Regional Greenhouse Gas Initiative

an Initiative of the Northeast and Mid-Atlantic States of the U.S.

CO_2 Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2011 Monitoring Report

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The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort of Northeast and Mid-Atlantic states to reduce emissions of carbon dioxide (CO2), a greenhouse gas that causes global warming.

RGGI, Inc. is a non-profit corporation created to provide technical and administrative services to the states participating in the Regional Greenhouse Gas Initiative.

Executive Summary

This report, the third report in a series of annual monitoring reports, summarizes data for electricity generation, electricity imports, and related carbon dioxide (CO_2) emissions for the ten states[1] that participated in the Regional Greenhouse Gas Initiative (RGGI) first control period for the period from 2005 through 2011. These monitoring reports were called for in the 2005 RGGI Memorandum of Understanding (MOU) in response to expressed concerns about the potential for the RGGI CO_2 Budget Trading Program to result in "emissions leakage[2]".[3]

In the Northeast and Mid-Atlantic states, CO_2 emissions from the regional electric power sector are a function of highly dynamic wholesale electricity markets. The cost of compliance with the RGGI CO_2 Budget Trading Program is only one of several factors that influence the dispatch of electric generation, and resulting CO_2 emissions, through the operation of these markets. As a result, this report presents data without assigning causality to any one of the factors influencing observed trends.

The observed trends in electricity demand, net electricity imports, and electricity generation from multiple categories of generation sources (including electricity imports), show there has been no increase in CO_2 emissions or the CO_2 emission rate (pounds of CO_2 per megawatt hour or lb CO_2/MWh) from non-RGGI electric generation serving load in the ten-state RGGI region in the first three year control period of the RGGI program, 2009 – 2011.

Summary of Results

Electric Load (Demand for Electricity) and Generation

- For 2009 to 2011, the annual average electricity load in the ten-state RGGI region was 16.1 million MWh less than the average 2006 to 2008 electricity load, about a 3.4% reduction.

- For 2009 to 2011, the annual average total electric generation in the ten-state RGGI region (fossil and non-fossil) decreased by 19.4 million MWh, or 5.0 percent from the 2006-2008 average.

[1] The "ten-state RGGI region" consists of Delaware, Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey withdrew its agreement to the RGGI Memorandum of Understanding effective January 1, 2012. See http://www.rggi.org/docs/Documents/NJ-Statement_112911.pdf.

[2] "Emissions leakage" is the concept that compliance with the RGGI CO_2 Budget Trading Program, and the incorporation of related CO_2 compliance costs by electric generators that are subject to the program, could result in a shift of electricity generation from CO_2-emitting sources that are subject to RGGI to CO_2-emitting sources that are not subject to RGGI.

[3] The Memorandum of Understanding called for monitoring electricity imports into the RGGI participating states commencing from the start of the RGGI CO_2 Budget Trading Program and reporting the results of such monitoring on an annual basis beginning in 2010.

- A comparison of the average electricity load in the ten-state RGGI region for 2011 only, to the base period of 2006 to 2008, shows a decrease of 15.5 million MWh, or 3.3 percent.

- A comparison of the average total electric generation in the ten-state RGGI region (fossil and non-fossil) for 2011 only to the base period of 2006 to 2008 shows a decrease of 18.4 million MWh, or 4.7 percent.

Non-RGGI Generation

- The monitoring results indicate that CO_2 emissions from non-RGGI electric generation did not increase in 2009 to 2011 – the first three years of RGGI program implementation – relative to the base period of 2006 to 2008.

- A comparison of the 2009 through 2011 annual average to the base period of 2006 to 2008 annual average shows the total electric generation from all non-RGGI electric generation sources serving load in the 10-state RGGI region increased, by 3.3 million MWh, an increase of 1.2 percent.

  - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows CO_2 emissions from all non-RGGI electric generation sources serving load in the ten-state RGGI region decreased by 5.6 million short tons of CO_2, or 9.2 percent.
  - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows the CO_2 emission rate for this category of electric generation decreased by 47 lb CO_2/MWh, or 10.3 percent.

- The monitoring results do not show an increase of annual CO_2 emissions related to either net electricity imports into the ten-state RGGI region or from small fossil fuel-fired electric generators in the ten-state RGGI region that are not subject to state CO_2 Budget Trading Program regulations in the first three years of the program, 2009 through 2011.

RGGI Generation

- A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows the electric generation from RGGI-affected electric generation sources decreased by 18.5 million MWh, or 9.1 percent.

  - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows CO_2 emissions from RGGI electric generation sources decreased by 33.8 million short tons of CO_2, or 21.3 percent.

- A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows the CO_2 emissions rate for RGGI electric generation sources decreased by 209 lb CO_2/MWh, or 13.4 percent.

- When 2011 only is compared to the baseline period of 2006 to 2008, the results similarly show a reduction in electric generation and CO_2 emissions from RGGI electric generation sources.

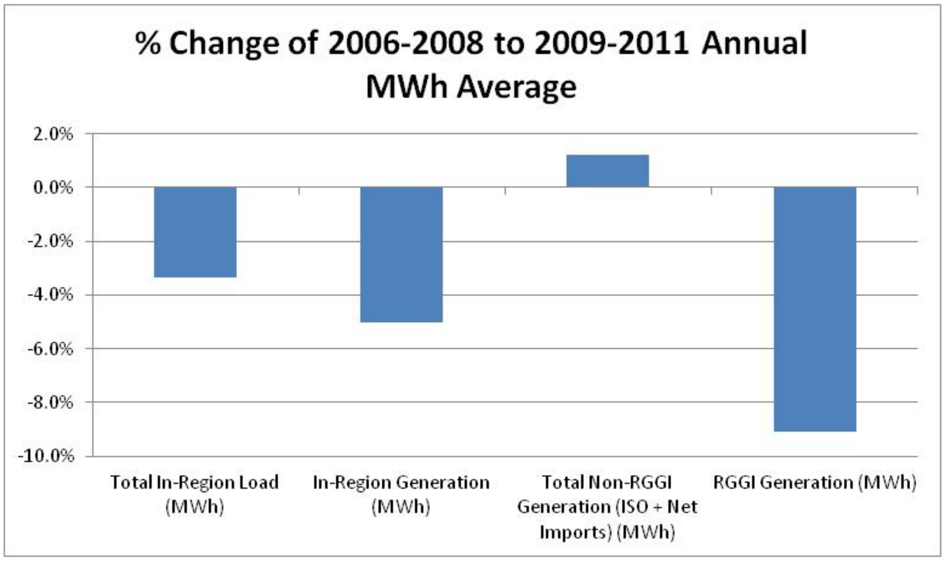

Figure 1. Comparison of percentage changes in electricity load and generation MWh serving the RGGI Region from 2009 through 2011 to the base period on 2006 to 2008.

Monitoring Approach

The data summarized track electricity generation and imports in each of the three independent system operator (ISO) regions fully or partially subject to the RGGI CO_2 Budget Trading Program (ISO-New England – "ISO-NE", New York ISO – "NYISO", and PJM). The data track all MWh of electricity used to serve electric load in each ISO (or portion of an ISO subject to RGGI in the case of PJM) and the actual or estimated related CO_2 emissions. For each ISO, data are tracked for the following categories:

- RGGI-Affected Generation: Electric generation and CO_2 emissions for electric generation units subject to a CO_2 allowance compliance obligation under a state CO_2 Budget Trading Program.

- Non-RGGI Generation: Total electricity supplied to serve load in the ten-state RGGI region and related CO_2 emissions. This category is also broken down into the following subcategories:

  - Non-RGGI Generation (Fossil): Fossil fuel-fired electric generators located in the ten-state RGGI region that are not subject to a CO_2

allowance compliance obligation (e.g., fossil generators under 25 megawatts electrical (MWe) capacity)

- Non-RGGI Generation (Non-Fossil): Non-fossil fuel-fired electric generators located in the ten-state RGGI region (e.g., nuclear, renewable energy, municipal solid waste combustors)
- Net Imports: Net electricity imports from adjacent control areas (or portion of a control area) outside the ten-state RGGI region and CO_2 emissions related to these net imports

Conclusions

The monitoring results show there has been no increase in CO_2 emissions from non-RGGI electric generation during the first three years of RGGI program operation, 2009 through 2011, compared to an annual average during 2006 to 2008.

Given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. The monitoring results for 2009 through 2011 are consistent with market dynamics given the relatively modest CO_2 allowance prices evident in the first three years of the program. These modest CO_2 allowance prices resulted in CO_2 compliance costs on a per MWh basis that were likely lower than the aggregate price signal of mitigating market factors discussed in this report that would advantageously limit emissions leakage.

I. Background

This annual report summarizes monitoring data for electricity generation and imports in the ten-state RGGI region[4] and related CO_2 emissions for the period from 2005 through 2011. This monitoring was called for in the 2005 RGGI MOU in response to expressed concerns about the potential for the RGGI CO_2 Budget Trading Program[5] to result in "emissions leakage".[6] The monitoring approach that was used to compile the data summarized in this report was specified in a March 2007 report from the RGGI Staff Working Group, *Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms*.[7]

The report provides data for evaluating CO_2 emissions related to electricity generation and imports in the ten-state RGGI region. The report tracks trends in electricity demand, net electricity imports, electricity generation from multiple categories of generation sources (including electricity imports), and the CO_2 emissions related to these categories of electric generation. The report should not be used to draw definitive conclusions about whether or not CO_2 emissions leakage has occurred, as it does not address the causes of changes in electricity generation and related CO_2 emissions among different categories of electric generation serving load in the ten-state RGGI region. This report is only an analysis of CO_2 emissions and does speak to other greenhouse gases.

II. Monitoring Approach

The data summarized in this report track electricity generation and electricity use in each of the three ISO regions fully or partially subject to the RGGI CO_2 Budget Trading Program. The data track all MWh of electricity used to serve electric load in each ISO (or portion of an ISO subject to RGGI in the case of PJM), the actual or estimated CO_2 emissions (in short tons of CO_2) related to the generation of this electricity, and the associated lb CO_2/MWh emission rate.[8]

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[4] The "ten-state RGGI region" consists of Delaware, Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey withdrew its agreement to the RGGI Memorandum of Understanding effective January 1, 2012. See http://www.rggi.org/docs/Documents/NJ-Statement_112911.pdf.

[5] RGGI is comprised of state CO_2 Budget Trading Programs. Under each of these state programs, a regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three-year control period. CO_2 allowances are issued by participating states in a finite amount, or "budget", resulting in a regional cap on CO_2 emissions from the electric generation sector in the RGGI region. Regulated power plants are fossil fuel-fired electric generating units with an electric generation capacity of 25 megawatts (MWe) or greater.

[6] Specifically, the Memorandum of Understanding called for monitoring electricity imports into the RGGI participating states commencing from the start of the RGGI CO_2 Budget Trading Program and reporting the results of such monitoring on an annual basis beginning in 2010.

[7] The report also specified requested changes that were made to generator attribute tracking systems for ISO-NE and PJM to facilitate RGGI monitoring. The report is available at http://www.rggi.org/docs/il_report_final_3_14_07.pdf

[8] Throughout this report, references to "electric generation" and "electric load" include only that portion of electric generation or electric load dispatched or served through the regional transmission system administered by ISOs and tracked by individual ISOs. This excludes most electric generation output and electric load typically referred to as "behind-the-meter", which refers to electric generation that is not dispatched by ISOs and electric load met through on-site electric generation facilities (e.g., industrial cogeneration and other smaller distributed generation resources, such as combined heat and power and solar photovoltaics). The electric generation MWh output that is not included in the monitoring results

For each year 2005 through 2011, the following categories of data are presented for the ten-state RGGI region as well as each ISO:

- RGGI-Affected Generation: Electric generation (MWh), CO_2 emissions (short tons), and lb CO_2/MWh emission rate for electric generators subject to the RGGI CO_2 Budget Trading Program. This category is limited to electric generating units subject to a CO_2 allowance compliance obligation under state CO_2 Budget Trading Program regulations.[9]

- Non-RGGI Generation: Total electricity generation (MWh), CO_2 emissions, and lb CO_2/MWh emission rate for all non-RGGI electric generation serving electric load in the ten-state RGGI region (includes both in-region electric generation and net electricity imports).[10] In addition to total non-RGGI generation, data for the following subcategories of non-RGGI generation are also presented:

    - Non-RGGI Generation (Fossil): Electric generation (MWh), CO_2 emissions, and lb CO_2/MWh emission rate for fossil fuel-fired electric generating units in the ten-state RGGI region that are not subject to a CO_2 allowance compliance obligation under state CO_2 Budget Trading Program regulations (e.g., electric generation units under 25 MWe)[11]
    - Non-RGGI Generation (Non-Fossil): Electric generation (MWh), CO_2 emissions, and lb CO_2/MWh emission rate for electric generating units in the ten-state RGGI region that do not meet the definition of fossil fuel-fired in state CO_2 Budget Trading Program regulations (e.g., renewable, nuclear, municipal solid waste combustors)
    - Net Imports: Net electricity imports (MWh) from adjacent control areas and CO_2 emissions and lb CO_2/MWh emission rate related to these net imports.[12]

includes the portion of electric generation output used on-site, if an electric generating unit supplies only a portion of its output to the ISO grid, or all electric generation output, if an electric generating unit supplies no electricity to the ISO grid. However, note that behind-the-meter electric generators eligible for credit under state renewable portfolio standards typically voluntarily report electric generation to the PJM Generation Attribute Tracking System (GATS) and NE-ISO Generation Information System (GIS), which are discussed in Section V. Methodology. These behind-the-meter electric generators that report to PJM GATS and ISO-NE GIS are included in the monitoring results.

[9] For the purposes of this report, this category does not include electric generators that may be subject to a state CO_2 Budget Trading Program regulation, or portion of such regulation, but that are not subject to a CO_2 allowance compliance obligation that requires the generator to submit CO_2 allowances equivalent to its CO_2 emissions. For example, under Maryland's CO_2 Budget Trading Program regulations, certain industrial cogenerators may be subject to alternative CO_2 compliance obligations under certain conditions in lieu of submission of CO_2 allowances.

[10] In practice, this category includes MWh and related CO_2 emissions from all electric generation serving load in the RGGI region, after subtracting out electric generation and related CO_2 emissions from electric generation units subject to a RGGI CO_2 allowance compliance obligation. For ISO-NE and NYISO, the "RGGI region" represents the full ISO footprint. For PJM, the "RGGI region" represents the three-state portion of PJM subject to the RGGI CO_2 Budget Trading Program in 2011(New Jersey, Delaware, and Maryland).

[11] This category also includes electric generation units at industrial facilities that are exempted from a CO_2 allowance compliance obligation under state CO_2 Budget Trading Programs.

[12] For individual ISOs, net imports represent actual annual net electricity flows between ISOs, as reported by the ISOs. For PJM, net electricity imports represent inferred transfers of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.

III. Summary of Monitoring Results

Monitoring results are summarized below for the ten-state RGGI region. Results are presented in detail for the ten-state RGGI region, as well as for each individual ISO, under Section VI – Monitoring Results.

Electric Load (Demand for Electricity) and Generation

- For 2009 to 2011, the annual average electricity load in the ten-state RGGI region was 16.1 million MWh less than the average 2006 to 2008 electricity load, or 3.4 percent.

- For 2009 to 2011, the annual average total electric generation in the ten-state RGGI region (fossil and non-fossil) decreased by 19.4 million MWh, or 5.0 percent from the 2006-2008 average.

- A comparison of the average electricity load in the ten-state RGGI region for 2011 only, to the base period of 2006 to 2008, shows a decrease of 15.5 million MWh, or 3.3 percent.

- A comparison of the average total electric generation in the ten-state RGGI region (fossil and non-fossil) for 2011 only to the base period of 2006 to 2008 shows a decrease of 18.4 million MWh, or 4.7 percent.

Non-RGGI Generation

- The monitoring results indicate that CO_2 emissions from non-RGGI electric generation did not increase in 2009 through 2011 – the first three years of RGGI program implementation - relative to the base period of 2006 to 2008.

- A comparison of the 2009 to 2011 average to the base period of 2006 to 2008 average shows the total electric generation from all non-RGGI electric generation sources serving load in the 10-state RGGI region increased, by 3.3 million MWh, an increase of 1.2 percent.

    - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows CO_2 emissions from all non-RGGI electric generation sources serving load in the ten-state RGGI region decreased by 5.6 million short tons of CO_2, or 9.2 percent.
    - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows the CO_2 emission rate for this category of electric generation decreased by 47 lb CO_2/MWh, or 10.3 percent.

- The monitoring results do not show an increase of annual CO_2 emissions related to either net electricity imports into the ten-state RGGI region or from small fossil fuel-fired electric generators in the ten-state RGGI region that are not subject to state CO_2 Budget Trading Program regulations in the first three years of the program, 2009 to 2011.

RGGI Generation

- A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows the electric generation from RGGI-affected electric generation sources decreased by 18.5 million MWh, or 9.1 percent.

  - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows CO_2 emissions from RGGI electric generation sources decreased by 33.8 million short tons of CO_2, or 21.3 percent.
  - A comparison of the 2009 to 2011 average to the base period of the 2006 to 2008 average shows the CO_2 emissions rate for RGGI electric generation sources decreased by 209 lb CO_2/MWh, or 13.4 percent.

- When 2011 only is compared to the baseline period of 2006 to 2008, the results similarly show a reduction in electric generation and CO_2 emissions and CO_2 emissions rate from RGGI electric generation sources.

IV. Evaluation of Monitoring Data

This section addresses issues considered in evaluation of the monitoring data, including the selection of base periods for comparison of data and general monitoring limitations.

<u>Selection of a Base Period</u>

In this report, 2009 through 2011 monitoring data is compared with data from the base period of the three-year period from 2006 through 2008. Conditions may change significantly during a base period and influence conclusions. This was the case with the electric power sector in the ten-state RGGI region during the period 2005 through 2008, which saw changes in wholesale electricity prices and in underlying market dynamics, such as electricity demand and relative fuel prices. These changes influenced electric generator dispatch and resulted in very significant changes in electric power sector CO_2 emissions in the ten-state RGGI region during the 2005 to 2008 timeframe.

During the period from 2000 through 2011, 2005 had the second highest CO_2 emissions for electric generators that met the applicability criteria of the

RGGI CO_2 Budget Trading Program, and the highest CO_2 emissions since 2001. As a result, this year was dropped as a point of comparison, considering the very significant subsequent drop in CO_2 emissions in subsequent years. The period of 2006 through 2008 was selected the base period to provide a three-year point of comparison that is comparable to the three-year compliance periods of the RGGI program. For 2009 and 2010 data comparisons to the base period please see the CO_2 Emissions from Electricity Generation and Imports in the 10-State Regional Greenhouse Gas Initiative: 2009 and 2010 Monitoring Reports.[13] NYCA data from years 2005-2011 was adjusted and corrected by NYDPS to account for previous years misclassifications of certain generators. The conclusions of the reports in 2009 and 2010 were not affected by these adjustments and corrections.

