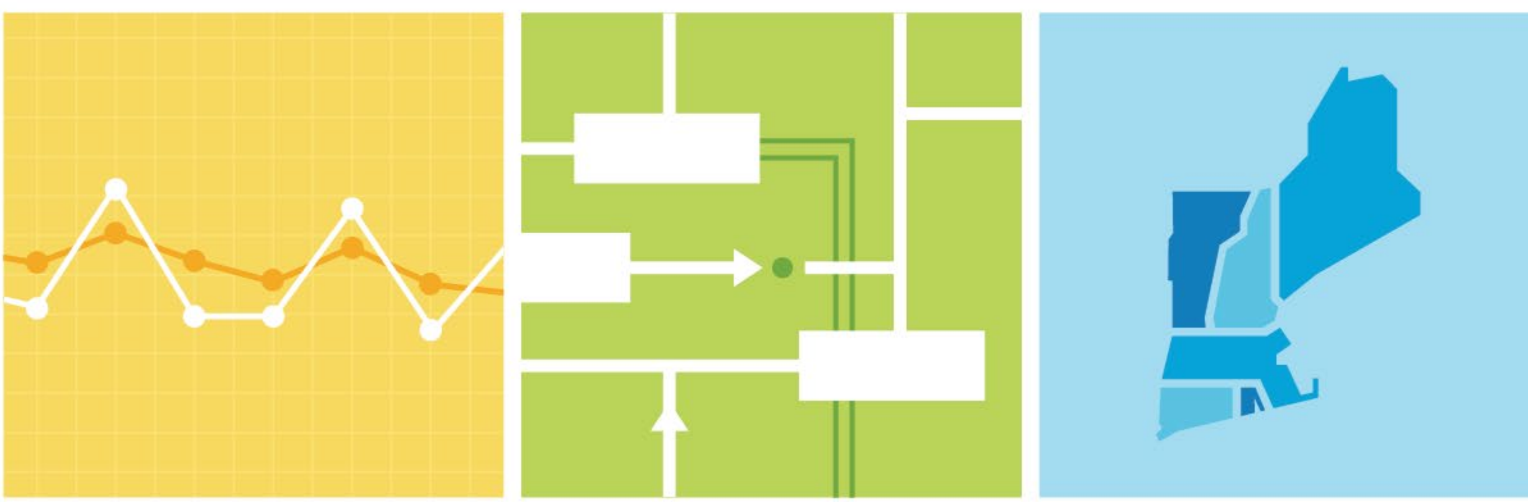
2024 ISO New England Electric Generator Air Emissions Report

OCTOBER 3, 2025



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Section 1
Executive Summary

1.1 Purpose of ISO New England Emissions Report

The 2024 ISO New England (ISO-NE) *Electric Generator Air Emissions Report* (*Emissions Report*) provides a comprehensive analysis of New England's electric generator air emissions (nitrogen oxides [NO_X], sulfur dioxide [SO_2], and carbon dioxide [CO_2]), along with CO_2 emissions associated with imported energy, load-weighted and time-weighted marginal emission rates, and a review of relevant system conditions. The main factors analyzed are as follows:

- Total annual emissions (ktons[1]) and average annual emission rates (lbs/MWh)
- Marginal emission rates (lbs/MWh and lbs/MMBtu [2])
- Marginal heat rates (MMBtu/MWh)

This executive summary provides a high-level overview of system conditions and an assessment of key monthly and annual trends from the 2024 emissions analysis. A spreadsheet appendix provides comprehensive data on the relevant system conditions, average CO_2 emission rates for imports/exports, marginal heat rates, and emissions data for the following:

- On-peak versus off-peak hours
- Ozone season versus non-ozone season
- Monthly variations
- 10+ historical years
- High electric demand days (HEDDs)

For a detailed overview on the background, data sources, and methodologies for the Emissions Report, refer to the ISO New England Electric Generator Air Emissions Report: Background and Methodology.

1.2 Methodology

This report provides two different CO_2 emissions and emission rates:

- New England generation only (excludes behind-the-meter (BTM) generators and imports)
- New England generation plus net imports (i.e. emissions from imports minus emissions from exports)

[1] The mass value of "tons" is equivalent to a U.S. short ton, or 2,000 lbs, and "ktons" is equivalent to 2,000,000 lbs.

[2] MMBtu is an abbreviation for million British thermal units, which represents the heat content of a fuel. The heat rates in MMBtu/MWh are used to convert the marginal emission rates from pounds (lbs)/MWh to lbs/MMBtu.

Total emissions and average emission rates for NO_X and SO_2 are calculated for New England generation only.

Marginal emission rates and heat rates in this report are determined by the locational marginal unit (LMU), or the last unit dispatched to balance the system, which sets the price. The percentage that each generator is marginal is calculated using both a load-weighted and time-weighted approach. The load-weighted approach reflects the share of the load served by the marginal unit, while the time-weighted approach accounts for the time intervals during which a resource was marginal and assumes that multiple marginal resources within that time interval contribute equally to meeting the load. The marginal emission rates are determined by calculating the percentage of time (time-weighted approach) and load (load-weighted approach) for which a generator was marginal and multiplying those percentages by the generator's emission rates. This number is then divided by the total on-peak or off-peak hours in the year. The rates are divided into two scenarios for both the time-weighted and load-weighted LMUs:

- All LMUs - includes all Locational Marginal Units (including imports) identified by the 5-minute locational marginal prices (LMPs)
- Emitting-LMUs - excludes all non-emitting units, such as nuclear, pumped storage, energy storage, hydro-electric generation, and other renewables (such as wind, solar, etc.) with no associated air emissions

1.3 Data Sources

Approximately 33% of the total NO_X emissions, 39% of the SO_2 emissions, and 84% of the CO_2 emissions in this report are calculated using the emission data reported in EPA's Clean Air Markets Program (CAMPD) database. Data from New England Power Pool Generation Information System (NEPOOL GIS), and if unavailable there, from the EPA's Emissions and Generation Resource Integrated Database (eGRID), are used to estimate emissions from generators that do not report to CAMPD.

Historically, about 50% of the NO_X and SO_2 emissions data in this report were sourced from NEPOOL GIS. These emissions are self-reported by the generators and NEPOOL GIS does not track or enforce each generator's report status. Compared to previous years, 2024 monthly NO_X and SO_2 emission data reported to the NEPOOL GIS database decreased significantly. About 19% of NO_X and 24% of SO_2 data in 2024's report is sourced from NEPOOL GIS.

Over 95% of the 2024 emission data used in this report comes from CAMPD, NEPOOL GIS, or eGRID. Estimates for the remaining generators rely on emission data from units with similar attributes.

1.4 Overview of 2024 System Conditions

Weather conditions in 2024 were comparable to 2023. Both years experienced mild winters and summers with few periods of tight system conditions. The New England wholesale electricity demand or Net Energy for Load (NEL) was 116,815 GWh in 2024, a 2% increase from historically low load in 2023.[3] New England generation was 7% higher year over year, at 108,599 GWh in 2024 compared to 101,289 GWh in 2023.

