2009 ISO New England Electric Generator Air Emissions Report

System Planning Department
ISO New England Inc.
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1. Executive Summary

Since 1993, ISO New England Inc. (ISO-NE) has analyzed annually the marginal emission rates of the ISO New England electric generation system administered by the ISO-NE. This was motivated by the need to determine the emission reductions that demand-side management (DSM) programs have had upon New England's aggregate NO_X, SO_2, and CO_2 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 in the region. The marginal emission rates for NO_X, SO_2 and CO_2 were reported in the annual publication of the Marginal Emission Rate Analysis (MEA Report). In 2008, the MEA Report was replaced by the ISO New England Electric Generator Air Emissions Report (Emissions Report), which was primarily based on the previous MEA Reports, but was restructured to place more of an emphasis on air emissions produced by the entire ISO New England electric generation system, while still reporting marginal emission rates. This 2009 Emissions Report provides estimates of the annual system NO_X, SO_2, and CO_2 generator air emissions during the calendar year 2009 as well as calculated marginal emission rates. The results of the 2009 system emissions calculations are shown in Table 1.1. The annual system emission rates are shown in pounds per megawatt-hour (lb/MWh) and the annual total emissions are shown in kilotons (kTons).[1]

Table 1.1: 2009 Calculated New England Annual System Emissions

	Annual System Emissions	
	Emission Rate (lb/MWh)	Total Emissions (kTons)
NO_X	0.46	27.55
SO_2	1.29	76.85
CO_2	828	49,380

Marginal emission rates are calculated using the energy-weighted, average emission rates of generating units that would typically increase their output if regional energy demand was higher during the time periods of interest. The marginal units are considered to be those that are fueled with oil (including residual, distillate, diesel, kerosene, and jet fuel), and/or natural gas[2].

The results of the 2009 marginal emission rate calculations are shown in Table 1.2 in pounds per megawatt-hour (lb/MWh) and Table 1.3 in pounds per million British thermal units (lb/MBtu)[3].

[1] Within this and prior ISO-NE MEA/emission reports, the mass value of "tons" is equivalent to 2,000 lbs and "kilotons" is equivalent to 2,000,000 lbs.

[2] The marginal emission rates are based on the generating unit's primary fuel type, as reported within the 2010 CELT Report.

[3] To convert from lb/MWh to lb/MBtu, the 2009 calculated marginal heat rate of 7.774 MBtu/MWh is used.

Table 1.2: 2009 Calculated New England Marginal Emission Rates (lb/MWh)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.17	0.13	0.19	0.16	0.17
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.24	0.19		0.22
CO_2		918	943		930

Table 1.3: 2009 Calculated New England Marginal Emission Rates (lb/MBtu)

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	0.022	0.016	0.025	0.021	0.021
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.031	0.024		0.03
CO_2		118	121		120

The 2009 system and marginal emissions and emission rates were calculated using primarily measured air emissions reported by generator owners to the U.S. Environmental Protection Agency (EPA) and actual 2009 ISO New England hourly generation data. This same methodology was used to calculate system and marginal emission rates for the 2004 through 2007 MEA Reports and the 2008 Emissions Report. In MEA Reports published prior to 2004, marginal emission rates were calculated using the output of a production simulation model of the ISO New England bulk power system.

The 2009 calculated marginal heat rate was determined using mostly power plant heat input data obtained from the U.S. EPA combined with actual 2009 energy production. This rate was used to convert the marginal emission rates from lb/MWh to lb/MBtu. The 2009 calculated marginal heat rate was determined to be 7.774 MBtu/MWh.

As shown in Table 1.4 below, the calculated system emission rates for 2009 have decreased from the 2008 values: the NO_X rate by 11.5%, the SO_2 rate by 14.6%, and the CO_2 rate by 7.0%. The decrease in emission rates can primarily be attributed to the decrease in residual oil and coal-fired generation between 2008 and 2009. The calculated marginal heat rate also decreased slightly, from 7.932 to 7.774 MBtu/MWh, a decrease of approximately 2.0%.

Table 1.4: Differences between 2008 and 2009 System Emission Rates (lb/MWh)

	System Emissions		
	2008 Annual Rate (lb/MWh)	2009 Annual Rate (lb/MWh)	Percent Change 2008 to 2009(%)
NO_X	0.52	0.46	-11.5
SO_2	1.51	1.29	-14.6
CO_2	890	828	-7.0

Table 1.5: Differences between 2008 and 2009 Marginal Emission Rates (lb/MWh)

	Marginal Emissions		
	2008 Annual Rate (lb/MWh)	2009 Annual Rate (lb/MWh)	Percent Change 2008 to 2009(%)
NO_X	0.21	0.17	-19.0
SO_2	0.33	0.22	-33.3
CO_2	964	930	-3.5

The marginal emission rates also decreased between 2008 and 2009. The changes in NO_X and SO_2 emission rates were the largest, exhibiting reductions of 19% and 33%, respectively. The marginal CO_2 emission rate decreased by 4%[4].

The results showed that the 2009 SO_2 and NO_X system emission rates are higher than the marginal rates for those pollutants. The CO_2 system emission rates, on the other hand, are lower than the marginal rates.

[4] For 2008 vs. 2009 NO_X, SO_2, and CO_2 marginal emission rates, refer to Tables 5.8, 5.9, and 5.10.

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_X air emissions in the calendar year 1992. The results were presented in a report entitled *1992 Marginal NO_X Emission Rate Analysis*. This report was subsequently used to support applications for obtaining NO_X 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_X, VOC, and CO_2 in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

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_X, SO_2, and CO_2 air emissions for the calendar year 1993. MEA Reports were also published for the years 1994 through 2007, to provide similar annual environmental analysis 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 the amount of emissions from the entire ISO New England electric generation system.[5] The ISO agreed to change the name of the MEA Report to the ISO New England Electric Generator Air Emissions Report (Emissions Report), and to place a greater emphasis on the calculated system emissions for the entire ISO New England electric generation system rather than focusing primarily on marginal emissions. The Emissions Report continues to include calculated marginal emission rates. These calculated marginal emissions can be used to estimate the impact DSM programs and renewable energy projects have had on reducing New England's NO_X, SO_2, and CO_2 power plant air emissions.

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

[5] The EAG is a stakeholder working group reporting to the Planning Advisory Committee (PAC). The EAG's web site is located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/index.html

3. Methodologies

For this 2009 Emissions Report, both the total system emissions and the marginal emission rate calculations for SO_2, NO_x and CO_2 were based primarily on the tons[6] of air emissions reported in the U.S. EPA Clean Air Markets Division (CAMD) database. When unit specific emissions data were not available from the CAMD database, the actual megawatt-hours (MWh) of generation, as reported to ISO-NE Settlements, were used to calculate tons of emissions 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. The total system and marginal emission rates were calculated from the actual or calculated tons of power plant emissions.

All electric generators that are administered 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 control area are not part of this analysis.

3.1. Calculating Total System Emission Rate

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

$$\text{System Emission Rate (lbs/MWh)} = \frac{\text{Total Annual Emissions (lbs) from all Generators}}{\text{Total Annual Energy (MWh) from all Generators}}$$

3.2. Calculating Marginal Emission Rate

3.2.1. History of Marginal Emissions Calculations

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 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.

