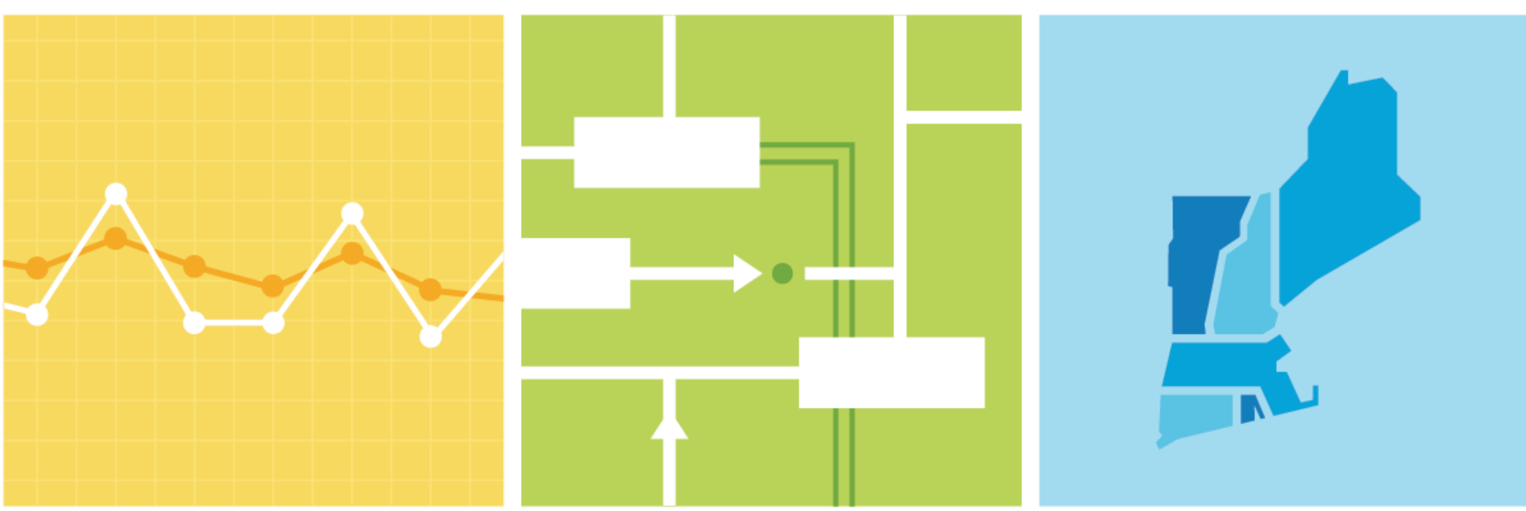
ISO New England Electric Generator Air Emissions Report: Background and Methodology

System Planning



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Section 1
Background

In 1994, the New England Power Pool (NEPOOL) Environmental Planning Committee (EPC) published the *1992 Marginal NO_X Emission Rate Analysis*, which examined the impact of demand-side management (DSM) programs on the nitrogen oxide (NO_X) air emissions of NEPOOL generating units. Results from this study helped support applications for NO_X Emission-Reduction Credits (ERC) in Massachusetts related to DSM programs, filed under the Massachusetts ERC banking and trading program that became effective January 1, 1994. [1] This program allows inventoried sources of NO_X, volatile organic compounds (VOC), and carbon monoxide (CO) in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Beginning with the *1993 Marginal Emission Rate Analysis*, published in 1994, annual MEA reports provided expanded analysis of the impact of DSM programs on power plant NO_X, sulfur dioxide (SO_2), and carbon dioxide (CO_2) air emissions.[2] In 2008, members of ISO New England's Environmental Advisory Group (EAG) requested that these annual reports be restructured to include both average and marginal emissions for the ISO New England generation system, rather than focusing primarily on marginal emissions.[3] In response, the annual report was revised and renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of average air emissions from the entire ISO New England electric generation system.

The *Emissions Report* includes a marginal emission rate analysis based on Locational Marginal Unit (LMU) methodology. This methodology, originally launched in 2011, uses marginal units identified by the Locational Marginal Price (LMP) to calculate the marginal emissions for LMUs. The emissions are based on a time-weighted approach, which reflects the percentage of time that a resource was marginal.

