2007 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 2007 New England Marginal Emission Rate Analysis (MEA Report) provides estimates of marginal NO_X, SO_2, and CO_2 air emissions for calendar year 2007. Marginal emission rates were calculated using the energy weighted average emission rates of generating units that would typically increase their output if regional energy demands were higher during the time periods of interest. In this document, these units are referred to as *marginal fossil* units[1]. The results of the 2007 marginal emission rate calculations are shown in Table 1.1 in pounds per megawatt-hour (lb/MWh) and Table 1.2 in pounds per million British thermal units (lb/MBtu)[2].

Table 1.1: 2007 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	0.25	0.20	0.34	0.30	0.28
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.60	0.53		0.57
CO_2		995	1,014		1,004

Table 1.2: 2007 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	0.031	0.025	0.043	0.037	0.034
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.074	0.065		0.070
CO_2		123	125		124

[1] *Marginal fossil* units, as defined in Section 3.1, are those fossil units that are fueled with oil (including residual, distillate, diesel, kerosene and jet fuel), and/or natural gas.
[2] To convert from lb/MWh to lb/MBtu, the 2007 calculated marginal heat rate of 8.095 MBtu/MWh is used.

For the marginal fossil units, the 2007 marginal emission rates were calculated using primarily measured emissions reported to the U.S. EPA and actual 2007 hourly generation data received by the ISO. 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 2007 calculated marginal heat rate was also determined using mostly heat input data obtained from the U.S. EPA and actual 2007 generation. This rate was used to convert the marginal emission rates from lb/MWh to lb/MBtu. The 2007 calculated marginal heat rate was determined to be 8.095 MBtu/MWh.

Calculated marginal emission rates for 2007 have not changed significantly from the 2006 calculated values. The NO_X rate decreased by 3.4%. Although there were increases in both the SO_2 and CO_2 rates of 7.5% and 1.1%, respectively, both of those emission rates are continuing along a generally decreasing trend. The small changes in 2007 follow significant decreases that occurred in 2006, primarily due to a substantial reduction in generation by residual oil-fired plants on the margin. Residual oil-fired generation rose in 2007, increasing by about 24% over 2006 values.

The calculated marginal heat rate also increased slightly between 2006 and 2007. Specifically, the rate increased from 7.667 MBtu/MWh to 8.095 MBtu/MWh.

The aggregate average annual emission rates of the New England system were also calculated. The results showed that the 2007 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. Similar to the changes in the marginal rates, the NO_X system rate decreased and the SO_2 and CO_2 rates increased in 2007.

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 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, 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 2006 to provide similar annual environmental analysis for those years. The 2007 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 2007.

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 generator air emissions between these two scenarios. However, this methodology had some drawbacks. Since the reference case results were based on production simulation modeling, the reference case could never exactly match the unit-specific energy production levels of the previous year due to numerous modeling reasons, including market dynamics, out-of-merit and reliability-based dispatches, and specific outages and deratings.

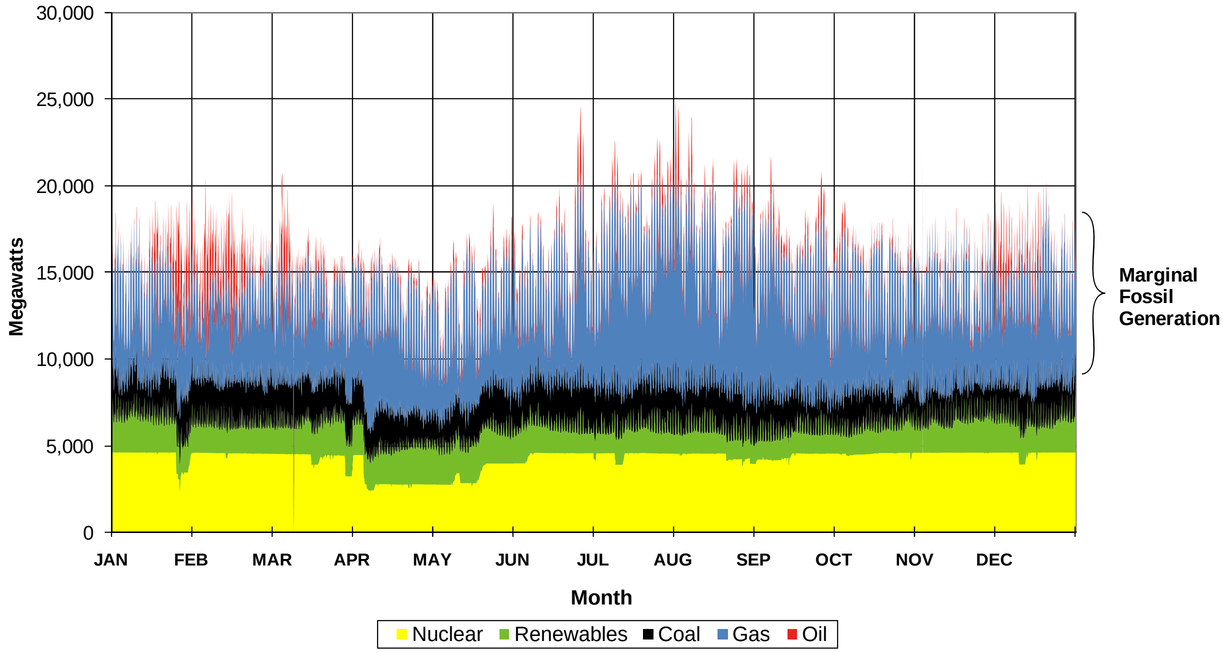
In 2004, a new methodology was developed to calculate the average emission rates of those units that are assumed to increase their loading during periods of high energy demand. This methodology used the actual metered hourly generation transmitted to ISO-NE, and annual air emissions and emission rates from the U.S. Environmental Protection Agency's (EPA) databases, along with other default emissions data. For the time periods investigated, the average air emission rates of a defined subset of generating units, the marginal fossil units, were calculated based on this information. 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 Generation Information System (GIS) were used, when available, to improve the accuracy of the calculations. This methodology was further improved in the 2007 MEA Report with the use of hourly emissions data, for those units that report hourly emissions to the U.S. EPA.

