the margin 96% of the time (Figure 4-10), SO<sub>2</sub> emission rates are very low. The associated marginal heat rate is 7.604 MMBtu/MWh. The monthly rates seen in Figure 5-13 can be found in Appendix Table 17.

**Table 5-8: 2013 LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.036	0.016	0.026	0.026	0.026
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.030	0.026		0.028
CO <sub>2</sub>		123	121		122

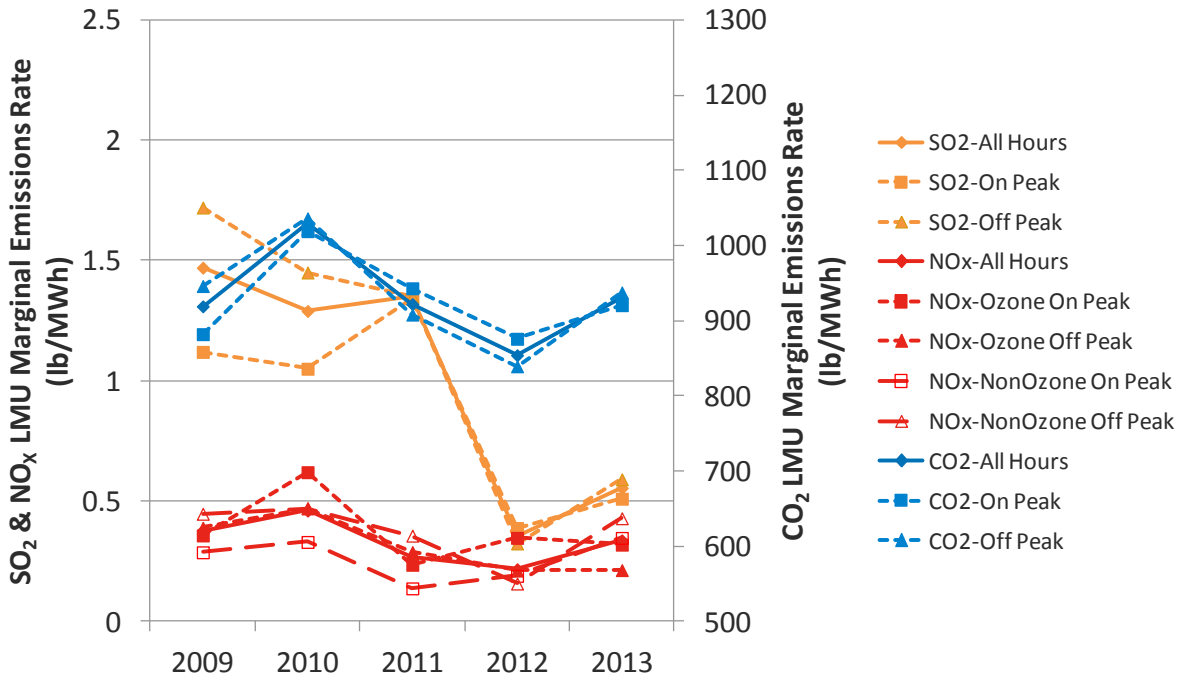
**Figure 5-13: 2013 Monthly LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)**