In 2004, a new methodology was used to calculate the average emission rates of those units that are assumed to increase their loading during periods of high energy demand. Those units, which consist of all natural gas and oil-fired generators, are referred to as the marginal fossil units. The methodology used the actual metered hourly generation reported to ISO-NE Settlements, and the annual air emissions and emission rates obtained from the U.S. EPA databases, along with other default emissions rates. For the time periods investigated, the average air emission rates of all of the marginal fossil units were calculated based on these information sources. The resultant emission rates were assumed to be the *marginal emission rates.* In 2005, monthly emissions from both the U.S. EPA and the NEPOOL GIS were used, when available, to improve the accuracy of the marginal emissions calculations. This methodology was further improved in the 2007

[6] A ton is equivalent to a U.S. short ton, or 2,000 lb.

MEA Report with the use of hourly emissions data, for those units that report hourly emissions to the U.S. EPA[7].

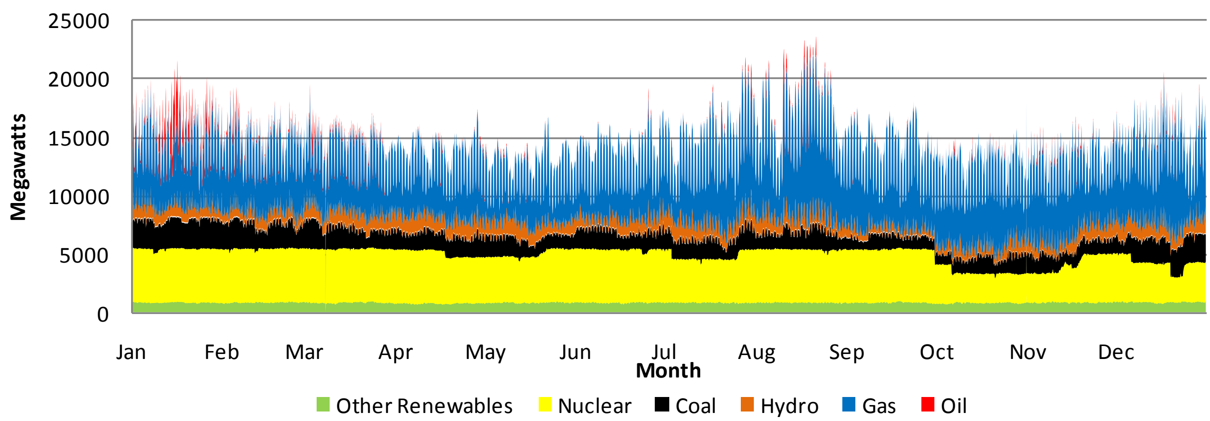
3.2.2. Current Method of Calculating Marginal Emissions

The marginal fossil units, on which the marginal emissions are based, consist of fossil units fueled with oil (including residual, distillate, kerosene, diesel and jet fuel), and/or natural gas. Units fueled with coal, wood, biomass, refuse, or landfill gas are excluded from the calculation, as they typically operate as base-load or non-dispatchable units and would typically not be dispatched to higher levels in the event of higher loads on the system.[8] Other resources that do not vary in output to serve load changes, such as hydro-electric, pumped storage, wind, and solar, as well as nuclear units, are also excluded from the calculation of marginal emission rates.

In calculating the 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 data 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 generator was added together to obtain the annual total marginal emissions. This quantity was then divided by the total on-peak or off-peak generation to get the corresponding emission rates (lb/MWh) for that time period. In the case of NO_X 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.

Figure 3.1 shows the 2009 New England hourly generation and illustrates how natural gas and oil units typically respond to changes in system demand.

Figure 3.1: New England 2009 Hourly Generation



[7] Generators report emissions to the U.S. EPA under the Acid Rain Program, which covers generators 25 MW or larger, and the NO_X 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_X Budget Trading Program.

[8] In an analysis of whether it would be appropriate to consider coal units as marginal units, ISO-NE found that although coal units were marginal 11% of the time in 2006, based on dispatch and load following for establishing Locational Marginal Prices, the analysis also confirmed that the dispatch of coal units was relatively independent of load levels. It was also observed that higher or lower loads would change the number of committed natural gas and/or oil units, while coal units would continue to 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 being marginal for purposes of establishing Locational Marginal Prices during those off-peak hours. It was concluded that when comparing cases with higher vs. lower loads, the marginal units for energy and emissions purposes are still largely the oil and natural gas units, not the coal units.

The average NO_X, SO_2, and CO_2 emission rates of the marginal fossil units in each time period analyzed are assumed to be equal to the marginal emission rates. These emission rates are calculated as:

$$Emission\ Rate\ (lbs/MWh) = \frac{Sum\ of\ Total\ Emissions (lbs)\ in\ Time\ Period\ from\ Marginal\ Fossil\ Units}{Total\ Energy\ (MWh)\ in\ Time\ Period\ from\ Marginal\ Fossil\ Units}$$

The 2009 marginal air emission rates for on and off-peak periods for New England and for each of the six states have been calculated for this report. The on-peak period, which excludes 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_X are calculated for five time periods:[9]

- On-Peak Ozone Season (where the Ozone Season is defined as occurring from May 1 to September 30) 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 weekends from May 1 to September 30
- 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 weekends 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_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 A.M. and 10 P.M.
- Off-Peak Annual consisting of all weekdays between 10 P.M. and 8 A.M. and all weekends
- Annual average

[9] There has been a separate ongoing effort at ISO-NE since 2009 to conduct an analysis of NO_X emissions during peak days. This report is scheduled to be released in the first quarter of 2011.

4. Data and Assumptions

The key parameters and assumptions modeled in the 2009 ISO New England Emissions Report are highlighted in this section. They include weather, emissions data, and installed capacity.

4.1. 2009 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 2009 total energy use and both cooling and heating degree days to previous years.

In New England, the summer of 2009 was much cooler than average, especially June and July, with the only "hot" weather occurring in late August. The 2009 summer peak electricity demand of 25,100 MW was 1,011 MW lower than the 2008 summer peak of 26,111 MW. There were 224 cooling degree days, which is 23.8% lower than the 20 year average[10]. The net energy for load was 3.7% lower in 2009 than 2008 over the year as a whole and 5.5% lower than 2008 during the ozone season months. With respect to the winter months, January and December were colder than average, but February was milder than normal.

New England's historical cooling degree days and heating degree days for 1993 through 2009 are shown in Table 4.1. The difference between the cooling and heating degree days for a particular year and the average is also provided.

Table 4.1: New England Total Cooling and Heating Degree Days - 1993 through 2009

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1993	283	-3.7	6,468	3.5
1994	374	27.2	6,403	2.4
1995	312	6.1	6,318	1.1
1996	245	-16.7	6,454	3.2
1997	211	-28.2	6,432	2.9
1998	312	6.1	5,483	-12.3
1999	360	22.4	5,774	-7.6
2000	217	-26.2	6,399	2.4
2001	323	9.9	5,895	-5.7
2002	354	20.4	5,959	-4.7
2003	355	20.7	6,651	6.4
2004	251	-14.6	6,354	1.6
2005	418	42.2	6,353	1.6
2006	335	13.9	5,552	-11.2
2007	288	-2.0	6,175	-1.2
2008	281	-3.4	6,049	-3.2
2009	224	-23.8	6,278	0.4

[10] The 20 year span of 1986 to 2005 average number of cooling degree days is 294 and the average number of heating degree days is 6,252.