Key Metrics

A key metric presented in this report that may provide a preliminary indication of *potential* emissions leakage, or a lack thereof, is electric generation and related CO_2 emissions from all non-RGGI affected electric generation that serves electric load in the ten-state RGGI region. This includes electric generation in the ten-state RGGI region from electric generating units that are not subject to a CO_2 allowance compliance obligation under a state CO_2 Budget Trading Program (e.g., small fossil units not subject to RGGI or non-fossil units not subject to RGGI), as well as net imports of electricity into the ten-state RGGI region. If CO_2 emissions leakage were to occur, it would manifest as an increase in CO_2 emissions from this category of non-RGGI electric generation, assuming all other factors that impact electricity system dispatch and CO_2 emissions, such as electricity demand, relative fossil fuel prices, and wholesale electricity prices, did not change. As a result, an increase in CO_2 emissions from this category of electric generation in a year subsequent to implementation of RGGI, relative to a baseline prior to the implementation of RGGI, could be an indicator of *potential* CO_2 emissions leakage.

General Limitations

It should be emphasized that this report does not provide indicators of CO_2 emissions leakage, but merely tracks electricity generation and imports and related CO_2 emissions in the RGGI region for 2009 through 2011 relative to baseline years prior to implementation of the RGGI program. Changes in these data over time may point to *potential* CO_2 emissions leakage as a result of the RGGI CO_2 Budget Trading Program, or a lack thereof, but may also be the result of wholesale electricity market and fuel market dynamics unrelated to the RGGI program.

[13] Report available at http://www.rggi.org/docs/Documents/Elec_monitoring_report_11_09_14.pdf and http://www.rggi.org/docs/Documents/Elec_Monitoring_Report_12_07_30_Final.pdf

The data and analysis in this Monitoring Report do not take into account the full lifecycle of sources of fuel. For example, the direct emissions of CO_2 and the lb CO_2/MWh emission rates from non-RGGI non-fossil fuel units in this report do not reflect the biomass lifecycle carbon reduction of atmospheric CO_2 levels resulting from uptake of CO_2 from the atmosphere as a result of forest and biomass growth. Likewise for municipal solid waste combustors, direct emissions of CO_2 are presented with no analysis of the lifecycle of the components of the waste. The analysis of lifecycle reductions and contributions of fuels used in non-RGGI non-fossil fuel units is not within the scope of this report and this report does not provide indicators of total atmospheric reductions or contributions from the fuels used in non-RGGI non-fossil fuel units.

This report cannot draw definitive conclusions about whether or not CO_2 emissions leakage has occurred, as it does not address the causes of shifts in electricity generation and related CO_2 emissions among different categories of electric generation serving load in the ten-state RGGI region. However, the results do demonstrate that there has been no increase in CO_2 emissions or lb CO_2/MWh emission rate from non-RGGI electric generation during the first three years of RGGI program operation, 2009 through 2011, compared to an annual average during 2006 – 2008.

Determining whether CO_2 emissions leakage has occurred requires the evaluation of a hypothetical counterfactual – the amount of CO_2 emissions from non-RGGI electric generation that would occur, assuming there is no shift in electric generation to CO_2-emitting non-RGGI electric generators as a result of the implementation of the RGGI CO_2 Budget Trading Program (i.e., assuming no CO_2 emissions leakage).

In theory, an increase in CO_2 emissions or CO_2 emission rate from non-RGGI electric generation as compared to a historical baseline year could occur in a scenario in which CO_2 emissions leakage does not occur. Conversely, leakage could theoretically occur in a scenario in which CO_2 emissions and CO_2 emission rate for non-RGGI electric generation *decreased* as compared to a historical baseline year, if such emissions would have decreased further under a hypothetical counterfactual where no CO_2 emissions leakage occurs.

Given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. The monitoring results for 2009 through 2011 are consistent with market dynamics given relatively modest CO_2 allowance prices evident in 2009 through 2011 that result in CO_2 compliance costs on a dollar per MWh basis that are likely lower than the aggregate dollar per MWh price signal of mitigating market factors discussed in this report that would be expected to impede emissions leakage. Considering these factors, with modest CO_2 allowance prices, no net market dynamic driving emissions leakage would be expected to occur.

V. Methodology

Data Sources

For ISO-NE and PJM, the data presented are primarily from the NEPOOL Generation Information System (GIS) and PJM Generation Attribute Tracking System (GATS),[14] supplemented by ISO electricity import/export data, and CO_2 emissions data for RGGI-affected electric generation from the RGGI CO_2 Allowance Tracking System (RGGI COATS) for 2009 to 2011 and emissions statement data reported to state environmental agencies in the RGGI participating states for 2005-2008. For non-RGGI electric generation, CO_2 emissions are based on CO_2 emissions for individual electric generation facilities in the NE GIS and PJM GATS tracking systems.

A summary of data sources for ISO-NE and PJM is provided in Appendix A.

For NYISO, MWh data were compiled by the New York Department of Public Service from NYISO data (MWh generation data) and PJM and Hydro Quebec data (MWh electricity net import data). This MWh data was supplemented by CO_2 emissions data compiled by the New York Department of Environmental Conservation (NYDEC). 2009 - 2011CO_2 emissions data for RGGI-affected electric generation units were taken from RGGI COATS and 2005-2008 CO_2 emissions data for these units were compiled from NYDEC emissions statement program data. CO_2 emissions data for fossil fuel-fired electric generation units that are non-RGGI affected were taken or extrapolated from reports compiled by NYDEC. A summary of data sources for NYISO is provided in Appendix A.

For each ISO, CO_2 emissions related to net electricity imports from each adjacent control area[15] are the product of a lb CO_2/MWh emission rate and the reported MWh of net imports. The CO_2 emission rate for electricity imports is based on the system average CO_2 emission rate for the respective exporting adjacent control area.[16] For ISO-NE and NYISO, net electricity imports are based on actual flow data for electricity transfers between adjacent control areas.[17] For PJM, net electricity imports are inferred and represent “transfers” of

[14] These ISO tracking systems track every MWh of electric generation for each electric generator that participates in the ISO wholesale market. Modifications were made to both systems at the request of the RGGI Staff Working Group to facilitate the tracking presented in this report. (See Staff Working Group, *Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms,* pp. 18-26; available at http://www.rggi.org/design/history/import_leakage.) These systems do not fully capture the portion of electric generation that is “behind the meter” and used to serve on-site electric load (e.g., MWh supplied from industrial cogeneration to meet on-site industrial electricity load).

[15] For PJM, this represents inferred imports from the non-RGGI geographic portion of PJM.

[16] This assumes that power transferred originates in the adjacent control area and is delivered for use in the receiving control area. This assumption does not account for the wheeling of power through control areas.

[17] The exception is net import data from Hydro Quebec into NYISO, which represents net scheduled electricity imports. Scheduled flows are those flows that are scheduled at an ISO interface for a defined period, while actual flows are the metered flows at an ISO interface for a defined period. Differences between the two can arise from transactions scheduled on contract paths that do not fully correspond to the physical paths on which the electricity related to the transaction actually flows.

electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM (Delaware, Maryland, and New Jersey). This data is compiled from PJM GATS, which reports data for both the non-RGGI and RGGI geographic portions of PJM. Inferred net imports are based on total MWh load in the RGGI geographic portion of PJM minus total electric generation in the RGGI geographic portion of PJM. Any shortfall in generation relative to load is assumed to be met through an inferred "import" of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.[18]

When aggregating individual ISO net import data, the reported regional net imports of electricity and related CO_2 emissions from net imports presented in this report represent net imports from adjacent regions not subject to the RGGI CO_2 Budget Trading Program. Some of the individual ISO net import subtotals represent net imports from another ISO (or portion of an ISO) that is also subject to the RGGI CO_2 Budget Trading Program. In order to avoid inappropriate double counting of MWh and related CO_2 emissions, the net import subtotals from adjacent ISOs (or portion of ISO) subject to the RGGI CO_2 Budget Trading Program were not included when rolling up the individual ISO data into regional summary totals, as the electricity and CO_2 emissions represented by these net imports are included in the electric generation subtotals for each ISO. In rolling up total regional net imports, NYISO net imports from PJM represent a prorated portion of total net imports from PJM that are assumed to originate from the non-RGGI geographic portion of PJM. For each year, this proration is based on the percentage of total PJM MWh generation that occurred in the non-RGGI geographic portion of PJM. (See next subsection for further discussion.)

Monitoring Limitations

The monitoring approach used in this report is subject to certain inherent limitations. These limitations primarily involve tracking for the PJM ISO, as well as how net exports from PJM to NYISO are addressed when rolling up ISO-specific data into regional totals for the ten-state RGGI region.

For ISO-NE and NYISO, net electricity import data is based on the tracking of actual electricity flows between adjacent control areas.[19] This type of tracking is not possible for the RGGI portion of PJM, as PJM is dispatched as a single control area, and electricity flows between geographic subsets of PJM on a state-by-state basis are not available. As a result, "electricity imports" into the three-state RGGI portion of PJM (Delaware, Maryland, and New Jersey) from the rest of PJM must be inferred.

This also means that net electricity exports from the non-RGGI portion of PJM into NYISO cannot be determined based on actual electricity flows, as the actual monitored flows of electricity between PJM and NYISO do not allow for a

[18] For PJM, this category of data does not technically represent an import of electricity, as PJM is dispatched as a single control area.
[19] The exception is net import data from Hydro Quebec into NYISO, which represents net scheduled electricity imports.

differentiation between these two geographic subsets of PJM. As a result, certain assumptions must be made in order to prorate the portion of net exports from the non-RGGI portion of PJM into NYISO. For this report, this proration is based on the annual percentage of electric generation in the non-RGGI portion of PJM for a respective reporting year, as a percentage of total PJM generation for that year. The actual monitored net electricity flows from PJM into NYISO are multiplied by this percentage to derive an estimate of net electricity exports from non-RGGI PJM into NYISO. These assumed flows may not be fully representative of the actual electric generation source of net exports from non-RGGI PJM into NYISO.

A more modest monitoring limitation involves the electric generation data tracked by the three ISOs. ISO tracking does not include electric generation that is not dispatched into the ISO.[20] This typically involves the portion of industrial cogeneration of electricity used on-site at industrial facilities as well as smaller distributed combined heat and power and renewable energy generation (sometimes referred to as "behind-the-meter" generation). Data for this sub-category of electric generation is not captured through the tracking methodology used in this report, as the methodology relies on unit-specific electric generation data provided by the ISOs.[21]

[20] This excludes most electric generation and electric load typically referred to as "behind the meter", which refers to electric generation that is not dispatched by ISOs and electric load met through on-site electric generation facilities (e.g., industrial cogeneration and other smaller distributed generation resources, such as combined heat and power and solar photovoltaics). However, behind-the-meter electric generators eligible for credit under state renewable portfolio standards typically voluntarily report electric generation to the PJM Generation Attribute Tracking System (GATS) and NE-ISO Generation Information System (GIS). MWh data for these behind-the-meter electric generators that report to PJM GATS and ISO-NE GIS are included in the monitoring results.

[21] CO_2 emissions data for behind-the-meter electric generation that is RGGI-affected are included in this report. In addition, only electricity output from cogeneration facilities is reported by ISOs, meaning that the average lb CO_2/MWh emission rate for all reporting years in this report is for electricity generation dispatched to the ISO grid only and does not account for behind-the-meter MWh output or useful steam output from cogeneration facilities.

VI. Monitoring Results

Monitoring results are provided below for the full ten-state RGGI region. These results provide a compilation of data from each ISO fully or partially subject to the RGGI CO_2 Budget Trading Program: ISO-NE, NYISO, and PJM. For PJM, monitoring data is compiled for the three-state portion of PJM affected by RGGI (Delaware, Maryland, and New Jersey). Monitoring data for each ISO is presented in Appendix B.

Monitoring results for the 10-state RGGI region for 2005 through 2011 are summarized below in Table 1 and Figures 2 through 5.[22]

Table 1. 2005 – 2011 Monitoring Summary for 10-State RGGI Region

	MWh							Tons CO_2							Lb CO_2/MWh						
	2005	2006	2007	2008	2009	2010	2011	2005	2006	2007	2008	2009	2010	2011	2005	2006	2007	2008	2009	2010	2011
Electricity Demand																					
Total in RGGI	480,362,390	469,584,886	477,090,574	466,247,097	448,024,418	461,285,678	455,434,193	245,169,071	224,913,893	228,282,271	206,488,413	175,160,896	193,576,857	172,802,707	1,021	958	957	886	782	839	757
Net Imports - from Ontario to NYISO	1,898,020	3,672,282	2,637,442	6,162,902	6,463,657	3,872,635	3,318,681	460,286	769,120	610,529	1,154,884	712,496	554,950	475,569	485	419	463	375	220	287	287
Net Imports - from Quebec to NY & NE	7,375,317	8,982,749	11,912,292	15,141,014	17,065,805	13,549,209	18,681,204	32,520	49,509	118,179	33,380	56,435	29,871	41,185	9	11	20	4	7	4	4
Net Imports - from New Brunswick to NE	1,620,000	1,047,000	896,000	1,285,000	1,569,000	737,000	846,000	846,443	508,967	438,526	718,150	984,101	410,264	470,940	1,045	972	979	1,118	1,254	1,113	1,113
Net Imports - from non-RGGI PJM to NY	6,379,823	8,101,829	8,659,727	9,062,826	7,073,143	10,460,586	9,506,790	4,257,772	5,246,328	5,536,825	5,720,147	4,213,398	6,339,400	5,670,522	1,335	1,295	1,279	1,262	1,191	1,212	1,193
Net Imports - from non-RGGI PJM to RGGI PJM	65,324,576	60,819,367	57,887,856	54,088,276	56,299,698	58,001,518	55,406,781	43,596,369	39,383,494	37,012,128	34,138,677	33,537,149	35,150,499	33,048,520	1,335	1,295	1,279	1,262	1,191	1,212	1,193
Total Net Imports - from All Adjoining ISOs	82,597,736	82,623,227	81,993,317	85,740,018	88,471,303	86,620,948	87,759,456	49,193,389	45,957,417	43,716,188	41,765,239	39,503,579	42,484,984	39,706,736	1,191	1,112	1,066	974	893	981	905
Electricity Generation																					
RGGI-Affected Units	211,948,440	199,593,115	213,091,389	198,454,328	175,344,325	195,032,446	185,313,180	180,946,904	159,862,042	167,050,592	149,715,865	122,156,938	135,570,546	117,539,864	1,707	1,602	1,568	1,509	1,393	1,390	1,269
Non-RGGI Fossil Fuel-Fired Units	9,456,126	8,853,355	7,444,927	3,520,886	2,960,649	3,369,448	3,698,562	8,073,191	8,202,959	6,531,324	2,786,884	2,432,792	3,558,591	3,863,630	1,708	1,853	1,755	1,583	1,643	2,112	2,089
Non-Fossil Fuel-Fired Units	176,491,364	178,751,235	174,777,668	178,383,105	181,707,959	177,052,252	180,204,565	6,955,587	10,891,475	10,984,167	12,220,426	11,067,587	11,962,735	11,692,478	79	122	126	137	122	135	130
All Non-RGGI Units	185,947,490	187,604,590	182,222,595	181,903,991	184,668,608	180,421,700	183,903,127	15,028,778	19,094,433	17,515,491	15,007,310	13,500,378	15,521,326	15,556,107	162	204	192	165	146	172	169
All Units	397,764,653	386,961,659	395,097,257	380,507,079	359,553,115	374,663,730	367,674,737	195,975,682	178,956,476	184,566,083	164,723,174	135,657,317	151,091,872	133,095,971	985	925	934	866	755	807	724
Summary Data																					
Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports = (B-2 + B-3) + A-3)	268,545,226	270,227,817	264,215,912	267,644,009	273,139,911	267,042,648	271,662,583	64,222,167	65,051,850	61,231,679	56,772,548	53,003,958	58,006,310	55,262,843	478	481	463	424	388	434	407

[22] Note that reported regional net imports of electricity represent net imports from adjacent control areas (or portion of a control area) not subject to the RGGI CO_2 Budget Trading Program. As a result, the net electricity imports and related CO_2 emissions as reported in tabular summaries for each ISO provided in Appendix B do not add up to the reported total regional net imports and related CO_2 emissions. This is because some of the individual ISO net import subtotals represent net imports from another ISO that is also subject to the RGGI CO_2 Budget Trading Program. In order to avoid inappropriate double counting of MWh and related CO_2 emissions, these net import subtotals were not included when rolling up the individual ISO data into regional summary totals, as the electricity and CO_2 emissions represented by these net imports are included in the electric generation subtotals for each ISO.

The monitoring results indicate that during the first three years of the RGGI program, 2009 through 2011, total average annual electric generation from all non-RGGI electric generation serving load in the ten-state RGGI region increased, by 3.3 million MWh, an increase of 1.2 percent, from the average annual generation from the benchmark period of 2006 to 2008. In a comparison of the 2009 to 2011 annual average to the 2006 to 2008 base period annual average, the CO_2 emissions from this category of electric generation decreased by 5.6 million short tons of CO_2, a reduction of 9.2 percent, and the CO_2 emission rate decreased by 47 lb CO_2/MWh, a reduction of 10.3 percent. (See Figures 2, 3, and 4.)