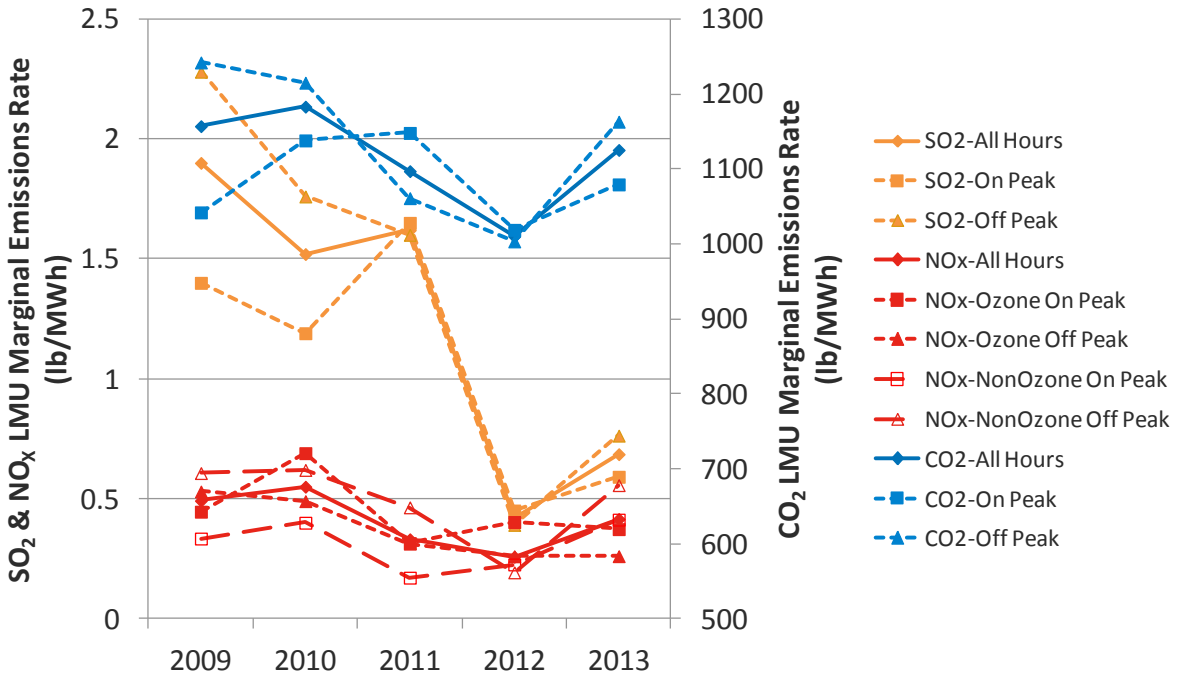
5.3.2.4 2009 - 2013 LMU Marginal Emission Rates

The LMUs (marginal units identified from the LMP) actively exhibit the changes in New England’s energy production. When considering all LMUs versus emitting LMUs, the latter will result in higher rates due to not accounting for zero air emission resources (e.g. wind, solar, nuclear and hydro-electric), which would lower the average emission rate. Figure 5-14, Figure 5-15 and Figure 5-16 summarize the three scenario of results calculated for the LMU Marginal Emission Rates, which are detailed in Appendix Table 18 through Appendix Table 26 in lb/MWh.

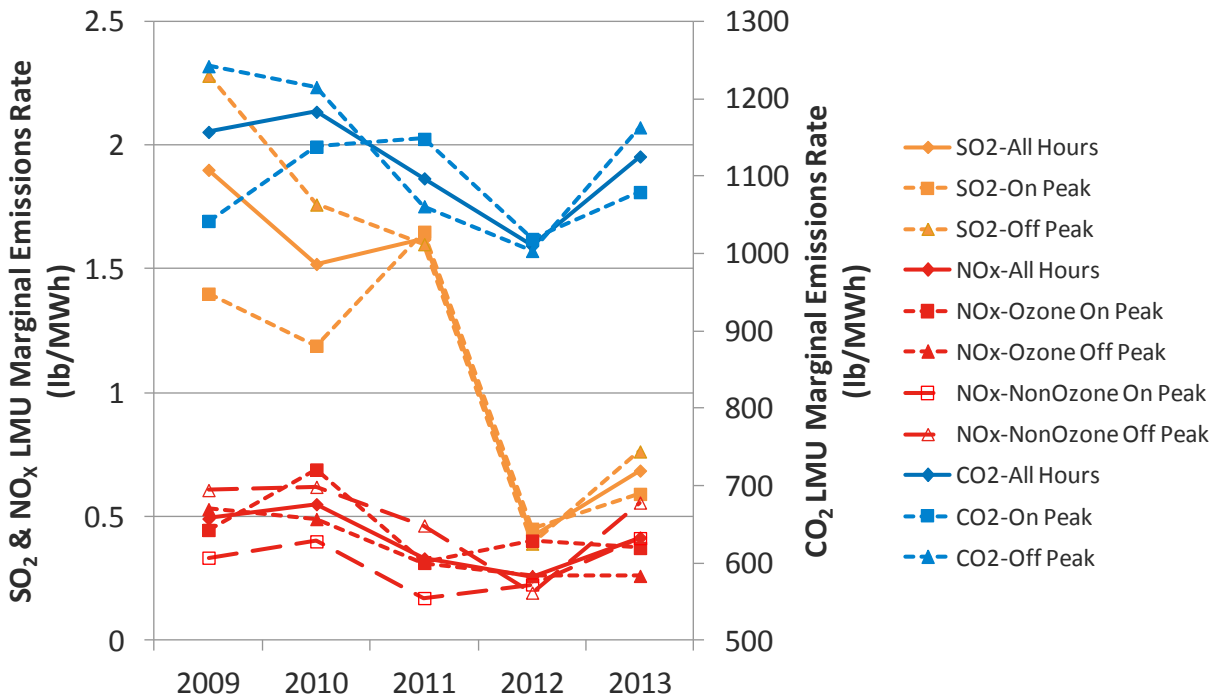
**Figure 5-14: 2009 - 2013 LMU Marginal Emission Rates – All LMUs (lb/MWh)**