Year-over-year changes in the regional generation mix over the last five years are illustrated in Figure 1-1. The darkest shaded bars represent the 2024 generation data, and the lighter shaded bars represent generation for prior years. Between 2023 and 2024, coal-fired generation increased 28%, while oil-fired generation was relatively unchanged. Although the year-over-year *increase* in coal generation was large, *overall* annual coal generation was very low, contributing less than 1% of total system generation. Oil generation increased just 2 GWh between 2023 and 2024, and coal generation increased 50 GWh, both fractions of the 108,599 GWh in total generation.

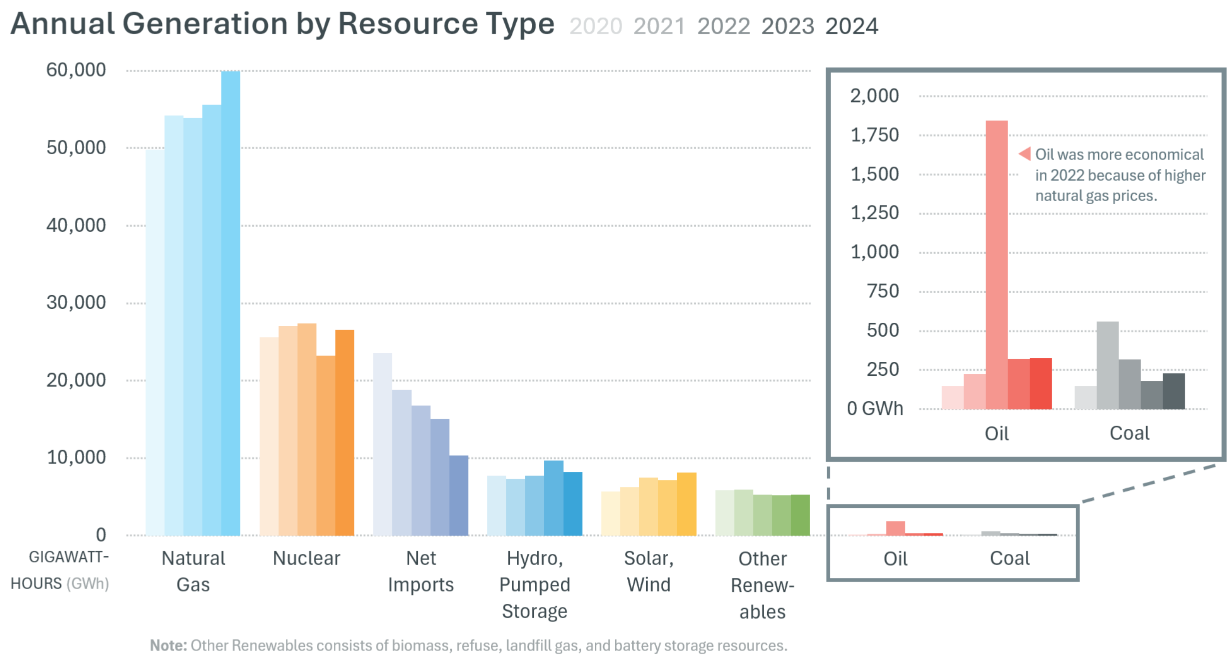

Figure 1-1: ISO New England annual generation by resource type, 2020 to 2024 (GWh)

Non-emitting renewable resources including wind and solar also generated more energy in 2024, up 14% from 2023. Together, wind and solar supplied more energy in 2024 than net imports from Canada (8,098 GWh vs. 6,083 GWh). Nuclear, another key non-emitting resource type, returned to normal operations in 2024 after multiple planned refueling outages in 2023 that contributed to a moderate drop in output between 2022 and 2023. This increase in nuclear generation and an 8% increase in natural gas generation between 2023 and 2024 helped offset the 32% in reduced imports from Canada. Ongoing droughts in Quebec and an extended nuclear outage in New Brunswick from April to December 2024 contributed to the overall reduction in Canadian imports. As in prior years, natural gas was the primary source of energy production in 2024 (55%), followed by nuclear generation (24%).

In addition to annual variations, energy generated by each resource varied from month to month, depending on factors such as weather and current system conditions. Figure 1-2 shows 2024 monthly energy production by resource type, which includes both New England generation and net

[3] NEL = New England Generation – Pumping Load + Net Imports

imports. The black line, corresponding with the right axis, represents the total energy (GWh) for each month.

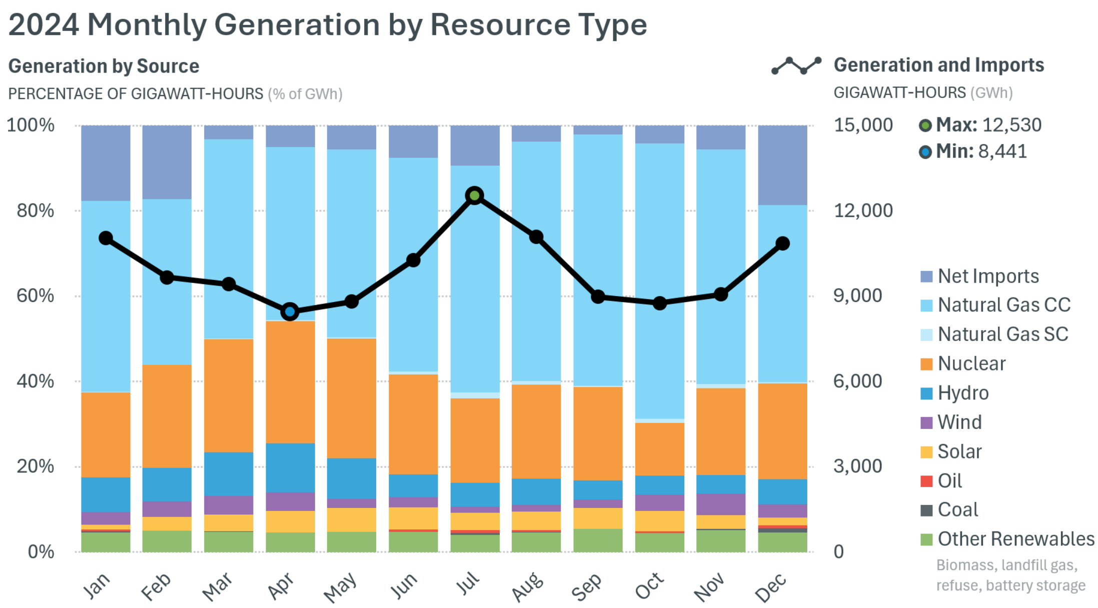

Figure 1-2: 2024 ISO New England monthly generation by resource type, including imports (%, GWh)[4]

Natural gas was the leading contributor to generation each month, but was sometimes constrained, mostly in the winter months, when increased heating demand reduced the amount of natural gas available for power generation. These periods of fuel constraints led to higher natural gas prices, which made coal and oil resources more economical to run during these times, typically in January and December. According to the [ISO-NE Monthly Market Operations Report](), average natural gas prices were 184% higher in December 2024 than December 2023, while residual fuel oil prices were down 9%. As a result, coal and oil resources generated more in December than any other month of the year. The average temperature in December 2024 was 33^{0}F, 6^{0}F cooler than December of 2023, however there were no prolonged cold snaps in 2024.

