2006 New England Marginal Emission Rate Analysis

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1.0 EXECUTIVE SUMMARY

Since 1993, ISO New England Inc. (ISO-NE) has analyzed annually the marginal emission rates of the New England Generation System. 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. Since then, the use of these rates has broadened to include the benefits of energy efficiency programs and renewable resource projects in the region. This 2006 New England Marginal Emission Rate Analysis (MEA Report) provides estimates of marginal NO_X, SO_2, and CO_2 air emissions for the calendar year 2006. Marginal emission rates were calculated using the energy weighted average emission rates of generating units that typically would increase their output if energy demand were higher during the four time periods of interest. In this document, these units are referred to as "marginal fossil" units[1]. The results of the 2006 marginal emission rate calculations are shown in Table 1.1 in lbs/MWh and Table 1.2 in lbs/MBtu[2].

Table 1.1: 2006 Calculated New England Marginal Emission Rates (lbs/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	0.35	0.24	0.30	0.25	0.29
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.60	0.47		0.53
CO_2		1,106	977		993

Table 1.2: 2006 Calculated New England Marginal Emission Rates (lbs/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	0.046	0.031	0.039	0.033	0.038
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.078	0.061		0.069
CO_2		144	127		130

[1] "Marginal fossil" units, as defined in Section 3.1, are those fossil units that are fueled with oil (including distillate, residual, diesel and jet fuel), and/or natural gas.
[2] To convert from lbs/MWh to lbs/MBtu, the 2006 calculated Marginal Heat Rate of 7.667 MBtu/MWh is used.

The 2006 marginal emission rate values were calculated using actual 2006 hourly generation. This method of calculating marginal emission rates was first used in the 2004 MEA analysis, and will continue to be used in future analyses. In MEA Reports prior to 2004, marginal emission rates were calculated using the output of a production simulation model.

The 2006 Calculated Marginal Heat Rate was also determined using actual 2006 generation. This rate was used to convert the marginal emission rates from lbs/MWh to lbs/MBtu. The 2006 Calculated Marginal Heat Rate was determined to be 7.667 MBtu/MWh.

Calculated marginal emission rates for 2006 are significantly lower than the 2005 calculated values. The greatest decrease occurred in SO_2 emission rates, which fell by nearly 70%. NO_X emissions were lower by 46% and CO_2 by 10%. The primary reason for these significant decreases was a substantial reduction in generation by residual oil-fired plants on the margin. As was the case with the calculated marginal emission rates, the calculated marginal heat rate decreased considerably between 2005 and 2006. Specifically, the rate decreased from 8.140 MBtu/MWh to 7.667 MBtu/MWh.

The aggregate average annual emissions of the New England system were also calculated. The results showed that the 2006 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.

2.0 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 (ERCs) resulting from those DSM program impacts. 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, VOCs, and CO_2 in Massachusetts to earn bankable and tradable credits by reducing 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 NO_X, SO_2, and CO_2 air emissions for the calendar year 1993. MEA reports were also published for the years 1994 through 2004 to provide similar annual environmental analysis for those years. The 2006 New England Marginal Emission Rate Analysis provides calculated marginal emission rates that can be used to estimate the impact of DSM programs and renewable energy projects on reducing New England's NO_X, SO_2, and CO_2 power plant air emissions during the calendar year 2006.

The MEA Report is used by a variety of stakeholders, including utilities, consulting firms, environmental advocacy groups, and state air regulators to estimate the avoided emissions of DSM programs and renewable energy projects.

3.0 METHODOLOGY

3.1 CALCULATING MARGINAL EMISSIONS

In MEA studies performed prior to 2004, production simulation models were used to replicate, as closely as possible, actual system operations for the study year. Then, an incremental load scenario was modeled in which the entire system load was increased by 500 MW in each hour. The marginal air emission rates were calculated based on the differences in emissions between these two scenarios. This methodology had some drawbacks. Since the reference case results were based on production simulation modeling, the reference case never exactly matched the previous year's unit level energy production because of numerous modeling reasons including market dynamics, specific outages and deratings.

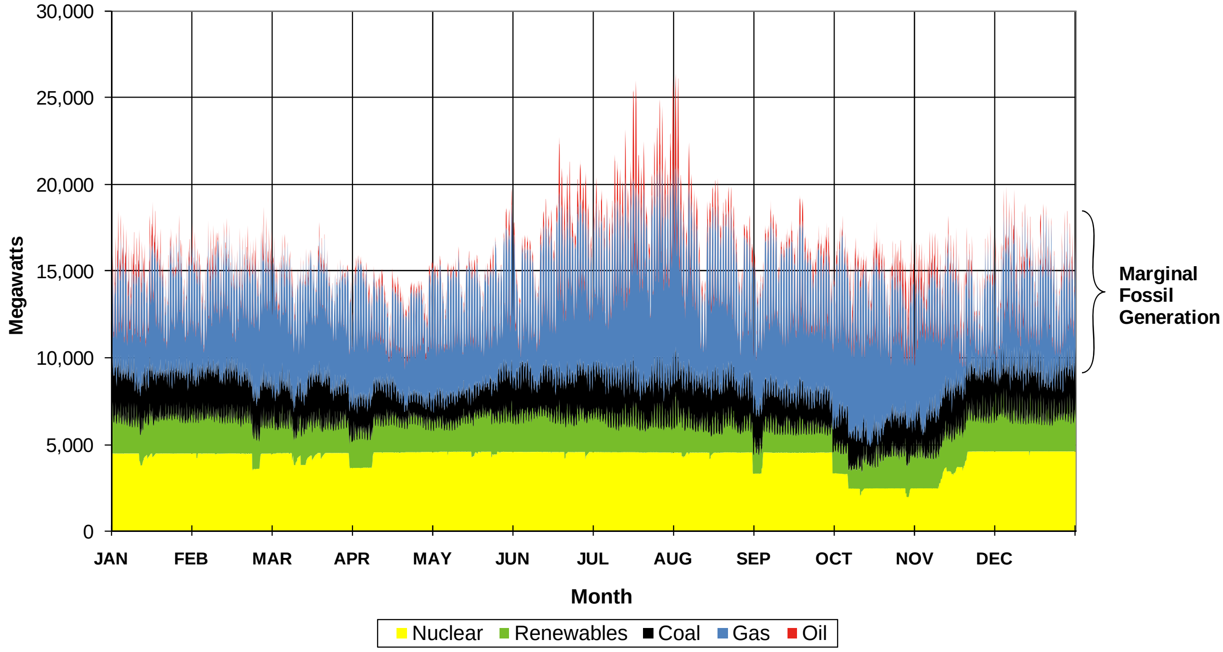
In 2004, a new methodology was developed to calculate the average emission rates of those units that are assumed to increase their loading during periods of high energy demand. This methodology used the actual hourly generation as reported to ISO-NE, and monthly and annual air emissions and emission rates from US Environmental Protection Agency (EPA) data and the NEPOOL Generation Information System (GIS), along with other default emissions data. For the time periods investigated, the average air emission rates of a defined subset of generating units were calculated based on this information. The resultant emission rates were assumed to be the marginal emission rates. In 2005, monthly emissions were used, when available, to improve the accuracy of the calculations. This methodology was again used to produce the 2006 MEA Report and will continue to be used for future MEA reports.