**Figure 5-15: 2009 - 2013 LMU Marginal Emission Rates - Emitting LMUs (lb/MWh)**



**Figure 5-16: 2009 - 2013 LMU Marginal Emission Rates - O&NG LMUs (lb/MWh)**





### 5.3.3 High Electric Demand Day (HEDD) Marginal Emission Rate

Using the LMU methodology, the top five energy demand days in 2013 were examined. In New England, HEDD days are typically characterized with high temperatures leading to elevated cooling (energy) demand. ISO-NE relies on generating units of all operating characteristics and fuel types. During peak energy demand, generating units less utilized during the rest of the year, such as peaking units, will respond quickly to meet system demand. These peaking units are often jet (aero-derivative) or combustion turbines with higher emission rates. Therefore, examining HEDD marginal emission rates will show the units responding to system demand and its associated emission rate.

In 2013, the top five HEDDs were Monday, July 15 to Friday, July 19. New England experienced high temperatures ( $\geq 89^{\circ}\text{F}$ ) during these consecutive days. Peak daily loads ranged from 26,111 MW on Monday, July 15, to a high of 27,379 MW on Friday, July 19 (fourth-highest demand day on record). Table 5-9 shows the average LMU Marginal Emission Rate during those five days.

**Table 5-9: High Electric Demand Day LMU Marginal Emission Rates (lb/MWh)**

HEDD LMU Marginal Emission Rate (lb/MWh)			
	All LMUs	Emitting LMUs	O&NG LMUs
<b>NO<sub>x</sub></b>	0.99	1.10	0.91
<b>SO<sub>2</sub></b>	1.13	1.22	0.94
<b>CO<sub>2</sub></b>	1,239	1,328	1,172

### 5.3.4 Observations

New England's power plant air emissions are directly dependent on the specific units that are available and dispatched to serve load for each hour of the year. Therefore, there could be wide variations in seasonal emissions, 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, could also affect emissions. The FTA and LMU Marginal Emission Rates reflect the dynamics of the New England power system.

As compared with 2004, the 2013 FTA SO<sub>2</sub> and NO<sub>x</sub> annual marginal rates have declined by 95% and 70%, while CO<sub>2</sub> decreased by 17%. This decline is clearly illustrated in Appendix Table 9, Appendix Table 10 and Appendix Table 11. Other factors have also contributed throughout the years to the reduction in calculated marginal emission rates. Since 1993, there has been an increase in the availability of New England's nuclear units as well as increases in some of their capacity ratings, and they have therefore been contributing more toward satisfying the base load electrical demand of the system.