Monthly generation in 2024 was lowest in April, at 8,441 GWh, a result of mild weather conditions and high output from BTM solar that effectively reduced overall load on the system. Generation then increased from April through midsummer, peaking at 12,530 GWh in July, due to increased electric energy use from air conditioning. Demand for electricity in New England peaked in summer, as is usual, and the top five high electric demand days (HEDDs) for 2024 were all in summer: June 20, July 15-17, and August 1. HEDDs are typically characterized by high temperatures that lead to increased cooling demand.

During HEDDs and other peak energy demand periods, usually during summer, the region relies on peaking units, which are used less throughout the rest of the year, but can respond quickly to meet system demand. These units are often oil-fired jets (aero-derivative) or combustion/gas turbines with higher emission rates. The temperatures in New England during the top five HEDDs in 2024 ranged from 87^{0}F to 91^{0}F, approximately 1 to 3^{0}F hotter than the top five HEDDs in 2023. The higher

[4] Here and elsewhere in the report, natural gas data is categorized as either combined cycle (CC) or simple cycle (SC).

HEDD temperatures also drove a 3% increase in summer peak demand year-over-year, from 24,043 MW in 2023 to 24,871 MW in 2024.

Figure 1-3 provides a side-by-side comparison of the region's generation by resource type for 2015 and 2024. Over the last ten years, wind and solar generation have more than doubled, contributing 7% of the total energy generated in 2024. Solar generation alone in 2024 (4%) was more than coal and oil generation combined in 2015 (3.6%). In 2024, coal and oil generated just 0.5% of the year's total energy generation.

Another notable trend since 2015 is the reduction in nuclear generation, which is attributable to the 2019 retirement of the Pilgrim Nuclear Power Station (~680 MW), located in Plymouth, MA. This reduction, along with a reduction in imports, contributed to an 8% increase in annual natural gas generation. Overall, the past ten years have seen the region's generation mix shifting away from high carbon-emitting resources like oil and coal to relatively lower-to-zero emission resources such as natural gas, wind, and solar. Wind and solar have largely replaced coal and oil generation, while increased natural gas generation has compensated for the reduction in imports.

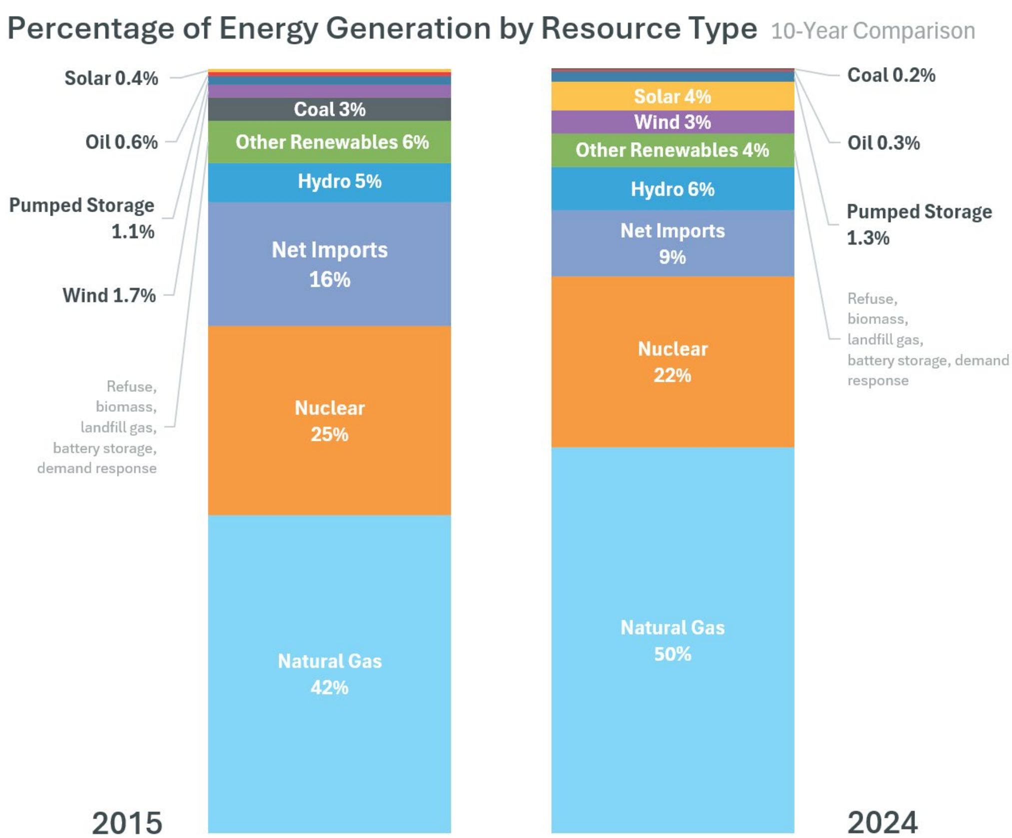

Figure 1-3: Percentage of energy generation by resource type, 2015 compared with 2024

1.5 Results and Observations

Results for New England's 2024 generation emissions calculations are reported as follows:

- Total emissions
- Average emission rates
- Marginal emission rates for all-LMUs and emitting-LMUs scenarios, using both the time-weighted and load-weighted approaches
- Heat rates for all-LMUs and emitting-LMUs scenarios, using both the time-weighted and load-weighted approaches

The spreadsheet appendix provides additional figures and tables on the historical, annual, and monthly emissions data.

1.5.1 Average Emissions

The total CO_2 emissions in 2024 were 32,442 kilotons (ktons) from New England generation, and 33,293 ktons when including emissions from net imports. Note that the emissions from net imports are calculated based on assumed annual average emission rates taken from the latest eGRID (for New York imports) and the National Inventory Report: Greenhouse Gas Sources and Sinks in Canada (for Canadian imports). The assumed annual average emission rates for imports are:

- 602 lbs/MWh for New Brunswick
- 3 lbs/MWh for Quebec
- 493 lbs/MWh for New York

From 2023 to 2024, emissions from New England generation slightly increased for CO_2 and NO_x, at 1% (392 ktons) and 3% (0.30 ktons), respectively. Emissions of SO_2 decreased by 8%, or 0.15 ktons. The similarity in emissions between 2023 and 2024 is largely attributable to similar weather conditions and load between years. Minor increases in emissions are mostly attributable to higher natural gas generation due to reduced imports from Canada.

Figure 1-4 shows the monthly variation in emission rates for 2024. Emission rates peaked in July and December, due in part to the tight system conditions discussed in Section 1.4. The CO_2 emission rate was lowest in April due to high BTM solar output that reduced load and subsequently reduced emitting generation. Nuclear generation was at its lowest level in October, which was compensated for by increased generation from carbon-emitting resources, such as natural gas, resulting in a higher emission rate. Outside of these events, average emission rates did not vary much from month-to-month. The average emission rate for CO_2 was 597 lbs/MWh (560 lbs/MWh with net imports). NO_X and SO_2 annual average emission rates were 0.20 lbs/MWh and 0.03 lbs/MWh respectively.