In response to a request by the EAG, in 2018 the ISO added a new, load-weighted LMU approach, which reflects emissions associated with the load served by the marginal unit when the system is constrained. This load-weighted approach is akin to the marginal unit reporting method used by the ISO New England Internal Market Monitor in their quarterly and annual reports.

Since 2020, estimated CO_2 emissions from imports have been included in the *Emissions Report*, which allows for an estimate of total CO_2 emissions from all of the electricity serving the ISO New England load, rather than just from New England generation. Stakeholders can use the calculated marginal emissions to track air emissions from ISO New England's electric generation system and to estimate the impact that DSM programs and non-emitting renewable energy projects (i.e., wind

[1] Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2020), https://www.mass.gov/doc/bwp-aq-18-creation-of-emission-reduction-credits-erc-form-instructions-march-2008/download

[2] ISO New England emissions analyses and reports from 1999 to the present are available at http://www.iso-ne.com/system-planning/system-plans-studies/emissions.

[3] The EAG is a stakeholder working group that assists the ISO's Planning Advisory Committee (PAC), the NEPOOL Reliability Committee (RC), and the NEPOOL Power Supply Planning Committee (PSPC); http://www.iso-ne.com/eag.

and solar units) have on reducing ISO New England's NO_X, SO_2, and CO_2 power plant air emissions. The *Emissions Report* focuses on analysis and observations from the past decade.

1.1 History of Marginal Emissions Methodologies

MEA studies performed before 2004 used production simulation models to replicate, as closely as possible, the actual system operations for the study year, since actual hourly generation, fuel type and emissions data were not readily available electronically. After this initial simulation (the reference case), an incremental load scenario was modeled in which the system load was increased by 500 MW each hour, representing the marginal case. Values for marginal air emission rates were based on the difference in air emissions between the reference and marginal scenarios. However, due to production simulation model limitations, the reference case simulation could not exactly match the actual unit-specific energy production levels of the study year. For example, the model could not accurately represent the historical dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit-specific short-term outages and deratings, or the effects of the daily volatility of regional (power plant) fuel prices.

From 2004 to 2013, Fuel Type Assumed (FTA) methodology was used to calculate marginal emission rates. This method relied on the assumption that only natural-gas-fired and oil-fired generators were capable of responding to changing system load by increasing or decreasing their production. Units fueled with other sources, such as coal, wood, biomass, refuse, or landfill gas, were excluded from the calculation, since historically (i.e., in the 2000s), these types of units operated as base load, must-run, or were non-dispatchable, and did not typically vary their output to balance supply with system demand. Other non-emitting resources, such as hydroelectric, pumped storage, wind, solar, and nuclear generators that do not vary their production output to follow load were also assumed not to be marginal units and were excluded from the FTA calculation of marginal emission rates.

In 2011, based on the recommendations of the Environmental Advisory Group (EAG), the ISO developed a methodology for calculating the marginal emission rate based on the locational marginal unit, and in 2014 began using this method in the emissions analysis. This methodology identifies marginal units using the LMP, a process that minimizes total cost of energy production for the entire ISO New England system while accounting for transmission and other constraints related to the physical limitations of the power system. This method identifies the last unit dispatched to balance the system, called the *locational marginal unit (LMU)*. Results relying on this methodology are available for 2009 onwards, the earliest year of available data.

This method was based on the assumption that multiple marginal resources operating within the same time interval will serve load equally, an approach this report refers to as the time-weighted LMU approach. However, in reality, when more than one resource is marginal, the system is typically constrained, and marginal resources likely do not contribute equally to serving load. At the request of regional stakeholders and the EAG, the ISO developed a new method for calculating marginal emission rates based on the percentage of system load a marginal unit can serve. This new load-weighted LMU approach was first included in the *2018 Emissions Report*, and relies on the same assumptions used by the ISO New England Internal Market Monitor (IMM) beginning in 2018 to report the percentage of the total system load that can be served by marginal units of a particular fuel or technology type.[4] Marginal emission rates based on the load-weighed LMU approach are included in emissions reports from 2018 onwards, along with time-weighted LMU marginal emission rates.