4.2. Emission Rates

Individual generating unit emissions were calculated primarily from the 2009 actual emissions (in tons) as reported under the U.S. EPA's Acid Rain Program and NO_X Budget Trading Program. This information is published on the U.S. EPA's web site under Clean Air Markets data[11]. Hourly EPA emissions data were used for calculating the marginal emission rates. In the 2005 and 2006 MEA Reports, monthly U.S. EPA data rather than hourly data were used for calculating marginal rates. Prior to 2005, the MEA reports used annual data obtained primarily from the U.S. EPA Emissions Scorecard.

For those units that were not required to file emissions data under the Acid Rain or NO_X Budget Trading Programs, 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, the Emissions Report analysis used annual emission rates (lb/MWh) from the U.S. EPA's eGRID2007 Version 1.1 data[12] and, if that information were not available, emission rates based on eGRID data was obtained for similar type units. The emission rates were then multiplied by the 2009 generation reported to the ISO to obtain the emissions (tons) from 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_2 emissions and 78% of the CO_2 emissions were based on Clean Air Markets data. For NO_X, Clean Air Markets data were used for 54% of total emissions. For the total marginal emissions, approximately 96% of the SO_2, 94% of the CO_2 and 87% of the NO_X emissions were based on Clean Air Markets data. Note that combined heat and power (CHP) units were included in this analysis. In calculating CHP units' emission rates, the units' emissions were assigned only to electric production and not to the heat generated, which resulted in slightly overestimating the system and marginal emission rates.

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[11] The U.S. EPA's Clean Air Markets emissions data can be accessed from http://www.epa.gov/airmarkets/.
[12] The U.S. EPA's eGRID2007 Version 1.1 is located at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

4.3. ISO New England System Installed Capacity

Table 4.2 and Table 4.3 show the total ISO New England generation capacity as obtained from ISO New England's 2010 Capacity, Energy, Loads and Transmission (CELT) Report[13] for the 2009 summer and winter periods, respectively.

The ISO-NE power grid operates as a unified system serving all load in the region. The amount of generation by fuel type and its associated emissions are affected by a number of factors, including forced and maintenance outages of resources and transmission system elements, fuel and emission allowance costs, imports and exports to neighboring regions, system peak load and energy consumption, water availability to hydro facilities, and a variety of other factors.

Table 4.2: 2009 New England Summer Capacity[14, 15]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	1,821.0	23.5	5,316.0	40.3	1,243.3	38.1	1,165.2	28.7	1,823.1	98.9	-	-	11,368.7	36.5
Gas Turbine	858.2	11.1	501.7	3.8	328.2	10.1	87.8	2.2	-	-	84.9	7.8	1,860.8	6.0
Hydro	106.7	1.4	247.0	1.9	585.3	18.0	456.8	11.3	0.5	0.0	298.2	27.5	1,694.5	5.4
Internal Combustion	21.1	0.3	139.4	1.1	16.0	0.5	5.2	0.1	19.7	1.1	25.6	2.4	227.1	0.7
Nuclear	2,014.4	26.0	677.3	5.1	-	-	1,245.5	30.7	-	-	604.3	55.6	4,541.4	14.6
Pumped Storage	29.4	0.4	1,659.7	12.6	-	-	-	-	-	-	-	-	1,689.1	5.4
Fossil Steam	2,898.1	37.4	4,649.7	35.2	1,086.5	33.3	1,070.3	26.4	-	-	72.5	6.7	9,777.2	31.3
Wind & Photovoltaic	-	-	4.4	0.0	1.0	0.0	23.5	0.6	0.5	0.0	0.7	0.1	30.1	0.1
Total	7,749.0	100.0	13,195.3	100.0	3,260.2	100.0	4,054.2	100.0	1,843.9	100.0	1,086.2	100.0	31,188.7	100.0

Table 4.3: 2009 New England Winter Capacity[14,15]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	2,077.5	24.8	6,243.5	43.3	1,350.4	38.4	1,317.4	30.8	2,077.7	98.9	-	-	13,066.6	38.6
Gas Turbine	1,063.0	12.7	694.7	4.8	396.5	11.3	108.4	2.5	-	-	110.9	9.4	2,373.4	7.0
Hydro	124.6	1.5	272.6	1.9	638.1	18.2	493.4	11.6	3.0	0.1	335.5	28.4	1,867.3	5.5
Internal Combustion	21.2	0.3	141.1	1.0	21.2	0.6	5.2	0.1	20.6	1.0	32.2	2.7	241.4	0.7
Nuclear	2,115.6	25.2	684.7	4.7	-	-	1,245.4	29.2	-	-	628.0	53.1	4,673.8	13.8
Pumped Storage	29.0	0.3	1,665.0	11.5	-	-	-	-	-	-	-	-	1,694.0	5.0
Fossil Steam	2,954.7	35.2	4,717.3	32.7	1,107.0	31.5	1,078.2	25.2	-	-	74.6	6.3	9,931.8	29.3
Wind & Photovoltaic	-	-	4.4	0.0	1.5	0.0	23.5	0.6	0.5	0.0	1.7	0.1	31.6	0.1
Total	8,385.5	100.0	14,423.4	100.0	3,514.6	100.0	4,271.6	100.0	2,101.8	100.0	1,183.0	100.0	33,879.9	100.0

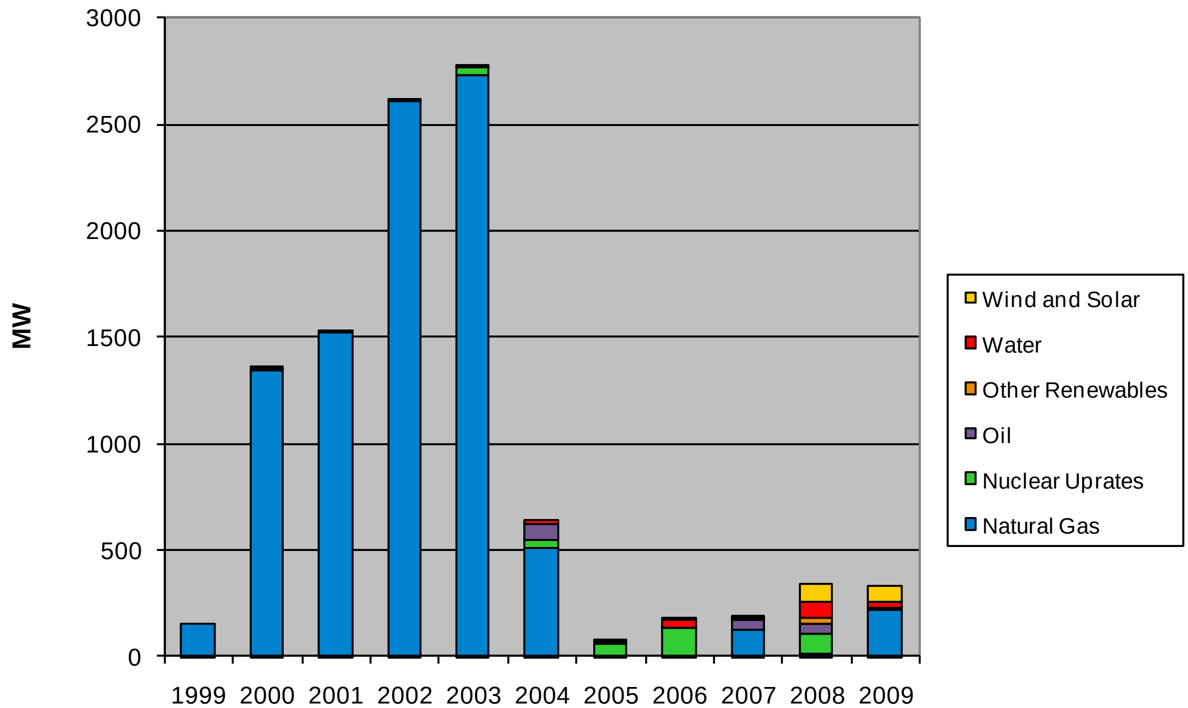
[13] The ISO-NE CELT Report is typically issued in April of each year. The 2010 CELT Report (using the January 1, 2010 ratings) was used in order to completely capture all the new capacity additions that occurred during the prior calendar year 2009.