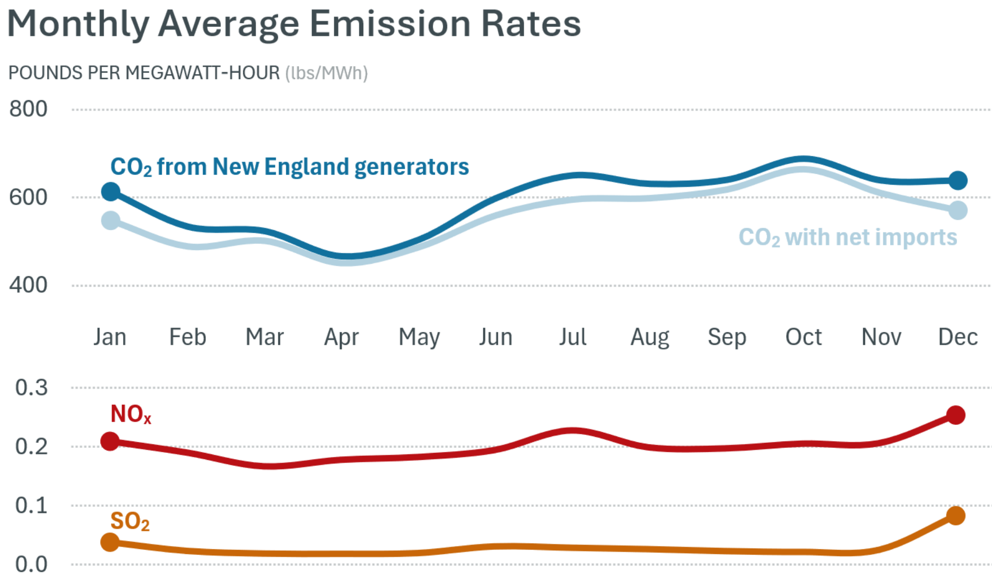

Figure 1-4: 2024 ISO New England monthly average emission rates (lbs/MWh)

Yearly SO_2, CO_2, and NO_X emissions from electric generation declined significantly between 2015 and 2024, as illustrated in Figure 1-5. SO_2 decreased by 82%, CO_2 by 20%, CO_2 with net imports by 21%, and NO_X by 42%. The annual average emission *rates* (lbs/MWh) also decreased for all three pollutants over the same period: SO_2 by 82%, CO_2 by 20%, CO_2 with net imports by 15%, and NO_X by 42%, as illustrated in Figure 1-6. This downward trend in emissions coincided with the region's oil and coal resources being displaced by relatively lower and zero emissions resources, such as natural gas, solar, and wind.

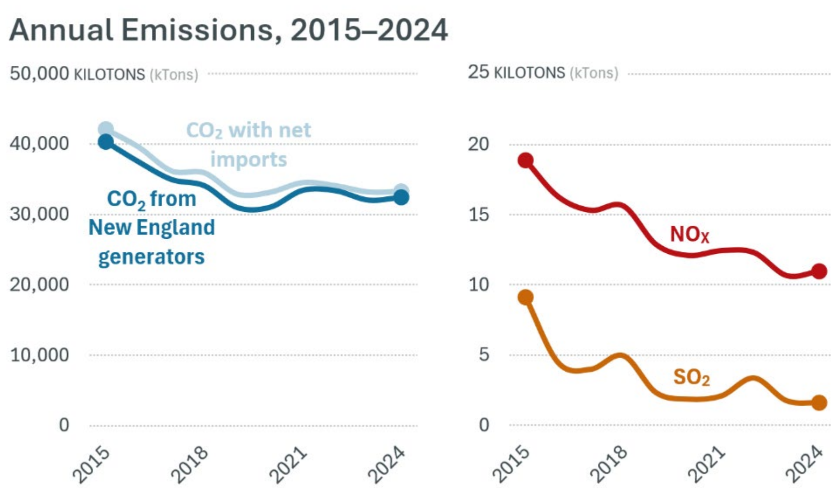

Figure 1-5: ISO New England total emissions, 2015 to 2024 (ktons)

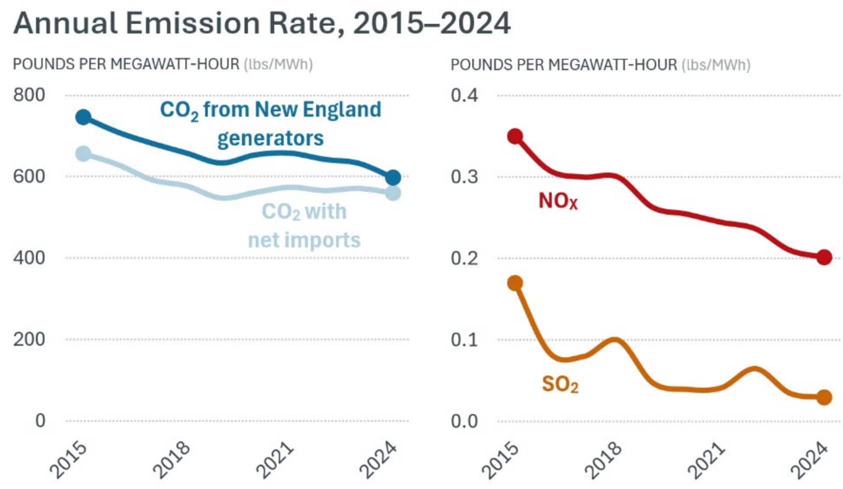

Figure 1-6: ISO New England annual average emission rates, 2015 to 2024 (lbs/MWh)

1.5.2 Marginal Emission Rates

As described in Section 1.2, marginal emission rates are determined using both a time-weighted and load-weighted approach, based on the locational marginal units (LMUs). LMUs are identified from historical real-time generation dispatch records. The load-weighted approach reflects the load served by the marginal unit and assumes that in a transmission constrained system, more than one marginal resource contributes to meeting load, but not all marginal resources contribute equally. The time-weighted approach reflects the time intervals for which a resource was marginal and assumes that if multiple marginal resources are meeting load within a certain time interval, each resource is meeting an equal share of the load. Each approach also analyzes two scenarios: the all-LMUs (all marginal units, with or without air emissions) and emitting-LMUs (excludes all non-emitting marginal units).

The portions of load and time that a resource type was marginal in the 2024 all-LMUs scenario are illustrated in Figure 1-7 and Figure 1-8. The major difference between the load-weighted and time-weighted approach for the all-LMUs scenario is the marginality of wind resources. In the load-weighted approach, wind was only marginal for 0.5% of the load compared to 7% of the time intervals under the time-weighted approach. Since many wind resources are located in "export-constrained" areas, their contribution to meeting load is much less than other resource types. "Export-constrained" areas are areas whose transmission network for exporting electricity outside the area is at maximum capacity. As a result, wind generators often cannot set the price outside of the constrained area, and do not contribute significantly to system-wide production. Consequently, the load-weighted CO_2 marginal emission rates for the all-LMUs scenario are typically higher than the time-weighted rates, as shown in Figure 1-11. This 2024 edition of the Emissions Report incorporates solar generating units in the marginal emissions analysis for the first time. Starting December 4, 2023, solar generator assets in ISO-NE markets have implemented do not exceed dispatch (DNE) rules and can now set price, be included in economic dispatch, and serve as a marginal resource. In 2024, solar generators were marginal for less than 0.1% of the load and time intervals. Including solar as a marginal resource therefore had a minimal impact on the marginal emission rates for the all-LMUs scenario.

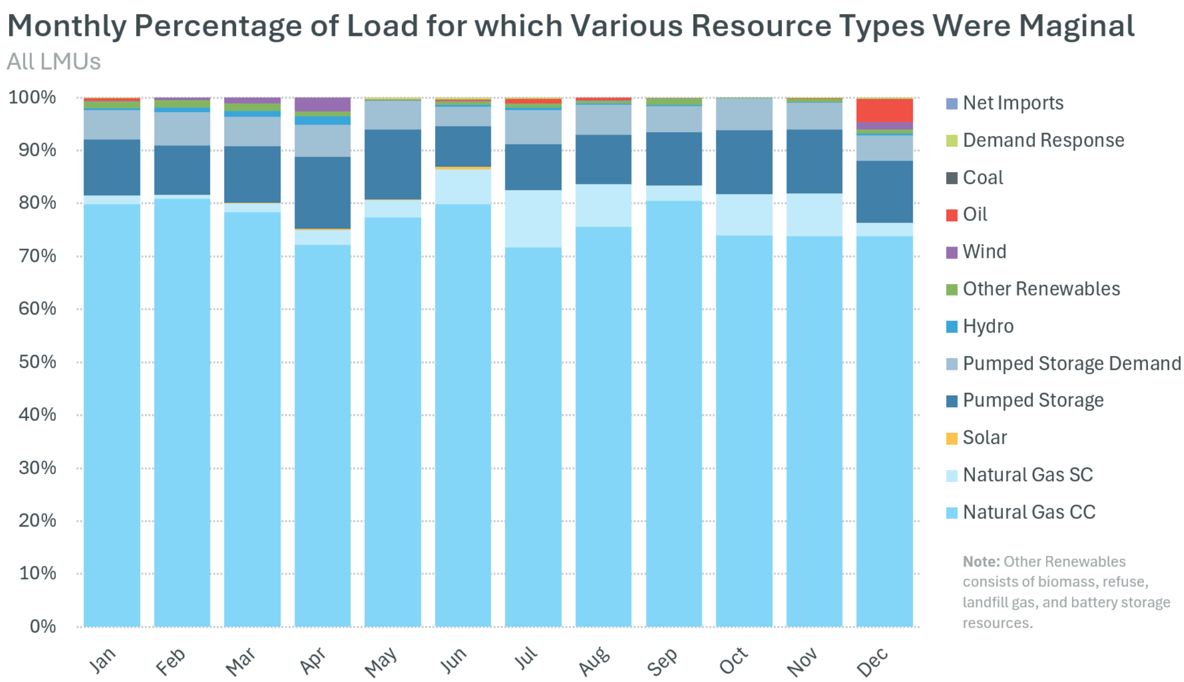

Figure 1-7: 2024 percentage of load for which various resource types were marginal —all LMUs

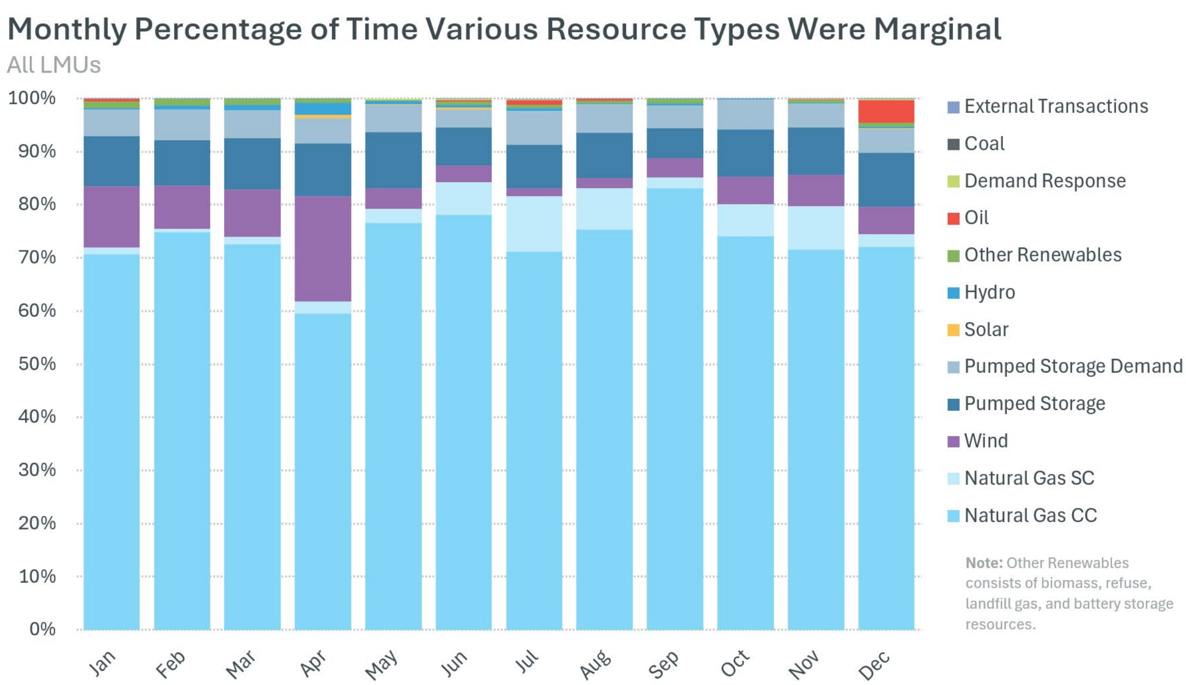

Figure 1-8: 2024 percentage of time for which various resource types were marginal —all LMUs

The marginality of Other Renewables differs slightly between the load and time-weighted approach for emitting LMUs. Like wind resources, many biomass plants are located in export-constrained areas and therefore contribute less to load. As a result, in 2024 the Other Renewables' load-weighted marginality was often less than the time-weighted marginality. Figure 1-9 and Figure 1-10 highlight this difference, particularly during February, March, and April.