There was a noticeable decrease in the FTA marginal emission rates for NO<sub>x</sub> in 1995 primarily due to the implementation of Reasonable Available Control Technology (RACT) regulations for NO<sub>x</sub> as 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 prior to that time in New England (see Figure 4-2), as well as a decrease in the price of natural gas. This was combined with the additional emission reductions as required under the Ozone Transport Commission's 1999 and U.S. EPA's 2003 NO<sub>x</sub> Budget Program. Because few new natural gas-fired power plants have been added since 2004, the decline in marginal NO<sub>x</sub> emission rates has tapered off.

In 2013, the off-peak marginal rate is generally higher than the on-peak rate for NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub> in both methodologies. Prior years show higher emission rates in SO<sub>2</sub> and NO<sub>x</sub> during on-peak hours and ozone season (for NO<sub>x</sub>) compared to off-peak hours. That was most likely because additional generation brought on line to meet the higher demand during on-peak periods generally had higher emission rates. These were typically peaking units that are more expensive and economic to operate only during high energy price hours. They may also have been older, fossil-steam resources with higher individual heat rates (lower thermal efficiency). The change from higher on-peak rates to higher off-peak rates may be due to the retirement of older fossil-steam resources.

FTA NO<sub>x</sub> and SO<sub>2</sub> marginal emission rates both increased by 14% and 267% between 2012 and 2013, while there was 2% change for the FTA CO<sub>2</sub> marginal emission rates. This is compared to an average increase of 58%, 60% and 10% when averaging the scenario of including all LMUs and the scenario of emitting LMUs marginal emission rates for NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub>. The increase observed across all three emissions was also observed in system emissions between 2012 and 2013. This can primarily be attributed to the decrease in generation by natural gas-fired units and the increase of coal- and oil-fired units.

Although FTA and LMU marginal emission rates use two different assumptions, the years 2009 - 2013 exhibit similar trends for the region's marginal emissions rates. NO<sub>x</sub> and SO<sub>2</sub> have both continued their historical downward trend while CO<sub>2</sub> has had minimal changes and remained at about the same level. When comparing the FTA and the O&NG LMU marginal emission rates, they are within the same magnitude.

## Section 6 Appendix

**Appendix Table 1: 1994 - 2013 New England Total Cooling and Heating Degree Days**

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1994	374	16.3%	6,403	5.5%
1995	312	-3.0%	6,318	4.1%
1996	245	-23.8%	6,454	6.3%
1997	211	-34.4%	6,432	6.0%
1998	312	-3.0%	5,483	-9.7%
1999	360	11.9%	5,774	-4.9%
2000	217	-32.5%	6,399	5.4%
2001	323	0.4%	5,895	-2.9%
2002	354	10.1%	5,959	-1.8%
2003	355	10.4%	6,651	9.6%
2004	251	-22.0%	6,354	4.7%
2005	418	30.0%	6,353	4.7%
2006	335	4.2%	5,552	-8.5%
2007	288	-10.5%	6,175	1.7%
2008	281	-12.6%	6,049	-0.3%
2009	224	-30.4%	6,278	3.4%
2010	406	26.2%	5,653	-6.9%
2011	357	11.0%	5,826	-4.0%
2012	409	27.2%	5,235	-13.8%
2013	401	24.7%	6,156	1.4%