The subset of units, referred to as marginal fossil units for purposes of the 2007 MEA Report, is comprised of those fossil units that are fueled with oil (including residual, distillate, kerosene, diesel and jet fuel), and/or natural gas. Fossil 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 load on the system.[3] Non-emitting resources such as hydro and wind, as well as nuclear units, are also excluded from the marginal calculation.

Figure 3.1 shows the 2007 New England hourly generation and illustrates the way in which natural gas and oil units typically respond to changes in 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 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.

Figure 3.1: New England 2007 Hourly Generation



As noted earlier, 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:

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

This report calculates the 2007 marginal air emission rates for on- and off-peak periods for New England and each of the six states. 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 reductions during those hours. The marginal emission rates for NO_X are calculated for five time periods:

- 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

4.0 DATA AND ASSUMPTIONS

The key parameters and assumptions modeled in the 2007 Marginal Emission Rate Analysis are highlighted in this section. They include weather, emission rates, and installed capacity.

4.1 2007 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 marginal emission rates by comparing total energy use and both cooling and heating degree days to previous years.

In New England, the summer of 2007 can be characterized as normal with respect to overall temperature and humidity. The summer peak electricity demand of 26,145 MW was 7.1% lower than the 2006 summer peak of 28,130 MW. There were 288 cooling degree days, which is 2% lower than the normal of 294 cooling degree days[4]. The net energy was 1.8% higher in 2007 than 2006 over the year as a whole, and was nearly the same as in 2006 during the ozone season months. With respect to the winter months, January 2007 can be characterized as very mild, with colder weather returning in late January and February, followed at the end of the year by a colder than normal December.

New England's 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 294 and the normal number of heating degree days is 6,252.

Table 4.1: New England Cooling and Heating Degree Days - 1993 through 2007

Year	Total Cooling Degree Days	Difference from Normal (%)	Total Heating Degree Days	Difference from Normal (%)
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%

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

4.2 Emission Rates

Individual generating unit emission rates were calculated from the 2007 actual hourly 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[5]. In the 2005 and 2006 MEA Reports, monthly U.S. EPA data rather than hourly data was used. Prior years' studies 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 (in 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 MEA study used annual emission rates (in lb/MWh) from the U.S. EPA's eGRID2007 Version 1.1 data[6] or, if that was not available, emission rates based on eGRID data obtained for similar units.

U.S. EPA Clean Air Markets data was the most significant source of emissions data used for this report. Approximately 98% of the SO_2 marginal emissions and 95% of the CO_2 marginal emissions were based on Clean Air Markets data. In the case of NO_X, Clean Air Markets data was used for 89% of total emissions by marginal units. Of the total system emissions, approximately 95% of the SO_2, 80% of the CO_2 and 61% 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. That resulted in overestimating the marginal and system emission rates since all CHP emissions but none of the heat generated are accounted for in the emission rates.

For those units that are included in the U.S. EPA database, the hourly emissions (in lbs) were grouped into on-peak and off-peak periods. When only monthly NEPOOL GIS data or annual eGRID data was available, those lb/MWh emission rates were multiplied by the associated monthly on-peak and off-peak generation. The pounds of emissions from each individual generator were then added together to obtain an annual total, which was then divided by the total on-peak or off-peak generation to get the emission rates in lb/MWh for that time period. In the case of NO_X, the monthly totals were combined into pounds of ozone and non-ozone season emissions and divided by the ozone and non-ozone season generation.

The use of U.S. EPA hourly emissions for a substantial portion of the emissions data in this year's MEA improves the accuracy of the on-peak and off-peak marginal emission rates. In prior MEA reports, on- and off-peak emissions were estimated by using hourly generation data to allocate the monthly U.S. EPA emissions to on- and off-peak periods.

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

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 2008 Capacity, Energy, Loads and Transmission (CELT) Report[7] for the summer and winter period, respectively. Table 4.4 illustrates the capacity that was added to the New England system during 1999 through 2007, 91% of which was gas-fired, combined cycle technologies.

Table 4.2: New England Summer Capacity – 2008 CELT[8, 9]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Combined Cycle	1,744.4	23.1	5,232.9	39.8	1,406.1	42.6	1,165.6	28.9	1,823.3	99.5	-	-	11,372.2	36.8
Gas Turbine	740.4	9.8	617.9	4.7	162.3	4.9	87.6	2.2	-	-	82.8	7.8	1,691.0	5.5
Hydro	106.7	1.4	245.6	1.9	587.1	17.8	456.2	11.3	0.5	0.0	281.7	26.4	1,677.9	5.4
Internal Combustion	9.3	0.1	122.4	0.9	13.0	0.4	6.0	0.1	7.8	0.4	24.2	2.3	182.7	0.6
Nuclear	2,021.2	26.8	677.3	5.2	-	-	1,245.5	30.9	-	-	604.3	56.7	4,548.2	14.7
Pumped Storage	29.4	0.4	1,659.7	12.6	-	-	-	-	-	-	-	-	1,689.1	5.5
Fossil Steam	2,886.9	38.3	4,574.4	34.8	1,128.5	34.2	1,073.3	26.6	-	-	72.5	6.8	9,735.5	31.5
Wind	-	-	3.5	0.0	-	-	0.6	0.0	0.7	0.0	0.7	0.1	5.4	0.0
Total	7,538.3	100.0	13,133.7	100.0	3,296.9	100.0	4,034.6	100.0	1,832.3	100.0	1,066.1	100.0	30,901.9	100.0

Table 4.3: New England Winter Capacity – 2008 CELT[7, 8]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Combined Cycle	1,993.5	24.8	6,166.2	42.6	1,535.5	43.1	1,317.8	31.1	2,075.4	98.8	-	-	13,088.4	39.0
Gas Turbine	916.2	11.4	846.6	5.8	204.3	5.7	108.1	2.6	-	-	108.9	9.5	2,184.0	6.5
Hydro	125.0	1.6	268.8	1.9	627.9	17.6	484.7	11.4	3.1	0.1	314.2	27.3	1,823.7	5.4
Internal Combustion	11.2	0.1	124.4	0.9	19.7	0.6	6.0	0.1	20.7	1.0	32.1	2.8	213.9	0.6
Nuclear	2,037.4	25.3	684.7	4.7	-	-	1,245.4	29.4	-	-	620.3	53.9	4,587.9	13.7
Pumped Storage	29.0	0.4	1,665.0	11.5	-	-	-	-	-	-	-	-	1,694.0	5.0
Fossil Steam	2,940.1	36.5	4,723.7	32.6	1,174.8	33.0	1,074.7	25.4	-	-	74.6	6.5	9,987.9	29.7
Wind	-	-	3.5	0.0	-	-	0.6	0.0	0.7	0.0	1.7	0.1	6.4	0.0
Total	8,052.4	100.0	14,482.9	100.0	3,562.1	100.0	4,237.3	100.0	2,099.7	100.0	1,151.7	100.0	33,586.1	100.0

[7] The CELT Report is typically issued in April of each year. The 2008 CELT Report (using the January 1, 2008 ratings) was used in order to completely capture all the capacity additions that occurred during calendar year 2007.
[8] Sum may not equal total due to rounding.
[9] Capability as of January 1, 2008

Table 4.4: New England Generator Unit Additions - 1999 through 2007[10]

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

[10] Sum may not equal total due to rounding

Generator Name	State	Unit Type	Summer Capability (MW)	Winter Capability (MW)	Commercial Date
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
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**	
Coventry Clean Energy #4	VT	Landfill Gas	2	2	01/20/2007
East Windsor NORCAP LFG Plant	CT	Landfill Gas	3	3	05/07/2007
MATEP (Diesel)	MA	Diesel	20	20	06/28/2007
Jiminy Peak Wind	MA	Wind Turbine	2	2	07/01/2007
Waste Management Landfill	MA	Landfill Gas	3	3	08/29/2007
John Street 3	CT	Diesel	2	2	09/26/2007
John Street 4	CT	Diesel	2	2	09/26/2007
Pierce Station	CT	Gas Turbine	77	97	10/01/2007
Essex Diesels	VT	Diesel	8	8	10/30/2007
John Street 5	CT	Diesel	2	2	11/01/2007
Covanta Haverhill – LF Gas	MA	Landfill Gas	2	2	12/05/2007
MAT3	MA	Diesel	18	18	12/11/2007
Misc. less than 1 MW			2	2	
2007 Totals			**143**	**163**	
1999-2007 Totals			**10,240**	**11,252**	

5.0 RESULTS

5.1 2007 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[11] was assumed and then 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 heat rate is equal to fuel consumption divided by generation[12], the calculated marginal heat rate is defined as follows:

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

Beginning with this 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. The individual heat input values using the two methods, in MBtu, were added together and divided by total generation by marginal fossil units.

The calculated annual marginal heat rate reflects the average annual efficiency of all of the marginal fossil units dispatched throughout 2007. The lower the marginal heat rate value, the more efficient the system or marginal generator(s) with respect to converting raw fuel into electricity.

The annual calculated marginal heat rates from 1999 to 2007 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
2007	8.095

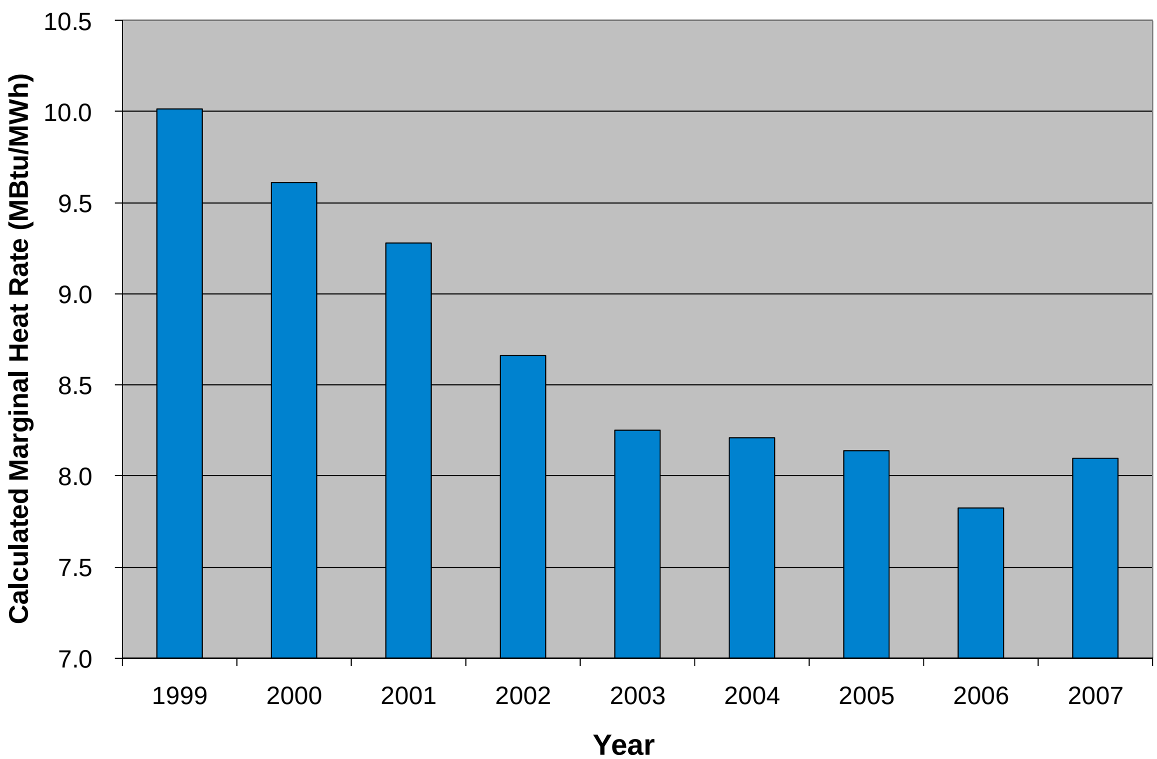
The 2007 calculated marginal heat rate was used as the conversion factor to convert from lb/MWh to lb/MBtu for the marginal emission rates in this report.

[11] 10 MBtu/MWh is equivalent to 10,000 BTU/kWh.
[12] 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.