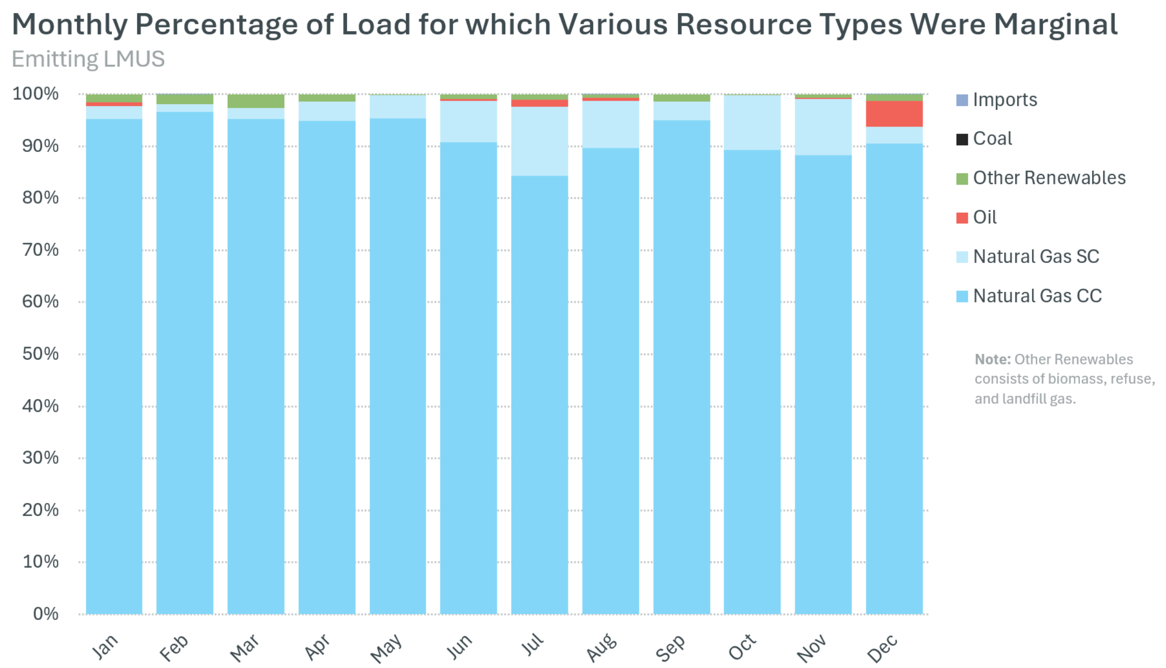

Figure 1-9: 2024 percentage of load for which various resource types were marginal — emitting-LMUs

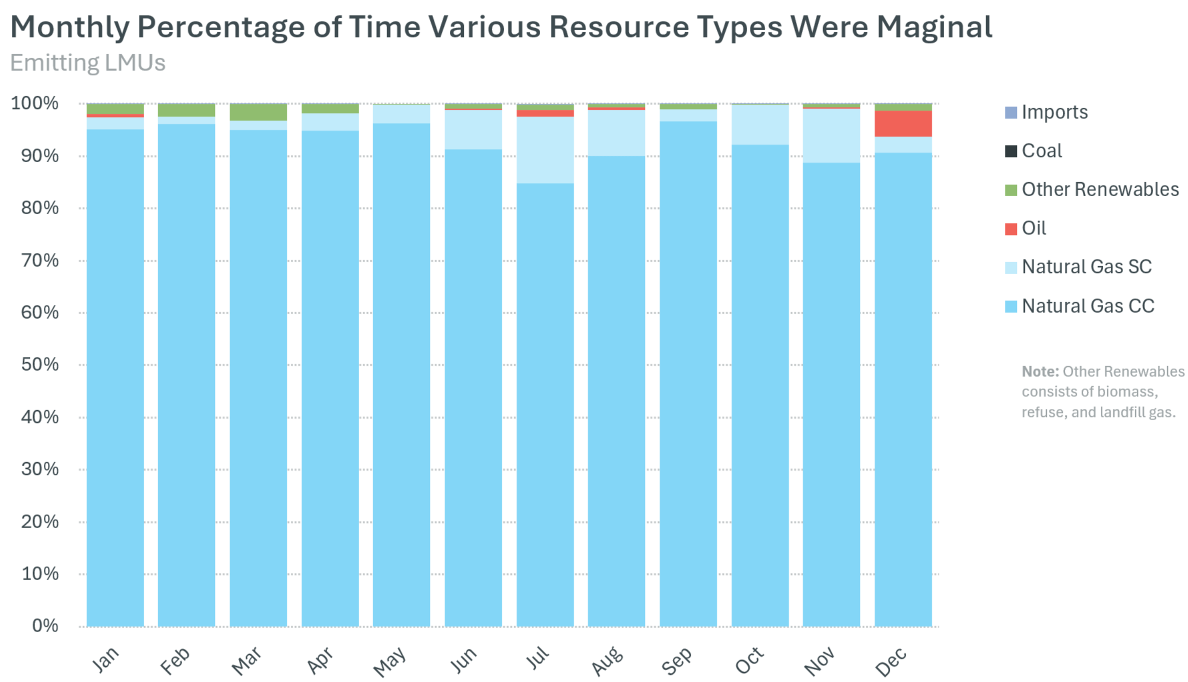

Figure 1-10: 2024 percentage of time for which various resource types were marginal — emitting-LMUs

Figure 1-11, Figure 1-12 and Figure 1-13 show the monthly variations in marginal emission rates (lbs/MWh) for CO_2, NO_X, and SO_2. The peaks in marginal emission rates coincide with the months when coal and oil were marginal for more of the load and time intervals during tight system conditions.

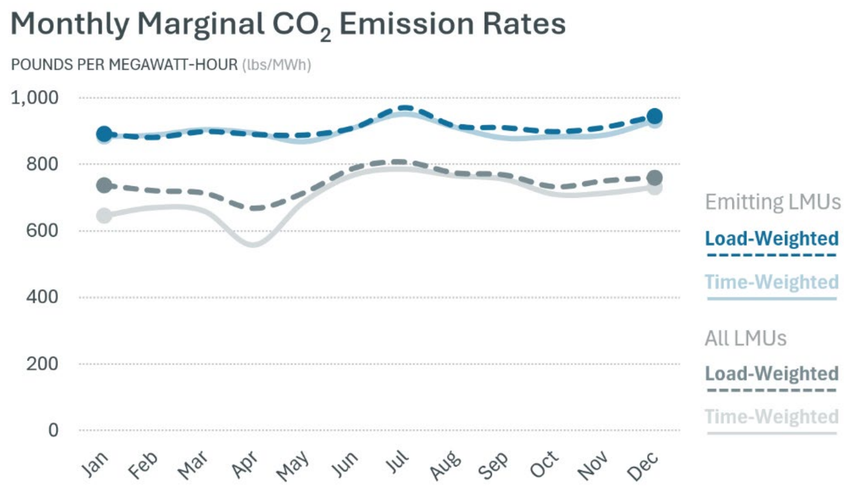

Figure 1-11: 2024 time- and load-weighted monthly LMUs marginal CO_2 emission rates