The subset of units, referred to as *marginal fossil units* for purposes of the 2006 MEA Report, is comprised of those fossil units that are fueled with oil (including distillate, residual, diesel and jet fuel), and/or natural gas. Fossil units fueled with coal, wood, biomass, or refuse/landfill gas are excluded from the calculation as they typically operate as baseload units and would not be dispatched to higher levels in the event of higher load on the system.[3] Hydro, wind, and nuclear units are also excluded from the marginal calculation.

Figure 3.1 shows the 2006 New England hourly generation, and illustrates the way in which gas and oil units respond to system demand.

[3] 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 gas and/or oil units, while the coal units would continue to be dispatched when available. During 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 the 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 largely the oil and gas units, not the coal units.

Figure 3.1: New England 2006 Hourly Generation



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

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

This report calculates the NO_X 2006 marginal air emission rates for New England and each of the six states over five time-periods. An on-peak period that 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 reductions during those hours. The five time periods are:

- 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 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 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 emissions 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

4.0 DATA AND ASSUMPTIONS

The key parameters and assumptions modeled in the 2006 Marginal Emissions Rate Analysis are highlighted in this section. They include weather, emission rates, and installed capacity

4.1 2006 NEW ENGLAND WEATHER

Since the demand for energy and peak load is significantly affected by the weather, it is useful to provide perspective for the changes in marginal emissions by comparing total energy use and cooling degree days to previous years.

In New England, the summer of 2006 was warm and humid, with a record-breaking heat wave in early August that resulted in a summer peak electricity demand 4.6% higher than the 2005 summer peak. There were 336 cooling degree days during the ozone season (May – September). This is 15% higher than the normal of 292 cooling degree days during those months[4], but 18% lower than the number of cooling days in 2005. Despite the fact that ISO New England reached an all-time peak demand in the summer of 2006, the net energy during the ozone season months, as well as during the year as a whole, was approximately 3% lower in 2006 than in 2005. With respect to the winter months, January, February and December 2006 can be characterized as very mild, which also contributed to the lower energy in 2006.

The historical cooling degree days and heating degree days since 1993 are shown in Table 4.1. The difference between the cooling and heating degree days for a particular year and the normal is also provided. The normal number of cooling degree days is 292 and the normal number of heating degree days is 6,261.

Table 4.1: New England Cooling and Heating Degree Days - 1993 through 2006

Year	Total Cooling Degree Days	Difference from Normal (%)	Total Heating Degree Days	Difference from Normal (%)
1993	283	-3.4	6,468	3.3
1994	374	27.6	6,403	2.3
1995	312	6.5	6,318	0.9
1996	245	-16.4	6,454	3.1
1997	211	-28.0	6,432	2.7
1998	312	6.5	5,483	-12.4
1999	360	22.9	5,774	-7.8
2000	217	-25.9	6,399	2.2
2001	323	10.2	5,895	-5.8
2002	354	20.8	5,959	-4.8
2003	355	21.2	6,651	6.2
2004	251	-14.3	6,354	1.5
2005	418	42.7	6,353	1.5
2006	335	14.3	5,552	-11.3

4.2 EMISSION RATES

Individual generating unit emission rates were calculated from the 2006 actual monthly emissions in tons as reported under the US EPA's Acid Rain Program and NO_X Budget Trading Program, and published on the

[4] "Normal" is defined as the average over the previous 20-year period.

EPA's web site under Clean Air Markets data[5]. Monthly data was also used in 2005, but previous years' studies used annual data obtained primarily from the US EPA Emissions Scorecard.

For those units that were not required to file under the Acid Rain or NO_X Budget Trading Programs, monthly emission rates in lb/MWh from the Generation Information System (GIS) were used. If the data could not be obtained from either of those sources, the study used annual emission rates in lb/MWh from the EPA's eGRID2006 Version 2.1 data[6], or if that was not available, emission rates based on eGRID data obtained for similar units.

EPA Clean Air Markets data was by far the most significant source of emissions data for this report. The SO_2 and CO_2 emissions from approximately 52,900 GWh (96%) out of a total of 55,000 GWh of generation by marginal units were based on Clean Air Markets data. In the case of NO_X emissions, Clean Air Markets data was used for 99% of total generation by marginal units.

In order to calculate the on-peak and off-peak emissions, the EPA emissions were divided by the total monthly generation to obtain a lb/MWh rate for each generator. Those rates, along with the rates obtained from GIS and eGRID, were then multiplied by the monthly on-peak and off-peak generation. The pounds of emissions from each individual generator were added together to obtain an annual total, which was then divided by the total on-peak or off-peak generation to get the lb/MWh emission rate for that time period. In the case of NO_X, the monthly totals were combined into ozone and non-ozone season emissions (lbs) and divided by the ozone and non-ozone season generation.

[5] The Clean Air Markets emissions data can be accessed from http://www.epa.gov/airmarkets/.
[6] EPA's eGRID2006 Version 2.1 is located at http://www.epa.gov/cleanenergy/egrid/index.htm.

4.3 NEW ENGLAND SYSTEM INSTALLED CAPACITY

Table 4.2 and Table 4.3 show the total New England capacity claimed for capability as listed in ISO New England's 2007 Capacity, Energy, Loads and Transmission (CELT) Report for the summer and winter period, respectively. Table 4.4 illustrates the capacity that was added to the New England system during 1999 through 2006, 91% of which was gas-fired combined cycle.

Table 4.2: New England Summer Capacity – 2007 CELT[7, 8]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Combined Cycle	1,727.8	22.9	5,175.2	39.7	1,408.2	43.4	1,146.7	28.6	1,818.7	98.9	-	-	11,276.6	36.6
Gas Turbine	743.8	9.9	582.7	4.5	160.0	4.9	83.1	2.1	-	-	81.3	7.4	1,651.0	5.4
Hydro	108.1	1.4	245.5	1.9	567.2	17.5	472.6	11.8	0.5	0.0	291.6	26.7	1,685.5	5.5
Internal Combustion	5.3	0.1	88.8	0.7	15.0	0.5	5.3	0.1	19.8	1.1	25.0	2.3	159.2	0.5
Nuclear	2,034.8	27.0	677.3	5.2	-	-	1,242.5	30.9	-	-	620.3	56.8	4,574.8	14.9
Pumped Storage	29.4	0.4	1,659.9	12.7	-	-	-	-	-	-	-	-	1,689.3	5.5
Fossil Steam	2,886.9	38.3	4,614.5	35.4	1,091.4	33.7	1,064.9	26.5	-	-	72.5	6.6	9,730.2	31.6
Wind	-	-	2.0	0.0	-	-	0.6	0.0	0.7	0.0	0.7	0.1	4.0	0.0
Total	7,536.1	100.0	13,045.9	100.0	3,241.8	100.0	4,015.5	100.0	1,839.7	100.0	1,091.4	100.0	30,770.4	100.0