1.2 History of Marginal Heat Rate Methodologies

A thermal power plant's heat rate is a measure of its efficiency in converting fuel (in British thermal units (Btus)) to electricity (kWh): the lower the heat rate, the more efficient the electrical generator. A power plant's heat rate depends on variables like individual plant design, operating conditions, and level of electrical power output, etc.

Before 1999, MEA studies assumed a fixed marginal heat rate of 10.0 million BTUs per megawatt-hour (MMBtu/MWh).[5] In studies from 1999 to 2003, 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 fuel units only.

Since 2007, the marginal heat rate is calculated using a combination of both US Environmental Protection Agency (EPA) heat input data and heat-rate information collected and maintained by the ISO. Marginal fossil units with EPA data are based on the heat inputs reported to EPA. For units without EPA data, heat inputs are calculated by multiplying each unit's monthly generation by the heat-rate data provided to the ISO by the generators. These individual heat input values (in MMBtu) are then totaled, and the sum divided by the total generation of the marginal fossil units. The heat rates in MMBtu/MWh are used to convert the marginal emission rates from pounds (lbs)/MWh to lbs/MMBtu.

The total marginal heat rate is based on the heat rates for each individual LMU. In the original time-weighted methodology, the percentage of time each generator was marginal per year is used to calculate that unit's contribution to the time-weighted LMU marginal heat rate. The load-weighted LMU uses a similar marginal heat rate calculation based on the percentage of load served by each marginal generator.

[4] The IMM began weighting marginal resources based on their contribution to load to better illustrate the impact of the marginal resources on the LMP. Renewable-type generation resources with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in these areas. This is particularly true of wind resources, which became frequently marginal with the implementation of the Do Not Exceed (DNE) dispatch rules on May 25, 2016. DNE incorporates wind and hydro intermittent units into economic dispatch, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and could not set price.

[5] 10 MMBtu/MWh is equivalent to 10,000 Btu/kWh.

Section 2
Data Sources and Methodologies

This section describes the data sources and methodologies used for the emissions analysis of the *Emissions Report*, including calculations used for average emission rate, marginal emission rate and marginal heat rate, and time periods studied.

2.1 Data Sources

2.1.1 New England Generation

The primary data source for the ISO New England generation average emissions and marginal emission rate calculations for NO_x, SO_2, and CO_2 is the US EPA Clean Air Markets Program Data (CAMPD).[6] The database contains measured air emissions (tons) reported by generators under EPA's monitoring and recordkeeping requirements for the Acid Rain Program, NO_X mass emissions, and the Regional Greenhouse Gas Initiative (RGGI).[7]

Monthly emission rates (lbs/MWh) from the New England Power Pool Generation Information System (NEPOOL GIS) were used for those units not required to report emissions data to EPA under 40 CFR Part 75 for a federal or state regulation. If this information is unavailable, annual emission rates (lbs/MWh) from EPA's eGRID are used.[8] In cases where there are no other sources of data, emission rates are based on eGRID data for similar type units. These unit-specific emission rates are then applied to data taken from the ISO's energy market settlement database for the actual report year's megawatt-hours of energy production (generation) to calculate tons of emissions.

All electric generators and demand response resources dispatched by ISO New England are included in the emissions calculations. Emissions from "behind-the-meter" resources or those generators not within the ISO New England balancing authority area (BAA) are not part of this analysis.

2.1.2 Imports and Exports

CO_2 emission rates for imports from NYISO are based on the eGRID database, and CO_2 emission rates for imports from New Brunswick and Quebec are based on Canada's Greenhouse Gas Inventory Report.[9] These emission rates are then multiplied by the imported energy values reported in the Net Energy and Peak Load by Source Report for each neighboring BAA in order to

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[6] EPA's Clean Air Markets Program data are available at https://campd.epa.gov/ , and the Clean Air Power Sector Programs emissions data are available at http://www.epa.gov/airmarkets/. Generators report emissions to EPA under the Acid Rain Program, which covers generators 25 MW or larger. Generators subject to RGGI also report CO_2 emissions to EPA. Additional details for the monitoring, recordkeeping, and reporting requirements of SO_2, NO_X, and CO_2 emissions, volumetric flow, and opacity data from affected units under 40 CFR Part 75 are available at https://www.epa.gov/airmarkets/emissions-monitoring-and-reporting.