[14] Sum may not equal total due to rounding.

[15] Capability as of January 1, 2010.

Figure 4.1 illustrates the new capacity that was added to the ISO New England system during 1999 through 2009, 91% of which was gas-fired, combined cycle technologies. From 1999-2004, 9,600 MW of new capacity was added and nearly 100% of the new capacity additions were gas-fired, combined cycle technologies. From 2005-2009, 1,097 MW was added, consisting of a mix of nuclear uprates, and new oil, natural gas, hydro-electric, and other renewable generation.

Figure 4.1 : ISO New England Generator Unit Additions - 1999 through 2009[16]

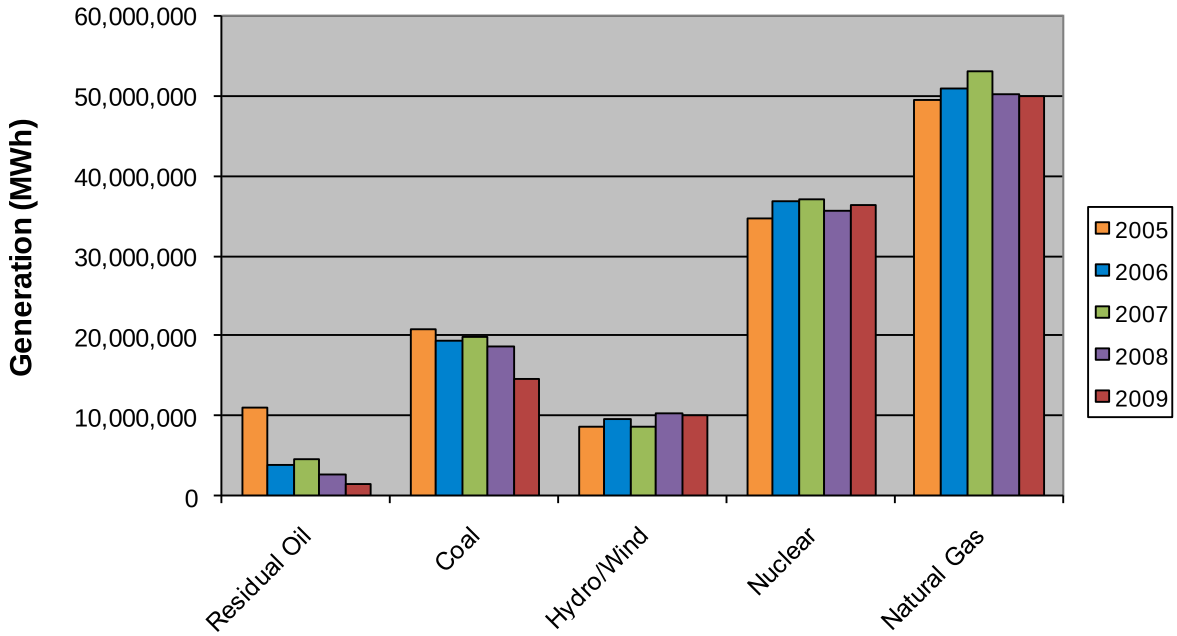


[16] The generator additions and uprate values are based on the seasonal claim capabilities as reported in the ISO-NE 2010 CELT Report.

4.4. ISO New England System Generation

Figure 4.2 shows the generation (MWh) by fuel types from 2005 – 2009, based on the resource's primary fuel type in the 2010 CELT Report. In 2009, residual oil and coal-fired generation was about 1,200 GWh and 4,035 GWh lower than in 2008, respectively. There was minimal change in natural gas and non-emitting generation and a slight increase in nuclear generation. Overall, system generation was about 5,311 GWh lower in 2009 than in 2008.

Figure 4.2 : 2005-2009 Generation by Selected Fuel Types



5. Results

5.1. ISO New England System Generator Air Emissions

Table 5.1 shows the aggregate 2009 NO_X, SO_2, and CO_2 air emissions for each state and for all of New England. These emissions were calculated based on the actual generation of all generating units in ISO-NE's balancing authority area[17] and the actual or assumed unit-specific air emissions or emission rates.

Table 5.1: 2009 Calculated ISO New England Electric Generation System Annual Aggregate Emissions of NO_X, SO_2, and CO_2 in kTons[18]

State	NO_x	SO_2	CO_2
Connecticut	5.65	4.61	9,780
Maine	2.77	1.61	5,832
Massachusetts	13.26	36.48	21,920
New Hampshire	4.79	33.69	7,693
Rhode Island	0.64	0.35	3,568
Vermont	0.44	0.12	588
New England	27.55	76.85	49,380

Table 5.2 shows the aggregate annual NO_X, SO_2, and CO_2 air emissions for the years 2001 through 2009, as calculated based on the actual generation and the actual or assumed air emissions or emission rates. Since 2001, NO_X emissions have dropped by 54% and SO_2 by 62%, while CO_2 has decreased by about 7%.

Table 5.2: 2001 - 2009 Calculated ISO New England Electric Generation System Annual Aggregate Emissions of NO_X, SO_2, and CO_2 in kTons

Year	NO_x	SO_2	CO_2
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
Percent Reduction, 2001 - 2009	54%	62%	7%

[17] This does not include Northern Maine, which is not electrically connected to the ISO-NE Control Area.
[18] Sum may not equal total due to rounding.

Table 5.3 shows the annual average 2009 NO_X, SO_2, and CO_2 air emission rates (lb/MWh), by state and for New England as a whole, calculated based on the actual hourly unit generation of all ISO-NE generating units located within that specific state and the actual or assumed unit-specific air emissions or emission rates.

Table 5.3: 2009 Calculated ISO New England Electric Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lb/MWh

State	NO_x	SO_2	CO_2
Connecticut	0.37	0.30	631
Maine	0.45	0.26	942
Massachusetts	0.65	1.79	1,077
New Hampshire	0.48	3.35	764
Rhode Island	0.17	0.09	934
Vermont	0.12	0.03	158
New England	0.46	1.29	828

Table 5.4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rate values (lb/MWh), for the 1999 – 2009 time period. These annual emission rates were calculated by dividing the total air emissions by the total generation from all units. Since 1999, the annual average NO_X emissions rate has decreased by 66%, SO_2 by 71%, and CO_2 by 18%.

Table 5.4: 1999-2009 Calculated ISO New England Electric Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates (lb/MWh)

Year	Total Generation (GWh)[19]	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
Percent Reduction, 1999 - 2009		66%	71%	18%

[19] The total generation shown in this table reflects total ISO New England generation and not necessarily the generation on which the system emission rates are based. Since the megawatt-hours associated with the Citizens Block Load located in northern Vermont are typically served by Quebec, that load/generation has not been included in the total generation used for calculating the 2006, 2007 and 2008 and 2009 ISO-NE New England generation system emission rates. In the years prior to 2004, emissions from the small, Settlement Only generators were not considered in the total system emissions; therefore, generation from those units was not included in the calculation of the system emission rates.

5.1.1. Observations

The calculated system emission rates for 2009 have decreased from the 2008 values. The NO_X emission rate by 11.5%, the SO_2 rate by 14.6% and the CO_2 rate by 7.0%. The decrease in emission rates can primarily be attributed to the decrease in residual oil and coal-fired generation between 2008 and 2009 by 1,200 GWh and 4,035 GWh respectively.

5.2. 2009 Calculated Marginal Heat Rate for the ISO New England Electric Generation System

Prior to 1999, MEA studies assumed a fixed marginal heat rate of 10.0 MBtu/MWh[20] which was used to convert from lb/MWh to lb/MBtu. 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[21], the calculated marginal heat rate is defined as follows:

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

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's Market Monitoring Unit (MMU). The individual heat input values using the two methods, in MBtu, 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 2009. 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.

The annual calculated marginal heat rates from 1999 to 2009 are shown in Table 5.5 below. The rate has declined over 22% since 1999.

[20] 10 MBtu/MWh is equivalent to 10,000 Btu/kWh.

[21] 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.

Table 5.5: Calculated New England Annual Marginal Heat Rate (MBtu/MWh)

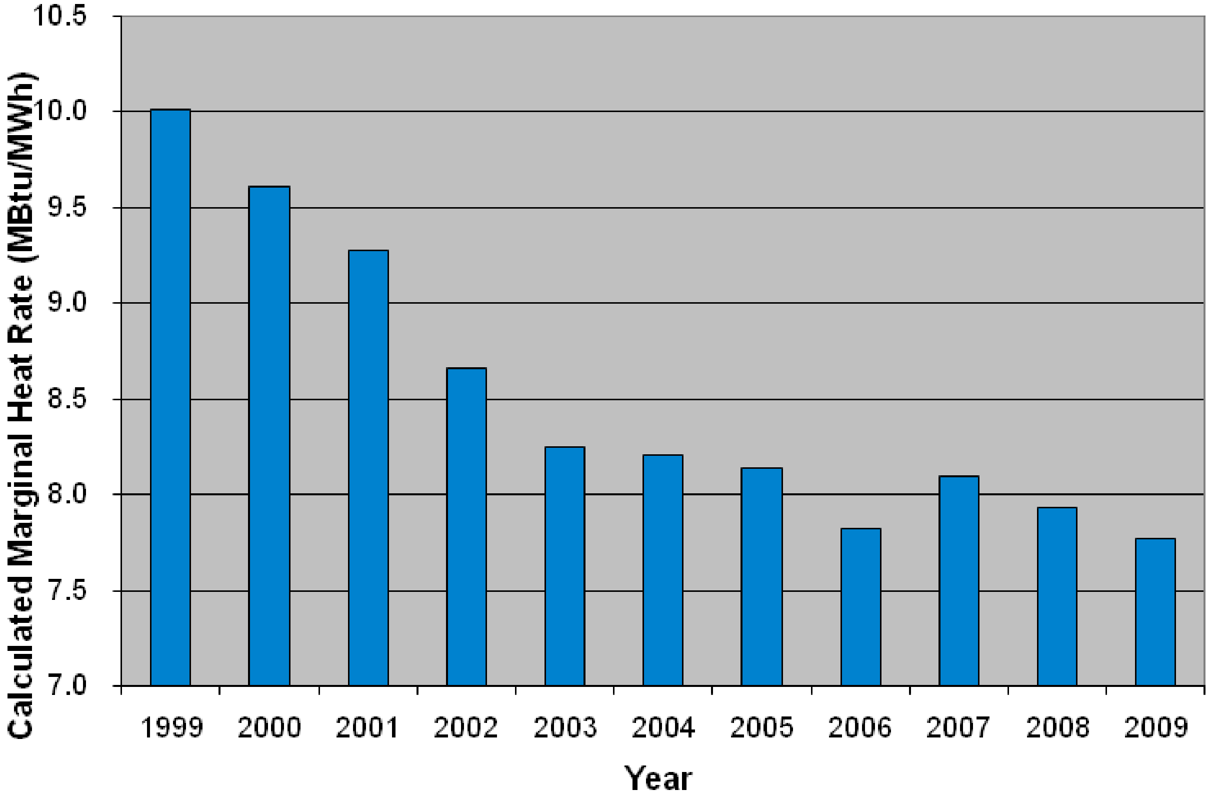
Year	Calculated Marginal Heat Rate (MBtu/MWh)
1999	10.013
2000	9.610
2001	9.279
2002	8.660
2003	8.249
2004	8.210
2005	8.140
2006	7.667
2007	8.095
2008	7.932
2009	7.774

The 2009 calculated marginal heat rate of 7.774 (MBtu/MWh) was used as the conversion factor to convert from lb/MWh to lb/MBtu for the marginal emission rates in this report.

5.2.1. Observations

Overall, the trend of decreasing marginal heat rates has been continuing, with rates declining from 10.013 MBtu/MWh to 7.774 MBtu/MWh over the past ten years. This is primarily due to the addition of over 9,200 MW of natural gas-fired, combined cycle units with higher efficiency, i.e., lower heat rates. Figure 5.1 illustrates the calculated annual marginal heat rate spanning the 1999 – 2009 timeframe. In general, the marginal heat rate has been declining since 1999. In 2006, there was a particularly large decrease in the marginal heat rate primarily due to a sharp decrease in residual oil-fired generation that year (see Figure 4.2). In 2007, residual oil-fired generation increased to about 4,700 GWh, an approximately 900 GWh increase over 2006 levels. This likely contributed to the increase in the marginal heat rate that occurred in 2007. The subsequent decrease in residual oil-fired generation in both 2008 and 2009 was accompanied by a decrease in the marginal heat rate those years.

Figure 5.1: Calculated New England Annual Marginal Heat Rate (MBtu/MWh)



5.3. 2009 New England Generation Marginal Emission Rates

Table 5.6 shows the NO_X, SO_2, and CO_2 calculated marginal emission rates in lb/MWh for ISO New England's generation system. The NO_X data 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 those emissions. Table 5.7 shows the same information expressed in lb/MBtu. As noted earlier, the 2009 calculated marginal heat rate of 7.774 MBtu/MWh was used as the conversion factor.

Table 5.6: 2009 Calculated New England Marginal Emission Rates (lb/MWh)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.17	0.13	0.19	0.16	0.17
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.24	0.19		0.22
CO_2		918	943		930

Table 5.7: 2009 Calculated New England Marginal Emission Rates (lb/MBtu)

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	0.022	0.016	0.025	0.021	0.021
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.031	0.024		0.03
CO_2		118	121		120

5.3.1. 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 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.

In 2009, there was a slight difference between the on-peak and off-peak marginal rates for NO_X, SO_2 and CO_2. The reason for the higher emissions rate in NO_X and SO_2 during on-peak hours compared to off-peak hours is most likely that the additional generation that is brought on line to meet the higher demand during on-peak periods generally has higher emission rates. These are typically peaking units that are more expensive or even uneconomic to operate except during high energy price hours, or may be older, fossil-steam resources with higher individual heat rates, i.e., lower thermal efficiency.