Table 4.3: New England Winter Capacity – 2007 CELT[7, 8]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Combined Cycle	1,983.8	24.7	6,091.6	41.5	1,537.7	42.8	1,291.9	30.5	2,069.5	98.9	-	-	12,974.4	38.4
Gas Turbine	917.6	11.4	793.1	5.4	202.0	5.6	107.3	2.5	-	-	109.6	9.5	2,129.7	6.3
Hydro	125.0	1.6	267.3	1.8	617.4	17.2	502.3	11.9	3.0	0.1	314.3	27.3	1,829.4	5.4
Internal Combustion	5.4	0.1	89.5	0.6	19.7	0.5	5.3	0.1	19.2	0.9	31.8	2.8	170.7	0.5
Nuclear	2,037.4	25.3	684.7	4.7	-	-	1,242.5	29.4	-	-	620.3	53.8	4,584.9	13.6
Pumped Storage	29.0	0.4	1,665.2	11.4	-	-	-	-	-	-	-	-	1,694.2	5.0
Fossil Steam	2,942.8	36.6	5,069.3	34.6	1,215.1	33.8	1,080.3	25.5	-	-	74.6	6.5	10,382.1	30.7
Wind	-	-	2.1	0.0	-	-	0.6	0.0	0.7	0.0	1.7	0.1	5.0	0.0
Total	8,041.0	100.0	14,662.9	100.0	3,591.9	100.0	4,230.2	100.0	2,092.4	100.0	1,152.2	100.0	33,770.5	100.0

[7] Sum may not equal total due to rounding.
[8] Capability as of January 1, 2007

Table 4.4: New England Generator Unit Additions - 1999 through 2006[9]

Generator Name	State	Unit Type	Summer Capability (MW)	Winter Capability (MW)	Commercial Date
Bridgeport Energy Phase II	CT	Combined Cycle	178	178	07/24/1999
Champion	ME	Steam Turbine	33	33	08/01/1999
Dighton	MA	Combined Cycle	144	144	08/01/1999
1999 Totals			**355**	**355**	
Maine Independence	ME	Combined Cycle	470	500	05/01/2000
Berkshire Power	MA	Combined Cycle	267	289	06/19/2000
Tiverton	RI	Combined Cycle	256	281	08/18/2000
Rumford	ME	Combined Cycle	266	279	10/16/2000
Androscoggin (Units 1 & 2)	ME	Combined Cycle	86	90	12/28/2000
Androscoggin (Unit #3)	ME	Combined Cycle	38	50	12/28/2000
2000 Totals			**1,383**	**1,489**	
Bucksport	ME	Combined Cycle	169	186	01/01/2001
Millennium	MA	Combined Cycle	331	388	04/06/2001
Westbrook	ME	Combined Cycle	520	578	04/13/2001
ANP Blackstone 1	MA	Combined Cycle	277	277	06/07/2001
ANP Blackstone 2	MA	Combined Cycle	277	277	07/13/2001
Wallingford Units 1 & 3	CT	Gas Turbine	84	98	12/31/2001
2001 Totals			**1,658**	**1,804**	
Wallingford Unit 4	CT	Gas Turbine	42	49	01/23/2002
Wallingford Unit 2	CT	Gas Turbine	42	49	02/07/2002
Wallingford Unit 5	CT	Gas Turbine	42	49	02/07/2002
Lake Road Unit #1	CT	Combined Cycle	270	270	03/15/2002
Lake Road Unit #2	CT	Combined Cycle	270	270	03/15/2002
Lake Road Unit #3	CT	Combined Cycle	270	270	05/22/2002
West Springfield 1 & 2	MA	Gas Turbine	80	98	06/07/2002
ConEd Newington Unit 1	NH	Combined Cycle	261	281	09/18/2002
ConEd Newington Unit 2	NH	Combined Cycle	261	281	09/18/2002
ANP Bellingham Unit #1	MA	Combined Cycle	288	308	10/24/2002
Hope Energy (RISE)	RI	Combined Cycle	500	531	11/05/2002
Kendall Repowering	MA	Combined Cycle	172	234	12/18/2002
ANP Bellingham Unit #2	MA	Combined Cycle	288	308	12/28/2002
2002 Totals			**2,786**	**2,998**	
AES Granite Ridge	NH	Combined Cycle	678	767	04/01/2003
Mystic Station Block 8	MA	Combined Cycle	707	850	04/13/2003
Great Lakes Hydro America	ME	Hydro	100	100	05/20/2003
Mystic Station Block 9	MA	Combined Cycle	707	850	06/11/2003
Pilgrim Uprate	MA	Nuclear	35	35	08/01/2003
Fore River	MA	Combined Cycle	700	843	08/04/2003
NECCO Cogeneration	MA	Internal Combustion	5	5	10/01/2003
2003 Totals			**2,932**	**3,450**	
Milford Power Unit 1	CT	Combined Cycle	268	287	02/12/2004
Ridgewood RI Generation	RI	Internal Combustion	2	2	02/18/2004
Millstone 2 Uprate	CT	Nuclear	16	3	03/10/2004
Cabot Turner's Falls Uprate	MA	Hydro	9	9	05/01/2004
Milford Power Unit 2	CT	Combined Cycle	268	287	05/03/2004
Millstone 3 Uprate	CT	Nuclear	25	-	05/03/2004
2004 Totals			**588**	**588**	
West Springfield Hydro	MA	Hydro	1	1	01/10/2005
Coventry Clean Energy	VT		5	5	02/01/2005

[9] Sum may not equal total due to rounding

Generator Name	State	Unit Type	Summer Capability (MW)	Winter Capability (MW)	Commercial Date
Seabrook Power Uprate	NH	Nuclear	60	60	05/01/2005
RRIG Expansion Phase II	RI	Landfill Gas	5	5	06/01/2005
Grtr New Bedford LFG Util Proj	MA	Landfill Gas	3	3	08/15/2005
North Hartland Hydro	VT	Hydro	4	4	09/27/2005
Misc. less than 1 MW			1	1	
2005 Totals			**79**	**79**	
Hull Wind Turbine II	MA	Wind Turbine	2	2	01/03/2006
UNH Cogen	NH	Gas Turbine	8	8	05/01/2006
Rumford Falls	ME	Hydro	40	40	06/09/2006
Devon 10	CT	Gas Turbine	17	20	06/29/2006
VT Yankee Station Upgrade	VT	Nuclear	110	110	06/15/2006
Waterside Power	CT	Gas Turbine	52	59	09/28/2006
MATEP	MA	Gas Turbine	42	42	10/12/2006
FIEC Diesel	ME	Diesel	2	2	12/01/2006
Harris Energy	MA	Hydro	2	2	12/01/2006
Seabrook Power Uprate Phase II	NH	Nuclear	23	23	12/04/2006
PPL Great Works – Red Shield	ME	Municipal Solid Waste	16	16	12/08/2006
Misc. less than 1 MW			2	2	
2006 Totals			**316**	**326**	
1999-2006 Totals			**10,097**	**11,089**	

5.0 RESULTS

5.1 2006 CALCULATED MARGINAL HEAT RATE FOR NEW ENGLAND ELECTRIC GENERATION SYSTEM

In MEA studies prior to 1999, a fixed Marginal Heat Rate of 10.0 MBtu/MWh[10] was assumed and then used to convert from lbs/MWh to lbs/MBtu. In the 1999 – 2003 New England Marginal Emissions Rate Analyses, the Marginal Heat Rate was calculated using the results of production simulation runs. Beginning with the 2004 MEA analysis, the Marginal Heat Rate has been based on the actual generation of *marginal fossil units*. Since heat rate is equal to fuel consumption divided by generation[11], the 2006 Calculated Marginal Heat Rate is defined as follows:

$$\text{2006 Calculated Marginal Heat Rate} = \frac{\text{(Calculated Fuel Consumption of Marginal Fossil Units)}}{\text{(Actual Generation of Marginal Fossil Units)}}$$

The fuel consumption of the marginal fossil units was calculated by multiplying each unit's monthly generation by the heat rate information collected and maintained by ISO-NE Market Monitoring. These individual values for fuel consumption, in terms of MBtu per month, were summed together and divided by the total annual generation to get the total for all marginal fossil units.