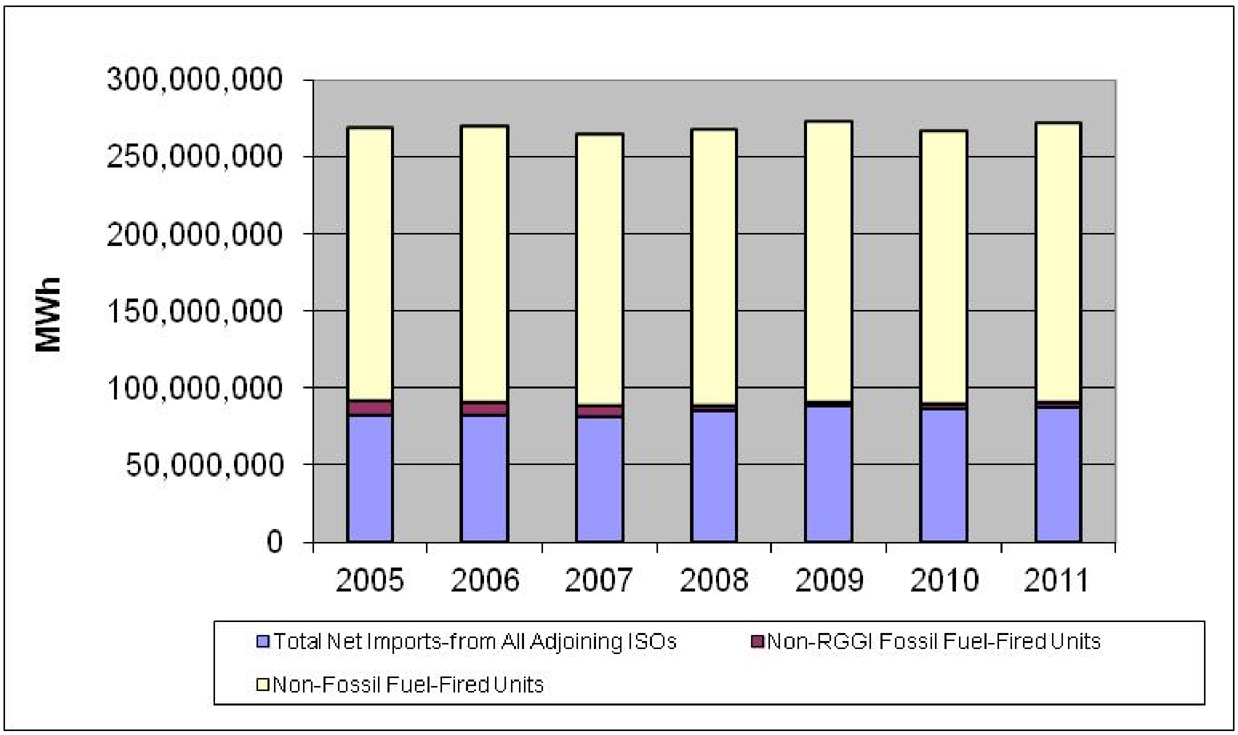

Figure 2. Non-RGGI Generation Serving Load in RGGI Region (MWh)

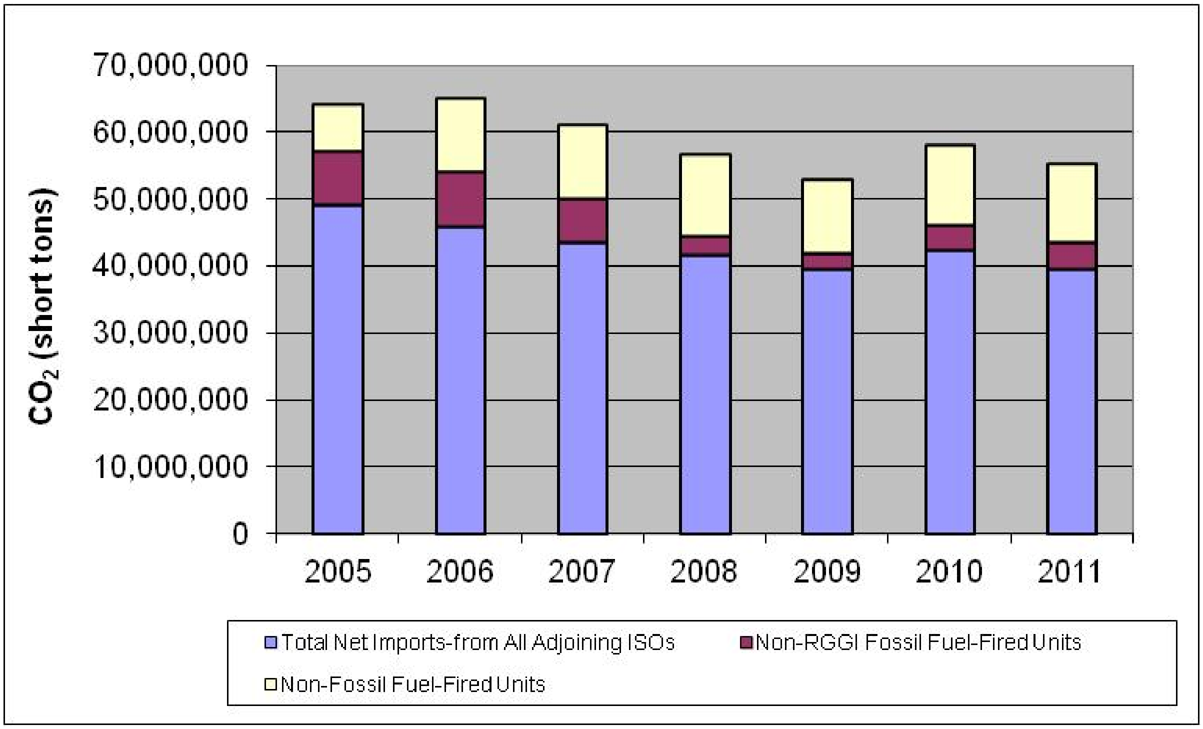

Figure 3. CO_2 Emissions from Non-RGGI Generation Serving Load in RGGI Region (short tons CO_2)

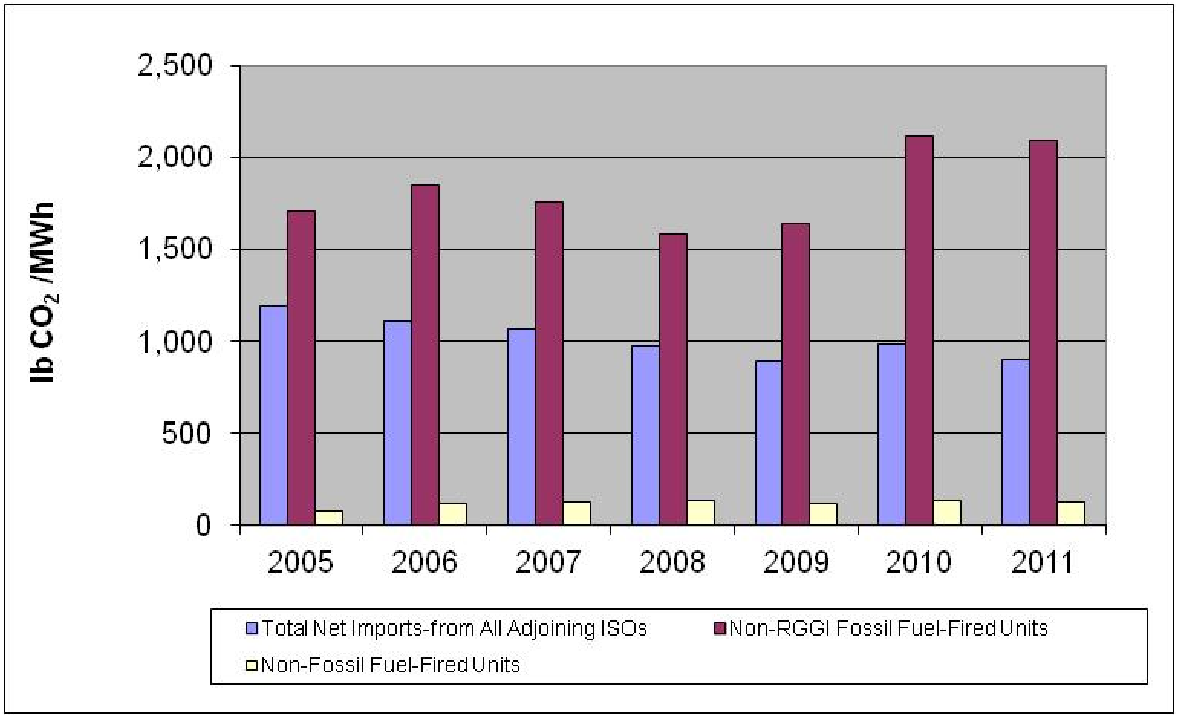

Figure 4. CO_2 Emission Rate for Non-RGGI Generation Serving Load in RGGI Region (lb CO_2/MWh)

The 2009 to 2011 annual average electricity load in the 10-state RGGI region decreased by 16.1 million MWh, or 3.4 percent, from the 2006 to 2008 base period annual average. In total, electric generation in the ten-state RGGI region (fossil and non-fossil) decreased by 19.4 million MWh, or 5.0 percent, from the base period annual average.

Electric generation from RGGI-affected generation decreased by 18.5 million MWh during this period, or 9.1 percent, and CO_2 emissions from RGGI-affected generation decreased by 33.8 million short tons, or 21.3 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 209 lb CO_2/MWh, a decrease of 13.4 percent. Electric generation from non-RGGI generation sources located in the 10-state RGGI region decreased by 913 thousand MWh, or 0.5 percent, during this period, and CO_2 emissions from this category of electric generation decreased by 2.3 million short tons, a reduction of 13.6 percent. The CO_2 emission rate of non-RGGI electric generation located in the ten-state RGGI region decreased by 25 lb CO_2/MWh, a reduction of 13.2 percent.

Average annual net electricity imports into the 10-state RGGI region increased by 4.2 million MWh, or 5.0 percent, from the 2009 to 2011 average compared to the 2006 to 2008 base period annual average. CO_2 emissions related to these net electricity imports decreased by 3.2 million short tons, or 7.4 percent, during this period, indicating a reduction in the average CO_2 emission rate of the electric generation supplying these imports of 124 lb CO_2/MWh, a reduction of 11.8 percent. (See Figures 5 and 6.)

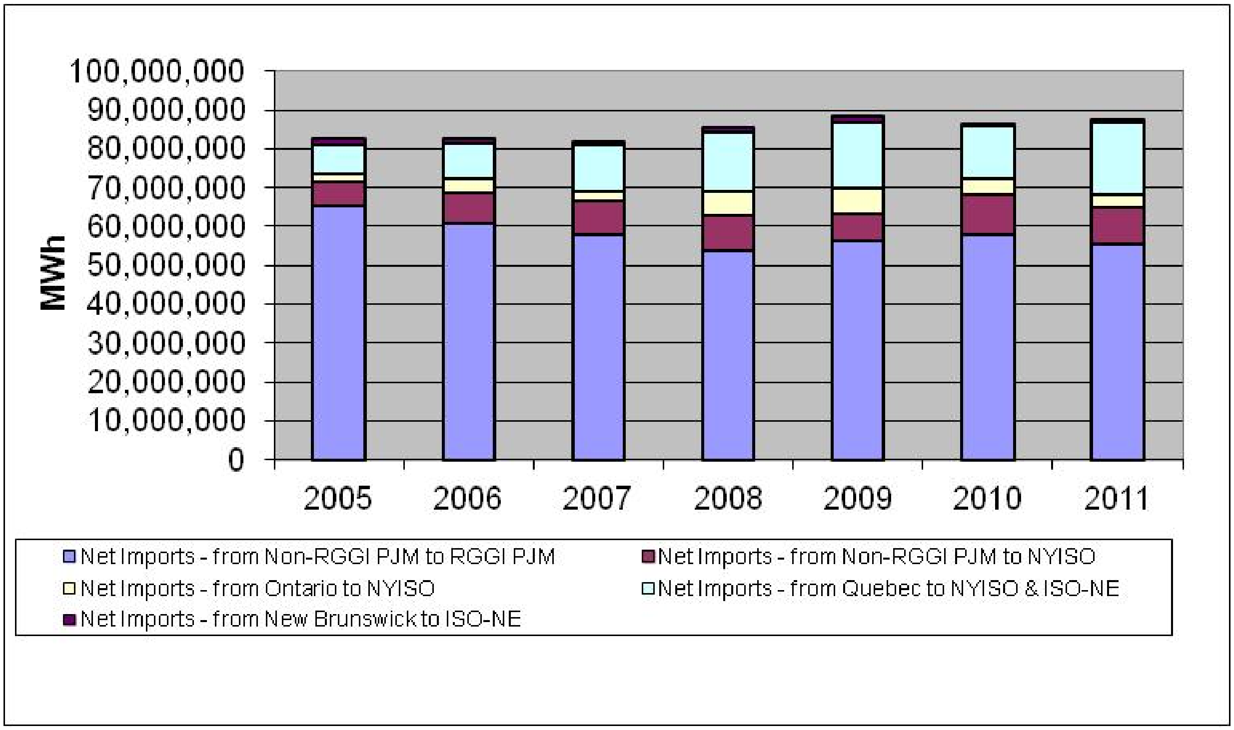

Figure 5. Net Electricity Imports to 10-State RGGI Region (MWh)

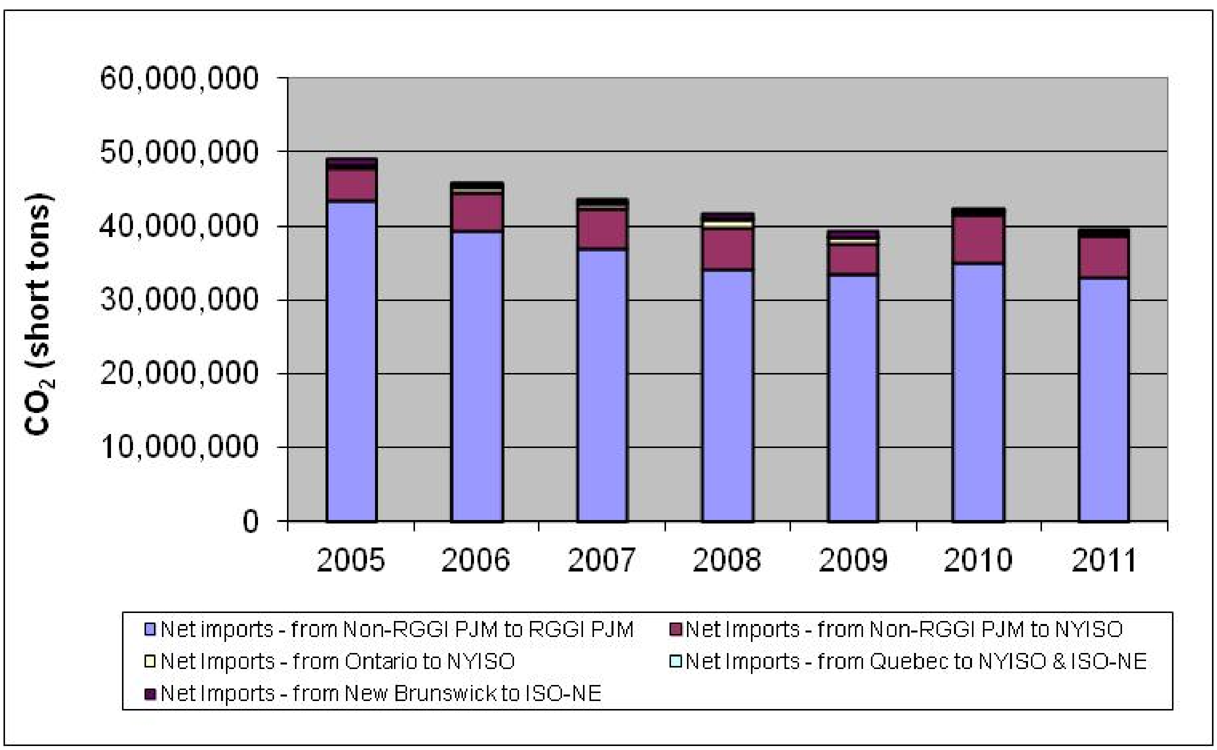

Figure 6. CO_2 Emissions Related to Net Electricity Imports to 10-State RGGI Region (short tons CO_2)

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 total electricity load in the ten-state RGGI region decreased by 15.5 million MWh, or 3.3 percent. Compared to the 2006 – 2008 annual average, total electric generation in 2011 in the ten-state RGGI region decreased by 18.4 million MWh, or 4.7 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 electric generation from RGGI-affected generation decreased by 18.4 million MWh, or 9.0 percent, and CO_2 emissions from RGGI-affected generation decreased by 41.3 million short tons of CO_2, or 26.0 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 291 lb CO_2/MWh, a reduction of 18.7 percent. Compared to the 2006 – 2008 annual average, 2011 electric generation from non-RGGI generation sources located in the ten-state RGGI region decreased by 7 thousand MWh, or less than 0.01 percent, and CO_2 emissions from this category of electric generation decreased by 1.6 million short tons, a reduction of 9.6 percent. The CO_2 emission rate of non-RGGI electric generation located in the ten-state RGGI region decreased by 18 lb CO_2/MWh, a reduction of 9.6 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 net electricity imports into the ten-state RGGI region increased by 4.3 million MWh, or 5.2 percent. CO_2 emissions related to these net electricity imports decreased by 4.1 million short tons of CO_2, or 9.4 percent, during this period, indicating a decrease in the average CO_2 emission rate of the electric generation supplying these imports of 145 lb CO_2/MWh, a reduction of 13.8 percent.

VII. Discussion

In the context of the multiple market factors outlined below that influence dispatch of electric generation, CO_2 allowance costs in 2009 through 2011, the first three years of RGGI operation, were relatively modest compared to other electric generation cost components that impact wholesale electricity prices. This modest carbon price signal is consistent with monitoring data in this report that indicate no net increase in CO_2 emissions for non-RGGI electric generation in the annual average of 2009 to 2011 compared to the annual average during 2006 – 2008.

Across the three ISOs subject to RGGI, CO_2 allowance costs accounted for 0.5 percent to 1.5 percent of the average all-in wholesale electricity price in 2011.[22] While CO_2 allowance costs represented a modest component of

[22] For 2011, the average all-in wholesale electricity price was $62.56/MWh for PJM, $53.71/MWh for ISO-NE, and $56.00/MWh for NYISO (energy only) (See ISO-NE Selectable Wholesale Load Cost Data; NYISO, *Power Trends 2012*, p. 14: Monitoring Analytics, *2011 State of the Market Report for PJM*, Section 1, Introduction, p. 11). The CO_2 allowance component is based on a 2011 average CO_2 allowance spot price of $1.89 per CO_2 allowance (See Potomac Economics, *Annual Report on the Market for RGGI CO_2 Allowances: 2010 p. 13*). For PJM, the CO_2 allowance component of the Locational Marginal Price (LMP) for 2011 was $0.31 per MWh (See Monitoring Analytics, *2011 State of the Market Report for PJM*, Section 2, Energy Market, Part 1, p. 79). ISO-NE and NYISO do not report the CO_2 allowance component of

wholesale electricity prices, wholesale prices dropped significantly from 2008 to 2009 in each of the three ISOs subject to RGGI. The wholesale electricity price reduction was primarily due to a reduction in natural gas prices and a reduction in electricity demand. Higher fuel prices in 2010, coupled with increased economic activity and hot weather led to an increase in wholesale prices in 2010 relative to 2009. Average electricity prices decreased in 2011 relative to 2010, primarily due to a decrease in natural gas prices and mild winter temperatures in late 2011.[23]

A number of market drivers have changed dramatically during the 2005 through 2011 monitoring timeframe. This includes changes in relative fossil fuel prices (prices for natural gas, coal, and oil), electricity demand, and the availability of different types of electric generation capacity with differing CO_2 emissions profiles. An analysis of these changes, and their estimated impact on CO_2 emissions in the 10-state RGGI region from 2005 to 2009, was completed by the New York State Energy Research and Development Authority (NYSERDA).[24]

The dynamics of a competitive wholesale electricity market could drive emissions leakage if they provide a sufficient net financial incentive to shift electric generation to units not subject to CO_2 regulation. The extent of this impact is likely to depend, at least in part, on the market value of CO_2 allowances (and the related $/MWh CO_2 costs incorporated into bids by generators subject to the RGGI CO_2 Budget Trading Program) in relation to other economic factors associated with the generation and delivery of electricity. These factors include locational marginal pricing (LMP), which includes both transmission congestion charges and line loss costs, standard transmission pricing, relative fuel prices, and relative heat rates of generation units.[25] Reliability constraints also play a role in determining the dispatch of electric generation units to the extent that units supply needed generation capacity and ancillary services in a specified region or location on the electricity grid.