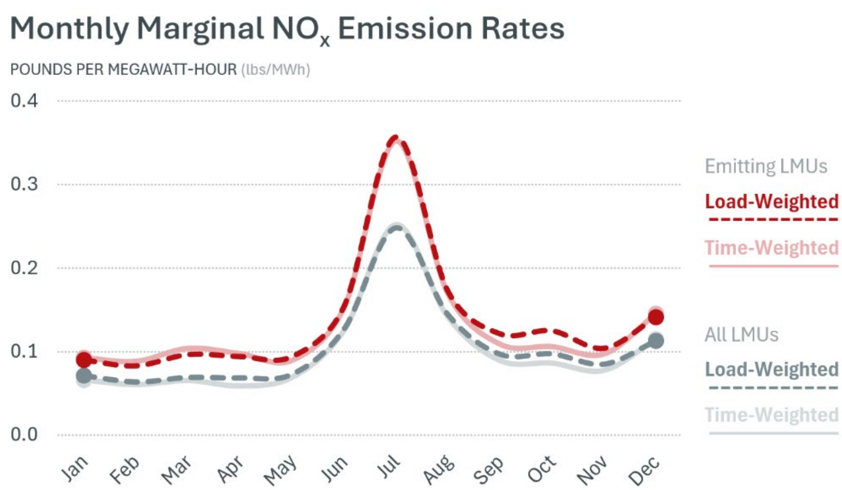

Figure 1-12: 2024 time- and load-weighted monthly LMUs marginal NO_x emission rates

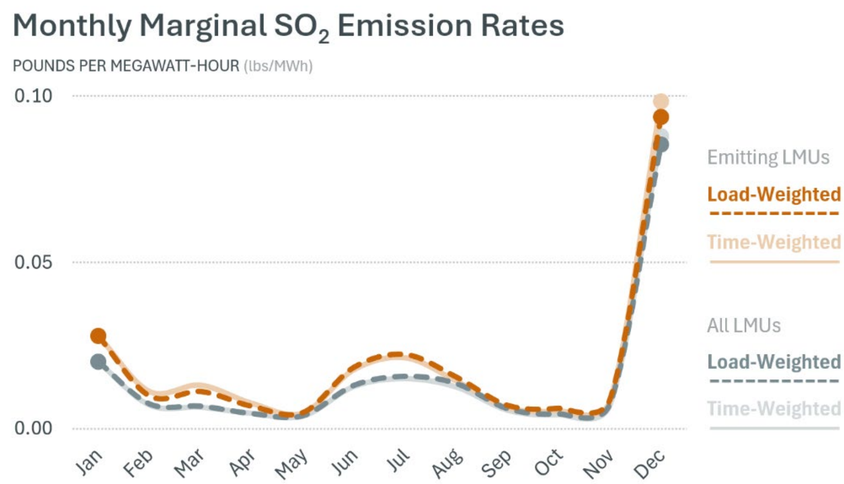

Figure 1-13: 2024 time- and load-weighted monthly LMUs marginal SO_2 emission rates

The 2024 time-weighted and load-weighted marginal emission rates for CO_2 , NO_X and SO_2 did not deviate significantly from the 2023 values. Overall, annual marginal emission rates have remained relatively static year-over-year, reflective of stable load and weather conditions. Figure 1-14 and Figure 1-15 show the decline in marginal emission rates over the past decade. Time-weighted annual marginal SO_2 rates have declined by 95% for the all-LMUs and emitting-LMUs scenarios, while annual marginal NO_X emission rates have decreased by 64% and 63% for the all-LMUs scenario and emitting-LMUs scenario, respectively. CO_2 marginal emission rates since 2015 have declined less dramatically than SO_2 and NO_X, with an 18% decline for the all-LMUs scenario and a 13% decline for the emitting-LMUs scenario.

Historical emission rate values can be found in Sections 3.3.1 and 3.3.2 of the spreadsheet appendix. Load-weighted approach values are not available for the 10-year timeframe, since this approach was first incorporated into the emissions analysis in 2018.

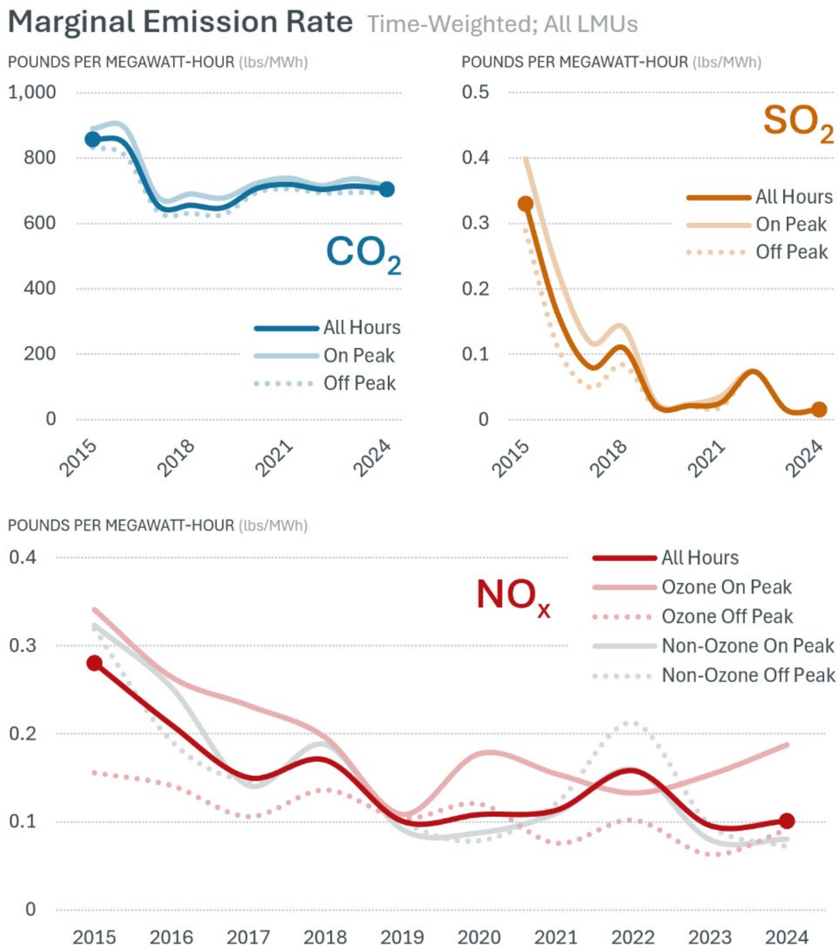

Figure 1-14: Time-weighted LMU marginal emission rates, 2015-2024 - all LMUs (lbs/MWh)