**Appendix Table 2: 2013 New England Summer Capacity<sup>22, 23</sup>**

Unit Type	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	383.4	4.6	1,198.8	10.2	0.5	0.0	533.3	13.0	-	-	-	-
Natural Gas	2,843.1	33.9	6,078.2	51.7	1,523.9	49.1	1,183.1	28.9	1,833.8	99.8	-	-
Nuclear	2,097.3	25.0	677.3	5.8	-	-	1,247.1	30.5	-	-	619.4	56.6
Oil	2,758.6	32.9	1,591.9	13.5	810.5	26.1	482.9	11.8	-	-	127.4	11.6
Hydro	97.0	1.2	207.1	1.8	496.7	16.0	462.6	11.3	0.7	0.0	252.9	23.1
Pumped	28.9	0.3	1,690.2	14.4	-	-	-	-	-	-	-	-
Solar	-	-	52.5	0.4	-	-	0.0	0.0	3.7	0.2	-	-
Wind	-	-	13.9	0.1	50.4	1.6	23.6	0.6	0.2	0.0	13.2	1.2
Other	171.9	2.1	249.6	2.1	223.6	7.2	162.7	4.0	-	-	81.8	7.5
<b>Total</b>	<b>8,380.1</b>	<b>100.0</b>	<b>11,759.6</b>	<b>100.0</b>	<b>3,105.6</b>	<b>100.0</b>	<b>4,095.3</b>	<b>100.0</b>	<b>1,838.3</b>	<b>100.0</b>	<b>1,094.8</b>	<b>100.0</b>

<sup>22</sup> Sum may not equal total due to rounding.

<sup>23</sup> Season Claimed Capability as of January 1, 2013.

**Appendix Table 3: 2013 New England Winter Capacity<sup>12, 13</sup>**

Unit Type	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	385.0	4.2	1,379.9	9.6	-	-	535.1	12.5	-	-	-	-
Natural Gas	3,144.6	34.0	6,963.6	48.6	1,669.6	49.2	1,322.3	30.8	2,092.6	99.6	-	-
Nuclear	2,110.9	22.8	683.4	4.8	-	-	1,246.7	29.0	-	-	615.0	53.7
Oil	3,310.1	35.7	3,080.6	21.5	880.9	26.0	502.1	11.7	-	-	166.0	14.5
Hydro	106.4	1.1	225.6	1.6	530.3	15.6	479.1	11.2	2.1	0.1	261.5	22.8
Pumped	28.1	0.3	1,701.9	11.9	-	-	-	-	-	-	-	-
Solar	-	-	23.3	0.2	-	-	-	-	3.6	0.2	-	-
Wind	-	-	20.6	0.1	81.5	2.4	42.3	1.0	2.0	0.1	18.6	1.6
Other	174.2	1.9	259.3	1.8	231.0	6.8	164.5	3.8	-	-	84.4	7.4
<b>Total</b>	<b>9,259.3</b>	<b>100.0</b>	<b>14,338.4</b>	<b>100.0</b>	<b>3,393.2</b>	<b>100.0</b>	<b>4,292.1</b>	<b>100.0</b>	<b>2,100.3</b>	<b>100.0</b>	<b>1,145.5</b>	<b>100.0</b>

**Appendix Table 4: 2001 - 2013 ISO New England System Annual Emissions of NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (kTons)**

Year	NO <sub>x</sub>	SO <sub>2</sub>	CO <sub>2</sub>
2001	59.73	200.01	52,991
2002	56.40	161.10	54,497
2003	54.23	159.41	56,278
2004	50.64	149.75	56,723
2005	58.01	150.00	60,580
2006	42.86	101.78	51,649
2007	35.00	108.80	59,169
2008	32.57	94.18	55,427
2009	27.55	76.85	49,380
2010	28.79	80.88	52,321
2011	25.30	57.01	46,959
2012	20.32	16.61	41,975
2013	20.32	18.04	40,901
<b>Percent Reduction, 2001-2013</b>	<b>66</b>	<b>91</b>	<b>23</b>

**Appendix Table 5: 2013 Monthly System Emission Rates of NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> (lb/MWh)**

<b>System Marginal Emission Rates (lb/MWh)</b>			
<b>Month</b>	<b>NO<sub>x</sub></b>	<b>SO<sub>2</sub></b>	<b>CO<sub>2</sub></b>
1	0.47	0.94	804
2	0.51	0.92	800
3	0.43	0.52	753
4	0.33	0.18	687
5	0.30	0.10	706
6	0.30	0.14	666
7	0.38	0.20	789
8	0.29	0.09	716
9	0.29	0.10	686
10	0.26	0.05	637
11	0.32	0.17	687
12	0.47	0.49	805