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wholesale electricity prices. Both the New England and New York analyses used a 2011 average CO_2 allowance spot price of $1.89 as a starting point for deriving a CO_2 allowance wholesale price component. The ISO-NE CO_2 allowance wholesale price component was calculated by assuming an aggregate oil/natural gas unit is the marginal unit, with a CO_2 emission rate of 0.465 short tons of CO_2 per MWh (see *2008 New England Electric Generator Air Emissions Report, August 2010, Table 5.10*). The NYISO CO_2 allowance wholesale price component was calculated by assuming that a natural gas plant is the marginal unit, with a 2009 fleet average heat rate of 8,758 Btu per kWh and a CO_2 emission rate of 117 pounds per MMBtu. For both ISO-NE and NYISO, the CO_2 emission rate of the assumed marginal unit was used to translate the annual average spot price for CO_2 allowances ($1.89) into a dollar per MWh value. For ISO-NE, this resulted in an average CO_2 allowance wholesale price component of approximately $0.88 per MWh. For NYISO, this resulted in an initial average CO_2 allowance wholesale price component of $0.97 per MWh. Since ISO-NE imports from Canada are not subject to RGGI and associated with a wholesale CO_2 allowance price component, the ISO-NE initial $0.88per MWh wholesale CO_2 allowance price component is reduced to $0.80 to account for the electricity imported from these areas, about 9.5% of the load. Since Canada and Pennsylvania are not RGGI participating jurisdictions, electricity imported into NYISO from these areas is not assumed to be associated with a CO_2 allowance wholesale price component in NYISO. Therefore, the initial $0.97 per MWh CO_2 allowance wholesale price component for NYISO was reduced to $0.66 to account for the amount of marginal electricity imported from these areas.

[23] See, for example, Monitoring Analytics, *2011State of the Market Report for PJM*, Section 1, Introduction; Potomac Economics, *2011State of the Market Report New York ISO*, pp. ii-iv; ISO New England Internal Market Monitor, *2011Annual Markets Report*, May 2011, pp. 1-2.

[24] New York State Energy Research and Development Authority (NYSERDA), Relative Effects of Various Factors on RGGI Electricity Sector CO_2 Emissions: 2009 Compared to 2005, November 2010; available at http://www.rggi.org/docs/Retrospective_Analysis_Draft_White_Paper.pdf.

[25] Heat rate is a measure of electric generator energy efficiency, represented as Btu of fuel input per kWh of electricity output.

A key factor impacting the potential for emissions leakage is the relative cost of electric generation inside and outside the RGGI region (both with and without the incorporation of CO_2 allowance costs), and the relationship of this cost differential with physical transmission capability, the all-in market costs of inter-region power transmission, and the market impacts of transferring significant incremental amounts of power into the RGGI region. The dynamic and highly specific nature of market factors and physical constraints that may cause or mitigate emissions leakage make both a retrospective analysis and future projections of emissions leakage difficult. The factors that may result in emissions leakage are likely to be both temporally and geographically specific, given the dynamic operation of the electric power system.

Locational marginal pricing (LMP) can be expected to affect the market response to the imposition of a CO_2 allowance cost adder to generation in the RGGI region. LMP is based on the principle that the generation of power has different values at different points in the electric power network. LMP is the cost of supplying the last MWh of generation dispatched at a specific location, which reflects transmission constraints and the marginal cost of local generation units. Market participants utilize finite transmission resources, and transfers of power in a region can impact the local generation economics in that area, due to the physics of the electric transmission network. Transmission “congestion” occurs when available, low-cost electric generation supply cannot be delivered to the demand location due to transmission network limitations. When electricity from the least-cost electric generation source in a region cannot be delivered to electricity load in a transmission-constrained area, higher cost units in this constrained area are dispatched to meet that load. The result is that the wholesale price of electricity in the constrained area is higher than in the unconstrained area due to a combination of electricity demand, transmission limitations, and the marginal cost of local generation.

If the cost of RGGI CO_2 compliance on a per MWh basis is lower than the aggregate per MWh price signal of mitigating market factors, which are discussed below, no net market dynamic driving emissions leakage would be expected to occur. This net market signal would be a function of the relationship between the generation cost differential due to RGGI CO_2 compliance and the all-in market cost of transferring incremental power into the RGGI region or shifting generation to other unregulated smaller fossil fuel-fired generation sources within the RGGI region. Market factors that may impact the economics of importing incremental power in response to a CO_2 allowance price signal include[26]:

- *Existing Generator Economics* – Including a CO_2 compliance cost into the generation costs of an individual electric generator may make that generator uneconomic relative to a competitor. However, whether this

[26] Some of these factors may also impact the economics of shifting dispatch to smaller in-region fossil fuel-fired electric generation in the ten-state RGGI region that is not subject to regulation of CO_2.

occurs depends on the operating costs of each electric generator, both with and without CO_2 compliance costs. Key factors that influence electric generator operating costs include fuel prices, generator heat rate (Btu of fuel input per kWh of electric generation output), and allowance costs for air pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and CO_2). As a result, inclusion of a CO_2 allowance cost must be sufficient to supplant any preexisting generator cost differentials in order to shift generation from a RGGI source to a non-RGGI source.

- *Existing Locational Generation Price Differentials* – Differential LMPs between regions represent the presence of transmission constraints that require the dispatch of higher priced electric generation in a certain region. Electricity demand, in particular, can have a large impact on LMPs in a specific region. For example, in 2010 the average day-ahead, load-weighted zonal LMP in eastern PJM (NJ, DE, MD) was $7.38 per MWh above the average PJM LMP, indicating the presence of existing transmission congestion.[27]

- *Congestion Charges* – Congestion charges and the standard cost of transmitting electricity may make significant incremental imports into the RGGI region uneconomic as a response to a modest generation price differential resulting from RGGI CO_2 allowance costs. As an example, in PJM, power transmission is subject to congestion charges, which are based on the difference between LMPs at the source (generator location, or "generator bus") and LMPs at the sink (electric distribution utility location, or "load serving entity (LSE) bus"). Thus, in addition to standard transmission charges, entities importing power into the RGGI region would need to pay congestion charges based on the differential between LMPs in the uncapped non-RGGI region where the generator is located and LMPs in the capped RGGI region where the electricity is delivered.[28]

- *Line loss charges* – The greater the distance that electricity is transmitted, and as more power is transmitted through a power line, the greater the loss of the power initially put into the line, based on the physics of the electricity transmission network. As a result, the costs of transmission line-losses impact the economics of importing power. For example, in PJM line loses are accounted for in the calculation of LMP through the application of a line loss "penalty factor." If the dispatch of an electric generator would result in an increase in system line losses in a certain location, a positive

[27] Monitoring Analytics, *2010 State of the Market for PJM*, 2010; Section 2, Energy Market, Part 1, pp. 91.

[28] As an example, the congestion component of the 2010 average day-ahead, load weighted LMP in the Delmarva Power & Light zone (Delaware and Maryland) zone of PJM was $3.73 per MWh. For the Baltimore Gas & Electric zone (Maryland), the congestion component was $6.83 per MWh, and for the PSEG zone (New Jersey), the congestion component was $3.47 per MWh. See, Monitoring Analytics, 2010 *State of the Market for PJM*, 2011; Section 2, Energy Market, Part 1, p. 91.

penalty factor is applied to the generator's bid into the wholesale market, making the unit look less economically attractive to dispatch.[29]

- *Long-Term Contracts* – Other factors, such as existing long-term power purchase agreements, can be expected to mitigate emissions leakage, especially in the near-term, since units that are subject to such agreements will continue to dispatch subject to the terms of the agreements. With existing contracts in place, LSEs are constrained from seeking alternative sources of generation supply.[30, 31] It is estimated that long-term contracts account for approximately 12% of electric generation in the ten-state RGGI region.[32]

VIII. Conclusions

This report presents data and trends for electricity generation, imports and related CO_2 emissions without assigning causality to any one of the factors influencing observed trends in electricity generation and related CO_2 emissions among different categories of electric generation serving load in the 10-state RGGI region. The results do demonstrate that there has been no increase in CO_2 emissions or CO_2 emission rate (lb CO_2/MWh) from non-RGGI electric generation serving load in the ten-state RGGI region during the first three years of RGGI program operation, 2009 to 2011. If emissions leakage were to occur, it would manifest through an increase in CO_2 emissions from this aggregate category of non-RGGI electric generation, assuming all other factors that impact electric generator dispatch and CO_2 emissions, such as electricity demand, relative fossil fuel prices, and wholesale electricity prices, did not change.

Given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. The monitoring data for 2009 through 2011, which show no increase from the base period of 2006 to 2008 in CO_2 emissions from non-RGGI electric generation serving electricity load in the ten-state RGGI region, are consistent with expectations, given the relatively modest CO_2 allowance prices evident in 2009 through 2011. The average CO_2 allowance price in 2009 through 2011 represented approximately 1.5 percent or less of the average wholesale

[29] As an example, the line loss component of the 2010 average day-ahead, load weighted LMP in the Delmarva Power & Light (Delaware and Maryland) zone of PJM was $3.02 per MWh. Similarly, for the Baltimore Gas & Electric zone (Maryland), the line loss component of LMP was $2.88 per MWh, and for the PSEG zone (New Jersey) the line loss component of LMP was $3.24 per MWh. See, Monitoring Analytics, 2010 *State of the Market for PJM*, 2011; Section 2, Energy Market, Part 1, Table 2-55, p. 90.
[30] For example, two thirds of Vermont's load is served under long-term contracts.
[31] The power purchase agreements (PPAs) referenced here are plant-specific. It should be noted that this is not the case for all long-term PPAs. With the advent of electricity restructuring, many PPAs with non-utility generators (NUGs) were renegotiated. These renegotiated contracts often granted generators the flexibility to dispatch on a merchant basis in exchange for reducing the price paid by the purchaser for delivered firm energy and capacity. The PPA seller retained the responsibility for providing energy and capacity to the purchaser from either the generation facility or other generation resources within the ISO. These types of PPAs would not be expected to mitigate emissions leakage.
[32] See Wilson et al., *The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative*, Resources for the Future Discussion Paper, RFF DP 05-37, August 2005.

electricity price in the three ISOs fully or partially subject to RGGI. The monitoring results are consistent with market dynamics given the modest CO_2 allowance prices that result in CO_2 compliance costs on a per MWh basis. The RGGI allowances prices are likely lower than the aggregate per MWh price signal of mitigating market factors discussed in this report that would counter emissions leakage. Considering these factors, with modest CO_2 allowance prices, no net market dynamic driving emissions leakage would be expected to occur.

This report is the third in a series of annual monitoring reports, as called for in the 2005 RGGI MOU. This continued monitoring is warranted, especially considering the fact that both electricity market drivers and non-market drivers that impact CO_2 emissions have shifted dramatically from year to year during the 2005 to 2011 time period evaluated in this report. Ongoing monitoring will further evaluate changes in market and non-market drivers that impact CO_2 emissions related to electricity generation and imports in the RGGI region.

Appendix A. ISO Monitoring Sources

Table 2. Summary of Data Sources for ISO-NE

Code	Monitoring Category Associated with Data Elements at Right	MWh	CO_2 lb/MWh	CO_2 Tons
	Electricity Demand (Annual)			
A-1	Total Electricity Use in ISO-NE	ISO-NE[1]	CO_2 tons divided by MWh	Sum of A-3 and B-5
A-2	Net Electricity Imports - from New York	ISO-NE[1]	B-5	MWh multiplied by CO_2/MWh
A-2	Net Electricity Imports - from Quebec	ISO-NE[1]	Environment Canada[3]	MWh multiplied by CO_2/MWh
A-2	Net Electricity Imports - from New Brunswick	ISO-NE[1]	Environment Canada[3]	MWh multiplied by CO_2/MWh
A-3	Total Net Electricity Imports - from All Adjoining ISOs	ISO-NE[1]	CO_2 tons divided by MWh	Sum of A-2s
	Electricity Generation (Annual)			
B-1	RGGI-Affected Units	NEPOOL-GIS[2]	CO_2 tons divided by MWh	State reported data for 2005-2008; RGGI COATS for 2009 to2011. [4] Includes only sources subject to a state CO_2 Budget Trading Program CO_2 allowance compliance obligation. Does not include biomass-derived CO_2 emissions.
B-2	Non-RGGI Units (Fossil Fuel-Fired; <25MW)	NEPOOL-GIS[2]	CO_2 tons divided by MWh	NEPOOL-GIS[2]
B-3	Non-RGGI Units (Non-Fossil Fuel-Fired)	NEPOOL-GIS[2]	CO_2 tons divided by MWh	NEPOOL-GIS[2]
B-4	All Non-RGGI Units (Fossil and Non-Fossil)	Sum of B-2 and B-3	CO_2 tons divided by MWh	Sum of B-2 and B-3
B-5	All Units	ISO-NE[1]	CO_2 tons divided by MWh	Sum of B-1 and B-4

Table Notes:
1. ISO-NE, Historical Data Reports, "Net Energy and Peak Load by Source" (Annual Summary). Available at <http://www.iso-ne.com/markets/hstdata/rpts/net_eng_peak_load_sorc/index.html>.
2. NEPOOL Generation Information System. Available at <http://www.nepoolgis.com>.
3. Environment Canada, *National Inventory Report 1990–2010: Greenhouse Gas Sources and Sinks in* Canada, Environment Canada, April 11, 2012. In Part 3, see Table A13-5 "Electricity Generation and GHG Emission Details for New Brunswick"; Table A13-6 "Electricity Generation and GHG Emission Details for Quebec". Available at < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/6598.php>. Note that New Brunswick emission factors for every year and Quebec emission factors for 2005-2007, 2009 and 2010 were updated, as compared to the previous year's report.
4. Historical 2005 – 2008 CO_2 emissions data reported by RGGI participating states compiled from CO_2 emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO_2 emissions and fuel use data reported to state emissions statement programs. Historical 2005 – 2008 CO_2 emissions data is available at <http://www.rggi.org/historical_emissions>. 2009 through 2011 CO_2 emissions data is from data reported to the RGGI CO_2 Allowance Tracking System (RGGI COATS), available at <http://www.rggi-coats.org>.

Table 3. Summary of Data Sources for NYISO

Code	Monitoring Category Associated with Data Elements at Right	MWh	CO_2 lb/MWh	CO_2 Tons
	Electricity Demand (Annual)			
A-1	Total Electricity Use in NYISO	Sum of A-3 and B-5	CO_2 tons divided by MWh	Sum of A-3 and B-5
A-2	Net Electricity Imports - from Hydro Quebec	Hydro Quebec[1]	Environment Canada[6]	MWh multiplied by CO_2/MWh
A-2	Net Electricity Imports - from ISO-NE	ISO-NE[2]	ISO-NE system average[7]	MWh multiplied by CO_2/MWh
A-2	Net Electricity Imports - from Ontario	Ontario Independent Electricity System Operator[3]	Environment Canada[6]	MWh multiplied by CO_2/MWh
A-2	Net Electricity Imports - from PJM	PJM Annual State of the Market Report[4]	PJM GATS[8]	MWh multiplied by CO_2/MWh
A-3	Total Net Electricity Imports - from All Adjoining ISOs	Sum of A-2s	CO_2 tons divided by MWh	Sum of A-2s
	Electricity Generation (Annual)			
B-1	RGGI-Affected Units	NYDPS Calculation[5]	CO_2 tons divided by MWh	State reported data for 2005-2008; RGGI COATS for 2009 to 2011[9, 10] Includes only sources subject to a state CO_2 Budget Trading Program CO_2 allowance compliance obligation.
B-2	Non-RGGI Units (Fossil Fuel-Fired; < 25 MW)	NYDPS Calculation [5]	CO_2 tons divided by MWh	NYSDEC Emissions Report[11]
B-3	Non-RGGI Units (Non-Fossil Fuel-Fired)	NYDPS Calculation[5]	CO_2 tons divided by MWh	NYSDEC Emissions Report[11]
B-4	All Non-RGGI Units (Fossil and Non-Fossil)	Sum of B-2 and B-3	CO_2 tons divided by MWh	Sum of B-2 and B-3
B-5	All Units	Sum of B-1 and B-4	CO_2 tons divided by MWh	Sum of B-1 and B-4

Table Notes:
1. Hydro Quebec response to information request.
2. ISO-NE, Historical Data Reports, "Net Energy and Peak Load by Source" (Annual Summary). Available at <http://www.iso-ne.com/markets/hstdata/rpts/net_eng_peak_load_sorc/index.html>.
3. Ontario IESO response to information request.

4. Monitoring Analytics, *State of the Market for PJM* (2005 through 2011 reports).
5. NYDPS calculation based on MWh for each generator reported by NYISO and assignment of each generator to appropriate monitoring classification.
6. Environment Canada, *National Inventory Report 1990–2010: Greenhouse Gas Sources and Sinks in Canada*, Environment Canada, April 11, 2012. In Part 3, see Table A13-6 "Electricity Generation and GHG Emission Details for Quebec"; Table A13-7 "Electricity Generation and GHG Emission Details for Ontario". Available at < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/6598.php> Note that Ontario emission factors for and Quebec emission factors for 2005-2007, 2009 and 2010 were updated, as compared to the previous year's report.
7. Calculated average, based on Row B-5 in Table 2 above.
8. PJM Generation Attribute Tracking System, accessible at http://www.pjm-eis.com.
9. MWh and CO_2 emissions data include Linden Cogeneration, units 005001 – 009001, as these units are physically located in New Jersey, but dispatch electricity into NYISO.
10. Historical 2005 – 2008 CO_2 emissions data reported by RGGI participating states compiled from CO_2 emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO_2 emissions and fuel use data reported to state emissions statement programs. Historical 2005 – 2008 CO_2 emissions data is available at <http://www.rggi.org/historical_emissions>. 2009 through 2011 CO_2 emissions data is from data reported to the RGGI CO_2 Allowance Tracking System (RGGI COATS), available at <http://www.rggi-coats.org>.
11. NYDPS calculation based on NYSDEC emissions data and other state data.