Both on-peak and off-peak emission rates for NO_X were lower during the ozone season than the non-ozone season. NO_X is a precursor of ozone air pollution, which is primarily a problem during the hot summer months (i.e., the ozone season), when peak load periods occur; therefore, it is good to observe lower ozone season NO_x emission rates.

5.4. Calculated Historical Marginal Emission Rates

Table 5.8, Table 5.9, and Table 5.10 show the historical calculated marginal emission rates for NO_X, SO_2, and CO_2, respectively, in lb/MWh for the years 1993 through 2009. Table 5.8 shows the ozone and non-ozone season rates, while the SO_2 and CO_2 tables include only the annual average emission rates. All three tables show the annual average percentage change from the previous year. Figure 5.2, Figure 5.3, and Figure 5.4 are graphical representations of Table 5.8, Table 5.9, and Table 5.10 respectively.

Table 5.8: Calculated New England Generation NO_X Marginal Emission Rates (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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
Percent Reduction 1993 - 2009	95.8	97.1	95.4	96.8	96.4	

Table 5.9: Calculated New England Generation SO_2 Marginal Emission Rates (lb/MWh)

Year	Annual Average (All Hours)	Annual Average Percentage Change
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
Percent Reduction 1993 - 2009	**98.3**	

Table 5.10: Calculated New England Generation CO_2 Marginal Emission Rates (lb/MWh)

Year	Annual Average (All Hours)	Annual Average Percentage Change
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
Percent Reduction 1993 - 2009	**43.4**	

5.4.1. Observations

Table 5.8 and Table 5.9 show that NO_X emission rates decreased by 19.0%, while SO_2 emission rates decreased by 33.3% between 2008 and 2009. As shown in Table 5.10, CO_2 emission rates decreased as well, but only by 3.5%. The relatively large decreases in NO_X and SO_2 emissions between 2008 and 2009 can primarily be attributed to the overall reduction in generation by residual oil-fired units in 2009, as seen in Figure 4.2 In 2009, residual oil-fired generation was about 1,200 GWh lower than in 2008. There was minimal change in generation from natural gas units.

As compared with 1993, the 2009 SO_2 and NO_X annual marginal rates have declined by over 96% and CO_2 by 43%. This decline is clearly illustrated in Figure 5.5, Figure 5.6, and Figure 5.7. There was a noticeable decrease in the marginal emission rates for NO_X in 1995 primarily due to the implementation of Reasonable Available Control Technology (RACT) regulations for NO_X as required under Title I of the 1990 Clean Air Act Amendments. This trend of decreasing NO_X marginal emission rates continued into the 2008 calendar year. 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 over the last several years in New England (see Figure 4.1). This was combined with the additional emission reductions as required under the Ozone Transport Commission's 1999 and U.S. EPA's 2003 NO_X Budget Program. Because few new natural gas-fired power plants have been added since 2004, the decline in marginal NO_X emission rates has tapered off.

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. This base load nuclear generation offsets generation from those marginal units that tend to have higher emission rates. One period that is an exception to this is 1996 to 1998, when there was an increase in fossil-based generation to compensate for the unavailability of three nuclear units.