**Appendix Table 6: 1999 - 2013 New England System Annual Average NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> Emission Rates (lb/MWh)**

<b>Year</b>	<b>Total Generation (GWh)</b>	<b>NO<sub>x</sub></b>	<b>SO<sub>2</sub></b>	<b>CO<sub>2</sub></b>
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
<b>Percent Reduction, 1999 - 2013</b>		74	93	28

**Appendix Table 7: 2009 - 2013 LMU Marginal Heat Rate (MMBtu/MWh)**

LMU Marginal Heat Rate (MMBtu/MWh)			
Year	All Marginal LMUs	Emitting LMUs	O&NG LMUs
2009	8.591	8.507	7.881
2010	7.414	8.385	7.821
2011	6.907	8.190	7.758
2012	6.678	7.870	7.676
2013	6.841	8.271	7.604

**Appendix Table 8: 2013 New England FTA Marginal Emission Rates (lb/MMBtu)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.022	0.018	0.020	0.024	0.021
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.016	0.014		0.014
CO <sub>2</sub>		119	122		120

**Appendix Table 9: 1993 - 2013 New England NO<sub>x</sub> FTA Marginal Emission Rates (lb/MWh)**

Year	Ozone Season		Non-Ozone Season		Annual Average (All Hours)	Annual Average Percentage Change
	On-Peak	Off-Peak	On-Peak	Off-Peak		
1993	4.00	4.50	4.10	5.00	4.40	-
1994	4.50	3.90	4.50	3.90	4.20	-4.5
1995	3.40	2.80	3.50	3.10	3.20	-23.8
1996	2.70	2.40	2.90	2.40	2.60	-18.8
1997	2.60	2.60	2.70	2.60	2.60	0.0
1998	2.20	2.00	2.10	2.10	2.10	-19.2
1999	2.20	2.00	1.90	1.80	2.00	-4.8
2000	2.00	1.80	1.80	1.80	1.90	-5.0
2001	1.90	1.50	1.70	1.60	1.70	-10.5
2002	1.40	0.80	1.50	1.00	1.10	-35.3
2003	0.80	0.30	0.90	0.90	0.70	-36.4
2004	0.48	0.38	0.66	0.59	0.54	-22.9
2005	0.51	0.39	0.62	0.57	0.54	0.0
2006	0.35	0.24	0.30	0.25	0.29	-46.3
2007	0.25	0.20	0.34	0.30	0.28	-3.4
2008	0.23	0.20	0.21	0.22	0.21	-25.0
2009	0.17	0.13	0.19	0.16	0.17	-19.0
2010	0.27	0.17	0.14	0.15	0.18	5.9
2011	0.16	0.13	0.14	0.13	0.14	-22.2
2012	0.18	0.13	0.12	0.12	0.14	0.0
2013	0.17	0.14	0.15	0.18	0.16	14.3
<b>% Reduction 1993 - 2013</b>	<b>95.8</b>	<b>96.9</b>	<b>96.3</b>	<b>96.4</b>	<b>96.4</b>	

**Appendix Table 10: 1993 - 2013 New England SO<sub>2</sub> FTA Marginal Emission Rates (lb/MWh)**

<b>Year</b>	<b>Annual Average (All Hours)</b>	<b>Annual Average Percentage Change</b>
1993	12.60	-
1994	9.80	-22.2
1995	7.00	-28.6
1996	9.60	37.1
1997	9.40	-2.1
1998	6.20	-34.0
1999	7.20	16.1
2000	6.20	-13.9
2001	4.90	-21.0
2002	3.30	-32.7
2003	2.00	-39.4
2004	2.03	1.5
2005	1.75	-13.8
2006	0.53	-69.7
2007	0.57	7.5
2008	0.33	-42.1
2009	0.22	-33.3
2010	0.09	-59.1
2011	0.05	-44.4
2012	0.03	-40.0
2013	0.11	266.7
<b>% Reduction 1993 - 2013</b>	<b>99.1</b>	



**Appendix Table 11: 1993 - 2013 New England CO<sub>2</sub> FTA Marginal Emission Rates (lb/MWh)**

Year	Annual Average	Annual Average
1993	1,643	-
1994	1,573	-4.3
1995	1,584	0.7
1996	1,653	4.4
1997	1,484	-10.2
1998	1,520	2.4
1999	1,578	3.8
2000	1,488	-5.7
2001	1,394	-6.3
2002	1,338	-4.0
2003	1,179	-11.9
2004	1,102	-6.5
2005	1,107	0.5
2006	993	-10.3
2007	1,004	1.1
2008	964	-4.0
2009	930	-3.5
2010	943	1.4
2011	907	-3.8
2012	899	-0.9
2013	914	1.7
<b>% Reduction 1993 - 2013</b>	<b>44.4</b>	

**Appendix Table 12: 2013 LMU Marginal Emission Rates – All LMUs (lb/MMBtu)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.047	0.031	0.051	0.063	0.050
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.075	0.086		0.080
CO <sub>2</sub>		135	137		136

**Appendix Table 13: 2013 Monthly LMU Marginal Emission Rates – All LMUs (lb/MWh)**

LMU Marginal Emission Rates (lb/MWh)			
Month	NO <sub>x</sub>	SO <sub>2</sub>	CO <sub>2</sub>
1	0.50	1.61	1047
2	0.61	1.44	1099
3	0.45	0.77	948
4	0.21	0.25	820
5	0.21	0.16	812
6	0.31	0.23	970
7	0.48	0.40	1017
8	0.15	0.08	813
9	0.15	0.10	830
10	0.12	0.03	770
11	0.26	0.37	919
12	0.61	1.27	1124

**Appendix Table 14: 2013 LMU Marginal Emission Rates – Emitting LMUs (lb/MMBtu)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.045	0.031	0.050	0.068	0.051
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.071	0.092		0.083
CO <sub>2</sub>		130	141		136

**Appendix Table 15: 2013 Monthly LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)**

LMU Marginal Emission Rates (lb/MWh)			
Month	NO <sub>x</sub>	SO <sub>2</sub>	CO <sub>2</sub>
1	0.59	1.89	1251
2	0.81	1.90	1421
3	0.59	1.01	1208
4	0.26	0.34	1029
5	0.25	0.18	979
6	0.38	0.32	1192
7	0.55	0.44	1143
8	0.19	0.10	958
9	0.19	0.11	970
10	0.14	0.03	936
11	0.33	0.47	1099
12	0.73	1.53	1341

**Appendix Table 16: 2013 LMU Marginal Emission Rates – O&NG LMUs (lb/MMBtu)**

Ozone / Non-Ozone Season Emissions (NO <sub>x</sub> )					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO <sub>x</sub>	0.036	0.016	0.026	0.026	0.026
Annual Emissions (SO <sub>2</sub> and CO <sub>2</sub> )					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO <sub>2</sub>		0.030	0.026		0.028
CO <sub>2</sub>		123	121		122

**Appendix Table 17: 2013 Monthly LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)**

LMU Marginal Emission Rates (lb/MWh)			
Month	NO <sub>x</sub>	SO <sub>2</sub>	CO <sub>2</sub>
1	0.28	0.58	989
2	0.33	0.89	1019
3	0.10	0.03	884
4	0.10	0.07	892
5	0.14	0.01	872
6	0.15	0.03	892
7	0.38	0.19	986
8	0.14	0.01	890
9	0.13	0.02	888
10	0.11	0.01	890
11	0.14	0.02	908
12	0.38	0.82	1044

**Appendix Table 18: 2009 - 2013 NO<sub>x</sub> LMU Marginal Emission Rates – All LMUs (lb/MWh)**

Year	Ozone Season		Non-Ozone Season		Annual Average (All Hours)	Annual Average Percentage Change
	On-Peak	Off-Peak	On-Peak	Off-Peak		
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
<b>% Change 2009 - 2013</b>	<b>-10.4</b>	<b>-46.0</b>	<b>20.7</b>	<b>-3.8</b>	<b>-10.1</b>	

