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Carbon-Tuning New York's Electricity System: Uncovering New Opportunities for CO2 Emissions Reductions

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Executive Summary

As initiatives like New York's REV continue, understanding the emission impacts of DER deployment becomes vital to ensure these efforts achieve the greatest environmental benefit possible.

DISTRIBUTED ENERGY RESOURCES (DER), including technologies and services such as behind-the-meter generation, demand response, energy management, and energy efficiency, are touted as effective ways to improve electric system efficiencies and reduce harmful air emissions. The New York State Public Service Commission's landmark Reforming the Energy Vision (REV) proceeding aims to unleash competitive forces that will invest in DER across the state with the explicit goal of reducing customer bills and the environmental impact of electricity production. As initiatives like New York's REV continue, understanding the emission impacts of DER deployment becomes vital to ensure these efforts achieve the greatest environmental benefit possible.

In this report, we present an analysis of the emission characteristics of New York's electricity system. Using a linear regression model, we estimate marginal emission rates for CO_2 and other pollutants from large centralized power plants. Our results show that the marginal emission rate of the State's electricity system—and thus the emission reduction potential of DER—is dependent on both the time and location of DER operation in New York. Specifically, our analysis revealed the following observations:

- In general, marginal emission rates increase as overall demand on the electric system increases. Relatively higher-emitting generators operate on the margin during peak demand hours relative to non-peak demand hours.
- The model has more difficulty estimating marginal emission rates during the early morning hours, which may signify a greater diversity of generators operating on the margin during these hours over the course of the year. On some days of the year, the marginal generator may be relatively higher-emitting, and on other days it may be relatively lower-emitting.
- Marginal emission rates are significantly lower from plants located in New York City than the rest of the state.
- Seasonal variations in marginal emission rates are only observed during winter on Long Island, likely due to increased fuel oil generation resulting from natural gas shortages during 2014's polar vortex event.
- The marginal emission rates for other harmful pollutants like NO_x may correlate with CO_2 marginal emission rates while rates for SO_2 may not. Additional analysis is needed to assess these relationships, and the interaction between different pollutant marginal emission rates should be considered.

Our results show that marginal emission rates should be incorporated into the design of DER markets and programs to help guide DER deployment towards maximizing emission reductions. The significant differences in these rates—as observed from our analysis—reinforces the benefit of including this metric in DER valuations in New York specifically. Incorporating these rates—as opposed to other metrics like system average emission rates—into valuation efforts increases the accuracy of appraising the benefits of DERs since marginal emission rates more closely represent the physical and economic operation of the electric grid. This, in turn, increases the economic efficiency of DER deployment and operation decisions There is value in deploying DER that displace the most amount of pollution possible, and regulators like the New York State Public Service Commission should strive to capture this value as they design DER markets through REV.

Marginal Emission Rates

Understanding the emission impacts of DER requires information on the emission characteristics of both the DER and the electric generation displaced elsewhere on the electricity system (see Figure 1) For distributed generation, if the emissions resulting from the operation of the DER are less than the emissions that would have resulted from the displaced central generation, then a net reduction in overall emissions can be attributed to the DER. Conversely, if a higher-emitting DER displaces relatively lower-emitting generation, then a net increase in overall emissions will occur. For DER that does not produce air pollution, such as demand response and energy efficiency, understanding emission impacts only requires knowledge of the emission characteristics of the displaced electric generation.

FIGURE 1: Net Emission Impacts of Distributed Energy Resources

Distributed Generation	Emissions created by distributed generation	+	Emissions avoided from central generation	=	Net Emissions Impact
Demand Response	Emissions created by shifted demand	+	Emissions avoided by shifted demand	=	
Energy Efficiency	Emissions avoided from central generation			=	

Determining the emission characteristics of DER is a straightforward exercise that requires analysis of the specific technology. Emission characteristics of fossil-fuel fired generators are generally determined through direct measurement or derived from generator efficiency and fuel factors.

Determining the emission characteristics of the electric generation displaced by DER is not as simple. A common approach uses a system-average emission factor derived from all generators in the electric system. However, this approach assumes any displaced generation resulting from DER will have a proportional impact on all generators in the electric system. In reality, specific individual generators will respond. It is the emission characteristics of these generators—referred to as marginal generators—that will influence the net emission impacts caused by DER. Accordingly, the degree of emissions displaced is referred to as the *marginal emission rate*.

The New York Independent System Operator (NYISO) coordinates the bulk energy system in the state (e.g. large-scale electric generators and transmission facilities). The NYISO administers energy markets with the goal of reliably balancing energy supply and demand at the lowest economic cost. At all times, NYISO must dispatch enough generation to fulfill demand within the New York Control Area (NYCA), which encompasses the entire state. To minimize economic costs, the least expensive generators are generally dispatched first with increasingly more expensive generators dispatched as demand increases. Consequently, the marginal generator is typically the next least expensive generator needed to fulfill demand at any given time after all other more inexpensive generators have been dispatched. Since the marginal generator typically changes with overall demand and overall demand varies over the course of the day and year, marginal emission rates tend to change as demand fluctuates both daily and seasonally.

This phenomenon should inform efforts to design DER markets and programs. The value of non-emitting and low-emitting DER like solar PV, energy efficiency, and combined heat and power is well recognized. However, this value can be maximized if markets and programs can be designed to incentivize the timing of DER operation that displaces higher emitting generation. DER that displaces generation during times with high marginal emission rates should be valued more than DER that displaces generation during times with relatively low marginal emission rates.

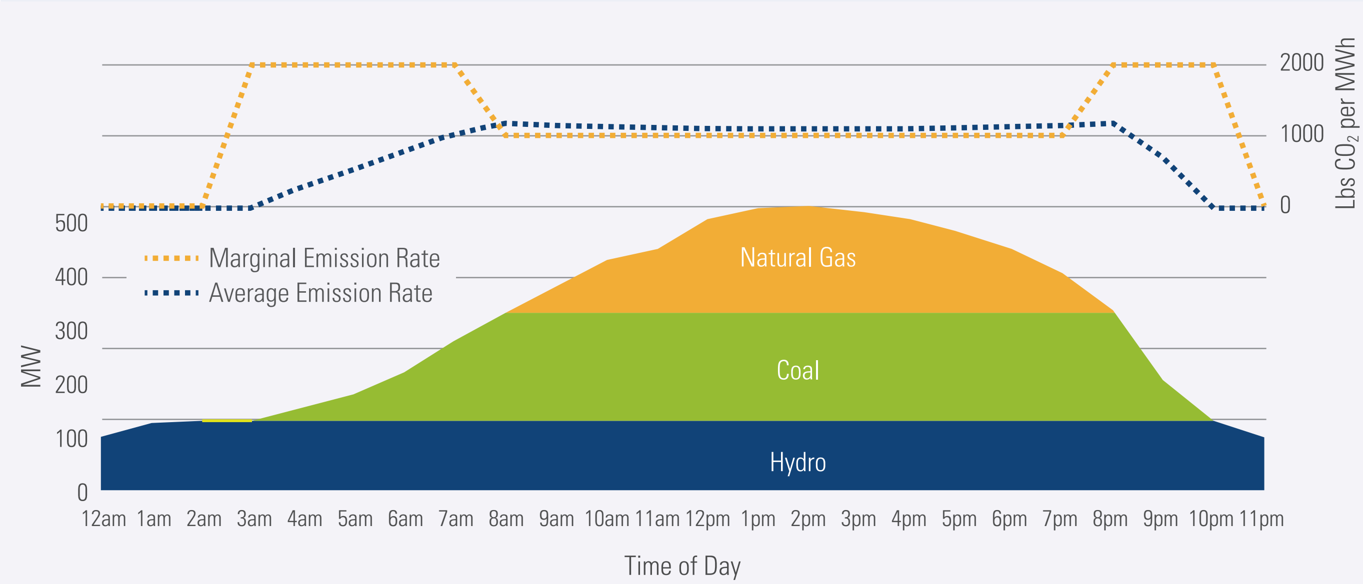
Understanding Marginal Emission Rates – A Hypoethical Example

Imagine an electric system that has only three types of generation—hydro, coal, and natural gas. In the late night and early morning hours when electric demand is relatively low, only hydro generation, which has the lowest operating costs of the three, is needed to fulfill demand. As demand increases during the course of the day, coal generation, with the second lowest operating costs, must be dispatched to fulfill increasing demand. Then, as demand peaks in the late afternoon, relatively expensive natural gas generation is utilized. Finally, natural gas generation and then coal generation is ramped back down as demand decreases in the late night hours.

This example illustrates how the marginal emission rate can vary over time. In the late night and early morning hours, hydro generation is the marginal generator. Any change in demand during these hours will cause a subsequent change in hydro generation. Since hydro generation does not any have associated CO_2 emissions, any change in demand when hydro is the marginal generator will not result in a change in CO_2 emissions. In other words, the marginal emission rate is 0 lbs. CO_2 per MWh. When coal becomes the marginal generator, the marginal emission rate jumps to 2000 lbs. CO_2 per MWh since coal generation is relatively high-emitting. Finally, during peak hours, the marginal emission rate declines to 1000 lbs. CO_2 per MWh since natural gas generation is relatively low-emitting compared to coal. Any increase or decrease in demand during these peak hours will subsequently increase or decrease CO_2 emissions by 1000 lbs. for each MWh.

The figure and table below illustrates the changing marginal emission rate as system demand changes over the course of the day in this hypothetical example. It also displays the average emission rate for all generation supplying demand in each hour. As can be seen, the average and marginal emission rates are often significantly different from each other.

Hypothetical System Demand and Emission Rates of Course of a Day



	1am	6am	10am	2pm	9pm	11pm
System Demand (MW)	125	220	430	530	205	100
Marginal Generator	Hydro	Coal	Natural Gas	Natural Gas	Coal	Hydro
Marginal Emission Rate (lbs. CO_2 / MWh)	0	2000	1000	1000	2000	0
Average Emission Rate (lbs. CO_2 / MWh)	0	818	1163	1132	732	0

Estimating Marginal Emission Rates

Using publicly available data from the U.S. Environmental Protection Agency's Air Markets Program Data (AMPD) database, we estimate marginal emission rates for New York in 2014 using a linear regression model that regresses hourly changes in a generator's load onto hourly changes in a generator's emissions. By segmenting the data into various tranches, we use the model to estimate emission rates for particular times of day, times of year, location, and overall electric demand. Due to limitations in the available data, our estimates should not necessarily be interpreted as prescriptive values of New York's marginal emission rates. Instead, they should be viewed as "average" marginal emission rates for a general time, location, or level of electric demand.

For example, we estimate marginal emission rates for each hour of the day by running the model 24 separate times using data from each given hour across the entire year. Each estimated marginal emission rate should be interpreted as the average rate for the given hour for 2014. The actual rate for a specific hour on a specific day may be higher or lower depending on a multitude of factors. However, on an average day, we would expect the rate to trend towards the estimated marginal emission rate.

The Methodology Appendix provides a more detailed description of the methods used to estimate marginal emission rates, along with more information on the data utilized and the limitations of the model. The remainder of this report presents modeling results and provides a discussion of their significance.

Average marginal emission rates vary through the course of the day and tend to increase during daylight hours when demand is typically higher.

CO_2 Marginal Emission Rates in New York

The estimated average CO_2 marginal emission rates for each hour of the day are displayed in Figure 2. The rates vary between 890 lbs. CO_2 per MWh and 1050 lbs. CO_2 per MWh indicating that natural-gas fired generators are the predominant units operating on the margin.[1] This observation supports the findings within the 2014 State of the Market Report for NYISO Markets, which reports that natural gas operated on the margin 80% of the time in real-time markets in 2014.[2]

As can be seen in the figure, average marginal emission rates vary through the course of the day and tend to increase during daylight hours when demand is typically higher. This is likely indicative of more expensive, less efficient, and higher-emitting generators acting on the margin as demand increases during the day—as would be expected.

Interestingly, the 95% confidence interval of the estimated rates is relatively large during the early morning hours indicating that the model has a harder time estimating these rates.[3] This could be an artifact of estimating rates with relatively fewer data points since fewer generators tend to run during the early morning, low-demand hours. However, it may also indicate a relatively more diverse fleet of generators operating on the margin during those hours over the course of the entire year. During some days of the year, relatively higher-emitting generators may operate on the margin during these early morning hours, while on other days relatively lower-emitting generators may operate during the same hours. This would provide a wider distribution of emission rates from which the model would estimate an average marginal emission rate, which would in turn result in a larger confidence interval.

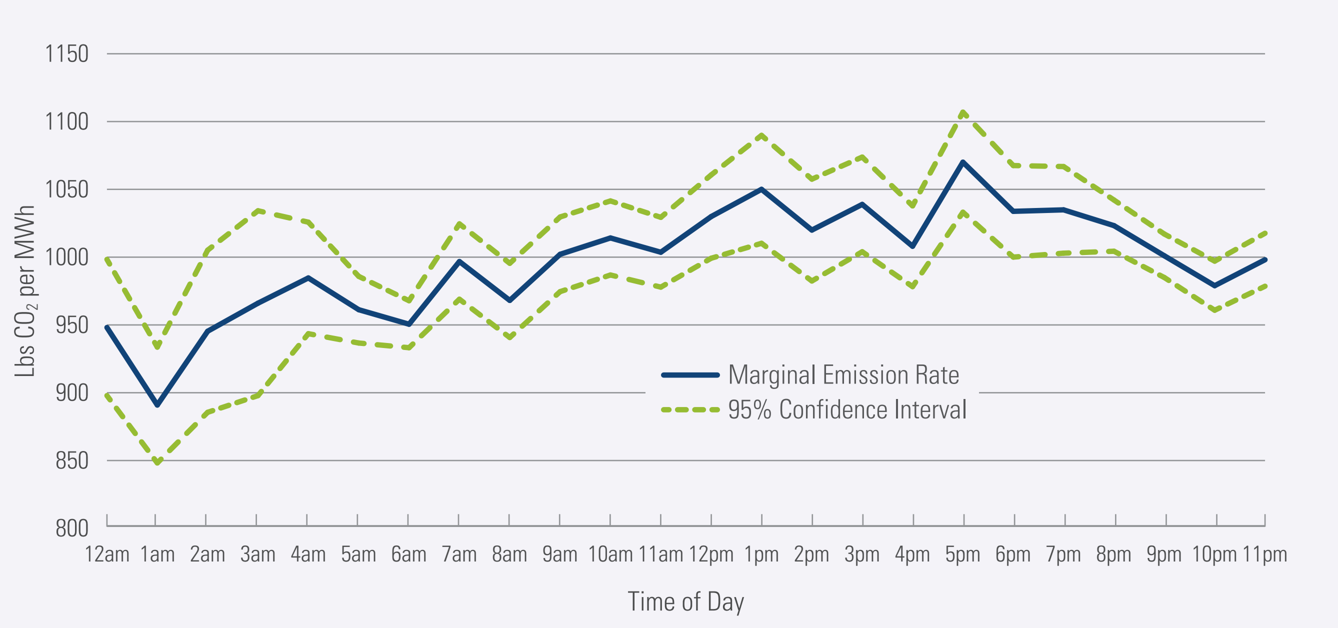
Figure 3 shows the estimated average CO_2 marginal emission rates as a function of overall generator load. To develop this graph, we segmented the data in 5%

1 The EPA reports that the average combined-cycle natural gas plant in the Eastern Interconnection region is 894 lbs CO_2/MWh. See "CO2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule". Link: http://www3.epa.gov/airquality/cpp/tsd-cpp-emission-performance-rate-goal-computation.pdf

2 See Figure A-10 on page A-14 in the 2014 State of the Market Report for NYISO Markets. Link: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf

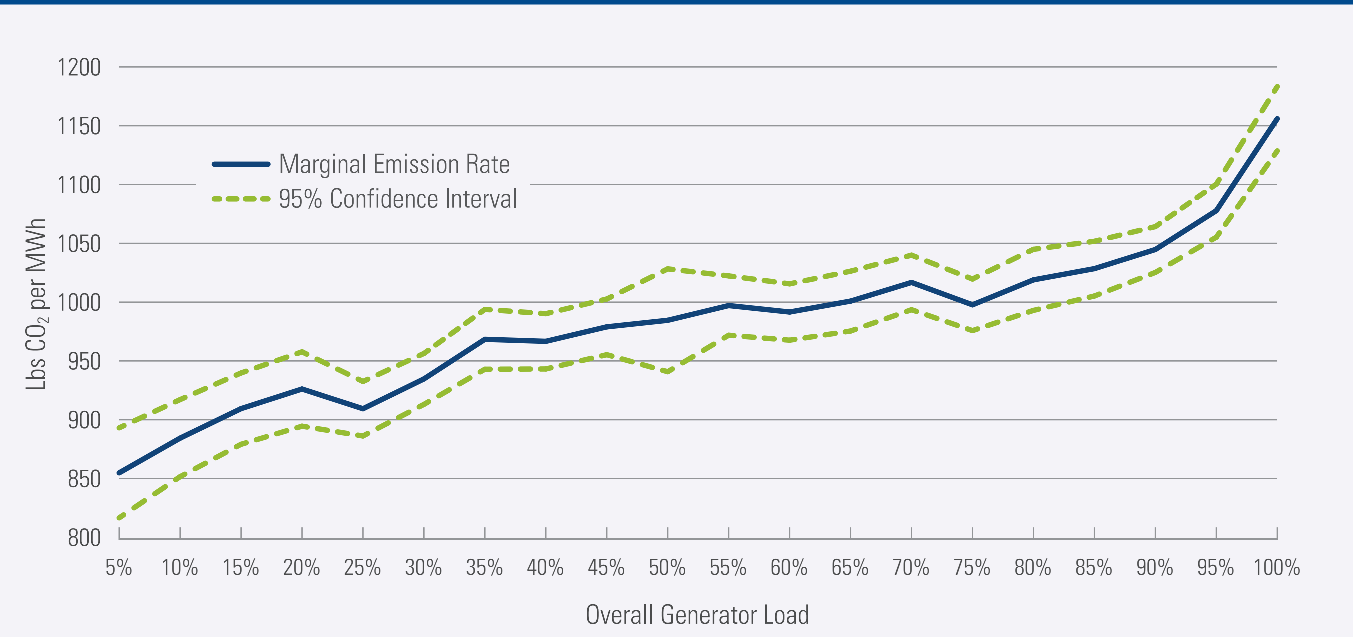
3 The average 95% confidence interval for hours 12am through 4am is 104.8 lbs. CO_2 per MWh, while it is only 55.3 lbs. CO_2 per MWh for hours 5am through 11pm.

FIGURE 2: Average CO_2 Marginal Emission Rates as a Function of Time of Day



centile bins based on the overall aggregate load of all generators in the EPA's dataset for the given hour and then used the model to estimate a marginal emission rate for each bin. For example, our results show that for the 5% of hours when overall generator load is at its lowest, the estimated CO_2 average marginal emission rate is approximately 854 lbs. CO_2 per MWh. Conversely, it is approximately 1156 lbs. CO_2 per MWh for the 5% of hours when overall generator load is at its highest. This represents an approximately 35% increase in the marginal emission rate between the hours where overall generator load is the lowest and highest.

FIGURE 3: Average CO_2 Marginal Emission Rates as a Function of Overall Generator Load



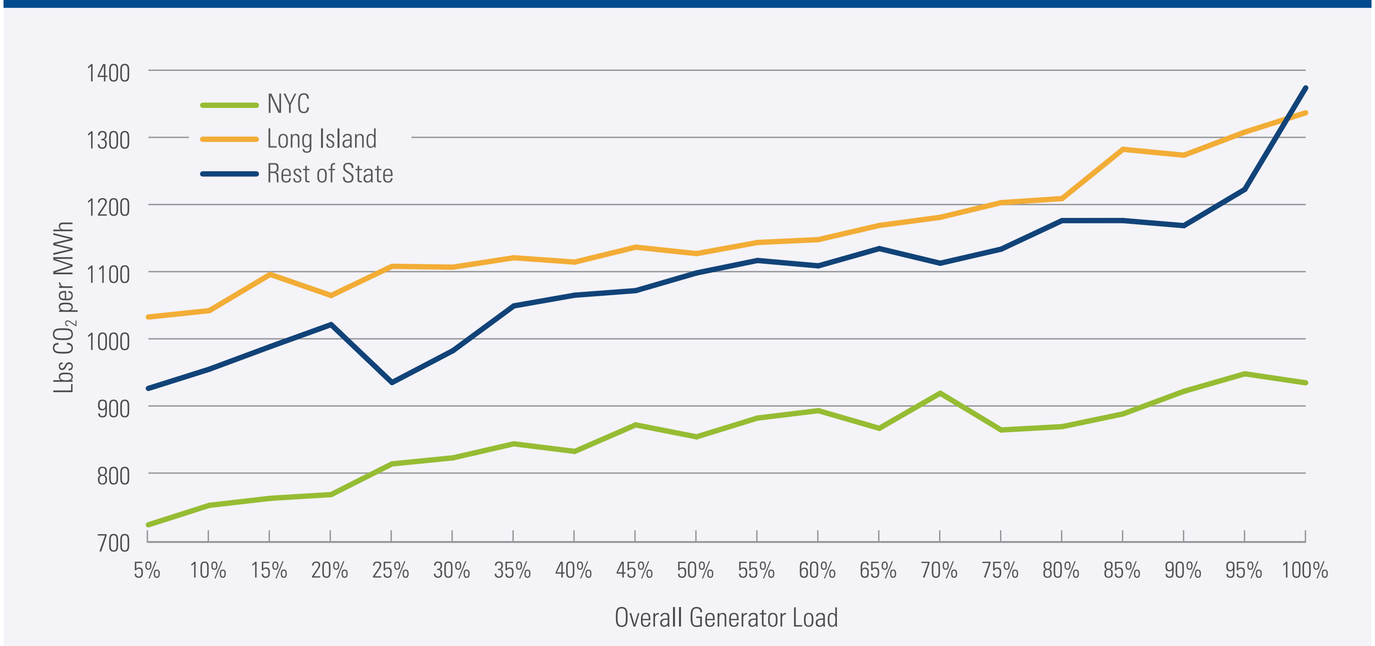
Locational and Seasonal Variations in Marginal Emission Rates

In New York, the marginal generator may not always be the next least expensive generator in the NYCA. Due to constraints in transmission facilities, certain areas of the state cannot receive additional electricity from less expensive generators when transmission lines are operating at full capacity. When this occurs, a generator closer to the load must be dispatched to fulfill demand. In other words, different locations in the state may have different marginal generators when high levels of demand cause transmission constraints.

Figure 4 shows how marginal emission rates may vary by location due to these transmission constraints. We show marginal emission rates as a function of overall generator load for New York City and Long Island compared to the rest of the state because these areas tend to experience transmission constraints most often. These constraints result from limited transmission capacity between the upstate and downstate regions. As can be seen in the graph, the average CO_2 marginal emission rate is significantly lower for generators located in New York City compared to Long Island and the rest of the state. This observation does not necessarily mean *any* change in demand in New York City will have a smaller impact on emissions than a change in demand elsewhere. This difference will only occur when transmission constraints require a generator located within New York City to respond to a change in demand within New York City. Our model and data do not allow us to accurately identify when these time periods occur; these results invite further investigation and analysis.

While there are locational differences in the magnitude of marginal emission rates, all three locations display an upward trend in average CO_2 marginal emission rates as overall generator load increases. However, New York City's and Long Island's rates display a smaller proportional increase than the rest of the state between the lowest and highest hours of overall generator load. The relative increase in the average CO_2 marginal emission rate between the lowest and highest generator load hours in New York City and Long Island is approximately 29%, while the same metric is approximately 48% for the rest of the state. This difference is due primarily to the relatively rapid increase in the marginal emission rate for the rest of the state in the highest 5% of demand hours.

FIGURE 4: Locational Average CO_2 Marginal Emission Rates as Function of Overall Generator Load



Note: Figures 4 through 6 do not include 95% confidence intervals for estimated marginal emission rates for reasons of visual clarity.

Our results also show some seasonal variation in average CO_2 marginal emission rates. Figure 5 shows rates segmented by summer, winter, and spring/fall.[4] The highest periods of sustained demand tend to occur in the summer and winter when space heating and cooling energy needs are the highest. In general, average CO_2 marginal emission rates increase as overall generator load increases in all seasonal periods. However, winter rates increase at a relatively faster rate than the other two periods. Above the 60th percentile of overall generator load, there is a clear separation between winter rates compared to summer and spring/fall rates.

The relatively higher marginal emission rates in winter are likely explained by the 2014 polar vortex phenomenon, which caused record cold temperatures across the region. The low temperatures caused natural gas prices to increase as heating demand increased. Dual-fuel generators switched from natural gas to fuel oil as natural gas became scarcer. Since fuel oil is a relatively higher-emitting fuel than natural gas, we observe a significant increase in marginal emission rates during these months. This is supported by NYISO's 2014 State of the Market Report, which indicates that residual oil fired generators on Long Island were the marginal unit roughly 50% of the time a marginal generator was located on Long Island.[5] Indeed, if we look at estimated marginal emission rates as a function of season for Long Island only (Figure 6), the winter marginal emission trend becomes even more apparent. This trend is not observed for New York City and the rest of the state (not pictured) as neither of these areas contained fuel oil marginal generators during 2014 according to the NYISO report.

4 Average CO_2 marginal emission rates are estimated as a function of total generator load for generating units for three seasonal periods—winter (Dec-Feb), summer (Jun-Aug), and spring/fall (Mar-May and Sep-Nov)

5 See Figure A-10 on page A-14 in the 2014 State of the Market Report for NYISO Markets. Link: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf

FIGURE 5: Seasonal Average CO_2 Marginal Emission Rates as a Function of Overall Generator Load

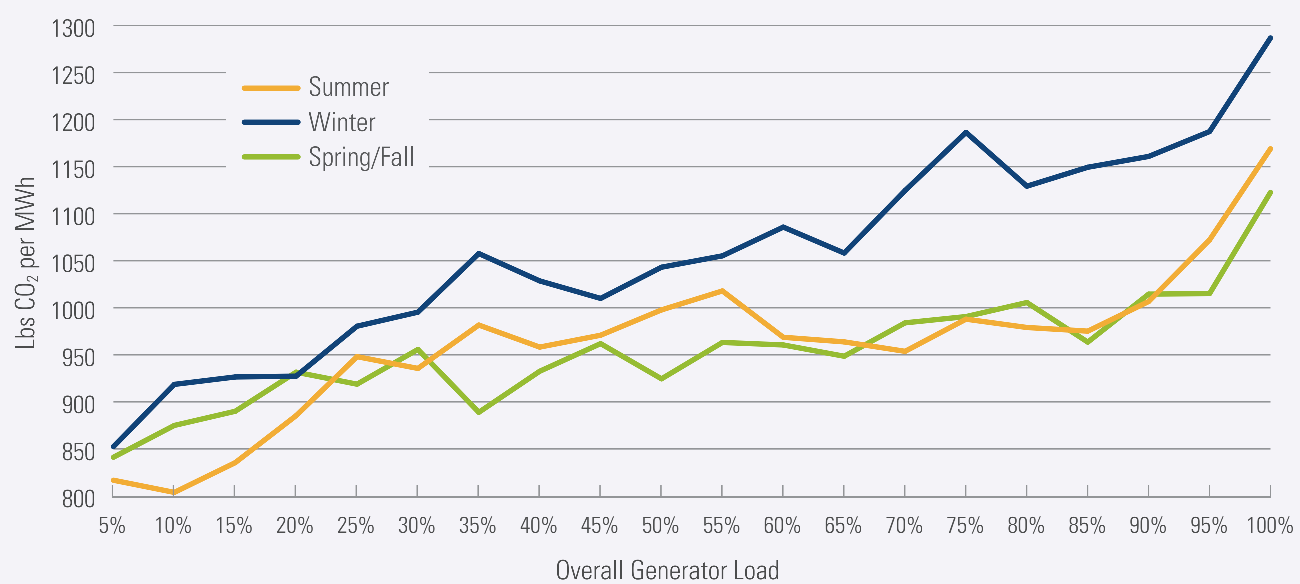
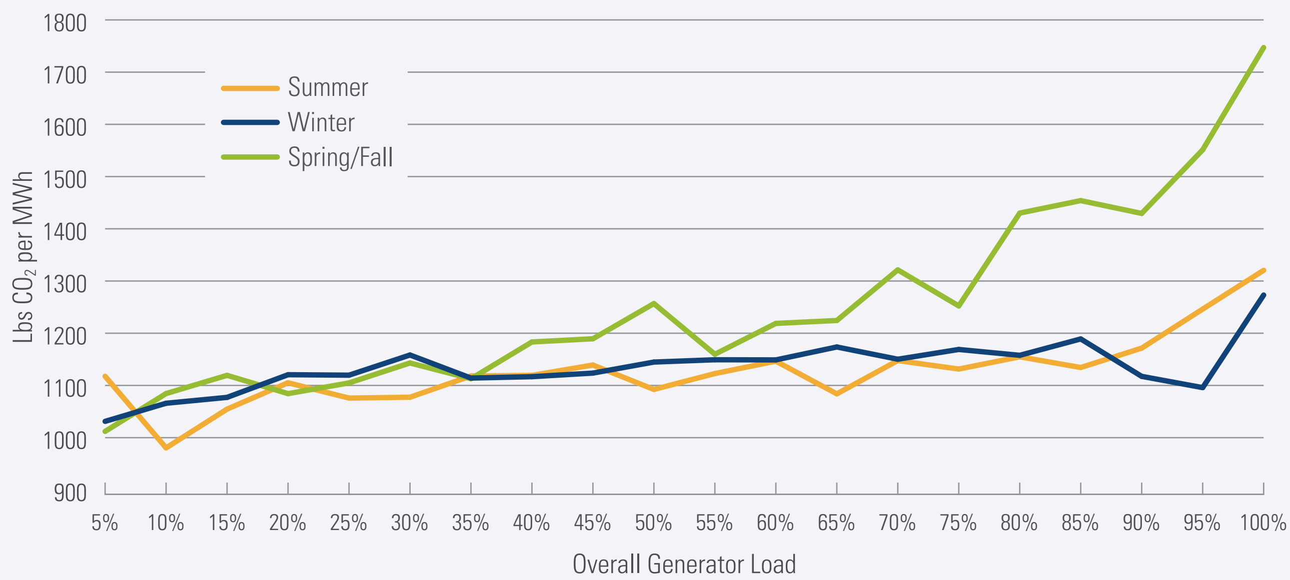


FIGURE 6: Seasonal Average CO_2 Marginal Emission Rates for Long Island as a Function of Overall Generator Load



Marginal Emission Rates for Other Pollutants

In addition to CO_2 emissions, generators are also required to report NO_x and SO_2 emissions to the EPA. For this reason, we are also able to estimate marginal emission rates for these pollutants using the same dataset and model.

Figure 7 shows average NO_x marginal emission rates by time of day. The rates for NO_x display a similar trend as CO_2 by time of day—tending to increase during daylight hours when electric demand generally increases. Likewise, the model has a harder time estimating marginal emission rates during the early morning hours compared to other hours.[6] As observed with CO_2 marginal emission rates, the daily trend for average NO_X marginal emission rates indicates both a tendency for less efficient, higher-emitting generators responding to increasing demand as well as a greater diversity in generator emission profiles during early morning hours during the course of the year.

Figure 8 shows average SO_2 marginal emission rates by time of day. Interestingly, the rates for SO_X display a significant spike in the early morning hours before falling to lower levels and slightly increasing during daylight hours when demand is increasing. This may be indicative of generators that utilize fuels with higher SO_2 content, such as coal-fired generators, operating on the margin during early morning average when demand is at its lowest.

Figures 9 and 10 display average marginal emission rates for NO_x and SO_2, respectively, as a function of overall generator load. Both pollutant marginal emission rates display a general upward trend as total generator load increases. NO_x rates, however, appear to have a steadier relationship with overall generator load—increasing at a relatively constant rate from the 25th percentile to 100th percentiles. Conversely, SO_X rates experience a relatively rapid increase only after the 75th percentile. This may indicate that, while the generating units operating on the margin during high load periods tend to be higher-emitting in both NO_X and SO_2 emissions, low load periods may be more likely to have higher-emitting SO_2 units operating on the margin.

6 The average 95% confidence interval for hours 12am through 4am is 0.30 lbs. NO_x per MWh, while it is only 0.16 lbs. NO_x per MWh for hours 5am through 11pm.

FIGURE 7: Average NO_x Marginal Emission Rates as Function of Time of Day

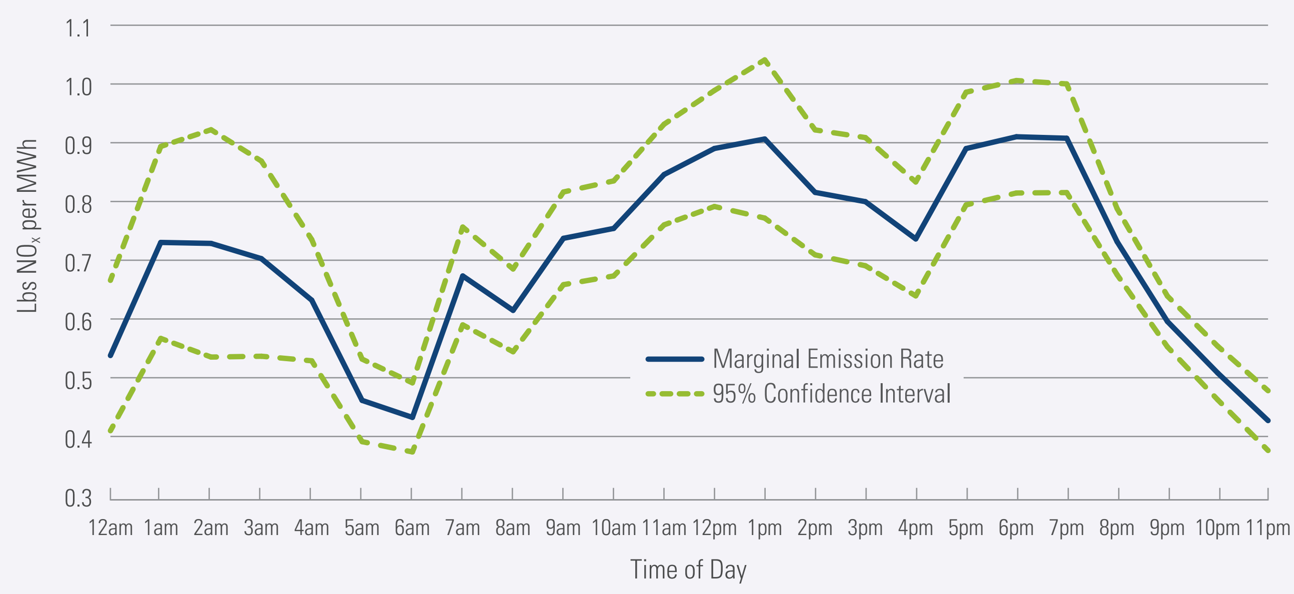
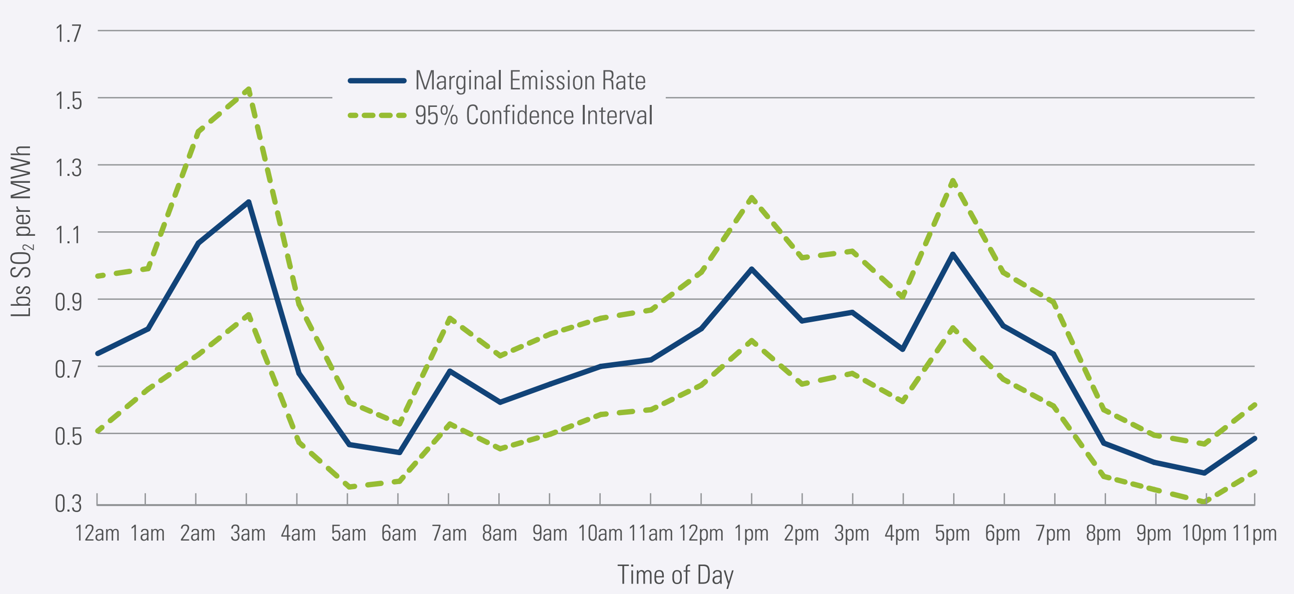


FIGURE 8: Average SO_2 Marginal Emission Rates as Function of Time of Day



Another important observation is the relative increase in average NO_X and SO_2 marginal emission rates between the lowest and highest hours of overall generator load. NO_x rates increase by approximately 265% between the lowest and highest hours of total generator load, and SO_2 rates increase by approximately 305%.

FIGURE 9: Average NO_x Marginal Emission Rates as Function of Overall Generator Load

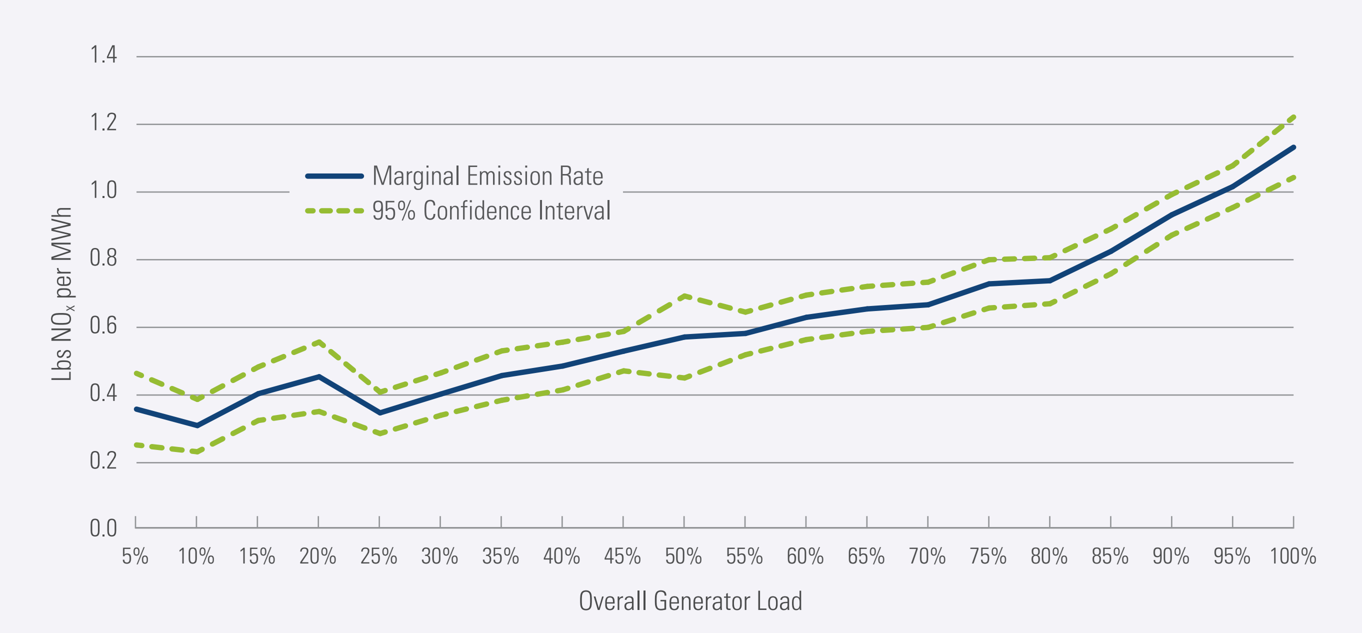
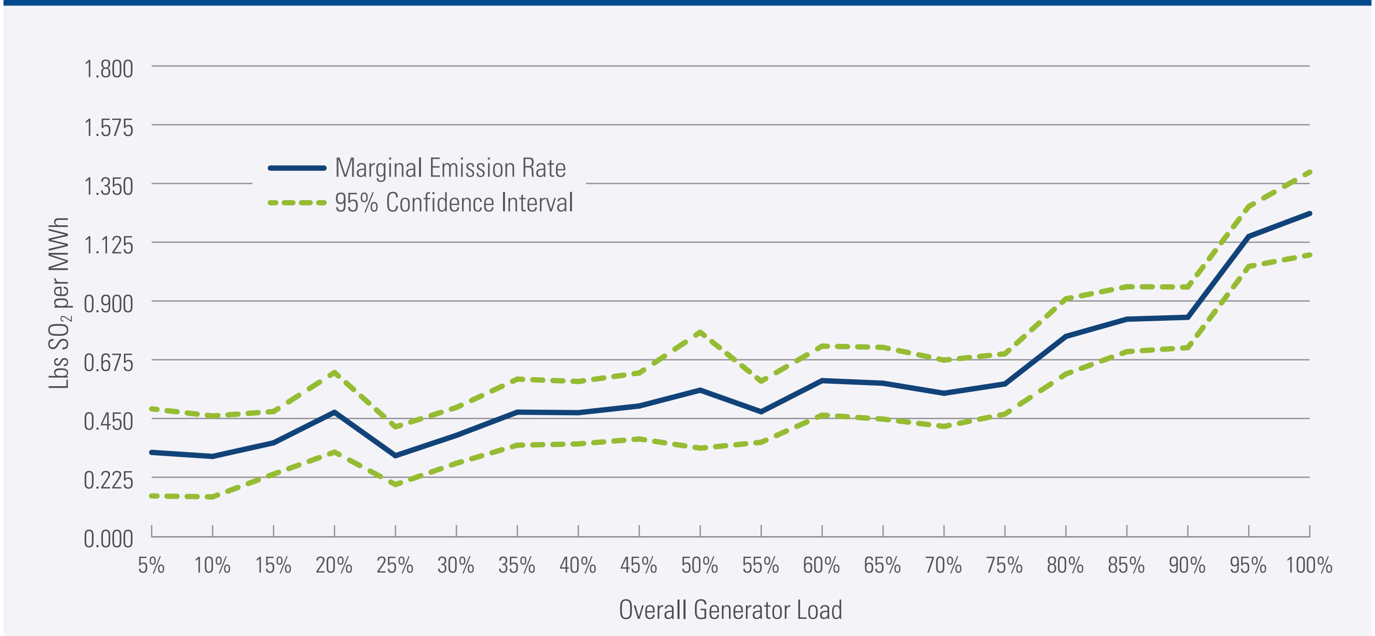


FIGURE 10: Average SO_2 Marginal Emission Rates as Function of Overall Generator Load



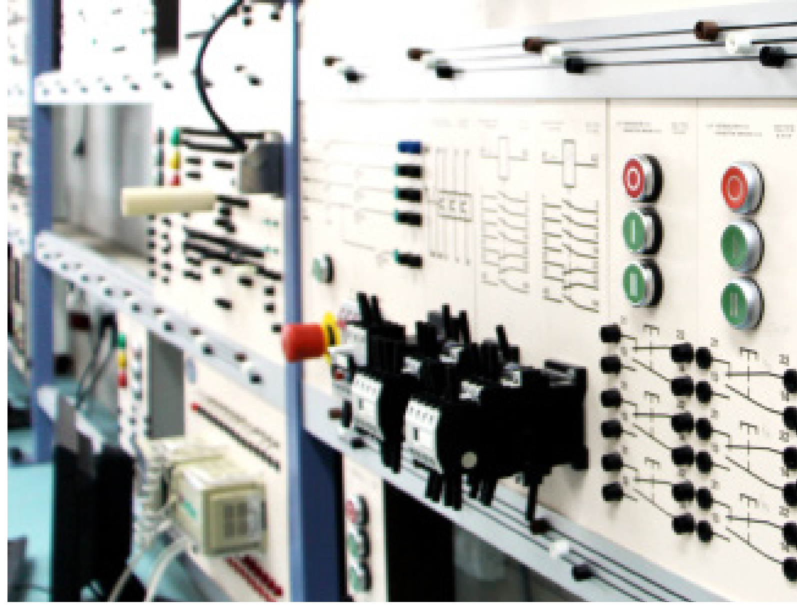
Discussion

Our analysis shows that average CO_2 marginal emission rates in New York vary daily, seasonally, and by location. There are times and locations where the generation DER is likely to displace is relatively higher-emitting than other times and locations. This means that greater emission reductions—and thus greater value—can be obtained from DER deployment by targeting higher-emitting times and locations. Policy makers may want to explore approving compensation or credit rates that reflect this higher value.

In New York, average CO_2 marginal emission rates closely track energy demand. As demand on the electric system increases, generally higher-emitting generators become the marginal units. Most of New York's fossil-fuel fired generators use natural gas, therefore there is not a significant shift from one fuel source to another as additional generator is dispatched to fulfill demand. However, since more expensive generators are generally used as demand increases, it reasons that the more expensive natural gas generators are also less efficient and therefore have higher fuel costs per unit of energy output. It is likely for this reason that we observe the relationship between overall electric demand and CO_2 marginal emission rates.

The close association between electric demand and average CO_2 marginal emission rates provides additional support for on-going efforts to reduce the amount and magnitude of peak energy demand hours. These hours are generally the most expensive times to consume energy since the most expensive generators must run and the entire electric system's capacity must be built out to accommodate the high level of demand. A major goal of New York's REV proceeding is to reduce electricity consumption during these peak hours to reduce costs to all ratepayers. From our observations, it also appears that REV may have the additional benefit of reducing some of the highest-emitting generation from New York's energy profile.

There is some indication, however, that the hours of highest demand are not the only opportunity for targeting the displacement of high-emitting generation. If our model's difficulty in estimating average CO_2 marginal emission rates in the early morning hours indicates recurrent periods of relatively higher-emitting marginal generation during these hours over

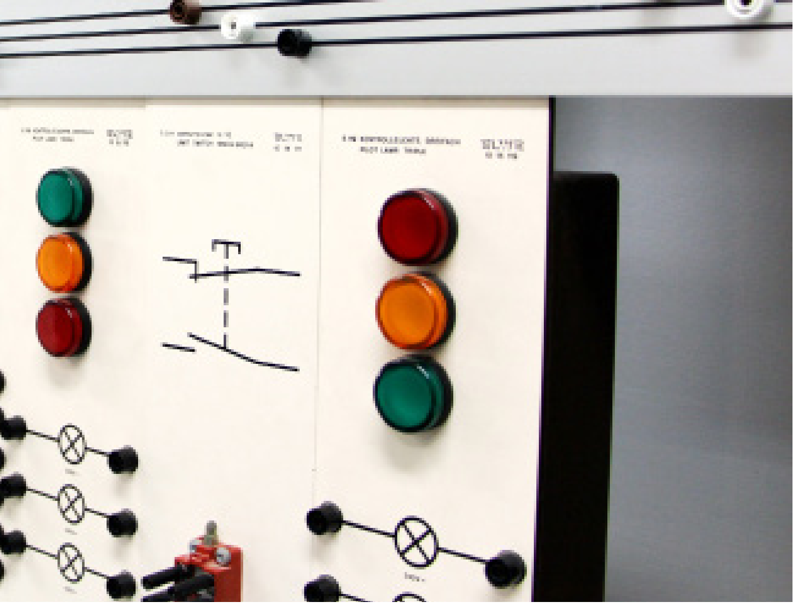


The close association between electric demand and average CO_2 marginal emission rates provides additional support for on-going efforts to reduce the amount and magnitude of peak energy demand hours.

the course of the year, then the opportunity exists to target emission reductions during these hours as well. Additionally, our analysis of locational marginal emission rates indicates a significant difference between rates for generators in New York City and for generators in the rest of the state. While these differences will only materialize when transmission constraints occur, it exemplifies the fact that location matters for DER benefits. Transmission constraints generally occur when demand is highest, therefore it may be appropriate to value the emission benefits of peak reduction in areas like Long Island more than New York City.[7]

The analysis of NO_X and SO_2 average marginal emission rates highlights the importance of considering possible complementary and competing relationships between CO_2 emission reductions and other pollutants. For DER like demand response that may shift demand from one time period to another, emissions for some pollutants may actually increase while others decrease. If demand shifts from a period of relatively high CO_2 and low SO_2 marginal emission rates to a period of low CO_2 and high SO_2 rates, then overall CO_2 emissions will decrease while SO_2 emissions increase.

7 DER operation in transmission constrained areas can also reduce line losses (i.e. energy lost in the transmission and distribution of electricity) and wear and tear on transmission and distribution infrastructure—both of which increase with higher levels of demand.



Moving Forward

Incorporating marginal emission rates into the design of DER markets and programs will help guide DER deployment towards maximizing emission reductions. The significant differences in these rates—as observed from our analysis—reinforces the benefit of including this metric in DER valuations in New York specifically. Incorporating these rates—as opposed to other metrics like system average emission rates—into valuation efforts increases the accuracy of appraising the benefits of DERs since marginal emission rates more closely represent the physical and economic operation of the electric grid. This, in turn, increases the economic efficiency of DER deployment and operation decisions. There is value in deploying DER that displaces the most amount of pollution possible, and regulators like the New York State Public Service Commission should strive to capture this value as they design DER markets through REV.

Efficiently incorporating marginal emission rates into DER markets and program design, however, should be informed by a more detailed analysis of marginal emission rates than could be provided by this report. While our analysis clearly shows marginal emission rate levels and trends in New York, it is predicated on the best publicly available data. Incorporating privately held data, such as the kind collected by NYISO as part of the administration of New York's energy markets, would significantly improve the accuracy and validity of estimating marginal emission rates by eliminating many of our model's limitations as detailed in the Methodology Appendix.

Appendix: Methodology

Model

Generator specific load and emission data was retrieved from the U.S. Environmental Protection Agency's Air Markets Program Data (AMPD) database for every generator serving the New York Control Area (NYCA) for all hours of 2014. This includes all generators located within New York State as well as several generators located in New Jersey that directly supply NYCA loads through merchant transmission lines.[8]

The first difference of the load and emission vectors (i.e. x_t-x_{t-1} for t=2…n) is determined for each generator to create vectors of n-1 observations of the change in hourly generator load ($\Delta LOAD_{g,t}$) and CO_2 emissions ($\Delta EMISSIONS_{g,t}$). Using linear regression, we regress the vector of hourly change in load onto the vector of hourly change in emissions to estimate average marginal emission rates. The generalized specification is shown below:

$$\Delta EMISSIONS_{g,t} = \beta_0 + \beta_1 \Delta LOAD_{g,t} + \varepsilon_{g,t}$$

The coefficient β_1 is interpreted as the average change in emissions caused by a 1MW change in load for the given set of data.

To explore daily, seasonal, and locational trends in marginal emission rates, we disaggregate the data into various segments such as hour of day, season, location, and overall generator load. We then apply the linear regression model to these segments to estimate an average marginal emission rate for each segment. For example, we apply the model 23 times to estimate an average marginal emission rate for each hour of the day to observe daily trends in the rate.

To show marginal emission rates as a function of system demand, we apply our model to data segmented by overall generator demand. We assume that overall generator demand correlates with overall system demand.

There is value in deploying DER that displaces the most amount of pollution possible.

8 These include the Linden Generating Station in Linden, NJ (1,647MW) and the Bayonne Energy Center in Bayonne, NJ (512MW).

We sum generator load for each hour and segment observations into twenty "centile bins" based on overall generator load. For example, the first bin consists of the observations during the 5% of hours when overall generator load is the lowest. The next bin consists of observations between the 5% and 10% of hours when overall generator load is the lowest. This is repeated until the final bin contains the 5% of hours when overall generator load is the highest. We then apply the linear regression model to each data centile bin to estimate an average marginal emission rate for each 5% increment of overall generator load.

Data

The AMPD database provides access to data collected as part of the EPA's emissions trading programs, which requires fossil-fuel fired generators greater than 25MW to report sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2) emission data, generation data, and other information. Fossil-fuel fired generators less than 25MW and non-fossil-fuel fired generators (e.g. hydro, nuclear, renewables) are excluded from the dataset.

Model Assumptions and Limitations

Due to the limitations of the available data, the model operates under four primary assumptions that may bias marginal emission rate estimations. The assumptions and their potential biases are described below.

First, since the data excludes non-fossil fuel generators, the model assumes that non-fossil fuel generators do not operate on the margin. This includes nuclear, hydro, and renewable generators. The exclusion of these generators does not likely bias the model's results because these units are generally not operated on the margin. Nuclear is run as baseload generation and will generally not respond to changes in demand. Run-of-the-river hydro and renewables like wind and solar will generate whenever they can and therefore will not respond to changes in demand. Hydro that is not run-of-the-river may operate on the margin, but it is simply displacing other generators that will then need to operate at other parts of the day.

Second, since the utilized data excludes generators outside NYCA, the model assumes that imports and exports from the system do not operate on the margin. New York imports and exports a significant amount of energy from New England, PJM, Ontario and Quebec. At any given time, energy imported from a neighboring control area to serve New York demand may be the price setting unit and thus be considered to be operating on the margin. The exclusion of these units from the analysis may bias the model's results if the emission rates of marginal imports is significantly different than the emission rates of marginal internal NYCA generation.

Third, since the utilized data excludes generators less than 25MW, the model assumes that such generators do not operate on the margin. It is likely that generators less than 25MW do operate on the margin during some time periods. However, the vast majority of internal NYCA fossil-fuel fired generators are larger than 25MW and thus report their emissions data to the EPA. The proportion of fossil-fuel fired generators not reporting to the EPA due to the size exclusion is approximately 1.3% of the NYCA capacity reported in NYISO's 2015 Gold Book.[9]

Fourth, approximately 71 generating units only reported load and emission data during the ozone season between the months of April and September. Most of these units are natural-gas fired and are part of several larger facilities located within the New York City area. The exclusion of these units during non-ozone season months (October through March) may bias the model's results if these units operated on the margin during these months.

9 See 2015 Load & Capacity Data. NYISO. http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2015%20Load%20and%20Capacity%20Data%20Report.pdf

About Pace Energy and Climate Center

More than a think tank, the Pace Energy & Climate Center turns ideas into action. We believe thoughtful engagement of government and key stakeholders leads to better public policy. We conduct research and analysis on legal, regulatory and policy matters because thorough, objective analyses are essential to finding solutions to today's complex energy and climate change challenges. We are lawyers, economists, scientists, and energy analysts, committed to achieving real-world progress.

About the Author

Nicholas Martin has been an Energy Policy Associate at the Pace Energy & Climate Center since 2013. His work focuses on increasing the deployment of clean distributed energy resources through rigorous policy analysis and direct community engagement. His areas of engagement include combined heat and power (CHP), microgrids and community energy, solar PV market policy, and CO_2 emission reduction policies like the Northeast's Regional Greenhouse Gas Initiative. Nick also serves as an Executive Director of the Northeast Clean Heat and Power Initiative, a 501(c)6 group representing the CHP industry in the Northeast.

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