5.1.1 Observations

Similar to marginal emission rates, there has been a significant decrease, followed by an increase, in the marginal heat rate over the past two years. In 2006, generation by older, less efficient residual oil-fired units decreased by about 66% from 2005 (see Figure 5.3), which contributed to a substantial drop in the marginal heat rate. A subsequent increase in residual oil-fired generation in 2007 was likely the primary reason for the increase in the marginal heat rate during that year to a level that was slightly lower than the 2005 heat rate. Overall, the trend of decreasing marginal heat rates has been continuing, with rates declining from 10.013 MBtu/MWh to 8.095 MBtu/MWh over the past nine years. This is primarily due to the addition of over 9,000 MW of natural gas-fired, combined cycle units with higher efficiency, i.e lower heat rates. Figure 5.1 illustrates the calculated marginal heat rate spanning the 1999 – 2007 timeframe.

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



5.2 2007 New England Generation Marginal Emission Rates

Table 5.2 shows the NO_X, SO_2, and CO_2 calculated marginal emission rates in lb/MWh for New England's 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 lb/MBtu. As noted earlier, the 2007 calculated marginal heat rate of 8.095 MBtu/MWh was used as the conversion factor.

Table 5.2: 2007 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	0.25	0.20	0.34	0.30	0.28
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.60	0.53		0.57
CO_2		995	1,014		1,004

Table 5.3: 2007 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	0.031	0.025	0.043	0.037	0.034
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.074	0.065		0.070
CO_2		123	125		124

5.2.1 Observations

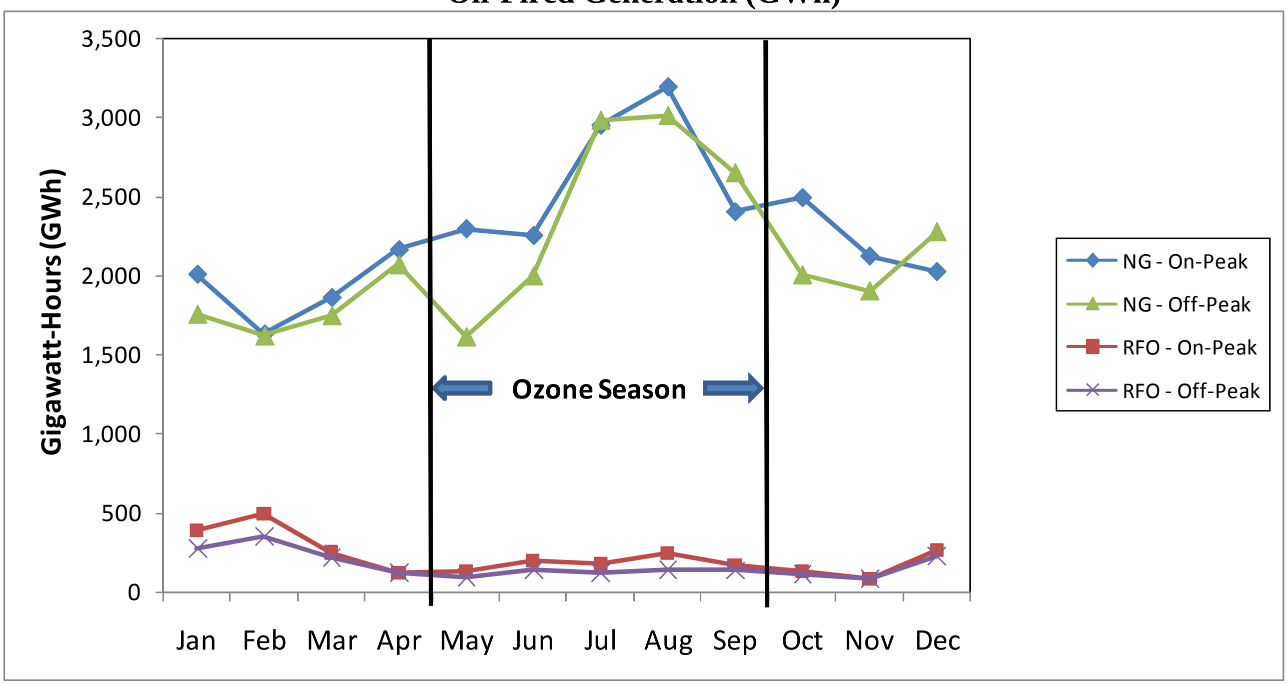
New England's power plant air emissions are directly dependent on the specific units that are available and dispatched to serve load for each hour of the year. Therefore, there could be wide variations in seasonal emissions, primarily due to changes in economic and reliability dispatch, unit availability,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

In the case of NO_X and SO_2 emission rates, the on-peak marginal rates are 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 generally has higher emission rates. These are typically peaking units that are more expensive or even uneconomic to operate except in high energy price hours, or are older, fossil-steam resources with higher individual heat rates, i.e., lower thermal efficiency. The on-peak CO_2 emission rates are just slightly lower than the off-peak rates.

Table 5.2 shows that in 2007, NO_X emission rates during both the on-peak and off-peak hours of the ozone season were lower than those same emission rates 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 lower NO_X emission rates during the ozone season could be explained by the fact that generation by plants burning residual fuel oil was significantly lower during those months than during the non-ozone season. Figure 5.2 shows the monthly natural gas and residual oil-fired generation in 2007[13]. The higher level of generation by residual oil-fired plants during the winter months is consistent with the temperatures at that time, which were relatively warm for most of January, and cold in both February and December 2007. The fuel price-parity relationships between natural gas and oil during the winter months may have also contributed to this outcome. In addition, in the states that are under the summer-time EPA NO_X Budget (cap and trade) Program, it may be cheaper for companies to operate their lower-emitting generating units because they would not need to use as many NO_X allowances.

Figure 5.2: 2007 Monthly On-Peak and Off-Peak New England Natural Gas and Residual Oil-Fired Generation (GWh)



[13] Generation by a particular fuel type is based on the primary fuel type as specified in the 2007 CELT Report.