**Appendix Table 19: 2009 - 2013 NO<sub>x</sub> LMU Marginal Emission Rates  
- Emitting LMUs (lb/MWh)**

Year	Ozone Season		Non-Ozone Season		Annual Average (All Hours)	Annual Average Percentage Change
	On-Peak	Off-Peak	On-Peak	Off-Peak		
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
<b>% Change 2009 - 2013</b>	<b>-17.0</b>	<b>-50.9</b>	<b>25.7</b>	<b>-7.7</b>	<b>-14.6</b>	

**Appendix Table 20: 2009 - 2013 NO<sub>x</sub> LMU Marginal Emission Rates  
- O&NG LMUs (lb/MWh)**

Year	Ozone Season		Non-Ozone Season		Annual Average (All Hours)	Annual Average Percentage Change
	On-Peak	Off-Peak	On-Peak	Off-Peak		
2009	0.18	0.11	0.20	0.23	0.18	-
2010	0.55	0.25	0.17	0.18	0.26	42.1
2011	0.35	0.11	0.20	0.17	0.19	-25.4
2012	0.32	0.11	0.12	0.14	0.16	-18.1
2013	0.27	0.12	0.20	0.20	0.20	25.9
<b>% Change 2009 - 2013</b>	<b>54.3</b>	<b>7.1</b>	<b>2.0</b>	<b>-12.3</b>	<b>9.3</b>	

**Appendix Table 21: 2009 - 2013 SO<sub>2</sub> LMU Marginal Emission Rates  
- 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
<b>% Change 2009 - 2013</b>	<b>-54.5</b>	<b>-65.7</b>	<b>-62.6</b>	

**Appendix Table 22: 2009 - 2013 SO<sub>2</sub> LMU Marginal Emission Rates  
- 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
<b>% Change 2009 - 2013</b>	<b>-57.9</b>	<b>-66.7</b>	<b>-63.7</b>	

**Appendix Table 23: 2009 - 2013 SO<sub>2</sub> LMU Marginal Emission Rates  
- O&NG LMUs (lb/MWh)**

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.13	0.16	0.15	-
2010	0.25	0.05	0.13	-13.3
2011	0.12	0.07	0.09	-28.5
2012	0.07	0.02	0.04	-55.3
2013	0.23	0.20	0.21	405.4
<b>% Change 2009 - 2013</b>	<b>71.6</b>	<b>22.7</b>	<b>40.0</b>	

**Appendix Table 24: 2009 - 2013 CO<sub>2</sub> LMU Marginal Emission Rates  
- All LMUs (lb/MWh)**

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	882	946	919	-
2010	1019	1036	1029	12.0
2011	943	908	922	-10.4
2012	876	839	854	-7.4
2013	921	937	930	8.9
<b>% Change 2009 - 2013</b>	<b>4.4</b>	<b>-1.0</b>	<b>1.2</b>	

**Appendix Table 25: 2009 - 2013 CO<sub>2</sub> LMU Marginal Emission Rates  
- 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	1138	1215	1183	2.2
2011	1148	1061	1097	-7.3
2012	1019	1003	1010	-7.9
2013	1079	1163	1125	11.4
<b>% Change 2009 - 2013</b>	<b>3.6</b>	<b>-6.4</b>	<b>-2.8</b>	

**Appendix Table 26: 2009 - 2013 CO<sub>2</sub> LMU Marginal Emission Rates  
- O&NG LMUs (lb/MWh)**

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	893	956	928	-
2010	987	948	965	4.0
2011	884	872	877	-9.1
2012	933	902	915	4.3
2013	933	923	928	1.4
<b>% Change 2009 - 2013</b>	<b>4.5</b>	<b>-3.5</b>	<b>0.0</b>	

***Prepared by:***

***ISO New England Inc. – System Planning***

***Customer Service: (413) 540-4220***

<http://www.iso-ne.com>