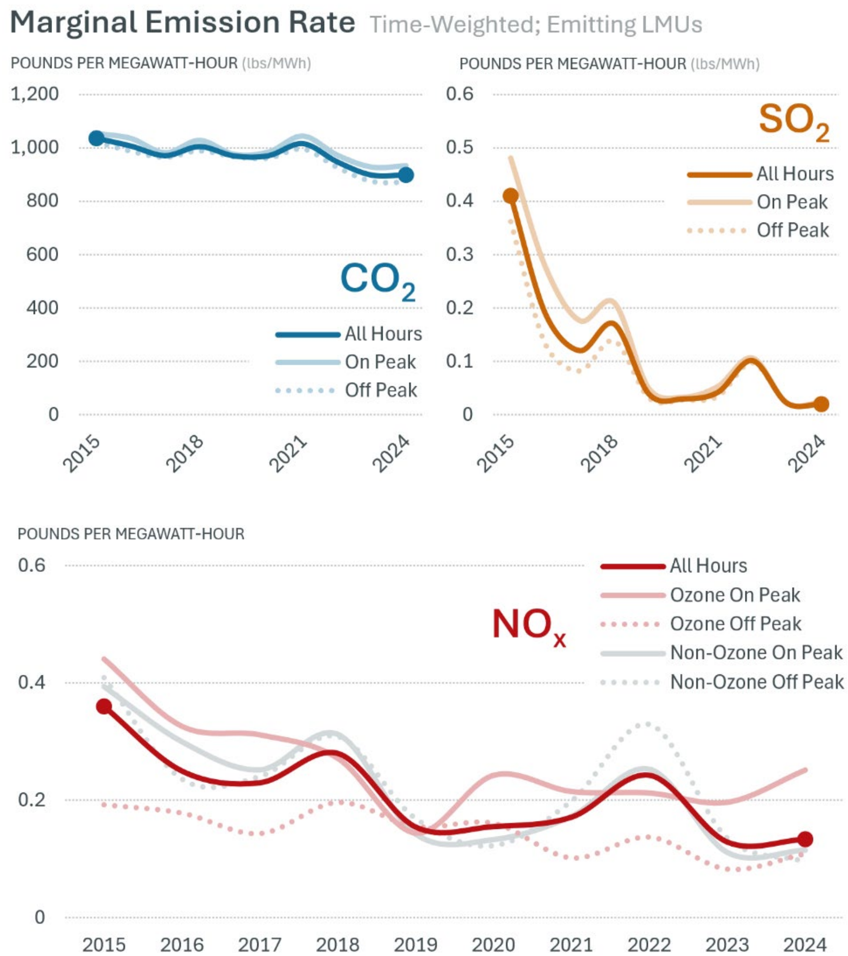

Figure 1-15: Time-weighted LMU marginal emission rates, 2015-2024 - emitting LMUs (lbs/MWh)

1.5.3 Marginal Heat Rates

The annual marginal heat rate reflects the average annual efficiency of all the marginal emitting units dispatched. Each generator's heat rate varies according to plant design, operating conditions, and power output level. The lower the heat rate, the more efficient the generator is at converting its fuel (input) to electricity. Figure 1-16 illustrates declining marginal heat rates from 2015 through 2024 using the time-weighted all-LMUs approach. Between 2016 and 2017, the heat rate in the all-LMUs scenario dropped sharply due to the large number of wind generators on the margin, a result of the Do Not Exceed (DNE) dispatch rules implemented in May 2016. These DNE rules incorporated wind and hydro intermittent units into economic dispatch and allowed these resources to set the price for energy. Prior to the DNE rules, these resources had to self-schedule their hourly output and could not set the marginal price.

Between 2019 and 2020, the marginal heat rates for the all-LMUs scenario increased 8% under the time-weighted approach and 4% under the load-weighted approach. This increase coincided with the 2019 retirement of the Pilgrim Nuclear Power Station and the 2019 addition of several new gas-fired generators that consistently offered their energy at a lower price than pumped-storage generators throughout 2020. Because their offer prices were lower, they displaced pumped-storage generators as the marginal units more frequently.[5]

Marginal heat rates have not changed significantly since 2020. In 2024, the time-weighted all-LMUs marginal heat rate was 5.89 MMBtu/MWh, down slightly from 5.96 MMBtu/MWh in 2023. The load-weighted marginal heat rate was 6.18 MMBtu/MWh in 2024, compared to 6.43 MMBtu/MWh in 2023. Under the emitting-LMUs scenario, the 2024 marginal heat rates for the time-weighted and load-weighted approach were 7.50 MMBtu/MWh and 7.54 MMBtu/MWh, respectively. These values were nearly the same as the 2023 time-weighted and load-weighted marginal heat rates of 7.50 and 7.51 MMBtu/MWh, respectively.

While the recent year-over-year changes in marginal heat rates have been nominal, overall efficiency in the region's fleet has improved incrementally over the past decade, as indicated by the downward trend in rates between 2015 and 2024. This improvement is attributable to the growth in wind and solar generation and declines in coal and oil mentioned in Section 1.4. The region has also shifted further towards natural gas generation, which is more efficient at converting fuel to electricity than other fossil fuel resources.

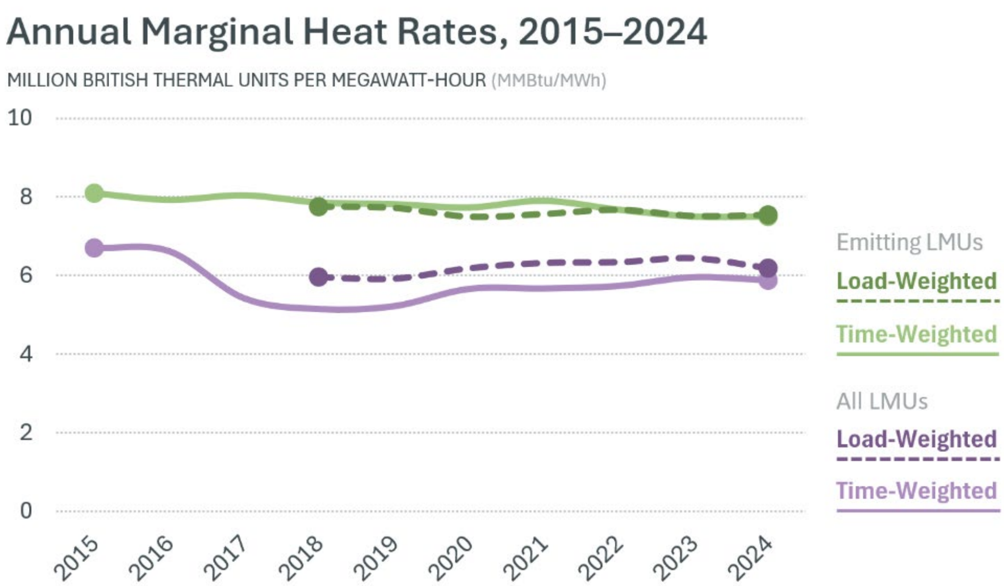

Figure 1-16: Annual marginal heat rates, 2015-2024 (MMBtu/MWh)

[5] Refer to the Marginal Resources in the Real-time Market section of the 2020 Annual Markets Report for an in-depth discussion on the 2019-2020 marginal resource trends.

1.6 Conclusion

New England saw minor increases in total CO_2 and NO_X emissions and slight decreases in SO_2 emissions from the electric sector in 2024. Marginal emission rates also did not vary significantly from 2023. Emissions have remained relatively static year over year due to similar weather and load conditions. The slight increases in emissions are mostly attributable to higher regional natural gas generation that made up for shortfalls in Canadian imports.

In the last decade, the New England resource mix has shifted away from coal and oil resources and more towards natural gas, wind, and solar. This change in the resource mix has contributed to notable reductions in CO_2, SO_2, and NO_X emissions, and a decline in marginal heat rates.