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 lb/MWh for the years 1993 through 2007. 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 5.4, Figure 5.5, and Figure 5.6 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 (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

Table 5.5: 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

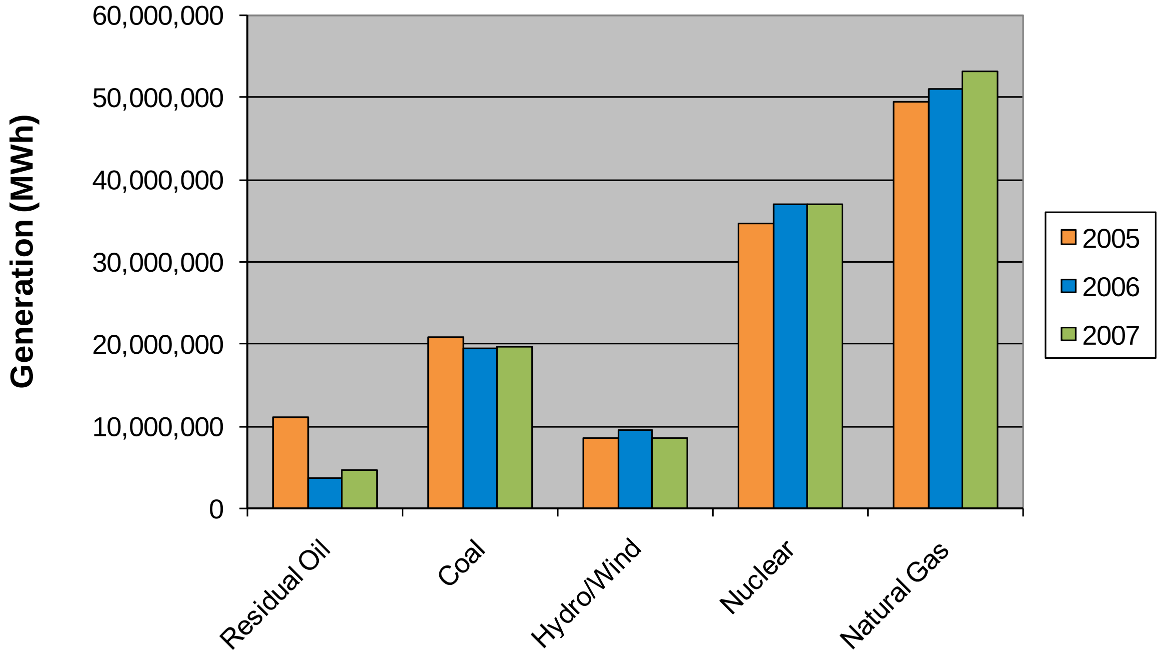
Table 5.6: Calculated New England Generation CO_2 Marginal Emission Rates (lb/MWh)

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
2007	1,004	1.1

5.3.1 Observations

Table 5.4, Table 5.5 and Table 5.6 show that there was little change in the average annual marginal emission rates between 2006 and 2007. NO_X emission rates decreased by 3.4%, while SO_2 emission rates increased by 7.5%, and CO_2 emission rates increased by 1.1%. These relatively small changes between 2006 and 2007 follow significant decreases in emission rates between 2005 and 2006. This was attributed to the overall reduction in generation by residual oil-fired units in 2006 and an increase in non- and low-emitting generation, as seen in Figure 5.3. In 2007, residual oil-fired generation increased to about 4,700 GWh, an approximately 900 GWh increase over 2006 levels. This was accompanied by a slight increase in natural gas generation. A small increase in generation by coal-fired units, and a slight decrease in hydro-electric and wind generation and no change in nuclear generation, also contributed to the higher system emission rates for SO_2 and CO_2. Overall, system load was about 2,300 GWh higher in 2007 than in 2006.

Figure 5.3: 2007 Generation by Selected Fuel Types Based on Primary Fuel Type in 2008 CELT Report



Since 1993, there has been a significant decrease in the marginal emission rates. In fourteen years, SO_2 and NO_X annual marginal rates have declined by over 93% and CO_2 by nearly 39%. This decline is clearly illustrated in Figure 5.4 Figure 5.5 and Figure 5.6. There was 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 I of the 1990 Clean Air Act Amendments. This trend of decreasing NO_X marginal emission rates continued into the 2007 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 emission reductions as required under the Ozone Transport Commission's 1999 and U.S. EPA's 2003 NO_X Budget Program. The emission reduction effects of new gas-fired generation have tapered off since 2004, primarily because the addition of new, larger natural gas-fired power plants has been minimal since that time.

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 existing New England nuclear units, 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.