The calculated annual marginal heat rate reflects the average annual efficiency of all of the *marginal fossil units* dispatched throughout 2006. The lower the marginal heat rate value, the more efficient the system or marginal generator(s).

The annual Calculated Marginal Heat Rates from 1999 to 2006 are shown in Table 5.1 below.

Table 5.1: Historically 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

The 2006 Calculated Marginal Heat Rate was used as the global conversion factor to convert from system-wide lbs/MWh to lbs/MBtu for all calculations within this report.

5.1.1 Observations

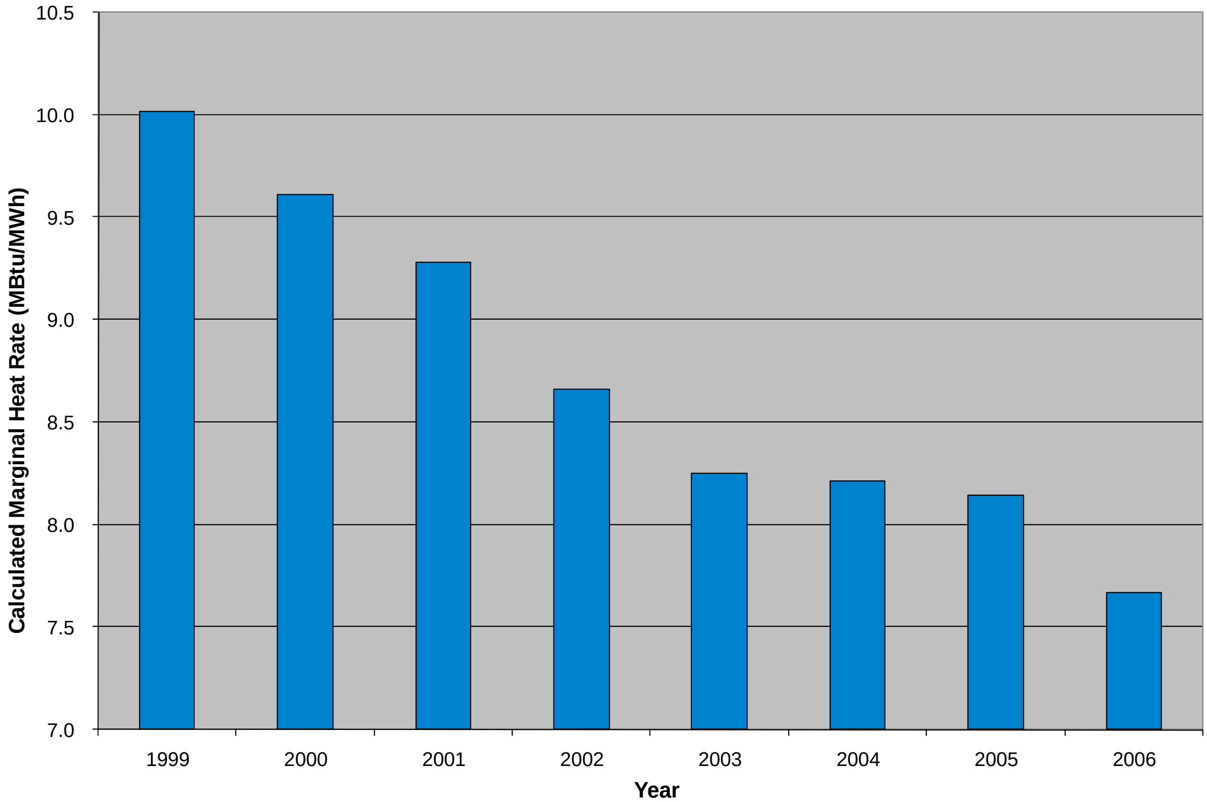
The annual Calculated Marginal Heat Rate has decreased since 1999 from 10.013 MBtu/MWh to 7.667 MBtu/MWh. This is primarily due to the addition of over 9,000 MW of natural gas-fired combined cycle

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

[11] Heat rate is the measure of efficiency in converting input fuel 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 plant.

units with high efficiency, i.e lower heat rates. Figure 5.1 illustrates the Calculated Marginal Heat Rate spanning the 1999 – 2006 timeframe.

Figure 5.1: Historically Calculated New England Electric System Generators' Marginal Heat Rate (MBtu/MWh)



5.2 2006 NEW ENGLAND GENERATION MARGINAL EMISSION RATES

Table 5.2 shows the NO_X, SO_2, and CO_2 calculated marginal emission rates in lbs/MWh for the New England generation system. The NO_X data is 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 5.3 shows the same information expressed in lbs/MBtu. As noted earlier, the 2006 Calculated Marginal Heat Rate of 7.667 MBtu/MWh was used as the conversion factor.

Table 5.2: 2006 Calculated New England Marginal Emission Rates (lbs/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	0.35	0.24	0.30	0.25	0.29
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.60	0.47		0.53
CO_2		1,106	977		993

Table 5.3: 2006 Calculated New England Marginal Emission Rates (lbs/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	0.046	0.031	0.039	0.033	0.038
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.078	0.061		0.069
CO_2		144	127		130

5.2.1 Observations

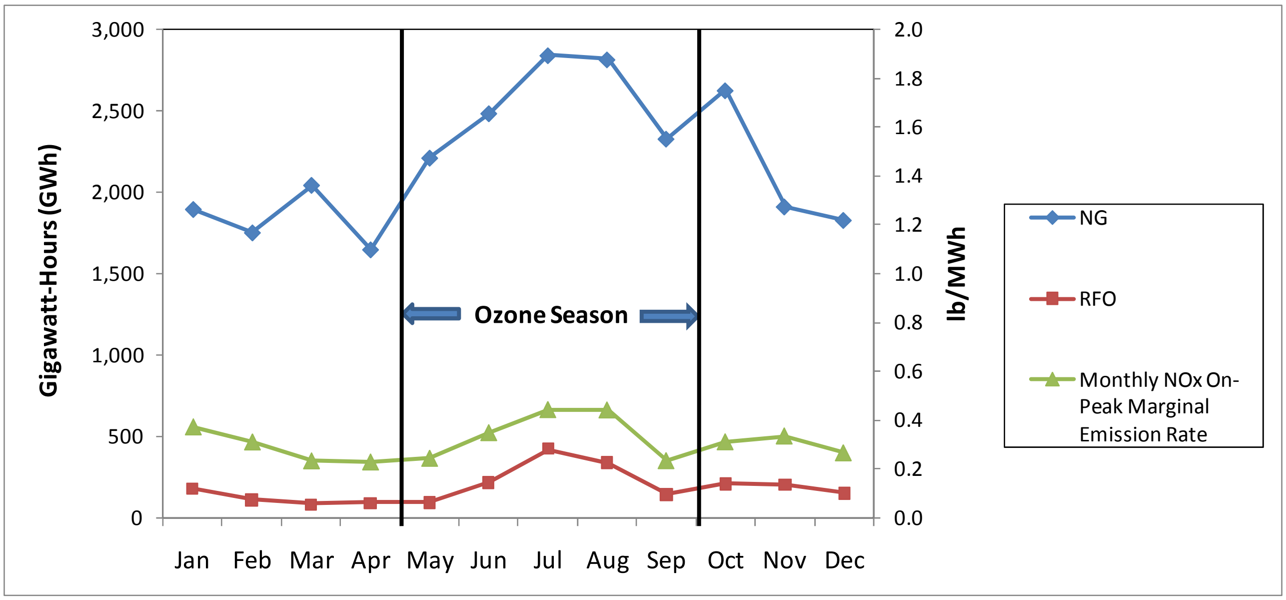
The overall New England emissions are directly dependent on the specific units that are available and dispatched to serve load for each hour of the year. Therefore, there could be wide variations in the seasonal emissions, primarily due to changes in unit availability, fuel consumption, fuel switching, and load levels.

In all ISO marginal air emissions calculations, the on-peak marginal rates are consistently higher than the off-peak marginal rates. This is most likely because the additional generation that is brought on line to meet the higher demand during on-peak periods has higher emission rates. These typically are older resources with higher individual heat rates, i.e lower thermal efficiency.

Table 5.3 also shows that in 2006, NO_X emissions during the on-peak hours of the ozone season were somewhat higher than during 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).

The higher NO_X emissions during the on-peak hours of the ozone season could be explained by the fact that on-peak generation by plants burning residual fuel oil was significantly higher during those months than during the non-ozone season. Figure 3.1 shows the monthly on-peak natural gas and residual oil-fired generation in 2006[12], along with the monthly on-peak marginal emission rate[13]. Although generation by residual oil-fired plants was low in general in 2006, it was especially low in the winter months due to the particularly mild weather during January, February and December.

Figure 3.1: 2006 Monthly On-Peak New England Natural Gas and Residual Oil-Fired Generation (GWh), and NO_X Monthly On-Peak Marginal Emission Rate (lb/MWh)



[12] Generation by a particular fuel type is based on the primary fuel type as specified in the 2007 CELT Report.
[13] Generation by distillate oil-fired plants was minimal and was therefore not included in the figure.

5.3 CALCULATED HISTORICAL MARGINAL EMISSION RATES

Table 5.4, Table 5.5, and Table 5.6 show the calculated marginal emission rates for NO_X, SO_2, and CO_2 in lbs/MWh for the years 1993 through 2006. The NO_X table 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 5.3, Figure 5.4, and Figure 5.5 are graphical representations of Table 5.4, Table 5.5, and Table 5.6, respectively.

Table 5.4: Calculated New England Generation NO_X Marginal Emission Rates (lbs/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

Table 5.5: Calculated New England Generation SO_2 Marginal Emission Rates (lbs/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

Table 5.6: Calculated New England Generation CO_2 Marginal Emission Rates (lbs/MWh)

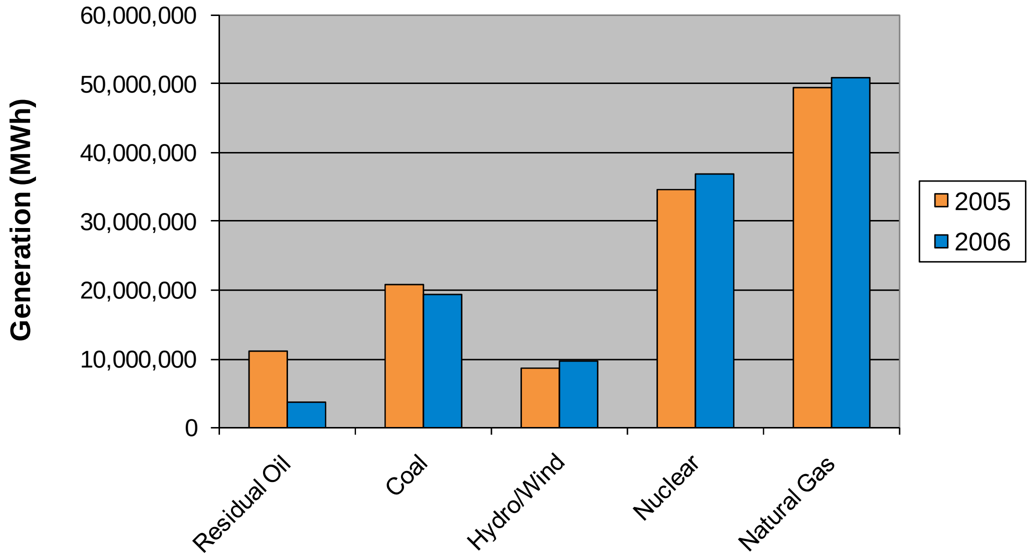
Year	Annual Average	Annual Average Percentage Change
1993	1,643	-
1994	1,573	-4.3
1995	1,584	0.7
1996	1,653	4.4
1997	1,484	-10.2
1998	1,520	2.4
1999	1,578	3.8
2000	1,488	-5.7
2001	1,394	-6.3
2002	1,338	-4.0
2003	1,179	-11.9
2004	1,102	-6.5
2005	1,107	0.5
2006	993	-10.3

5.3.1 Observations

Table 5.4, Table 5.5 and Table 5.6 show that the marginal emission rates fell significantly between 2005 and 2006. The greatest decrease occurred in SO_2 emissions (-69.7%), followed by NO_X (-46.3%) and CO_2 (-10.3%) emissions.

These significant changes can primarily be attributed to the overall reduction in generation by residual oil-fired units in 2006, the increase in the non- and low-emitting generation as seen in Figure 5.2, and a lower system load. Residual oil-fired generation decreased from over 11,000 GWh in 2005 to about 3,800 GWh in 2006, a nearly two-thirds reduction. This was accompanied by a slight increase in natural gas generation. A small decrease in generation by coal-fired units, and slight increases in hydro-electric and wind generation as well as in nuclear generation, also contributed to the lower system emissions. Overall, system load was about 4,300 GWh lower in 2006 than in 2005.

Figure 5.2: 2006 Generation by Selected Fuel Types Based on Primary Fuel Type in CELT Report



Since 1993, there has been a significant decrease in the marginal emission rates. In thirteen years, SO_2 and NO_X annual marginal rates have declined by over 93% and CO_2 by nearly 40%. This decline is clearly illustrated in Figure 5.3, Figure 5.4, and Figure 5.5. There is a noticeable decrease in the marginal emission rates for NO_X in 1995 primarily due to the implementation of NO_X RACT regulations as required under Title IV of the 1990 Clean Air Act Amendments. This trend of decreasing calculated NO_X marginal emission rates continued into the 2006 calendar year. Most of the decrease in emission rates that took place through 2004 can be attributed to the commercialization of many highly efficient, low emitting natural gas-fired combined cycle plants over the last several years (see Table 4.4) and additional reductions required under the NO_X Budget Program. The emission reduction effects of new gas-fired generation have tapered off since 2004 because no new natural gas plants have been commercialized since that time.

Other factors have also contributed throughout the years to the reduction in calculated marginal emission rates shown. Since 1993, there has been an increase in the availability of existing New England nuclear units[14], and they have therefore been contributing more toward satisfying the base load electrical demand of the system. This base load 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.

[14] This increase in nuclear availability is illustrated in *Understanding New England Generating Unit Availability* http://www.iso-ne.com/pubs/spcl_rpts/2002/Understanding_New_England_Generating_Unit_Availability.pdf

Figure 5.3: Historically Calculated New England NO_X Marginal Emission Rate

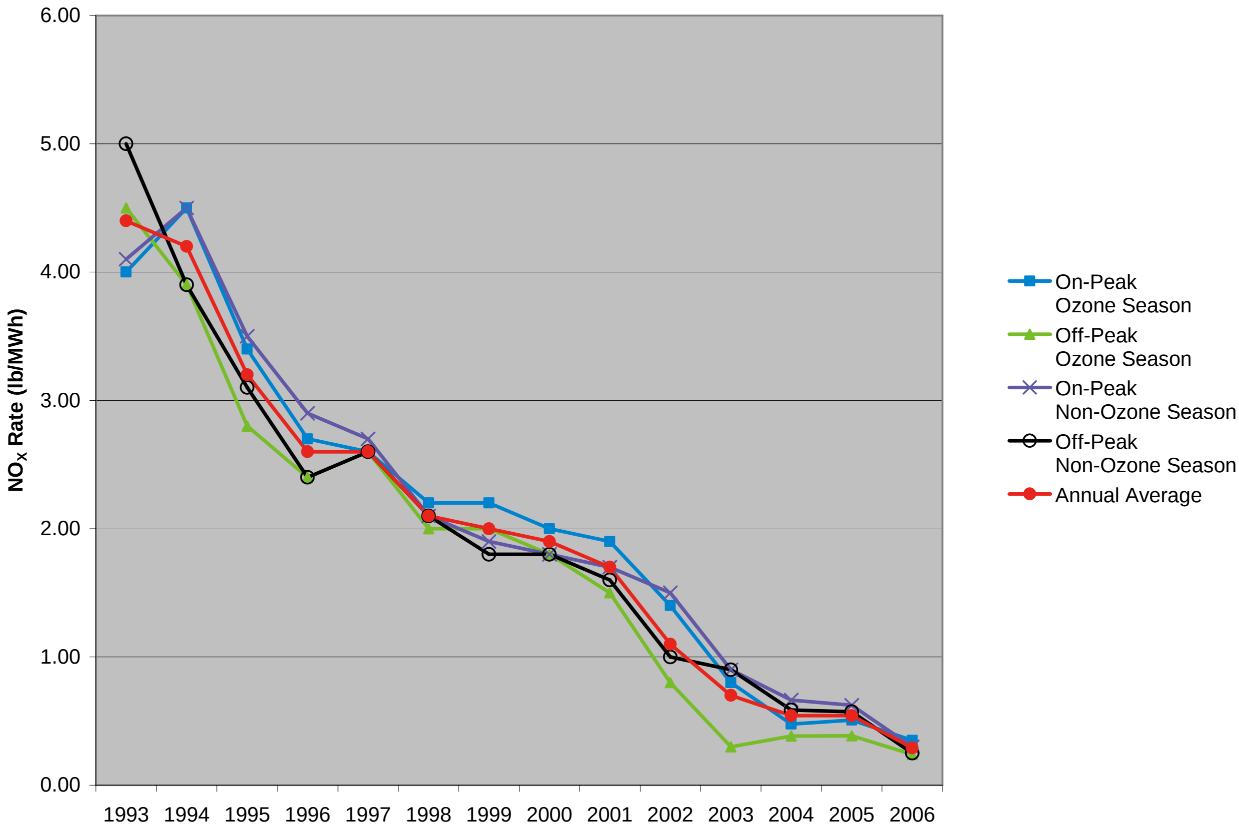


Figure 5.4: Historically Calculated New England SO_2 Marginal Emission Rates

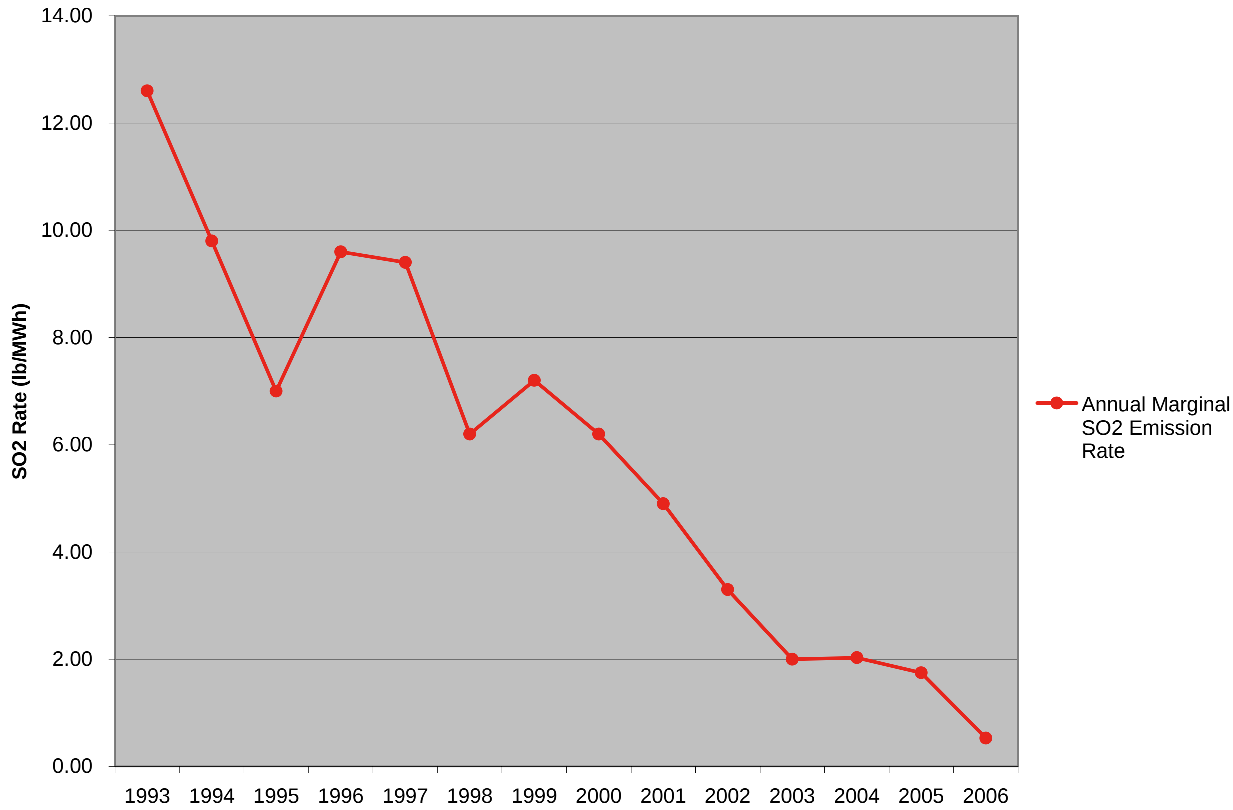
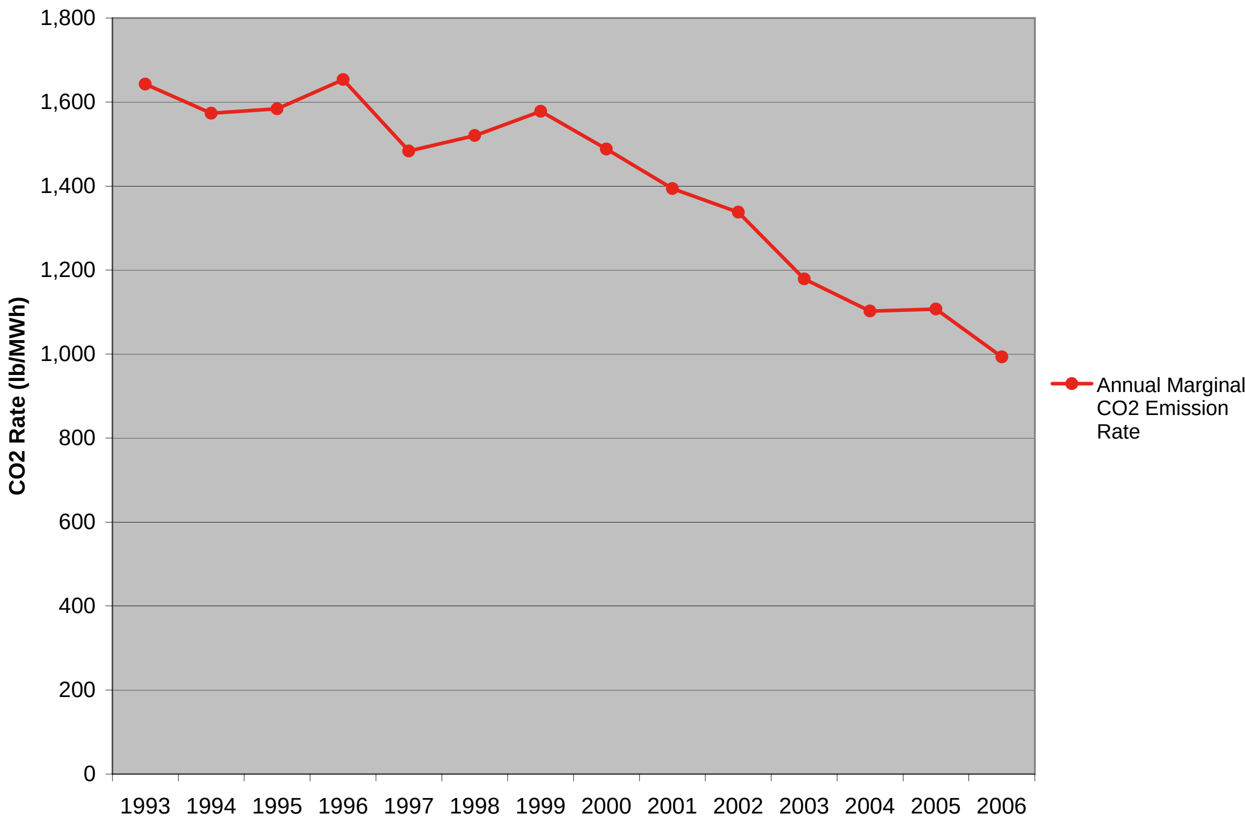


Figure 5.5: Historically Calculated New England CO_2 Marginal Emission Rate



5.4 CALCULATED MARGINAL EMISSION RATES BY STATE

Table 5.7, Table 5.8, and Table 5.9 show the 2006 calculated NO_X, SO_2 and CO_2 marginal air emission rates for each state based on the generation that operated in each 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 capacity located within each state is the major factor in the calculated marginal emission rates. For example, Rhode Island, where 99% of its in-state capacity is gas-fired combined cycle, has much lower marginal emissions rates than Vermont, which has the highest. Although the total emissions in Vermont are the lowest in New England, the marginal emission rates are high because the generating units in the marginal fossil category are mostly older internal combustion engines and gas turbine units.

Table 5.7: 2006 Calculated New England NO_X Marginal Emission Rates by State (lbs/MWh)

State	Ozone Season		Non-Ozone Season		
	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)
Connecticut	0.56	0.36	0.42	0.35	0.43
Maine	0.17	0.14	0.15	0.15	0.16
New Hampshire	0.26	0.09	0.25	0.10	0.18
Rhode Island	0.14	0.10	0.16	0.14	0.14
Vermont	5.76	4.91	5.45	4.81	5.37
Massachusetts	0.39	0.26	0.33	0.30	0.32
New England Average	0.35	0.24	0.30	0.25	0.29

Table 5.8: 2006 Calculated New England SO_2 Marginal Emission Rates by State (lbs/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.45	0.29	0.38
Maine	0.13	0.05	0.09
New Hampshire	1.11	0.21	0.66
Rhode Island	0.01	0.01	0.01
Vermont	4.72	4.43	4.63
Massachusetts	0.84	0.79	0.82
New England Average	0.60	0.46	0.53

Table 5.9: 2006 Calculated New England CO_2 Marginal Emission Rates by State (lbs/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	1,062	994	1,030
Maine	968	981	975
New Hampshire	952	882	917
Rhode Island	933	910	925
Vermont	2,258	2,196	2,238
Massachusetts	1,026	1,003	1,015
New England Average	1,007	977	993

5.5 CALCULATED NEW ENGLAND SYSTEM AVERAGE EMISSIONS

In addition to calculating the marginal emission rates, the aggregate emissions of the entire system were also calculated. The 2006 system average emissions were calculated using the same types of data as the marginal emissions calculations: actual hourly generation reported to ISO-NE, along with available monthly or annual EPA emissions data, or, alternatively, assumed emission rates based on unit type. Table 5.10 shows the aggregate NO_X, SO_2, and CO_2 air emissions calculated based on the actual hourly unit generation of all generating units in ISO's balancing authority area and the actual or assumed unit air emission rates.

Table 5.10: 2006 Calculated New England Generation System Annual Aggregate Emissions of NO_X, SO_2, and CO_2 in kTons[15]

State	NO_X	SO_2	CO_2
Connecticut	7.39	6.58	11,018
Maine	5.59	1.46	4,394
Massachusetts	19.77	52.21	24,708
New Hampshire	8.94	41.13	8,158
Rhode Island	0.55	0.29	2,753
Vermont	0.64	0.11	617
New England	42.86	101.78	51,649

Table 5.11 shows the aggregate NO_X, SO_2, and CO_2 air emissions for the years 2001 through 2006, as calculated based on the modeled and actual generation[16] and the actual or assumed air emissions.

Table 5.11: 2001 - 2006 Calculated New England Generation System Annual Aggregate Emissions of SO_2, NO_X, 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

Table 5.12 illustrates the annual average SO_2, NO_X, and CO_2 air emission rate values in lbs/MWh for the 1999 – 2006 time period. These rates were calculated by dividing the total air emissions by the total generation from all units.

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[15] Sum may not equal total due to rounding

[16] The 1999-2003 data is based on production simulation model results while the 2004 through 2006 data is based on actual generation and calculated air emissions.

Table 5.12: 1999 – 2006 Calculated New England Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lbs/MWh

Year	Total Generation (GWh)	NO_X	SO_2	CO_2
1999	104,409	1.36	4.52	1,009
2000	110,199	1.12	3.88	913
2001	114,626	1.05	3.51	930
2002	120,539	0.94	2.69	909
2003	127,195	0.93	2.75	970
2004	129,459	0.78	2.31	876
2005	131,874	0.88	2.27	919
2006	128,046	0.67	1.59	808

Figure 5.6, Figure 5.7, and Figure 5.8 show the relationship between the system emission rates in Table 5.12 and the marginal emission rates for NO_X, SO_2, and CO_2 during that same period.

Figure 5.6: 1999 – 2006 Calculated New England Annual Average System Emission Rate vs. Marginal Emission Rate for NO_X, in lbs/MWh

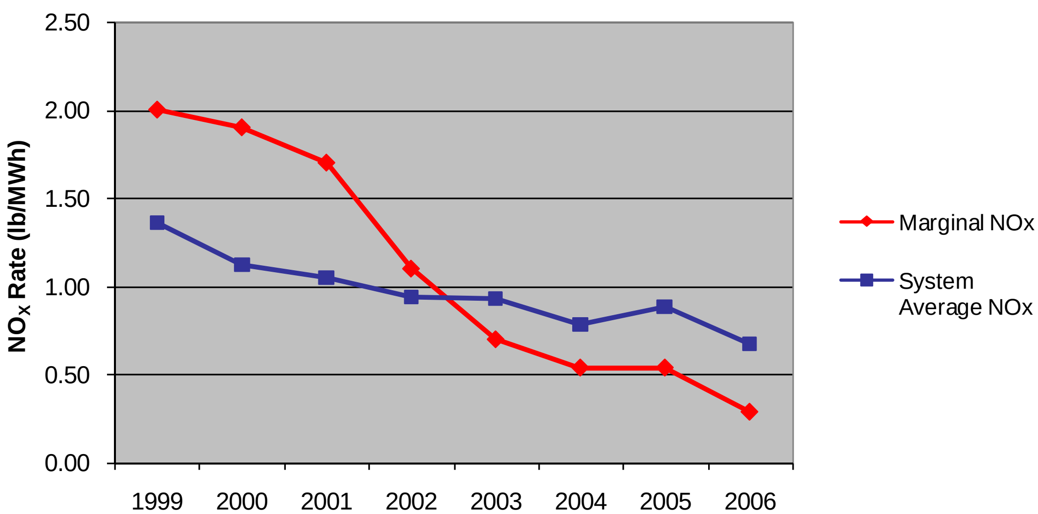


Figure 5.7: 1999 – 2006 Calculated New England Annual Average System Emission Rate vs. Marginal Emission Rate for SO_2, in lbs/MWh

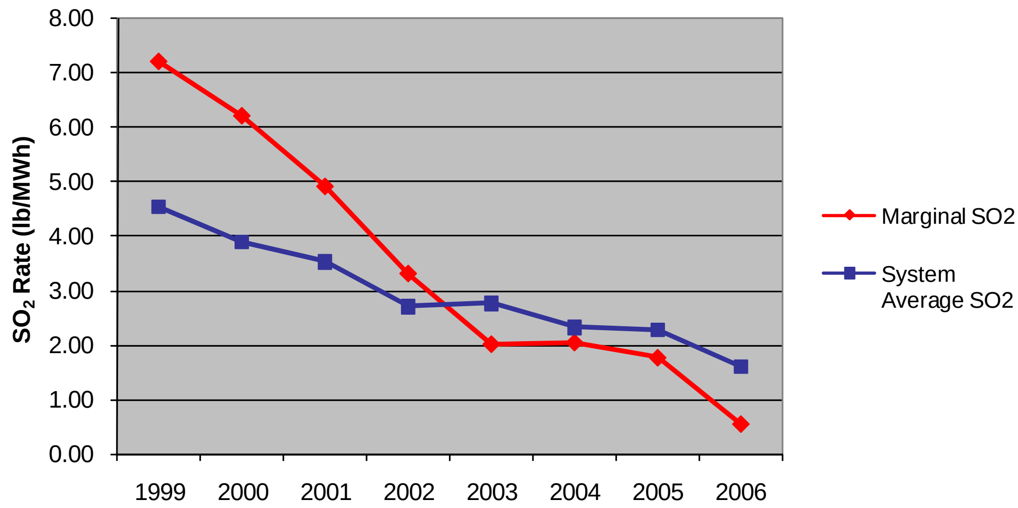
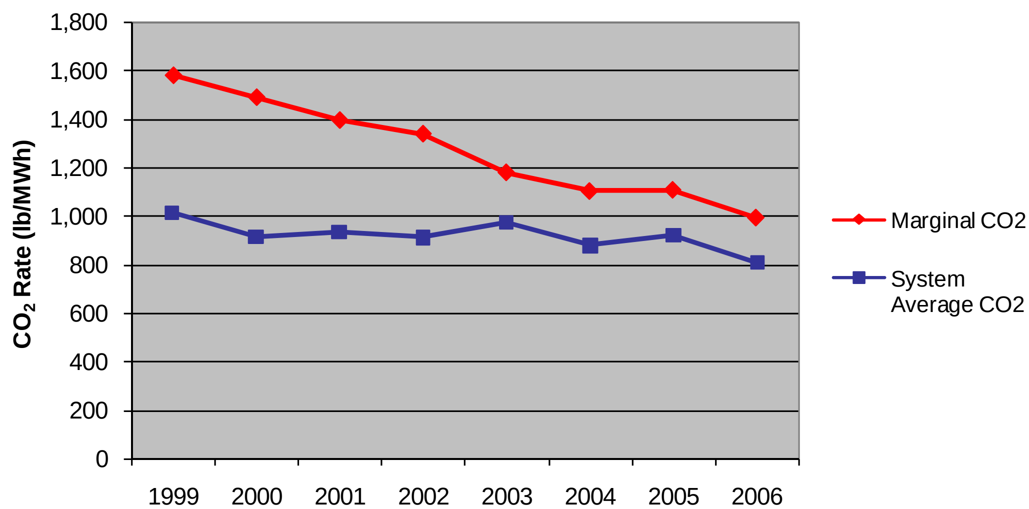


Figure 5.8: 1999 – 2006 Calculated New England Annual Average System Emission Rate vs. Marginal Emission Rate for CO_2, in lbs/MWh



5.5.1 Observations

During the period from 1999 to 2006, the system emission rates for both NO_X and SO_2 decreased, but at a slower rate than the marginal emission rates for those 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 system emission rate had only decreased by about 9% between 1999 and 2005, while the CO_2 marginal emission rate declined 30% during that period. This was caused by increased load growth and demand for fossil energy that is counteracting the lower marginal CO_2 rates as new units are added. However, in 2006 the significant decrease in calculated marginal CO_2 emission rates was accompanied by a similar decrease in the calculated system emission rate for CO_2, bringing the reduction in system emissions to 20% below 1999 levels. 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 2006.

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