Figure 5.2: Historically Calculated New England NO_X Marginal Emission Rates

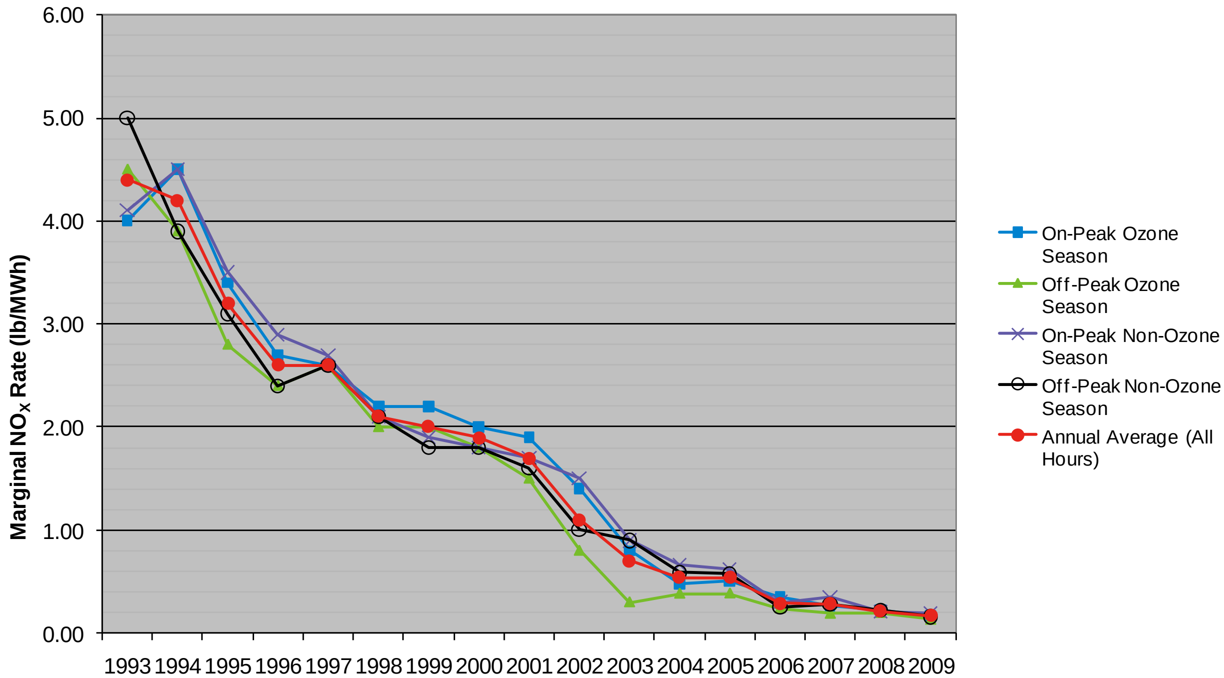


Figure 5.3: Historically Calculated New England SO_2 Marginal Emission Rates

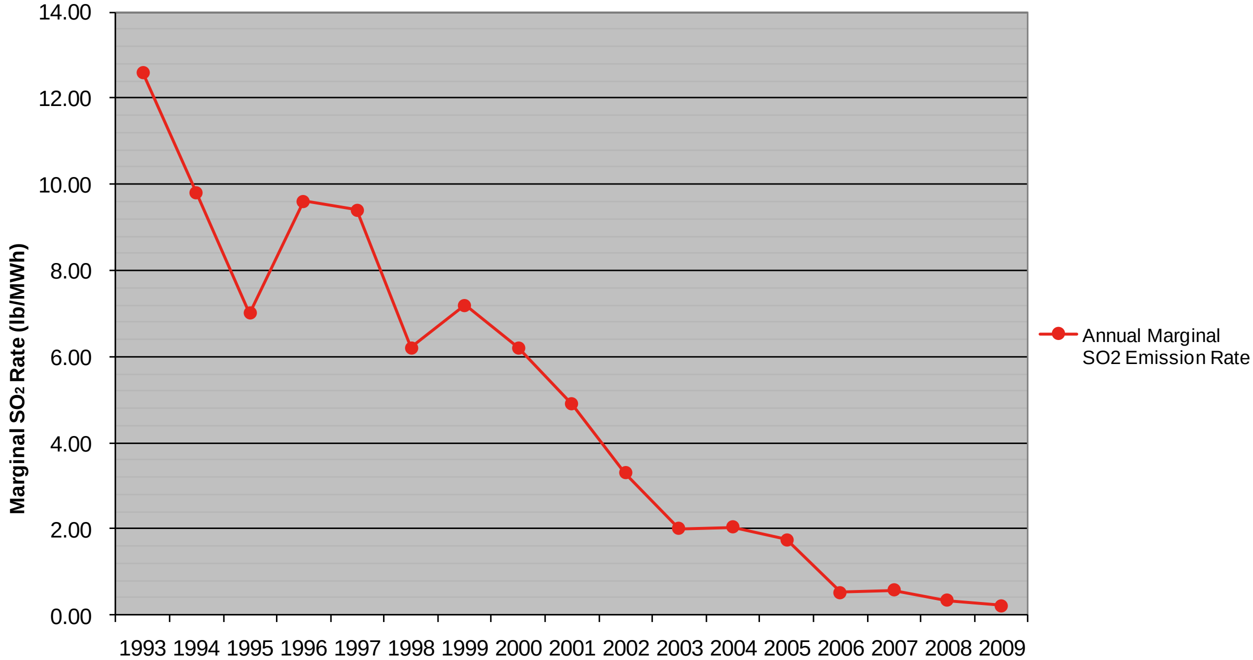
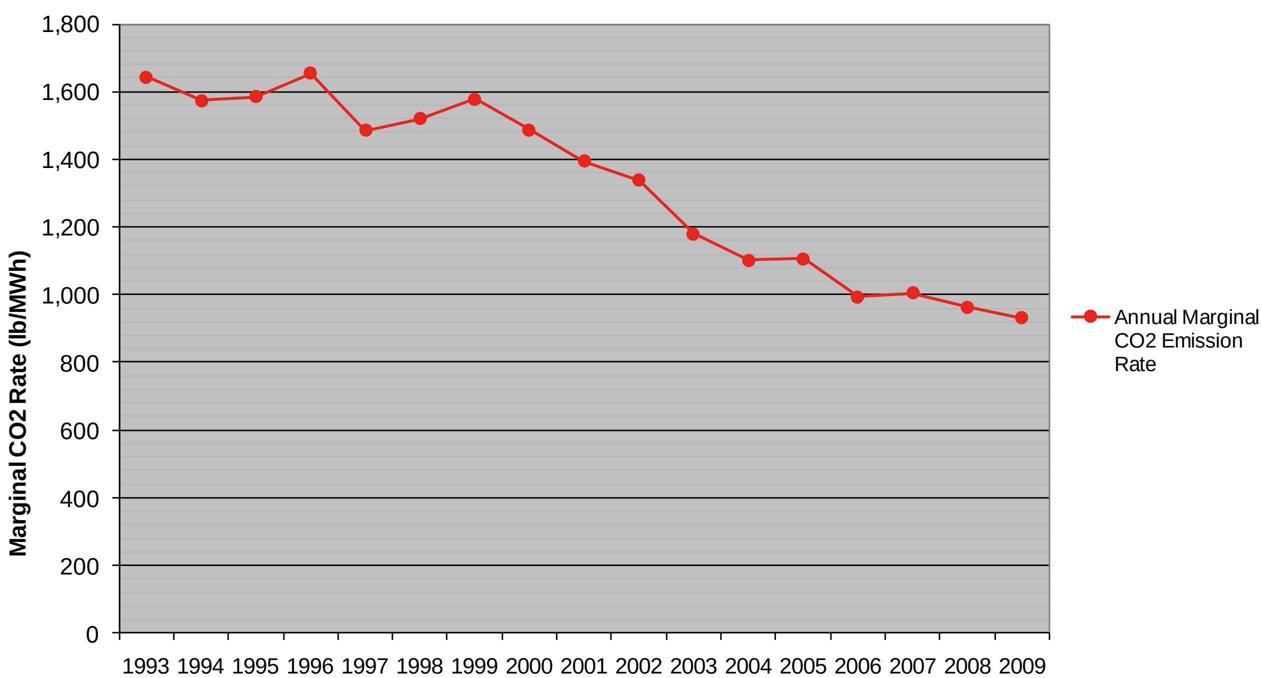


Figure 5.4: Historically Calculated New England CO_2 Marginal Emission Rates



5.5. Calculated Marginal Emission Rates by State

Table 5.11, Table 5.12, and Table 5.13 show the 2009 calculated NO_X, SO_2 and CO_2 marginal air emission rates for each state based on the generation that operated in that state. The NO_X emission rates are broken down into the ozone and non-ozone seasons, and the SO_2 and CO_2 rates are shown for the annual on-peak and off-peak 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 its in-state capacity is gas-fired combined cycle, has much lower marginal emission rates than Vermont, which has the highest. Although the total amount of emissions in Vermont is the lowest in New England, 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.

Table 5.11: 2009 Calculated New England NO_X Marginal Emission Rates by State (lb/MWh)

	Ozone Season		Non-Ozone Season		
State	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)
Connecticut	0.25	0.19	0.25	0.21	0.22
Maine	0.14	0.19	0.21	0.25	0.20
New Hampshire	0.10	0.10	0.21	0.18	0.16
Rhode Island	0.14	0.15	0.14	0.15	0.15
Vermont	7.60	7.29	6.92	9.57	7.51
Massachusetts	0.17	0.11	0.17	0.15	0.15
New England Average	0.17	0.13	0.19	0.16	0.17

Table 5.12: 2009 Calculated New England SO_2 Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.32	0.08	0.20
Maine	0.27	0.26	0.26
New Hampshire	0.38	0.33	0.36
Rhode Island	0.01	0.00	0.01
Vermont	3.25	3.53	3.31
Massachusetts	0.24	0.24	0.24
New England Average	0.24	0.19	0.22

Table 5.13: 2009 Calculated New England CO_2 Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	932	924	928
Maine	957	1,050	999
New Hampshire	919	925	922
Rhode Island	894	912	902
Vermont	2,566	1,393	2,321
Massachusetts	907	932	919
New England Average	918	943	930

Figure 5.5, Figure 5.6, and Figure 5.7 show the relationship between the average system emission rates in Table 5.4 and the marginal emission rates for NO_X, SO_2, and CO_2 in Table 5.8, Table 5.9, and Table 5.10 during the 1999 – 2009 period.

Figure 5.5: 1999 – 2009 Calculated New England Annual Average System NO_X Emission Rate vs. Marginal NO_X Emission Rate (lb/MWh)

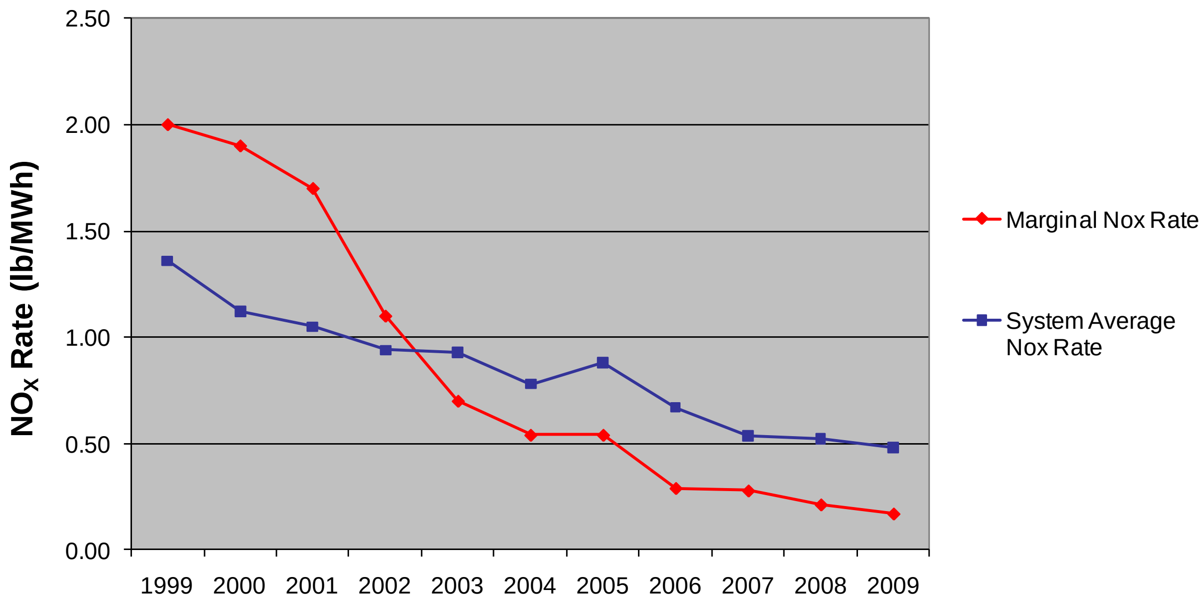


Figure 5.6: 1999 – 2009 Calculated New England Annual Average System SO_2 Emission Rate vs. Marginal SO_2 Emission Rate (lb/MWh)

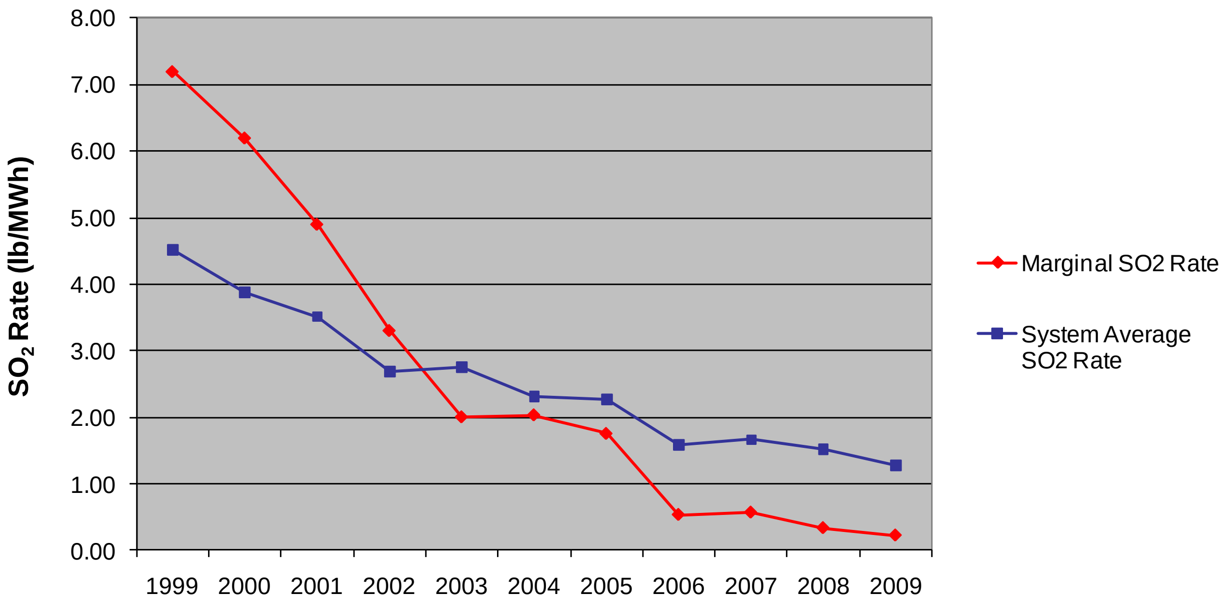
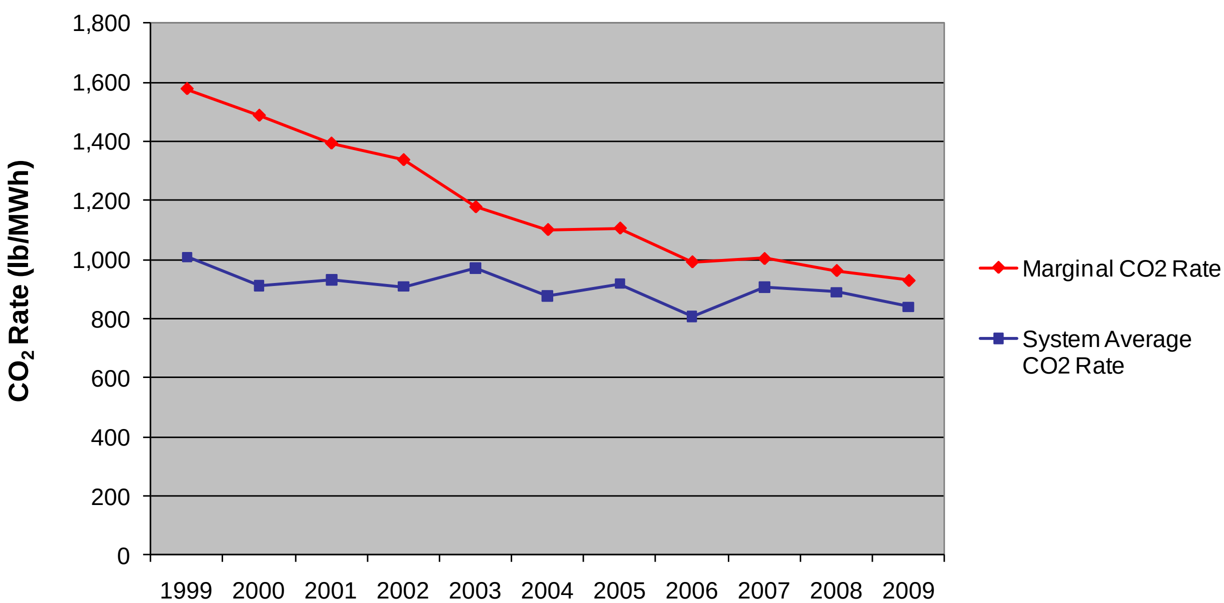


Figure 5.7: 1999 – 2009 Calculated New England Annual Average System CO_2 Emission Rate vs. Marginal CO_2 Emission Rate (lb/MWh)



5.5.1. Observations

During the period from 1999 to 2009, the average system emission rates decreased for both NO_X and SO_2, but at a slower rate than the marginal emission rates for those same pollutants. In fact, the marginal emission rates for NO_X and SO_2 were initially higher than the system emission rates for those pollutants, but due to their relatively fast decline, have been lower than the system rates since 2003.

The CO_2 average system emission rate decreased by about 17% between 1999 and 2009, while the CO_2 marginal emission rate declined 41% during that same period. This was caused by increased load growth and demand for fossil-based energy that was counteracting the lower marginal CO_2 rates as new units were added. Unlike the SO_2 and NO_X marginal emission rates, the CO_2 marginal emission rate has remained higher than the system emission rate during the entire period from 1999 through 2009. However, the CO_2 marginal emission rate has been decreasing more quickly than the system average emission rate over the past nine years, and the two rates were similar in 2009.

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