Figure 5.4: Historically Calculated New England NO_X Marginal Emission Rate

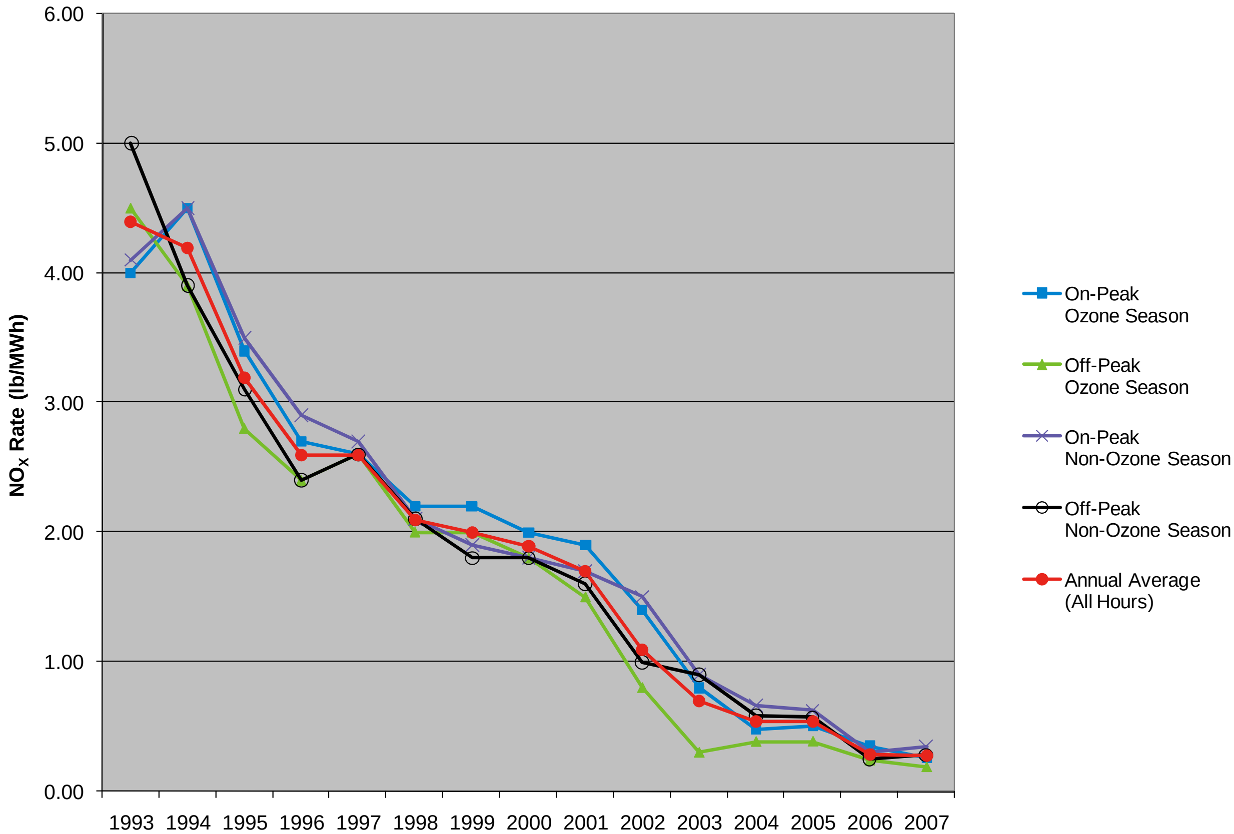


Figure 5.5: Historically Calculated New England SO_2 Marginal Emission Rates

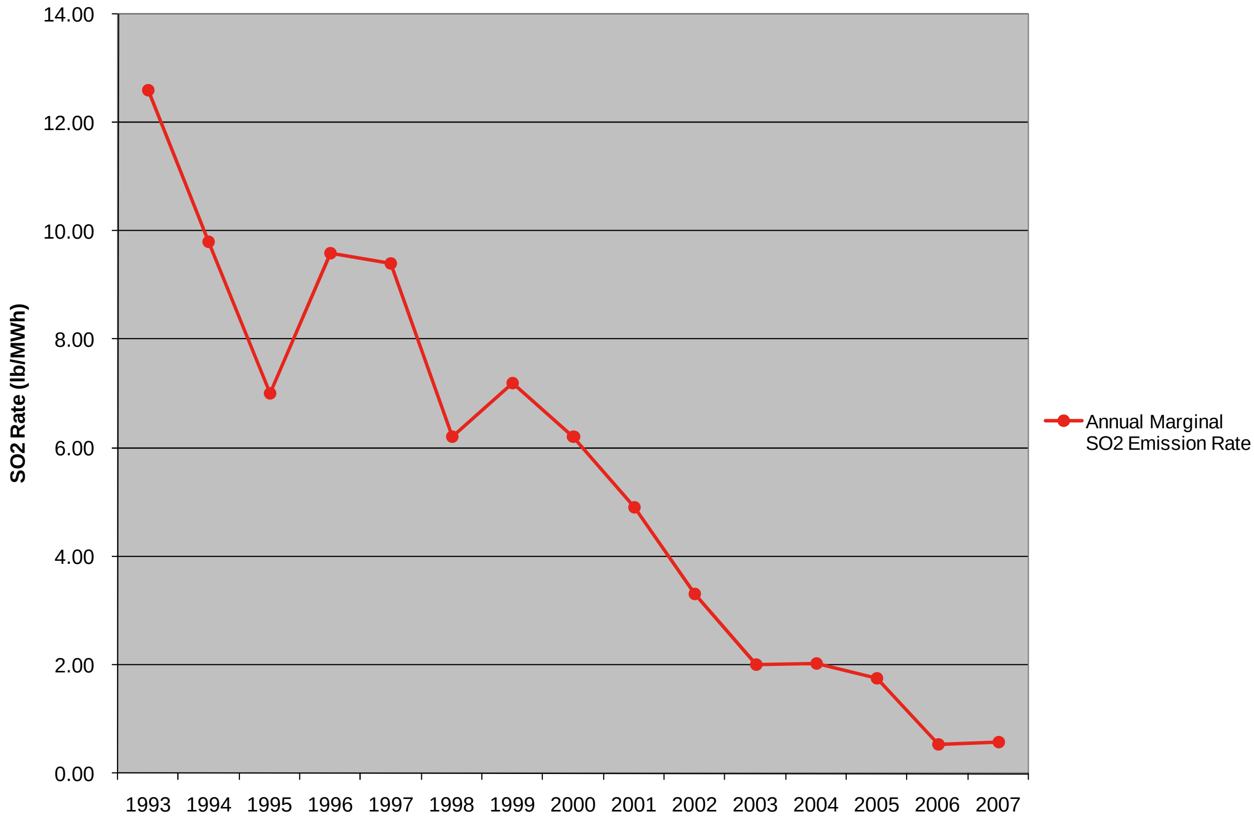
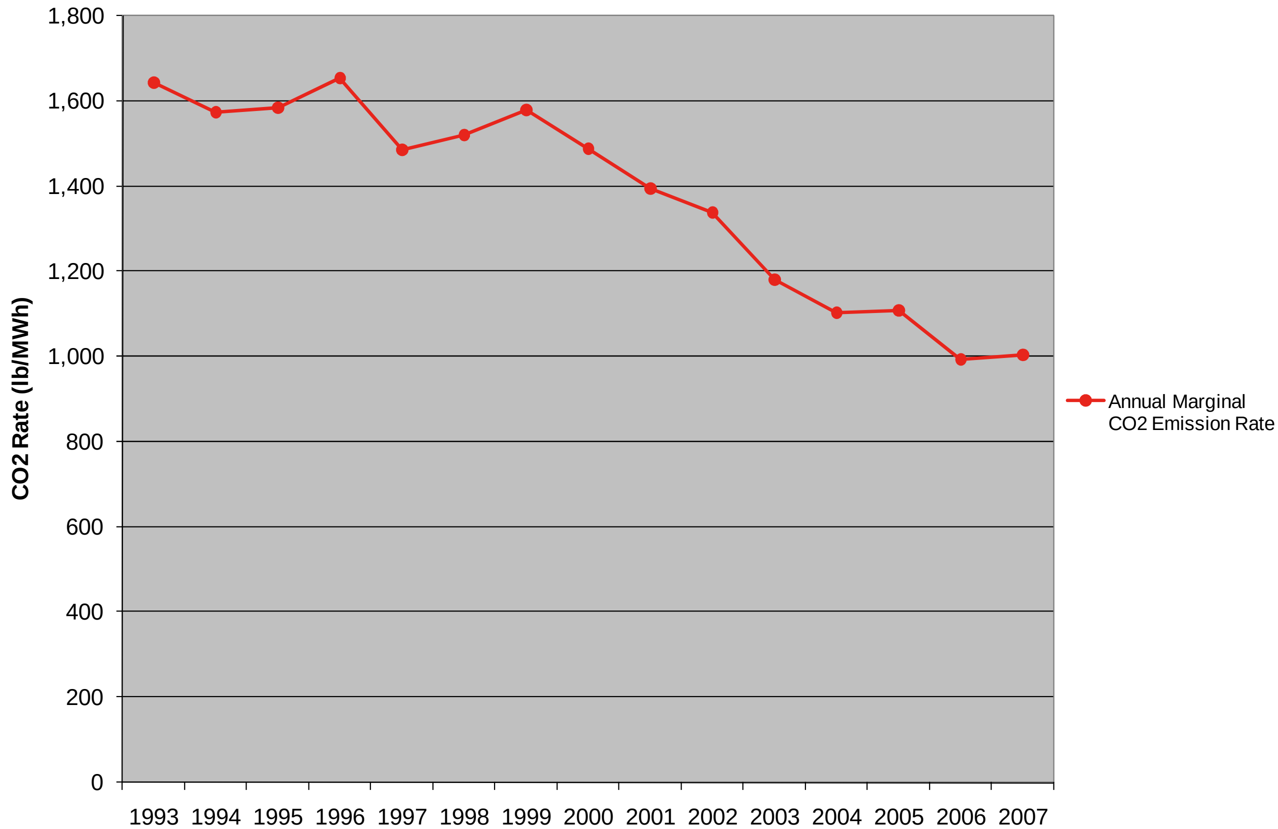


Figure 5.6: Historically Calculated New England CO_2 Marginal Emission Rate



5.4 CALCULATED MARGINAL EMISSION RATES BY STATE

Table 5.7, Table 5.8, and Table 5.9 show the 2007 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 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 emissions 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, internal combustion engines and gas turbine units.

Table 5.7: 2007 Calculated New England NO_X Marginal Emission Rates by State (lb/MWh)

State	Ozone Season		Non-Ozone Season		
	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)
Connecticut	0.44	0.30	0.50	0.46	0.43
Maine	0.17	0.18	0.28	0.28	0.23
New Hampshire	0.12	0.08	0.42	0.22	0.21
Rhode Island	0.10	0.14	0.16	0.19	0.14
Vermont	5.18	5.72	6.24	5.98	5.69
Massachusetts	0.27	0.21	0.33	0.28	0.27
New England Average	0.25	0.20	0.34	0.30	0.28

Table 5.8: 2007 Calculated New England SO_2 Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.43	0.34	0.39
Maine	0.56	0.43	0.50
New Hampshire	1.07	0.46	0.77
Rhode Island	0.01	0.01	0.01
Vermont	2.17	2.77	2.38
Massachusetts	0.75	0.74	0.75
New England Average	0.60	0.53	0.57

Table 5.9: 2007 Calculated New England CO_2 Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	1,037	1,040	1,039
Maine	1,023	1,096	1,058
New Hampshire	959	928	943
Rhode Island	925	945	933
Vermont	2,511	2,540	2,521
Massachusetts	998	1,017	1,008
New England Average	995	1,014	1,004

5.5 CALCULATED NEW ENGLAND SYSTEM AVERAGE EMISSIONS

In addition to calculating the marginal emission rates, the aggregate air emissions of the entire system were also calculated. The 2007 system average emissions were calculated using the same data as the marginal emissions calculations, with the addition of annual emissions data for the non-marginal units and actual hourly generation reported to ISO-NE for all units. The annual emissions data was obtained from the U.S. EPA or the NEPOOL GIS, or, alternatively, was assumed based on unit type. Table 5.10 shows the aggregate 2007 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 hourly unit generation of all generating units in ISO's balancing authority area and the actual or assumed unit air emissions or emission rates, using emissions data sources similar to those of the marginal units.

Table 5.10: 2007 Calculated New England Generation System Annual Aggregate Emissions of NO_X, SO_2, and CO_2 in Short kTons[14]

State	NO_X	SO_2	CO_2
Connecticut	7.85	6.94	11,995
Maine	3.87	3.63	6,234
Massachusetts	15.83	54.92	28,017
New Hampshire	6.19	42.86	8,869
Rhode Island	0.57	0.33	3,393
Vermont	0.70	0.13	661
New England	35.01	108.80	59,169

Table 5.11 shows the aggregate annual NO_X, SO_2, and CO_2 air emissions for the years 2001 through 2007, as calculated based on the modeled and actual generation[15] and the actual or assumed air emissions or emission rates.

Table 5.11: 2001 - 2007 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
2007	35.01	108.80	59,169

[14] Sum may not equal total due to rounding
[15] The 2001through 2003 data is based on production simulation model results while the 2004 through 2007 data is based on actual generation and calculated air emissions.

Table 5.12 shows the average 2007 NO_X, SO_2, and CO_2 air emission rates in 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 air emissions or emission rates.

Table 5.12: 2007 Calculated New England Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lb/MWh

State	NO_X	SO_2	CO_2
Connecticut	0.48	0.42	727
Maine	0.67	0.63	1,079
Massachusetts	0.64	2.22	1,136
New Hampshire	0.53	3.70	765
Rhode Island	0.16	0.09	972
Vermont	0.21	0.04	203
New England	0.54	1.67	906

Table 5.13 illustrates the annual average NO_X, SO_2, and CO_2 air emission rate values in lb/MWh for the 1999 – 2007 time period. These rates were calculated by dividing the total air emissions by the total generation from all units.

Table 5.13: 1999 – 2007 Calculated New England Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lb/MWh

Year	Total Generation[16] (GWh)	NO_X	SO_2	CO_2
1999	104,409	1.36	4.52	1,009
2000	110,199	1.12	3.88	913
2001	114,626	1.05	3.51	930
2002	120,539	0.94	2.69	909
2003	127,195	0.93	2.75	970
2004	129,459	0.78	2.31	876
2005	131,874	0.88	2.27	919
2006	128,046	0.67	1.59	808
2007	130,723	0.54	1.67	906

[16] The total generation shown in this table reflects total 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 generation has not been included in the total generation used for calculating the 2006 and 2007 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.

Figure 5.7, Figure 5.8, and Figure 5.9 show the relationship between the system emission rates in Table 5.13 and the marginal emission rates for NO_X, SO_2, and CO_2 during that same period.

Figure 5.7: 1999 – 2007 Calculated New England Annual Average System NO_X Emission Rate vs. Marginal NO_X Emission Rate, in lb/MWh

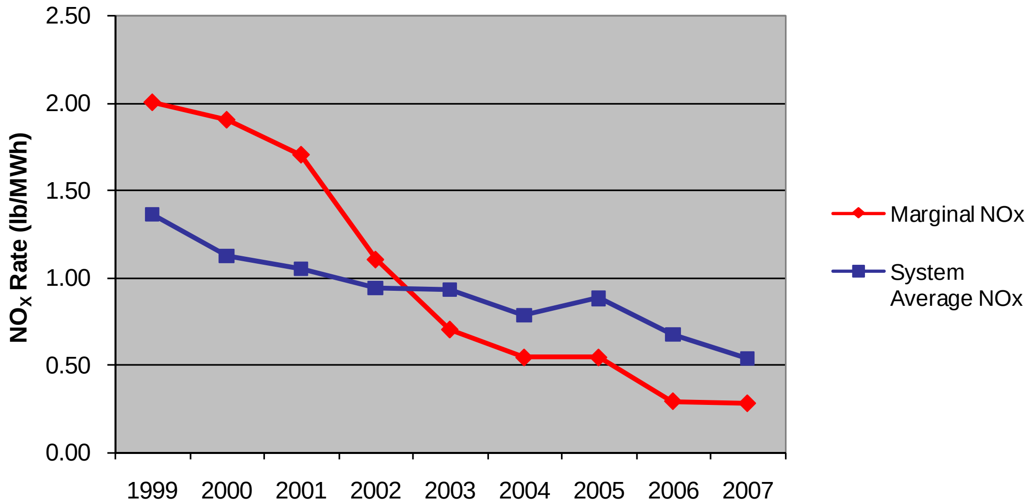


Figure 5.8: 1999 – 2007 Calculated New England Annual Average System SO_2 Emission Rate vs. Marginal SO_2 Emission Rate, in lb/MWh

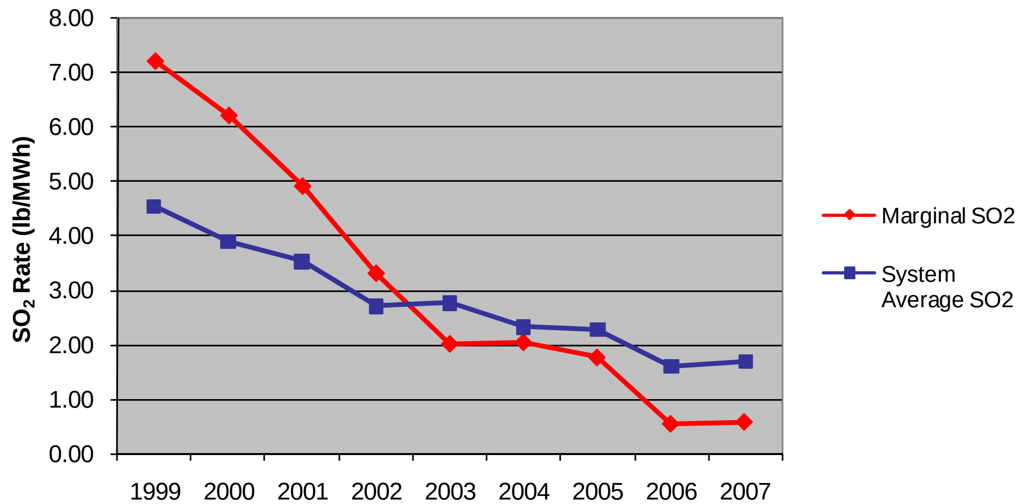
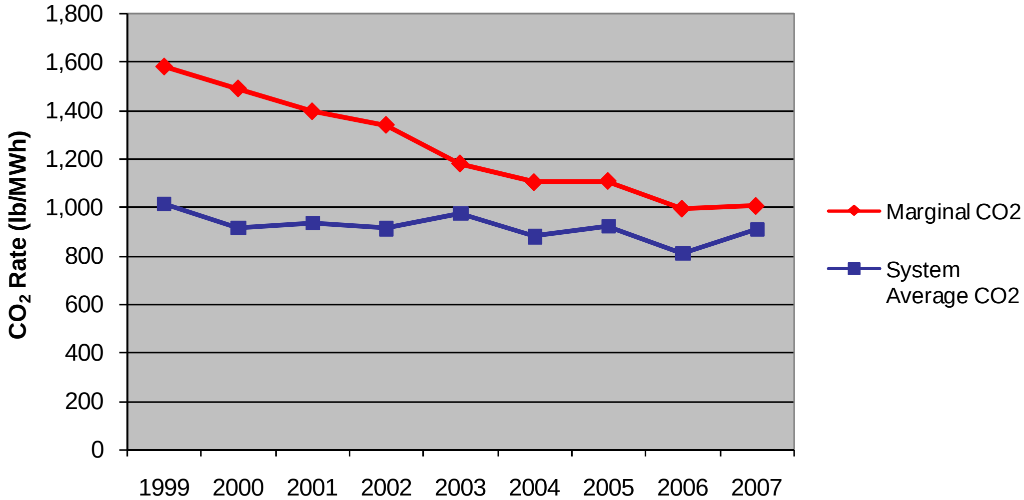


Figure 5.9: 1999 – 2007 Calculated New England Annual Average System CO_2 Emission Rate vs. Marginal CO_2 Emission Rate, in lb/MWh



5.5.1 <u>Observations</u>

During the period from 1999 to 2007, 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 decreased by about 10% between 1999 and 2007, while the CO_2 marginal emission rate declined 36% 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. In 2006, the significant decrease in the calculated marginal CO_2 emission rate was accompanied by a similar decrease in the calculated system emission rate for CO_2. However, in 2007, the CO_2 system emission rate went back up to the 2005 level while the marginal rate remained about the same as in 2006. 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 2007.

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