[7] Before 2005, MEA reports used annual data obtained primarily from the EPA Emissions Scorecard. In the 2005 and 2006 MEA reports, monthly EPA data, rather than hourly data, were used for calculating marginal rates.

[8] The U.S. EPA's eGRID database is available at https://www.epa.gov/egrid.

[9] Canadian greenhouse gas emissions reported as consumption intensity (g CO_2 eq/kWh) are located at https://publications.gc.ca/site/eng/9.506002/publication.html

calculate tons of emissions.[10] The assumed emission rate for exports is the ISO New England annual generation emission rate. This rate is then multiplied by the amount of exported energy in order to calculate total emissions associated with exports.

2.2 Average Emission Rate Calculation for New England Generation

The annual average emission rate for New England generation is based on the emissions produced by all ISO New England generators during a calendar year. The rates are calculated by dividing the total generator air emissions by the total generation from all units. The formula for calculating the annual New England generation emission rate is:

$$\text{Annual New England Generation Emission Rate (lbs/MWh)} = \frac{\text{Total Annual Emissions (lbs)}_{\text{All ISO-NE Generators}}}{\text{Total Annual Energy (MWh)}_{\text{All ISO-NE Generators}}}$$

2.3 Average Emission Rate Calculation for New England Generation Plus Imports

The calculation for determining the average emission rate for New England generation plus net imports is similar to the formula in the previous section, with the addition of emissions from imports and subtraction of emissions from exports. Emissions from imports are calculated by multiplying the average emission rate (lbs/MWh) reported by the resource's balancing authority, by the energy (MWh) imported across the tie line(s) from that BAA. Emissions from energy exported from New England are calculated by multiplying the average annual emission rate for ISO New England generation by the amount of energy exported to other BAAs.

$$\text{Annual Avg. Emission Rate} \left(\frac{\text{lbs}}{\text{MWh}}\right) = \frac{\text{Annual Emissions (lbs)}_{\text{ISO-NE Generators}} + (\text{Annual Emissions(lbs)}_{\text{Imports}} - \text{Annual Emissions(lbs)}_{\text{Exports}})}{\text{Annual Energy (MWh)}_{\text{ISO-NE Generators}} + (\text{Annual Energy(MWh)}_{\text{Imports}} - \text{Annual Energy(MWh)}_{\text{Exports}})}$$

2.4 Marginal Emission Rate Calculation

The Locational Marginal Unit (LMU) is identified by the LMP, which is set by the cost of the resource dispatched to meet the next increment of load at a specific pricing location. The resource that sets price is called the marginal unit. LMPs minimize total energy costs for the entire ISO New England system, subject to a set of constraints reflecting the physical (transmission) limitations of the power system.

The process to determine the LMP identifies at least one locational marginal unit for each five-minute period, which is associated with meeting the energy requirements on the system during that pricing interval. When transmission is not constrained, the marginal unit is classified as the unconstrained marginal unit. Each binding transmission constraint adds an additional marginal unit, resulting in *n + 1 marginal units* (LMUs) for every *n* binding constraints, in each five-minute period.

The LMU percent marginal in an hour is calculated using two different approaches: the time-weighted and load-weighted approach. The time-weighted approach involves calculating the percentage of time that each unit was marginal in an hour based on the five-minute interval data.

[10] The ISO New England energy, load, and demand reports are available at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load

The load-weighted approach uses the amount of load served by each unit in a five-minute interval to calculate the percentage of total system load served by each unit in an hour.