Table 4. Summary of Data Sources for RGGI PJM

Code	Monitoring Category Associated with Data Elements at Right	MWh	CO_2 lb/MWh	CO_2 Tons
	Electricity Demand (Annual)			
A-1	Total Electricity Use in RGGI PJM	Sum of A-3 and B-5	CO_2 tons divided by MWh	Sum of A-3 and B-5
A-2	Net Electricity Imports - from Non-RGGI PJM	PJM GATS[1]	PJM GATS[1]	MWh multiplied by CO_2/MWh
A-2	Net Electricity Imports - from NYISO	PJM Annual State of the Market Report[2]	B-5	MWh multiplied by CO_2/MWh
A-3	Total Net Electricity Imports - from All Adjoining ISOs	Sum of A-2s	CO_2 tons divided by MWh	Sum of A-2s
	Electricity Generation (Annual)			
B-1	RGGI-Affected Units	PJM GATS[1]	CO_2 tons divided by MWh	State reported data for 2005-2008; RGGI COATS for 2009 through 2011. Includes only sources subject to a state CO_2 Budget Trading Program CO_2 allowance compliance obligation; does not include Maryland LIESA sources; does not include Linden Cogeneration units 005001-009001.[3, 4]
B-2	Non-RGGI Units (Fossil Fuel-Fired; < 25 MW)	PJM GATS[1]	CO_2 tons divided by MWh	PJM GATS[1]
B-3	Non-RGGI Units (Non-Fossil Fuel-Fired)	PJM GATS[1]	CO_2 tons divided by MWh	PJM GATS[1]
B-4	All Non-RGGI Units (Fossil and Non-Fossil)	Sum of B-2 and B-3	CO_2 tons divided by MWh	Sum of B-2 and B-3
B-5	All Units	Sum of B-1 and B-4	CO_2 tons divided by MWh	Sum of B-1 and B-4

Table Notes:
1. PJM Generation Attribute Tracking System, accessible at <http://www.pjm-eis.com>.
2. Monitoring Analytics, *State of the Market for PJM* (2005 through 2011 reports) at <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.
3. Historical 2005 – 2008 CO_2 emissions data reported by RGGI participating states compiled from CO_2 emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO_2 emissions and fuel use data reported to state emissions statement programs. Historical 2005 – 2008 CO_2 emissions data is available at <http://www.rggi.org/historical_emissions>. 2009 through 2011 CO_2 emissions data is from data reported to the RGGI CO_2 Allowance Tracking System (RGGI COATS), available at <http://www.rggi-coats.org>.
4. MWh and CO_2 emissions data do not include Maryland Limited Industrial Exemption Set-aside (LIESA) sources. LIESA sources for 2009, 2010, and 2011 include Severstal Sparrows Point LLC and Luke Paper Company. LIESA sources refer to certain industrial cogenerators under Maryland's CO_2 Budget Trading Program regulations that are subject to alternative CO_2 compliance obligations under certain conditions in lieu of submission of CO_2 allowances. MWh and CO_2 emissions data do not include Linden Cogeneration, units 005001 – 009001, as these units are physically located in New Jersey but dispatch electricity into NYISO; MWh and CO_2 emissions data for these units are included in NYISO data.

Appendix B. ISO-Specific Monitoring Results

Detailed monitoring results for ISO-NE, NYISO, and the RGGI portion of PJM are presented below.[33]

ISO-NE

Monitoring results for ISO-NE for 2005 through 2011 are summarized below in Table 5 and Figures 6 through 10.

Table 5. 2005 – 2011 Monitoring Summary for ISO-NE

	MWh						
	2005	2006	2007	2008	2009	2010	2011
Electricity Demand							
Total in ISO	138,174,000	134,243,000	136,869,000	134,000,000	128,801,000	131,956,000	130,752,000
Net Imports - from NYISO	-115,000	-877,000	-2,477,000	-1,529,000	-3,031,000	-4,412,000	-2,262,000
Net Imports - from Quebec	4,792,000	6,023,000	7,727,000	9,495,000	10,826,000	9,214,000	11,558,000
Net Imports - from New Brunswick	1,620,000	1,047,000	896,000	1,285,000	1,569,000	737,000	846,000
Total Net Imports - from All Adjoining ISOs	6,297,000	6,193,000	6,146,000	9,251,000	9,363,000	5,539,000	10,142,000
Electricity Generation							
RGGI-Affected Units	77,439,814	70,911,131	75,345,502	70,591,734	65,426,926	71,314,622	69,466,788
Non-RGGI Fossil Fuel-Fired Units <25MW	94,304	75,137	64,598	152,110	627,311	908,731	1,139,223
Non-RGGI Fossil Fuel-Fired Units >=25MW	5,953,312	5,212,883	4,419,405	2,484,119	2,095,712	2,195,189	2,206,681
Non-Fossil Fuel-Fired Units	48,520,847	52,086,895	51,110,222	51,372,277	51,746,869	52,787,874	49,338,878
All Non-RGGI Units	54,568,463	57,374,915	55,594,225	54,008,506	54,469,892	55,891,794	52,684,782
All Units	131,877,000	128,050,000	130,723,000	124,749,000	119,437,000	126,416,000	120,610,000
Summary Data	6,047,616	5,288,020	4,484,003	2,636,229	2,723,023	3,103,920	3,345,904
Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports = (B-2 + B-3) + A-3)	60,865,463	63,567,915	61,740,225	63,259,506	63,832,892	61,430,794	62,826,782

	Tons CO2						
	2005	2006	2007	2008	2009	2010	2011
Electricity Demand							
Total in ISO	64,207,040	58,342,696	58,439,751	53,249,752	48,230,332	51,118,586	46,612,338
Net Imports - from NYISO	-55,282	-398,599	-1,118,781	-651,589	-1,229,274	-1,833,018	-881,419
Net Imports - from Quebec	21,129	33,196	76,658	20,933	35,801	20,313	25,481
Net Imports - from New Brunswick	846,443	508,967	438,526	718,150	984,101	410,264	470,940
Total Net Imports - from All Adjoining ISOs	812,290	143,564	-603,597	87,494	-209,372	-1,402,441	-384,998
Electricity Generation							
RGGI-Affected Units	54,223,939	47,783,423	49,434,978	44,508,400	38,815,561	41,682,538	35,469,318
Non-RGGI Fossil Fuel-Fired Units <25MW	37,197	42,415	47,105	98,880	374,282	875,835	1,030,383
Non-RGGI Fossil Fuel-Fired Units >=25MW	4,054,743	3,565,819	2,744,219	1,734,332	1,810,538	2,406,571	2,516,545
Non-Fossil Fuel-Fired Units	5,078,871	6,807,476	6,817,046	6,820,646	7,439,324	7,556,082	7,981,091
All Non-RGGI Units	9,170,811	10,415,709	9,608,370	8,653,859	9,624,143	10,838,488	11,528,018
All Units	63,394,750	58,199,133	59,043,348	53,162,258	48,439,704	52,521,026	46,997,336
Summary Data	4,091,940	3,608,234	2,791,324	1,833,213	2,184,820	3,282,406	3,546,928
Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports = (B-2 + B-3) + A-3)	9,983,101	10,559,273	9,004,773	8,741,353	9,414,771	9,436,047	11,143,021

	Lb CO2 /MWh						
	2005	2006	2007	2008	2009	2010	2011
Electricity Demand							
Total in ISO	929	869	854	795	749	775	713
Net Imports - from NYISO	961	909	903	852	811	831	779
Net Imports - from Quebec	9	11	20	4	7	4	4
Net Imports - from New Brunswick	1,045	972	979	1,118	1,254	1,113	1,113
Total Net Imports - from All Adjoining ISOs	258	46	-196	19	-45	-506	-76
Electricity Generation							
RGGI-Affected Units	1,400	1,348	1,312	1,261	1,187	1,169	1,021
Non-RGGI Fossil Fuel-Fired Units <25MW	789	1,129	1,458	1,300	1,193	1,928	1,809
Non-RGGI Fossil Fuel-Fired Units >=25MW	1,362	1,368	1,242	1,396	1,728	2,193	2,281
Non-Fossil Fuel-Fired Units	209	261	267	266	288	286	324
All Non-RGGI Units	336	363	346	320	353	388	438
All Units	961	909	903	852	811	831	779
Summary Data	1,353	1,365	1,245	1,391	1,605	2,115	2,120
Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports = (B-2 + B-3) + A-3)	328	332	292	276	295	307	355

The monitoring results indicate that the 2009 to 2011 annual average compared to the 2006 to 2008 base period annual average, total electric generation from all non-RGGI electric generation serving load in ISO-NE decreased by 159 thousand MWh, a decrease of 0.3 percent. From the 2006 to 2008 base period annual average to the 2009 to 2011 annual average, CO_2 emissions from this category of electric generation increased by 563 thousand short tons of CO_2, an

[33] The tons of CO_2 emitted and the lb of CO_2/MWh emission rates in this report do not represent total lifecycle reductions or contributions of greenhouse gases. Such analysis is outside the scope of this report.

increase of 6.0 percent, and the CO_2 emission rate increased by 19 lb CO_2/MWh, an increase of 6.2 percent. (See Figures 7, 8, and 9.)

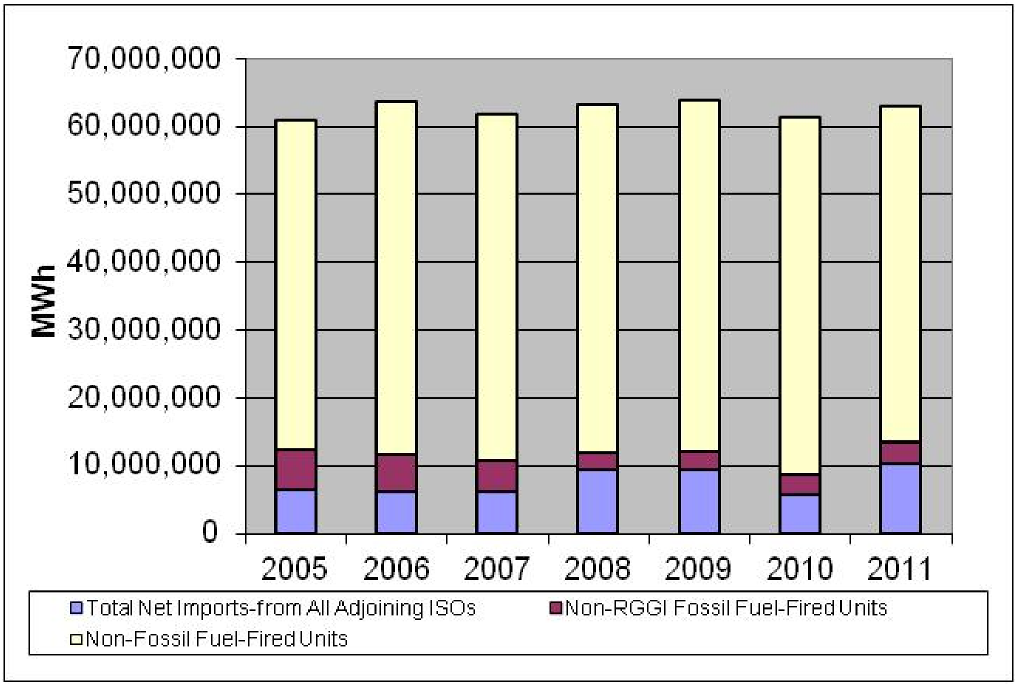

Figure 7. Non-RGGI Generation Serving Load in ISO-NE (MWh)

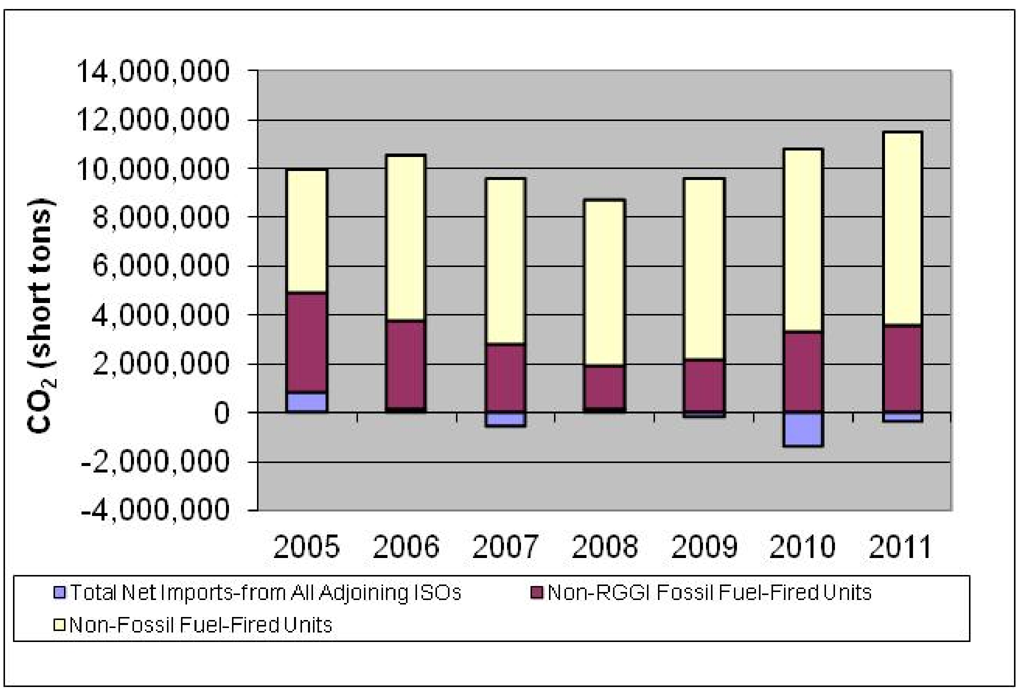

Figure 8. CO_2 Emissions from Non-RGGI Generation Serving Load in ISO-NE (short tons CO_2)

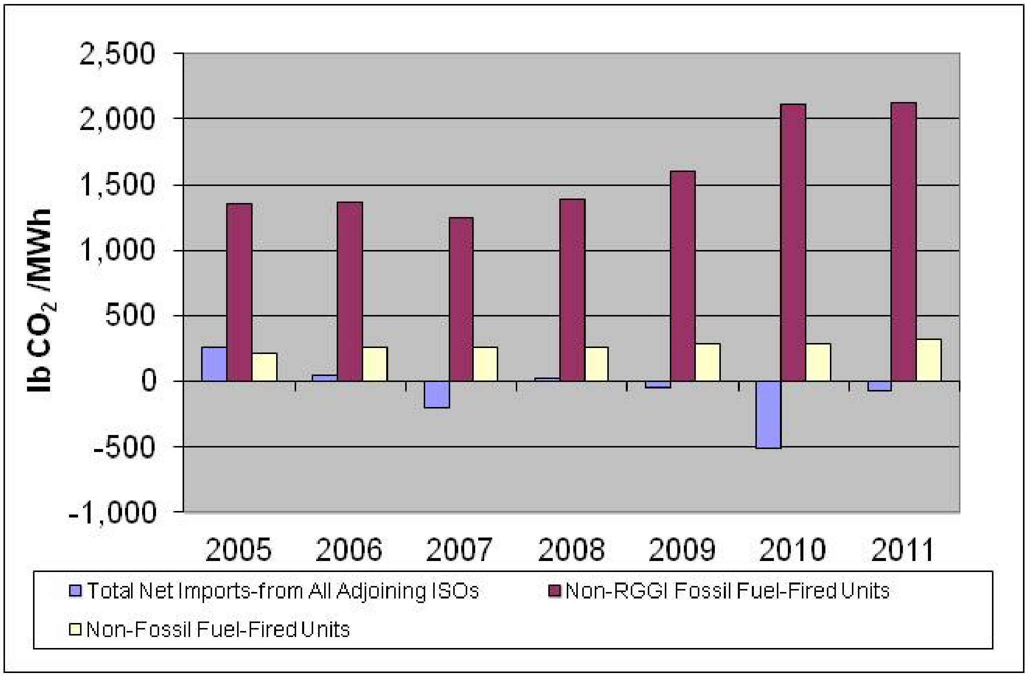

Figure 9. CO_2 Emission Rate for Non-RGGI Generation Serving Load in ISO-NE (lb CO_2/MWh)

The annual average electricity load in ISO-NE decreased by 4.5 million MWh, or 3.4 percent for 2009 to 2011 as compared to the annual average from the baseline period of 2006 to 2008. In total, electric generation (fossil and non-fossil) in ISO-NE decreased by 4.9 million MWh, or 3.8 percent, when comparing the 2006 to 2008 annual average to the 2009 to 2011 annual average.

Electric generation from RGGI-affected generation in ISO-NE decreased by 3.5 million MWh during this period, or 4.9 percent, and CO_2 emissions from RGGI-affected electric generation in ISO-NE decreased by 8.6 million short tons of CO_2, or 18.2 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 182 lb $CO_{2/}$MWh, a reduction of 13.9 percent. Electric generation from non-RGGI electric generation sources located in ISO-NE decreased by 1.3 million MWh, or 2.4 percent, during this period, and CO_2 emissions from this category of electric generation increased by 1.1 million short tons of CO_2, an increase of 11.6 percent. The CO_2 emission rate of non-RGGI electric generation located in ISO-NE increased by 49 lb CO_2/MWh, an increase of 14.4 percent.

Net electricity imports into ISO-NE increased by 1.2 million MWh, or 16.0 percent, when comparing the base period annual average from 2006 to 2008 to the annual average from 2009 to 2011. CO_2 emissions related to these net electricity imports decreased by 541 thousand short tons of CO_2, or 436 percent, during this period.[34] The CO_2 emission rate of the electric generation supplying these imports decreased by 175 thousand lb CO_2/MWh, a decrease of 505.6 percent.

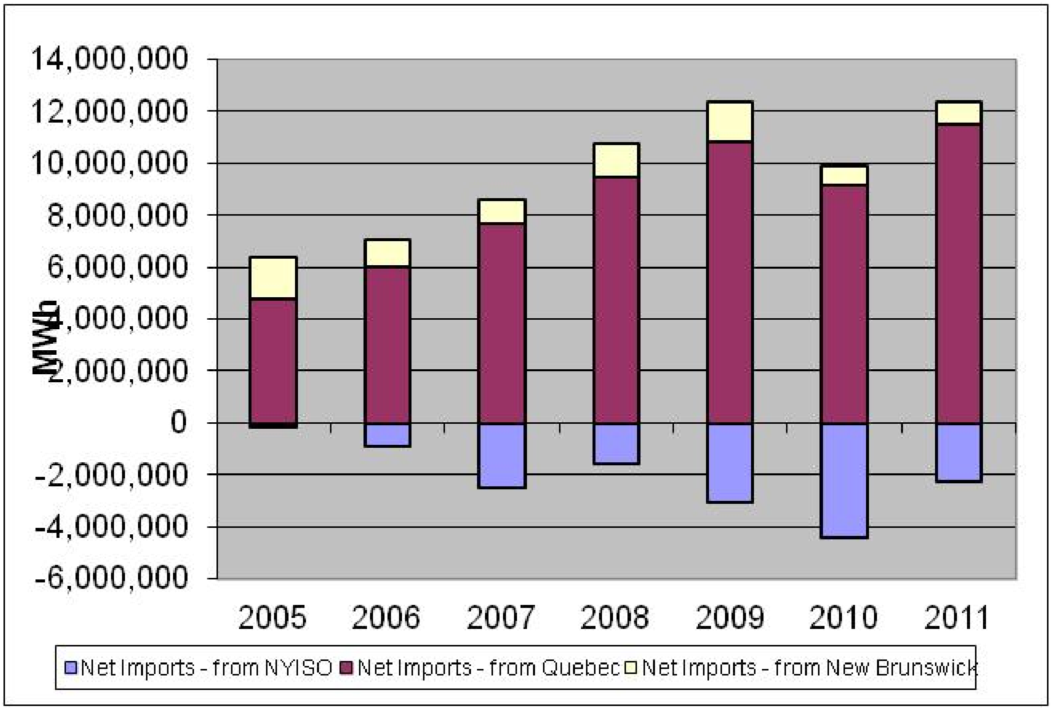

Figure 10. Net Electricity Imports to ISO-NE (MWh)

[34] This significant percentage change is due to the fact that ISO-NE net exports to NYISO doubled from 2008 to 2009, and increased again in 2010. Negative values for MWh and CO_2 tons indicate that more MWh were exported than imported. As a result, the increase in net exports to NYISO in 2009 and 2010 increased the amount of CO_2 emissions debited from the ISO-NE net import total, resulting in a negative CO_2 emissions value for total CO_2 emissions related to total net electricity imports in 2009 and 2010 for ISO-NE. In 2011, the affect continues with a negative value for CO_2 emissions reflecting exports to New York. In 2008, CO_2 emissions related to net imports of electricity to ISO-NE were 651,589 short tons of CO_2; in 2009, 2010, and 2011 CO_2 emissions related to net imports of electricity to ISO-NE were -1,229,274, -1,833,018, and 881,419 short tons of CO_2,respectively, representing the assignment of an increased amount of CO_2 emissions to NYISO for tracking purposes.

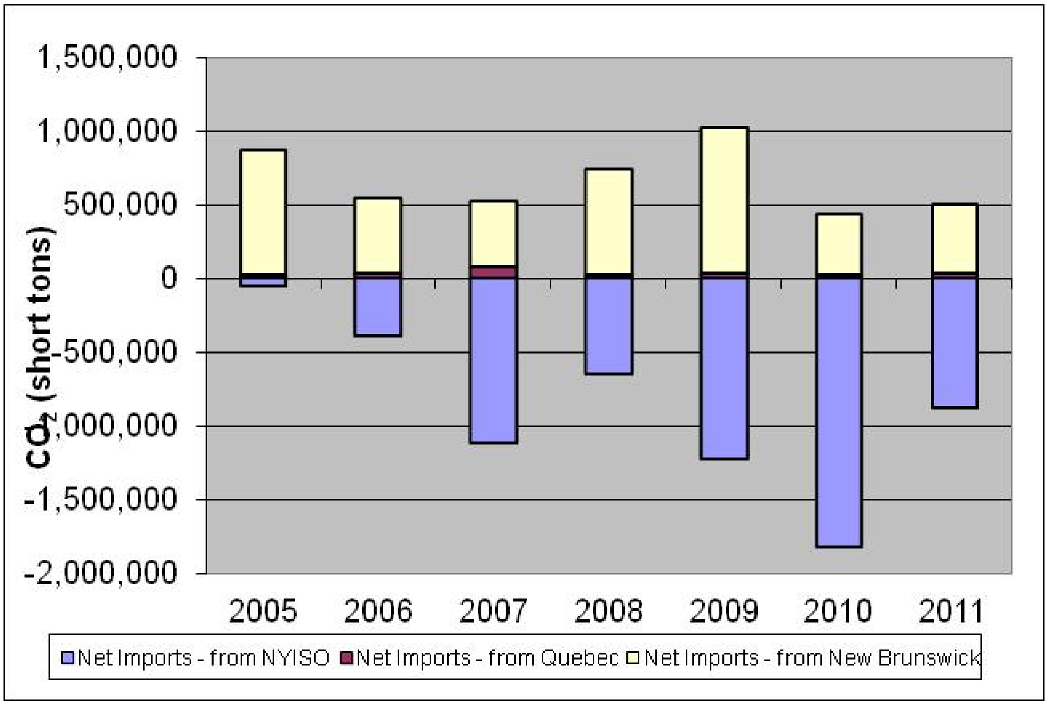

Figure 11. CO_2 Emissions Related to Net Electricity Imports to ISO-NE (short tons CO_2)

Compared to the annual average during a multi-year base period of 2006 – 2008, electric generation in 2011 from all non-RGGI electric generation sources serving load in ISO-NE decreased by 29 thousand MWh, a decrease of 0.05 percent. Compared to the 2006 – 2008 annual average, 2011 CO_2 emissions from this category of electric generation increased by 1.7 million short tons of CO_2, an increase of 18.1 percent, and the CO_2 emission rate increased by 55 lb CO_2/MWh, an increase of 18.2 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 total electricity load in ISO-NE decreased by 4.3 million MWh, or 3.2 percent. Compared to the 2006 – 2008 annual average, 2011 total electric generation in ISO-NE decreased by 5.8 million MWh, or 4.5 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 electric generation from RGGI-affected generation in ISO-NE decreased by 2.8 million MWh, or 3.9 percent, and CO_2 emissions from RGGI-affected generation in ISO-NE decreased by 11.8 million short tons of CO_2, or 24.9 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 286 lb CO_2/MWh, a reduction of 21.9 percent. Compared to the 2006 – 2008 annual average, 2011 electric generation from non-RGGI generation located in ISO-NE decreased by 3 million MWh, or 5.3 percent, and CO_2 emissions from this category of electric generation increased by 2 million short tons of CO_2, an increase of 20.6 percent. The CO_2 emission rate of non-RGGI electric generation located in ISO-NE increased by 94 lb CO_2/MWh, an increase of 27.4 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 net electricity imports into ISO-NE increased by 2.9 million MWh, or 40.9 percent. CO_2 emissions related to these net electricity imports declined by 261 thousand short tons of CO_2, or 210.0 percent during this period. The CO_2 emission rate of the electric generation supplying these imports declined by 41 lb CO_2/MWh, a reduction of 120.0 percent.

NYISO

Monitoring results for NYISO for 2005 through 2011 are summarized below in Table 6 and Figures 12 through 15.

Table 6. 2005 – 2011 Monitoring Summary for NYISO

	MWh							Tons CO2							Lb CO2 /MWh						
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Electricity Demand																					
Total Annual Electricity Load in NYISO	164,783,642	166,654,413	169,932,177	168,646,767	160,565,962	164,282,144	163,748,396	74,759,661	69,804,817	71,574,903	63,039,863	48,306,321	55,316,578	48,306,319	907	838	842	748	602	673	590
Net Imports - from Quebec	2,583,317	2,959,749	4,185,292	5,646,014	6,239,805	4,335,209	7,123,204	11,390	16,313	41,521	12,447	20,635	9,557	15,704	9	11	20	4	7	4	4
Net Imports - from ISO-NE	115,000	877,000	2,477,000	1,529,000	3,031,000	4,412,000	2,262,000	55,282	398,599	1,118,781	651,589	1,229,274	1,833,018	881,419	961	909	903	852	811	831	779
Net Imports - from Ontario	1,898,020	3,672,282	2,637,442	6,162,902	6,463,657	3,872,635	3,318,681	460,286	769,120	610,529	1,154,884	712,496	554,950	475,569	485	419	463	375	220	287	287
Net Imports - from PJM	7,604,000	9,559,000	10,225,000	10,690,000	8,331,000	12,305,000	11,079,911	4,912,184	5,983,934	6,349,725	6,520,900	4,736,174	7,179,968	6,348,946	1,292	1,252	1,242	1,220	1,137	1,167	1,146
Total Net Electricity Imports - (Sum of all A-2's)	12,200,337	17,068,031	19,524,734	24,027,916	24,065,462	24,924,844	23,783,796	5,439,142	7,167,966	8,120,556	8,339,821	6,698,578	9,577,493	7,721,638	892	840	832	694	557	769	649
Electricity Generation																					
Annual Electric Generation - RGGI-Affected Units (1)	71,936,054	70,961,783	75,388,500	68,520,047	59,911,945	66,092,652	62,225,030	65,041,240	55,637,919	57,693,658	50,239,607	39,536,767	43,762,015	38,686,919	1,808	1,568	1,531	1,466	1,320	1,324	1,243
Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units	2,929,072	3,225,402	2,596,315	719,246	85,738	121,568	125,577	3,611,265	4,319,567	3,454,091	785,254	95,647	130,481	133,732	2,466	2,678	2,661	2,184	2,231	2,147	2,130
Annual Electric Generation - Non-Fossil Fuel-Fired Units	77,718,179	75,399,197	72,422,628	75,379,558	76,502,817	73,143,080	77,613,993	668,014	2,679,365	2,306,598	3,675,181	1,975,329	1,846,589	1,764,030	17	71	64	98	52	50	45
Annual Electric Generation - All Non-RGGI Units	80,647,251	78,624,599	75,018,943	76,098,804	76,588,555	73,264,648	77,739,570	4,279,279	6,998,932	5,760,689	4,460,435	2,070,976	1,977,070	1,897,762	106	178	154	117	54	54	49
Total Annual Electric Generation - All Units	152,583,305	149,586,382	150,407,443	144,618,851	136,500,500	139,357,300	139,964,600	69,320,519	62,636,851	63,454,347	54,700,042	41,607,743	45,739,085	40,584,681	909	837	844	756	610	656	580
Summary Data																					
Annual CO_2 Emissions from Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports = (B-2 + B-3) + A-2	92,847,588	95,692,630	94,543,677	100,126,720	100,654,017	98,189,492	101,523,366	9,718,421	14,166,898	13,881,245	12,800,256	8,769,554	11,554,563	9,619,400	209	296	294	256	174	235	190

The monitoring results indicate that the 2009 to 2011 annual average compared to the 2006 to 2008 base period annual average, total electric generation from all non-RGGI electric generation serving load in NYISO increased by 3.3 million MWh, an increase of 3.4 percent. From the 2006 to 2008 base period annual average to the 2009 to 2011 annual average, CO_2 emissions from this category of electric generation decreased by 3.6 million short tons of CO_2, a decrease of 26.7percent, and the CO_2 emission rate decreased by 82 lb CO_2/MWh, a decrease of 29.1 percent. (See Figures 12, 13, and 14.)

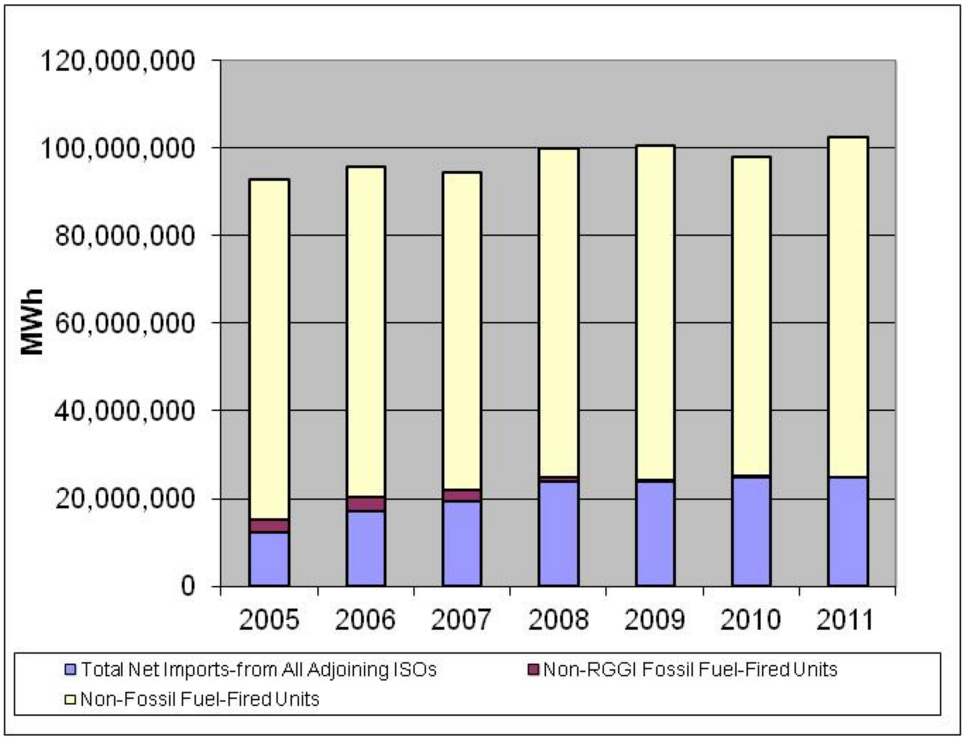

Figure 12. Non-RGGI Generation Serving Load in NYISO (MWh)

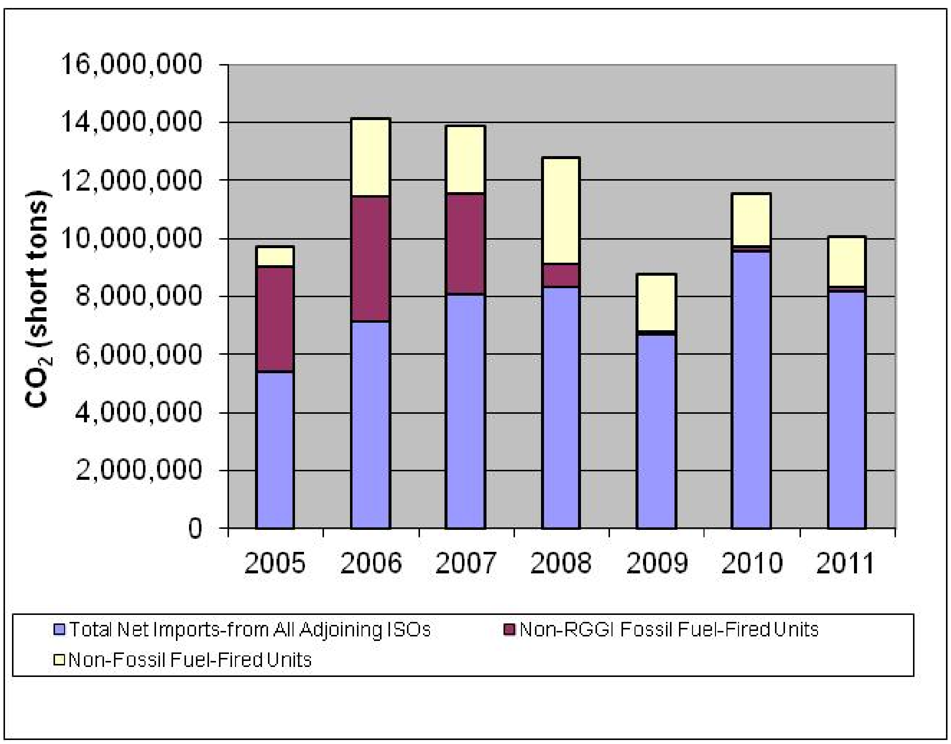

Figure 13. CO_2 Emissions from Non-RGGI Generation Serving Load in NYISO (short tons CO_2)

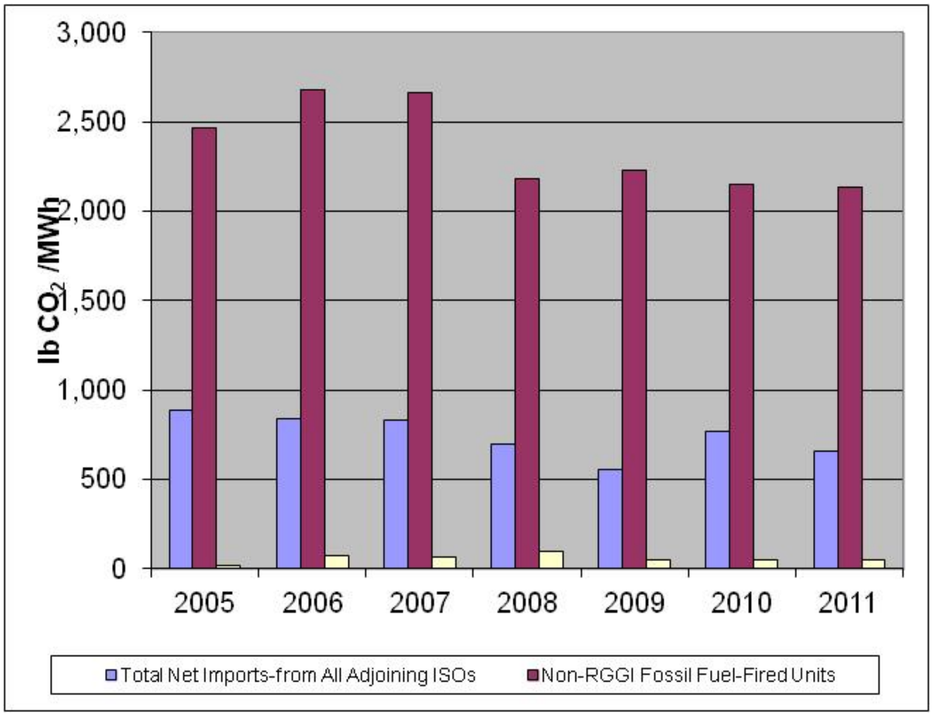

Figure 14. CO_2 Emission Rate for Non-RGGI Generation Serving Load in NYISO (lb CO_2/MWh)

The annual average electricity load in NYISO decreased by 5.5 million MWh, or 3.3 percent for 2009 to 2011 as compared to the annual average from the baseline period of 2006 to 2008. In total, electric generation (fossil and non-fossil) in NYISO decreased by 9.6 million MWh, or 6.5 percent, when comparing the 2006 to 2008 annual average to the 2009 to 2011 annual average.

Electric generation from RGGI-affected generation in NYISO decreased by 8.9 million MWh during this period, or 12.4 percent, and CO_2 emissions from RGGI-affected electric generation in NYISO decreased by 13.9 million short tons of CO_2, or 25.4 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 227 lb CO_2/MWh, a reduction of 14.9 percent. Electric generation from non-RGGI electric generation sources located in NYISO decreased by 716.5 thousand MWh, or 0.9 percent, during this period, and CO_2 emissions from this category of electric generation decreased by 3.8 million short tons of CO_2, a decrease of 65.5 percent. The CO_2 emission rate of non-RGGI electric generation located in NYISO decreased by 98 lb CO_2/MWh, a decrease of 65.1 percent.

Net electricity imports into NYISO increased by 4.1 million MWh, or 20.0 percent, when comparing the base period annual average from 2006 to 2008 to the annual average from 2009 to 2011. CO_2 emissions related to these net electricity imports increased by 123 thousand short tons of CO_2, or 1.6 percent, during this period. The CO_2 emission rate of the electric generation supplying these imports decreased by 121 lb CO_2/MWh, a decrease of 15.6 percent.(See figures 15 and 16).

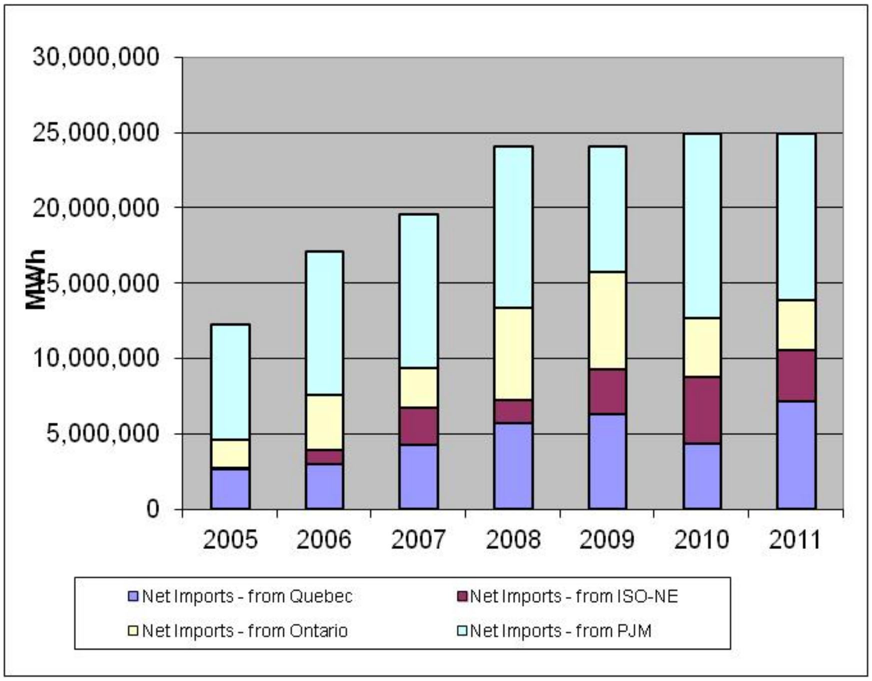

Figure 15. Net Electricity Imports to NYISO (MWh)

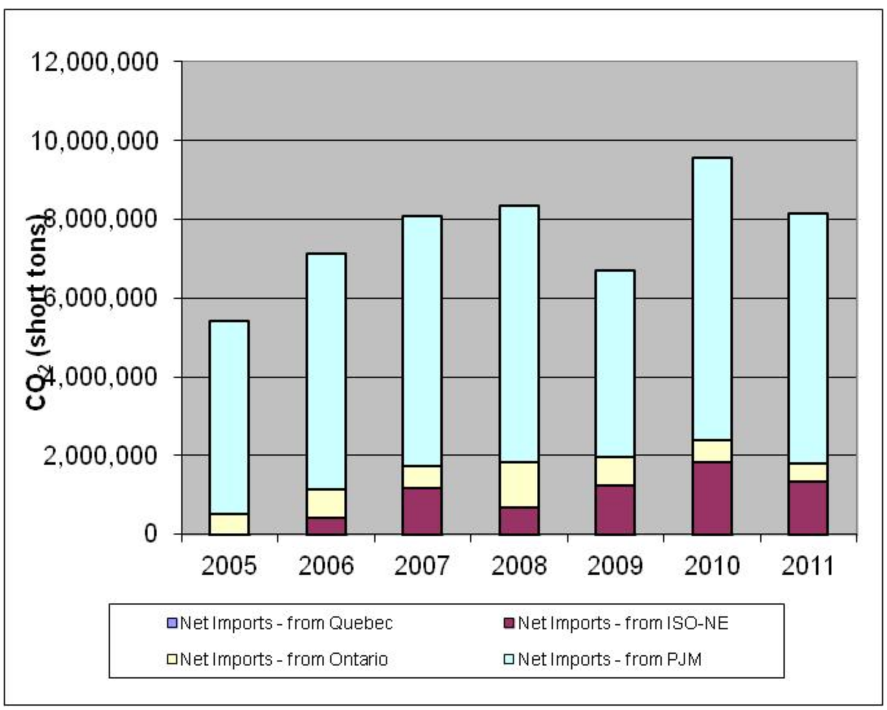

Figure 16. CO_2 Emissions Related to Net Electricity Imports to NYISO (short tons CO_2)

Compared to the annual average during a multi-year base period of 2006 – 2008, electric generation in 2011 from all non-RGGI electric generation sources serving load in NYISO increased by 4.7 million MWh, an increase of 4.9 percent.

Compared to the 2006 – 2008 annual average, 2011 CO_2 emissions from this category of electric generation decreased by 4.0 million short tons of CO_2, a reduction of 29.4 percent, and the CO_2 emission rate decreased by 92 lb CO_2/MWh, a reduction of 32.6 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 total electricity load in NYISO decreased by 4.7 million MWh, or 2.8 percent. Compared to the 2006 – 2008 annual average, total electric generation in 2011 in NYISO decreased by 8.2 million MWh, or 5.6 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 electric generation from RGGI-affected generation in NYISO decreased by 9.4 million MWh, or 13.1 percent, and CO_2 emissions from RGGI-affected generation in NYISO decreased by 15.8 million short tons of CO_2, a reduction of 29.0 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 279 lb CO_2MWh, a reduction of 18.3 percent. Compared to the 2006 – 2008 annual average, 2011 electric generation from non-RGGI generation located in NYISO increased by 1.2 million MWh, or 1.5 percent, and CO_2 emissions from this category of electric generation decreased by 3.8 million short tons of CO_2, a reduction of 66.9 percent. The CO_2 emission rate of non-RGGI electric generation located in NYISO decreased by 101 lb CO_2/MWh, a reduction of 67.4 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 net electricity imports into NYISO increased by 3.6 million MWh, or 17.7 percent. CO_2 emissions related to these net electricity imports decreased by 154 thousand short tons of CO_2, or 2.0 percent. The CO_2 emission rate of the electric generation supplying these imports decreased by 130 lb CO_2/MWh, a reduction of 16.7 percent.

PJM (RGGI Portion)

Monitoring results for PJM for 2005 through 2011 are summarized below in Table 7 and Figures 17 through 20. Note that for PJM, the data presented below is for the RGGI geographic portion of PJM (Delaware, Maryland, and New Jersey referred to below as “RGGI PJM”). Net “imports” represent inferred flows of electricity from the non-RGGI geographic portion of PJM (Non-RGGI PJM) to the RGGI geographic portion of PJM (RGGI PJM) to make up for shortfalls in electric generation relative to total electricity load for this subset of PJM.[35]

Table 7. 2005 – 2011 Monitoring Summary for RGGI PJM

	MWh							Tons CO2							Lb CO2 /MWh						
	2005	2006	2007	2008	2009	2010	2011	2005	2006	2007	2008	2009	2010	2011	2005	2006	2007	2008	2009	2010	2011
Electricity Demand																					
Total Annual Electricity Load in ISO	177,404,747	168,687,473	170,289,397	163,600,330	158,657,456	165,047,534	160,933,797	106,173,296	96,729,311	98,228,040	90,167,059	78,593,331	87,087,382	77,893,950	1,197	1,147	1,154	1,102	991	1,055	968
Net Imports - from Non-RGGI PJM	65,324,576	60,819,367	57,887,856	54,088,276	56,299,698	58,001,518	55,406,781	43,596,369	39,383,494	37,012,128	34,138,677	33,537,149	35,150,499	33,048,520	1,335	1,295	1,279	1,262	1,191	1,212	1,193
Net Imports - from NYISO	-1,224,177	-1,457,171	-1,565,273	-1,627,174	-1,257,857	-1,844,414	-1,573,121	-683,486	-774,675	-852,476	-832,492	-553,688	-894,878	-668,523	1,117	1,063	1,089	1,023	880	970	850
Total Net Electricity Imports - from All Adjoining ISOs	64,100,399	59,362,196	56,322,583	52,461,102	55,041,841	56,157,104	53,833,660	42,912,883	38,608,819	36,159,652	33,306,185	32,983,461	34,255,621	32,379,997	1,339	1,301	1,284	1,270	1,198	1,220	1,203
Electricity Generation																					
Annual Electric Generation - RGGI-Affected Units	62,572,572	57,720,201	62,357,387	59,342,547	50,005,454	57,625,172	53,621,362	61,681,725	56,440,700	59,921,956	54,967,858	43,804,611	50,125,993	43,383,627	1,972	1,956	1,922	1,853	1,752	1,740	1,618
Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units	479,438	339,933	364,609	165,411	151,888	143,960	227,081	369,986	275,158	285,909	168,417	152,325	145,704	182,970	1,543	1,619	1,568	2,036	2,006	2,024	1,611
Annual Electric Generation - Non-Fossil Fuel-Fired Units	50,252,338	51,265,143	51,244,818	51,631,270	53,458,273	51,121,298	53,251,694	1,208,702	1,404,634	1,860,523	1,724,599	1,652,934	2,560,064	1,947,357	48	55	73	67	62	100	73
Annual Electric Generation - All Non-RGGI Units	50,731,776	51,605,076	51,609,427	51,796,681	53,610,161	51,265,258	53,478,775	1,578,688	1,679,792	2,146,432	1,893,016	1,805,259	2,705,768	2,130,327	62	65	83	73	67	106	80
Total Annual Electric Generation - All Units	113,304,348	109,325,277	113,966,814	111,139,228	103,615,615	108,890,430	107,100,137	63,260,413	58,120,492	62,068,388	56,860,874	45,609,870	52,831,761	45,513,954	1,117	1,063	1,089	1,023	880	970	850
Summary CO_2 Emissions and MWh Data																					
Annual CO_2 Emissions from Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports = (B-2 + B-3) + A-2	114,832,175	110,967,272	107,932,010	104,257,783	108,652,002	107,422,362	107,312,435	44,491,571	40,288,611	38,306,084	35,199,201	34,788,720	36,961,389	34,510,324	775	726	710	675	640	688	643

The monitoring results indicate that the 2009 to 2011 annual average compared to the 2006 to 2008 base period annual average, total electric generation from all non-RGGI electric generation serving load in PJM increased by 77 thousand MWh, an increase of 0.1 percent. From the 2006 to 2008 base period annual average to the 2009 to 2011 annual average, CO_2 emissions from this category of electric generation decreased by 2.5 million short tons of CO_2, a

[35] This data is compiled from PJM GATS, which reports data for both the non-RGGI and RGGI geographic portions of PJM. Inferred net imports are based on total MWh load in the RGGI geographic portion of PJM minus total electric generation in the RGGI geographic portion of PJM. Any shortfall in generation relative to load is assumed to be met through an inferred “import” of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.

decrease of 6.6 percent, and the CO_2 emission rate decreased by 47 lb CO_2/MWh, an decrease of 6.7 percent. (See Figures 17, 18, and 19.)

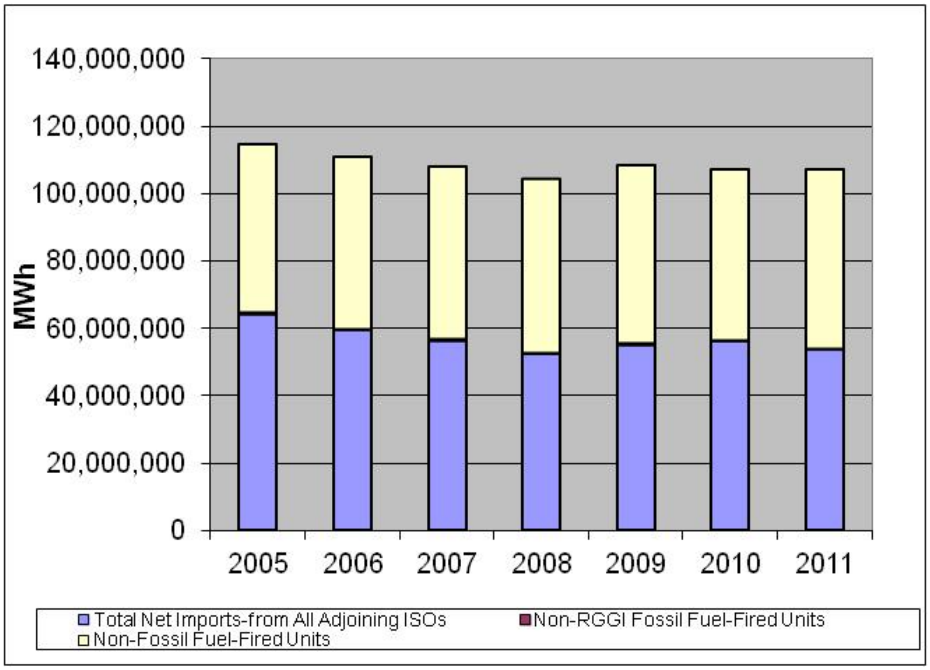

Figure 17. Non-RGGI Generation Serving Load in RGGI PJM (MWh)

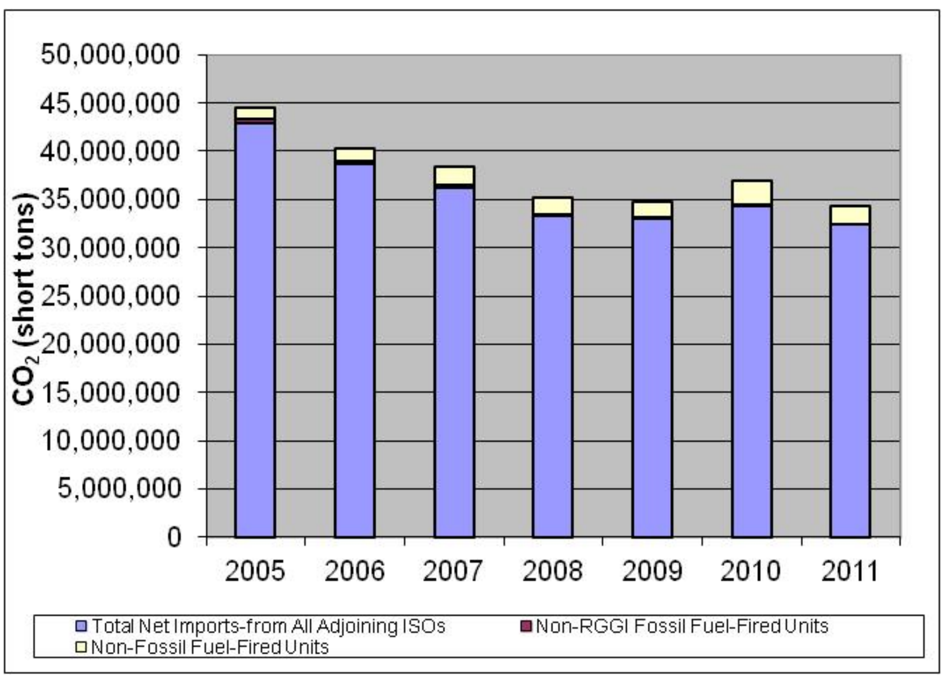

Figure 18. CO_2 Emissions from Non-RGGI Generation Serving Load in RGGI PJM (short tons CO_2)

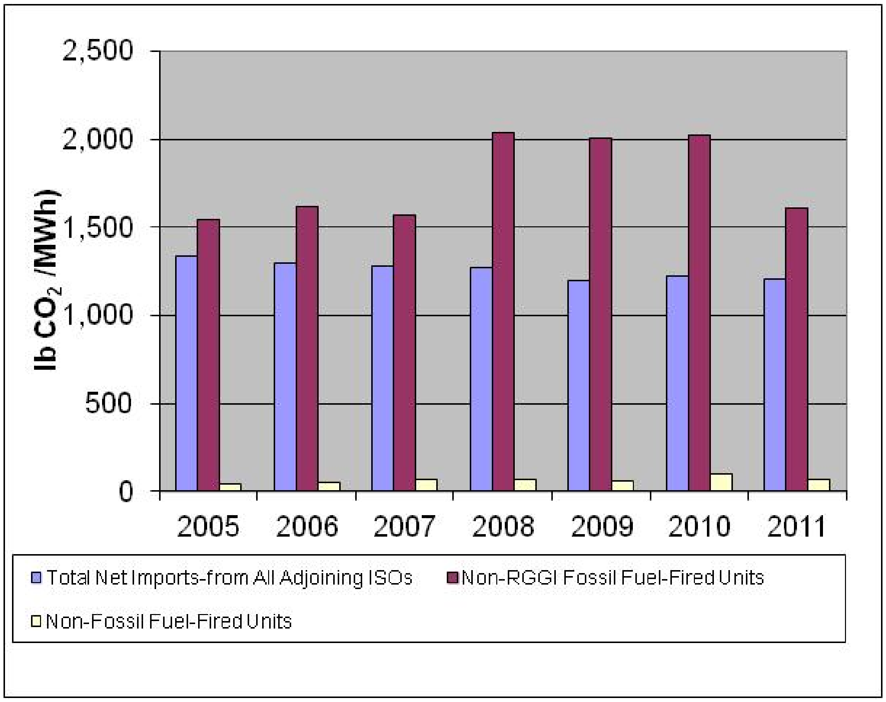

Figure 19. CO_2 Emission Rate for Non-RGGI Generation Serving Load in RGGI PJM (lb CO_2/MWh)

The annual average electricity load in PJM decreased by 6 million MWh, or 3.6 percent for 2009 to 2011 as compared to the annual average from the baseline period of 2006 to 2008. In total, electric generation (fossil and non-fossil) in PJM decreased by 4.9 million MWh, or 4.4 percent, when comparing the 2006 to 2008 annual average to the 2009 to 2011 annual average.

Electric generation from RGGI-affected generation in PJM decreased by 6.1 million MWh during this period, or 10.1 percent, and CO_2 emissions from RGGI-affected electric generation in PJM decreased by 11.3 million short tons of CO_2, or 19.9 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 207 lb CO_2/MWh, a reduction of 10.8 percent. Electric generation from non-RGGI electric generation sources located in PJM increased by 1.1 million MWh, or 2.2 percent, during this period, and CO_2 emissions from this category of electric generation increased by 307 thousand short tons of CO_2, an increase of 16.1 percent. The CO_2 emission rate of non-RGGI electric generation located in PJM increased by 10 lb CO_2/MWh, an increase of 14.1 percent.

Net electricity imports into PJM decreased by 1.0 million MWh, or 1.9 percent, when comparing the base period annual average from 2006 to 2008 to the annual average from 2009 to 2011. CO_2 emissions related to these net electricity imports decreased by 2.8 million short tons of CO_2, or 7.8 percent, during this period. The CO_2 emission rate of the electric generation supplying these imports decreased by 78 lb CO_2/MWh, a decrease of 6.1 percent. (See Figures 20 and 21.)

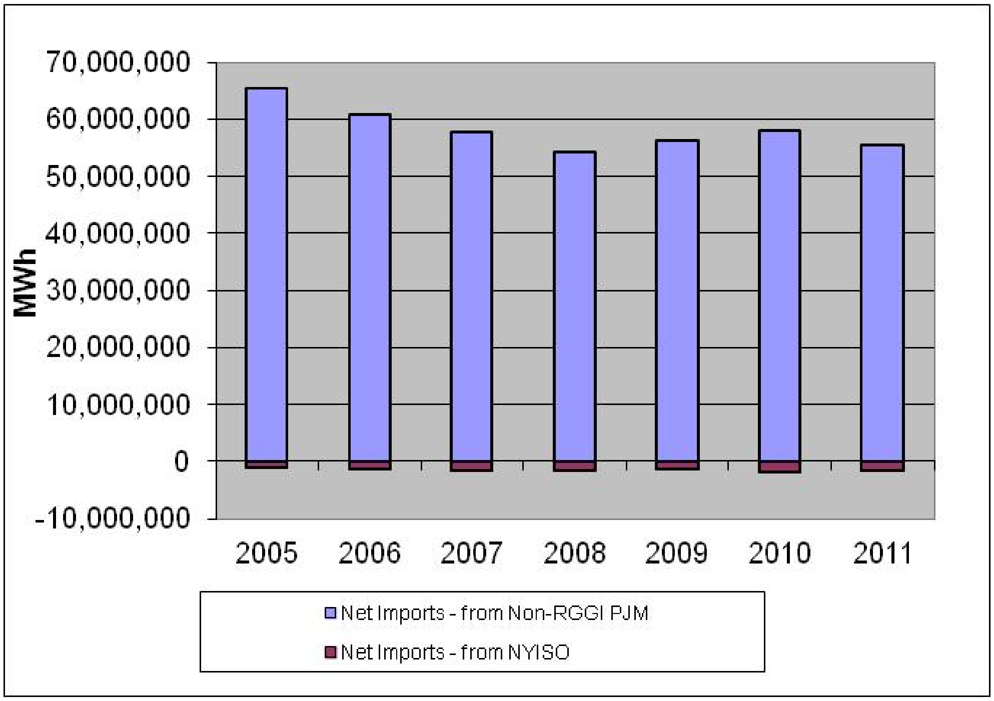

Figure 20. Net Electricity Imports to RGGI PJM (MWh)

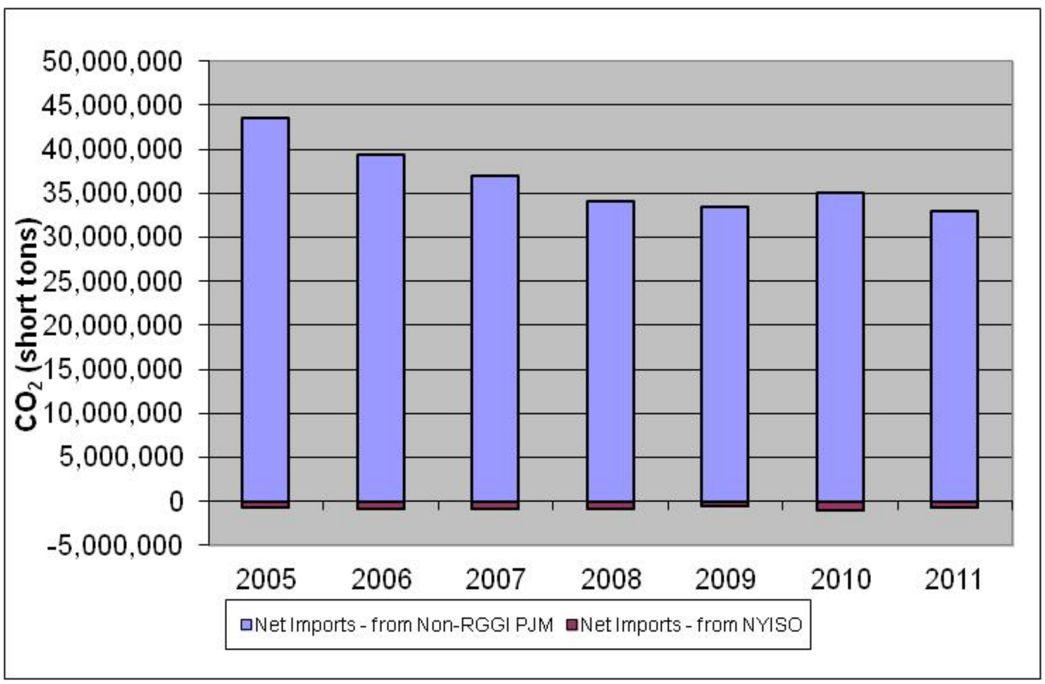

Figure 21. CO_2 Emissions Related to Net Electricity Imports to RGGI PJM (short tons CO_2)

Compared to the annual average during a multi-year base period of 2006 – 2008, electric generation in 2011 from all non-RGGI electric generation sources serving load in RGGI PJM decreased by 407 thousand MWh, a decrease of 0.4

percent. Compared to the 2006 – 2008 annual average, 2011 CO_2 emissions from this category of electric generation decreased by 3.4 million short tons of CO_2, a reduction of 9.0 percent, and the CO_2 emission rate decreased by 61 lb CO_2/MWh, a reduction of 8.7 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 total electricity load in RGGI PJM decreased by 2.5 million MWh, or 1.5 percent. Compared to the 2006 – 2008 annual average, total electric generation in RGGI PJM decreased by 4.4 million MWh, or 3.9 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 electric generation from RGGI-affected generation in RGGI PJM decreased by 6.2 million MWh, or 10.3 percent, and CO_2 emissions from RGGI-affected generation in RGGI PJM decreased by 13.7 million short tons of CO_2, or 24.0 percent. The CO_2 emission rate of RGGI-affected electric generation decreased by 292 lb CO_2/MWh, a reduction of 15.3 percent. Compared to the 2006 – 2008 annual average, 2011 electric generation from non-RGGI generation located in RGGI PJM increased by 1.8 million MWh, or 3.5 percent, and CO_2 emissions from this category of electric generation increased by 224 thousand short tons of CO_2, an increase of 11.7 percent. The CO_2 emission rate of non-RGGI electric generation located in RGGI PJM increased by 6 lb CO_2/MWh, an increase of 8.0 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2011 net electricity imports into RGGI PJM decreased by 2.2 million MWh, or 4.0 percent. CO_2 emissions related to these net electricity imports declined by 3.6 million short tons of CO_2, or 10.1 percent, during this period, indicating a reduction in the average CO_2 emission rate of the electric generation supplying these imports of 83 lb CO_2/MWh, a reduction of 6.4 percent.

Appendix C. Monitoring Trends

Detailed monitoring trends for the 10-State RGGI Region, ISO-NE, NYISO, and the RGGI portion of PJM are presented in Tables 8 through 11. The tables summarize the comparison between the 2006 to 2008 base period and the first three years of program operation, 2009 to 2011.

10-State RGGI Region

Table 8. Monitoring Trends for 10-State RGGI Region

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	183,910,392	17,205,745	187	203,712,944	158,876,166	1,560	83,452,187	43,812,948	1,050	267,362,579	61,018,693	456
2009-2011	182,997,812	14,859,271	162	185,229,984	125,089,116	1,351	87,617,236	40,565,100	926	270,615,048	55,424,370	410
Difference	-912,580	-2,346,474	-25	-18,482,960	-33,787,050	-209	4,165,049	-3,247,848	-124	3,252,468	-5,594,322	-47
% change	-0.5%	-13.6%	-13.2%	-9.1%	-21.3%	-13.4%	5.0%	-7.4%	-11.8%	1.2%	-9.2%	-10.3%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	387,623,336	470,974,186
2009-2011	368,227,795	454,914,763
Difference	-19,395,541	-16,059,422
% change	-5.0%	-3.4%

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	183,910,392	17,205,745	187	203,712,944	158,876,166	1,560	83,452,187	43,812,948	1,050	267,362,579	61,018,693	456
2011	183,903,127	15,556,107	169	185,313,180	117,539,864	1,269	87,759,456	39,706,736	905	271,662,583	55,262,843	407
Difference	-7,265	-1,649,638	-18	-18,399,764	-41,336,302	-291	4,307,269	-4,106,212	-145	4,300,004	-5,755,850	-50
% change	-0.00395%	-9.6%	-9.6%	-9.0%	-26.0%	-18.7%	5.2%	-9.4%	-13.8%	1.6%	-9.4%	-10.9%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	387,623,336	470,974,186
2011	369,216,307	455,434,193
Difference	-18,407,029	-15,539,992
% change	-4.7%	-3.3%

ISO-NE

Table 9. Monitoring Trends for ISO-NE

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	55,659,215	9,559,313	343	72,282,789	47,242,267	1,307	7,196,667	-124,180	-35	62,855,882	9,435,133	300
2009-2011	54,348,823	10,663,550	393	68,736,112	38,655,806	1,126	8,348,000	-665,603	-209	62,696,823	9,997,946	319
Difference	-1,310,393	1,104,237	49	-3,546,677	-8,586,461	-182	1,151,333	-541,424	-175	-159,059	562,813	19
% change	-2.4%	11.6%	14.4%	-4.9%	-18.2%	-13.9%	16.0%	436.0%	505.6%	-0.3%	6.0%	6.2%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	127,942,004	135,037,333
2009-2011	123,084,935	130,503,000
Difference	-4,857,070	-4,534,333
% change	-3.8%	-3.4%

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	55,659,215	9,559,313	343	72,282,789	47,242,267	1,307	7,196,667	-124,180	-35	62,855,882	9,435,133	300
2011	52,684,782	11,528,018	438	69,466,788	35,469,318	1,021	10,142,000	-384,998	-76	62,826,782	11,143,021	355
Difference	-2,974,433	1,968,705	94	-2,816,001	-11,772,949	-286	2,945,333	-260,818	-41	-29,100	1,707,887	55
% change	-5.3%	20.6%	27.4%	-3.9%	-24.9%	-21.9%	40.9%	210.0%	120.0%	0.0%	18.1%	18.2%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	127,942,004	135,037,333
2011	122,151,570	130,752,000
Difference	-5,790,434	-4,285,333
% change	-4.5%	-3.2%

NYISO

Table 10. Monitoring Trends for NYISO

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	76,580,782	5,740,019	150	71,623,443	54,523,728	1,523	20,206,894	7,876,114	780	96,787,676	13,616,133	281
2009-2011	75,864,258	1,981,936	52	62,743,209	40,661,900	1,296	24,258,034	7,999,236	658	100,122,292	9,981,172	199
Difference	-716,524	-3,758,083	-98	-8,880,234	-13,861,828	-227	4,051,140	123,122	-121	3,334,616	-3,634,961	-82
% change	-0.9%	-65.5%	-65.1%	-12.4%	-25.4%	-14.9%	20.0%	1.6%	-15.6%	3.4%	-26.7%	-29.1%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	148,204,225	168,411,119
2009-2011	138,607,467	162,865,501
Difference	-9,596,759	-5,545,618
% change	-6.5%	-3.3%

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	76,580,782	5,740,019	150	71,623,443	54,523,728	1,523	20,206,894	7,876,114	780	96,787,676	13,616,133	281
2011	77,739,570	1,897,762	49	62,225,030	38,686,919	1,243	23,783,796	7,721,638	649	101,523,366	9,619,400	190
Difference	1,158,788	-3,842,257	-101	-9,398,413	-15,836,809	-279	3,576,902	-154,477	-130	4,735,690	-3,996,733	-92
% change	1.5%	-66.9%	-67.4%	-13.1%	-29.0%	-18.3%	17.7%	-2.0%	-16.7%	4.9%	-29.4%	-32.6%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	148,204,225	168,411,119
2011	139,964,600	163,748,396
Difference	-8,239,625	-4,662,723
% change	-5.6%	-2.8%

RGGI-PJM

Table 11. Monitoring Trends for RGGI-PJM

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	51,670,395	1,906,413	74	59,806,712	57,110,171	1,910	56,048,627	36,024,885	1,285	107,719,022	37,931,299	704
2009-2011	52,784,731	2,213,785	84	53,750,663	45,771,410	1,703	55,010,869	33,206,360	1,207	107,795,600	35,420,144	657
Difference	1,114,337	307,371	10	-6,056,049	-11,338,761	-207	-1,037,758	-2,818,526	-78	76,578	-2,511,154	-47
% change	2.2%	16.1%	14.1%	-10.1%	-19.9%	-10.8%	-1.9%	-7.8%	-6.1%	0.1%	-6.6%	-6.7%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	111,477,106	167,525,733
2009-2011	106,535,394	161,546,263
Difference	-4,941,712	-5,979,471
% change	-4.4%	-3.6%

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	51,670,395	1,906,413	74	59,806,712	57,110,171	1,910	56,048,627	36,024,885	1,285	107,719,022	37,931,299	704
2011	53,478,775	2,130,327	80	53,621,362	43,383,627	1,618	53,833,660	32,379,997	1,203	107,312,435	34,510,324	643
Difference	1,808,380	223,914	6	-6,185,350	-13,726,545	-292	-2,214,967	-3,644,889	-83	-406,586	-3,420,975	-61
% change	3.5%	11.7%	8.0%	-10.3%	-24.0%	-15.3%	-4.0%	-10.1%	-6.4%	-0.4%	-9.0%	-8.7%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	111,477,106	167,525,733
2011	107,100,137	165,047,534
Difference	-4,376,969	-2,478,199
% change	-3.9%	-1.5%

Appendix D. Concept of "Emissions Leakage"

"Emissions leakage" is the concept that the RGGI CO_2 compliance obligation and related CO_2 compliance costs for electric generators could result in a shift of electricity generation from CO_2-emitting sources subject to the RGGI CO_2 Budget Trading Program to CO_2-emitting sources not subject to RGGI. Key to this concept is that the cause of such a shift would be due to the RGGI CO_2 Budget Trading Program, rather than other factors that influence electric power sector CO_2 emissions. The concept of emissions leakage presumes that an increase in electricity production costs for certain electric generators due to RGGI CO_2 compliance costs would be the driver of changes in the operation of the electric power system that result in an increase in CO_2 emissions from electric generation that is not subject to the RGGI CO_2 Budget Trading Program.

Factors that Influence Electric Generator Dispatch and CO_2 Emissions

In the Northeast and Mid-Atlantic, electric generation is deregulated and subject to competitive wholesale electricity markets. In the simplest terms, wholesale electricity markets are used to determine which power plants run to meet electricity demand and determine the wholesale price of electricity. Electric generators bid into day-ahead and real-time auctions for generation supply, in which the lowest priced plants are selected one by one until electricity demand is met. The last plant selected, or "dispatched," to meet demand is referred to as the marginal unit, and sets the wholesale clearing price. A number of elements factor in to the bid offers made by individual electric generators, including fuel prices, operation and maintenance costs, and environmental compliance costs. For this latter category, certain environmental compliance costs are represented by the market value of emissions allowances, such as CO_2, NO_X, and SO_2 allowances. The market value of these emission allowances influences the production costs of individual electric generators in a similar manner as fuel costs, and therefore play a role in influencing the dispatch of electric generators and the wholesale market clearing price of electricity.

In addition to the production costs of electric generators, the dispatch of electric generators and wholesale electricity prices are also influenced by electricity demand and electricity transmission constraints. Since electricity cannot be stored, it must be delivered instantaneously to where it is needed. In locations where electric demand is high, transmission capability may be constrained, meaning that electric generation has different values in different areas – because the lowest cost electric generation cannot always be delivered to where it is needed based on transmission limitations. As a result, wholesale electricity prices also differ by location, a concept referred to as locational marginal pricing.

All of the above, including production costs, market factors, and physical limitations, impact the dispatch of electric generation, and related CO_2 emissions, through a highly dynamic wholesale electricity market.

The concept of emissions leakage assumes a scenario in which only a subset of CO_2-emitting electric generators are subject to a CO_2 allowance requirement.[36] As a result, certain electric generators are subject to an additional production cost – the cost of CO_2 allowances – that is not faced by other CO_2-emitting electric generators. In theory, this could result in a shift in electric generation to emitting units that do not face a CO_2 compliance cost. If such a shift results in an increase in CO_2 emissions from electric generation as a whole, such an increase is referred to as emissions leakage.

If emissions leakage were to occur, it would result from an increase in dispatch (and related CO_2 emissions) from: (a) in-region non-RGGI units (i.e., small fossil fuel-fired units in the ten-state RGGI region with a capacity less than 25 MWe, which are not subject to RGGI); (b) electric generation outside the ten-state RGGI region (represented as electricity imports); or (c) a combination of the two, both of which are referred to in this report as "non-RGGI generation".

[36] The ten-state RGGI region does not completely align with the geographic footprint of wholesale electricity markets in the greater Northeast and Mid-Atlantic region, and electric power can flow across multiple wholesale markets in North America.