To calculate the marginal emission rates, the hourly emissions (lbs) for those units in the EPA CAMPD database are grouped into on-peak and off-peak periods (defined in Section 2.6) for each month. When only monthly NEPOOL GIS or annual eGRID data is available, these emission rates are multiplied by the associated monthly on-peak and off-peak generation. The monthly emissions (lbs) from each individual marginal generator are then divided by that generator's monthly on-peak or off-peak generation to obtain the corresponding emission rate (lbs/MWh) for that time period. For NO_X emission rates, the monthly totals (lbs) for each generator are grouped into ozone and non-ozone season emissions and divided by the respective ozone and non-ozone season generation.

The percentage of time each generator is marginal in each month (time-weighted approach) or the percentage of load served by the generator in each month (load-weighted approach) during on- or off-peak hours is calculated and then multiplied by the generator's month-specific on-peak or off-peak average emission rate as described above. That amount is totaled for each marginal unit and then divided by the total on-peak or off-peak hours in the year. The LMU marginal emission rate calculations are as follows, where generator *k* is identified to be marginal during hour *h* and has a specific monthly emission rate during month *m*:

LMU On-Peak Marginal Emission Rate

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

LMU Off-Peak Marginal Emission Rate

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

The annual LMU marginal emission rate is then calculated by combining the on-peak and off-peak rates using a weighted approach.

The analysis of time-weighted and load-weighted LMU marginal emission rates is conducted for two different scenarios. Each scenario includes or excludes certain generators, depending on their characteristics. The two scenarios are as follows:

- **All LMUs**—includes all locational marginal units identified by the LMP process
- **Emitting LMUs**—excludes all non-emitting units with no associated air emissions, such as pumped storage, hydro-electric, and nuclear generation, as well as wind and solar renewables. Pumped storage demand, i.e. the energy used to pump water into a pumped-storage generator's storage pond, and external transactions are also assumed to have no emissions.

2.5 Marginal Heat Rate Calculation

The marginal heat rate is found by first calculating a heat rate for each individual generator.[11] The heat rates for individual LMUs are then multiplied by the percentage of time each generator is marginal (time-weighted LMU), or by the percentage of load served (load-weighted LMU). These values are then totaled and divided by the total number of hours in the year, resulting in the time-weighted and load-weighted LMU marginal heat rates.

As with the marginal emission rate calculation, the analysis is performed for both the all-LMU and the emitting-LMU scenarios. Since a unit's heat rate is equal to its heat input, or fuel consumption, divided by its generation, the calculated marginal heat rate is defined as follows:

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

2.6 Time Periods Analyzed

Data for the on-peak period are presented so that a typical industrial and commercial user providing load response during a traditional weekday can explicitly account for its emissions reductions during the on-peak hours. The marginal emission rates for NO_X are calculated for five time periods:[12]

- On-peak ozone season, consisting of all weekdays between 7:00 a.m. and 11:00 p.m. from May 1 to September 30.
- Off-peak ozone season, consisting of all weekdays between 11:00 p.m. and 7:00 a.m. and all weekend hours from May 1 to September 30.
- On-peak non-ozone season, consisting of all weekdays between 7:00 a.m. and 11:00 p.m. from January 1 to April 30 and from October 1 to December 31.
- Off-peak non-ozone season, consisting of all weekdays between 11:00 p.m. and 7:00 a.m. and all weekend hours from January 1 to April 30 and from October 1 to December 31.
- Annual average.

Since ozone and non-ozone seasons are only relevant to NO_X emissions, the SO_2 and CO_2 emission rates are only calculated for the following time periods:

- On-peak annual, consisting of all weekdays between 7:00 a.m. and 11:00 p.m.
- Off-peak annual, consisting of all weekdays between 11:00 p.m. and 7:00 a.m. and all weekend hours.
- Annual average.

[11] The heat rate for noncombustible renewables, i.e. pumped storage, hydroelectric, wind, and solar resources, was considered to be zero in these calculations since those resources do not burn fuel to produce energy. Pumped storage demand and imports were also assumed to have a zero heat rate.
[12] The ISO developed a special report, *Analysis of New England Electric Generators' NO_X Emissions on 25 Peak-Load Days in 2005–2009*, released September 23, 2011, which summarized its analysis of NO_X emissions during peak days: https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf