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Marginal Emissions Factors for the U.S. Electricity System

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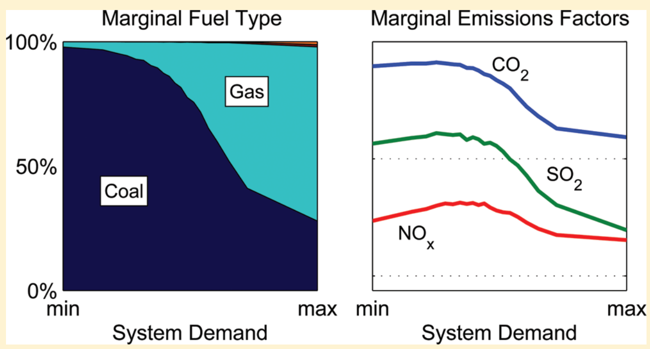
Supporting Information

ABSTRACT: There is growing interest in reducing emissions from electricity generation in the United States (U.S.). Renewable energy, energy efficiency, and energy conservation are all commonly suggested solutions. Both supply- and demand-side interventions will displace energy—and emissions—from conventional generators. Marginal emissions factors (MEFs) give a consistent metric for assessing the avoided emissions resulting from such interventions. This paper presents the first systematic calculation of MEFs for the U.S. electricity system. Using regressions of hourly generation and emissions data from 2006 through 2011, we estimate regional MEFs for CO_2, NO_x, and SO_2, as well as the share of marginal generation from coal-, gas-, and oil-fired generators. Trends in MEFs with respect to system load, time of day, and month are explored. We compare marginal and average emissions factors (AEFs), finding that AEFs may grossly misestimate the avoided emissions resulting from an intervention. We find significant regional differences in the emissions benefits of avoiding one megawatt-hour of electricity: compared to the West, an equivalent energy efficiency measure in the Midwest is expected to avoid roughly 70% more CO_2, 12 times more SO_2, and 3 times more NO_x emissions.



INTRODUCTION

There is growing interest in reducing greenhouse gas and criteria air pollution emissions from electricity generation in the United States (U.S.). Renewable energy, such as wind and solar generation, is a commonly suggested solution. Emissions reductions could also be achieved by increasing the efficiency of end-use applications. In the short term, both supply- and demand-side interventions displace energy—and emissions—from conventional generators. In the long term, interventions in the electricity system may also affect plant retirements and construction. Here we focus on the short-term avoided CO_2, NO_x, and SO_2 resulting from interventions in the U.S. electricity system.

Avoided emissions can be measured using marginal emissions factors (MEFs). MEFs reflect the emissions intensities of the marginal generators in the system—the last generators needed to meet demand at a given time, and the first to respond given an intervention. MEFs constantly change as different generators are dispatched to meet demand. Identifying the marginal generator is difficult due to the many economic and operational constraints on the grid, which is a large and highly interconnected system. Further complicating matters, MEFs depend on the local generation mix and the type and quality of fuels used, which vary considerably from region to region.

Previous studies have developed a range of methods for estimating MEFs. Most commonly, a dispatch model is used to predict the marginal generator for a given time and place.[1] These models assume that generators are dispatched in order of marginal cost, where the last generator needed to meet demand sets the marginal emissions rate for the system. Dispatch models have been used to calculate MEFs for various regions, including the United Kingdom, California, and New England.[2−5] Dispatch models have also been used to assess the emissions implications of plug-in electric vehicles, wind and solar generation, distributed cogeneration, and various energy efficiency measures.[6−8] These analyses vary greatly in their treatment of transmission, generator, and reliability constraints.

Regressions of historical data are a less common method of estimating MEFs. Hawkes estimates marginal CO_2 rates for the United Kingdom using a regression of half-hourly data from 2002 through 2009.[1] More detailed econometric models have been used to study the emissions implications of wind energy and real-time electricity pricing.[9,10] By relying on historical operating data, these studies circumvent the problem of modeling dispatch orders, outage rates, transmissions constraints, etc.

Estimates of marginal CO_2 rates are available for only a few regions in the U.S. Marginal NO_x and SO_2 rates are even harder to come by. As a result, studies may revert to average emissions factors (AEFs) to estimate the emissions implications of an

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intervention.[11] This is problematic because AEFs may result in significant errors, potentially misinforming decision makers.[1,2,12]

This paper presents the first systematic calculation of MEFs for the U.S. electricity system, giving a consistent metric for assessing the emissions benefits of various interventions. Using hourly generation and emissions data from 2006 through 2011, we estimate regional MEFs for CO_2, NO_x, and SO_2 across the continental U.S. We provide a comparison between marginal and average emissions factors, estimate the share of marginal generation from coal-, gas-, and oil-fired plants, and explore trends in MEFs with respect to system load, time of day, and month.

DATA

Our estimates of MEFs are based on an analysis of historic emissions and generation data. We estimate MEFs separately for the eight regions of the North American Electric Reliability Corporation (NERC). NERC regions are as follows: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), Southeastern Reliability Council (SERC), Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC). A map of the NERC regions is included in the Supporting Information (SI).

The generation mix varies considerably from region to region (see SI). Coal accounts for as much as 70% and as little as 15% of regional electricity production, gas accounts for 5% to 49%, and nuclear accounts for 5% to 28%. Oil contributes very little with the exception of FRCC (Florida) and NPCC (Northeast), and hydropower is significant in only two regions—NPCC (Northeast) and WECC (West).

Emissions data are from the Environmental Protection Agency's (EPA) Continuous Emissions Monitoring System (CEMS).[13] CEMS data include hourly, generator-level SO_2, NO_x, and CO_2 emissions as well as gross power output. CEMS data were sorted into NERC regions by cross-referencing generator identification numbers with eGRID, a separate database maintained by the EPA.[14]

Unfortunately, the CEMS database is limited to fossil-fueled generators greater than 25 MW.[15] As a result, our estimates of MEFs do not account for biomass, wind, nuclear, hydropower, waste-to-power, geothermal, solar, and small fossil-fueled generators. The MEFs presented here are only valid if we assume that these CEMS-exempt generators do not operate on the margin. In other words, we must assume that demand-reducing interventions will not displace nuclear, hydro, etc. These assumptions are discussed in further detail in the SI.

METHOD AND EXAMPLE ANALYSIS

Average MEFs. Marginal emissions factors are calculated separately for each NERC region and emissions type (CO_2, SO_2, and NO_x). We use CEMS data to calculate the change in fossil generation (G) and change in emissions (E) between one hour and the next:

$$\Delta G_h = G_h - G_{h+1}(\text{MWh})$$

$$\Delta E_h = E_h - E_{h+1}(\text{kg})$$

From 2006 through 2011, there are more than 50 000 observed changes in emissions corresponding to a change in generation. The slope of a linear regression of ΔE on ΔG estimates the average MEF. For example, Figure 1 shows ΔCO_2 plotted

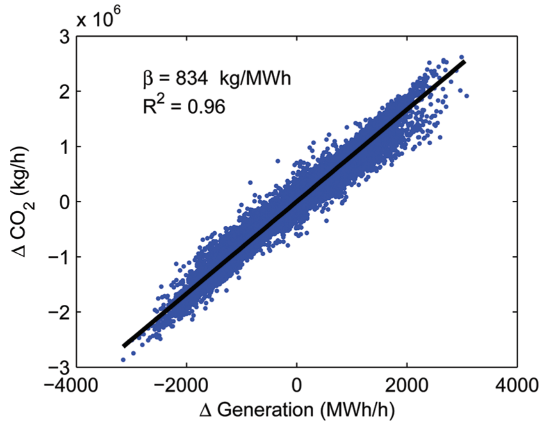

Figure 1. Linear regression of ΔCO_2 on ΔG for MRO from 2006 through 2011. The slope of the regression line estimates the marginal CO_2 rate of the system (834 kg/MWh).

against ΔG for the MRO region. In this case, reducing demand by one megawatt-hour is expected to displace, on average, 834 kg of CO_2. Note that we assume that only generators within the MRO region are displaced (i.e., imports and exports between regions are ignored). In addition, interventions that have high variability (e.g., wind and solar) may require conventional generators to cycle more often, or may increase the burden on generators providing regulation and rolling reserves; these impacts are not captured in our analysis. This method was originally demonstrated by Hawkes and used to calculate marginal CO_2 rates for the United Kingdom.[1]

Trends in MEFs. Figure 1 is an example of the most general result: the average MEF from 2006 through 2011. Trends are explored by applying the above method to subsets of the data. Monthly MEFs are calculated using 12 separate regressions of ΔE on ΔG for all observations in each month. Similarly, time-of-day MEFs are calculated using 24 separate regressions for all observations occurring at a given time (e.g., the MEF for 1 is based on the delta between 1 a.m. and 2 a.m. for each day).

Due to economic dispatch, we expect that the level of electrical demand is a strong predictor of the system MEF. Unfortunately, system demand data are not consistently available. For the remainder of this paper, we use total fossil generation (based on CEMS data) as a proxy for system demand. In SPP, the correlation between the two is 0.90 with an R^2 of 0.93. In other regions, the correlation may be better or worse depending on the relative shares of fossil and nonfossil generation and the level of interconnection with other regions.

Trends in MEF with respect to system demand are explored by binning data by every fifth percentile. The first bin contains the 5% of data occurring during the lowest-demand hours, and the twentieth bin contains the 5% of data occurring during the highest-demand hours. Separate regressions are used to calculate MEFs for data within each bin.

Marginal Fuel Source. Using a variation of the method discussed above, we calculate the share of marginal generation from coal-, gas-, and oil-fired generators. We calculate the change in total generation between one hour and the next (ΔX), and the corresponding change in coal-, gas-, and oil-fired generation (ΔY_{coal}, ΔY_{gas}, and ΔY_{oil}). Separate regressions of

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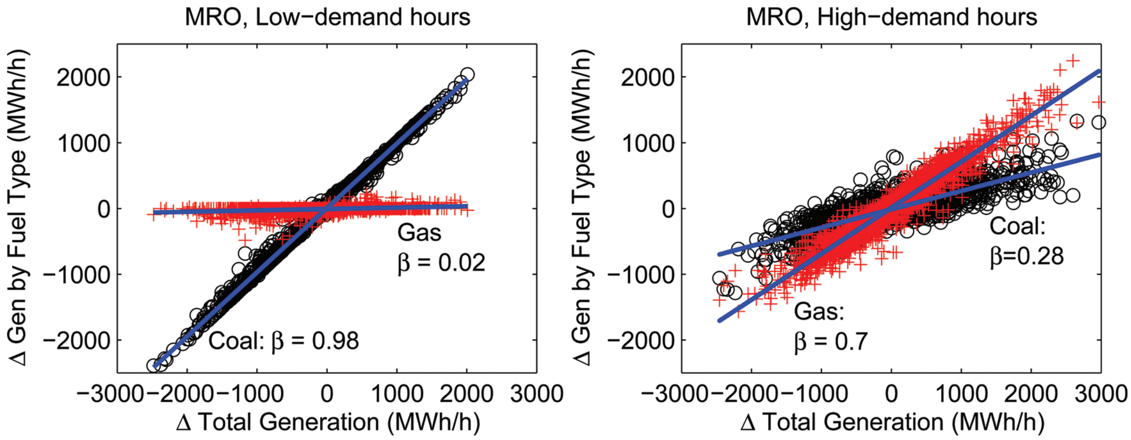

Figure 2. Change in coal and gas generation vs change in total generation in MRO (Midwest). During low demand hours (left), coal is the dominant marginal fuel source (β_{coal} = 0.98, β_{gas} = 0.02). Gas accounts for a larger share of marginal generation during high-demand hours (right; β_{coal} = 0.28, β_{gas} = 0.70).

Table 1. Average Marginal Fuel Sources and Marginal Emissions Factors for Regional Electricity Generation from 2006 to 2011

	marginal fuel source (%)			CO_2		SO_2		NO_x[a]	
region	coal	gas	oil	MEF ± 2σ	R^2	MEF ± 2σ	R^2	MEF ± 2σ	R^2
FRCC (Florida)	17	71	12	532 ± 1	0.96	1.33 ± 0.01	0.66	0.8 ± 0.01/0.76 ± 0.01	0.76/0.67
MRO (Midwest)	79	20	0	834 ± 1.5	0.96	2.11 ± 0.01	0.77	1.07 ± 0.01/1.12 ± 0.01	0.79/0.6
NPCC (Northeast)	8	81	11	489 ± 0.8	0.96	0.55 ± 0.01	0.46	0.33 ± 0/0.3 ± 0	0.44/0.4
RFC (Mid-Atlantic)	70	29	0	731 ± 0.9	0.98	3.29 ± 0.01	0.78	0.76 ± 0/1.19 ± 0.01	0.88/0.79
SERC (Southeast)	55	45	0	680 ± 0.9	0.97	2.01 ± 0.01	0.73	0.53 ± 0/0.8 ± 0.01	0.8/0.72
SPP (Southwest)	35	65	0	596 ± 1.3	0.94	0.71 ± 0.01	0.41	0.85 ± 0.01/0.95 ± 0.01	0.78/0.73
TRE (Texas)	16	84	0	527 ± 1.1	0.94	0.4 ± 0.01	0.19	0.32 ± 0	0.48
WECC (West)	14	86	0	486 ± 0.8	0.97	0.18 ± 0	0.11	0.32 ± 0	0.48

[a]Summer ozone season (May 1 through September 30)/offseason. For the period of interest, TRE and WECC were not affected by seasonal NO_x regulation.

ΔX on ΔY approximate the share of marginal generation for each fuel type.

Figure 2 shows an example of this method applied to coal- and gas-fired generation in MRO (Midwest) for low-demand hours (bottom 5%, shown left) and high-demand hours (top 5%, shown right). Coal is the dominant marginal fuel source when demand is low (β_{coal} = 0.98, β_{gas} = 0.02). During high-demand hours, gas accounts for a larger share of marginal generation (β_{coal} = 0.28, β_{gas} = 0.70).

■ RESULTS

Marginal Emissions Factors and Marginal Fuel Sources: 2006−2011. Table 1 presents overall results by region, based on all data from 2006 through 2011. Columns two through four give the marginal fuel source—that is, the extent to which coal-, gas-, and oil-fired generators are expected to respond to interventions in the electricity system.

Note that this is a different metric than what is commonly reported by Independent System Operators (ISOs). ISOs report the percentage of time that a fuel source is on the margin, where marginal generators in all balancing areas are weighted equally (see ref 16). Our estimates reflect the degree to which different generators respond to changes in demand. This implicitly weights our results such that marginal generators in areas with greater demand will represent a larger share of the total marginal fuel source. Despite this difference, we find good agreement with our results and those reported by the Southwest Power Pool, as shown in the SI.

Table 1 shows that gas is the dominant marginal fuel source in most regions. Coal accounts for a large share of marginal generation in MRO and RFC (79% and 70%), and oil is significant in NPCC and FRCC (11% and 12%).

Columns four through ten present MEFs (±two standard deviations of the coefficient estimate) and R^2 values. In all cases, the 95% confidence intervals are remarkably narrow, which we believe grossly overstates the precision of this analysis. Errors that arise from data limitations and modeling choices dominate the statistical uncertainty of the regressions.

Across regions, marginal CO_2 rates vary from 486 (WECC) to more than 830 (MRO) kg/MWh. R^2 values range from 94% to 98%, indicating that a change in system generation is a very strong predictor of changes in CO_2 emissions.

Marginal SO_2 rates vary from 0.2 (WECC) to 3.3 (RFC) kg/MWh. In other words, an energy efficiency measure in RFC

Table 2. Comparison between 2007 Marginal and Average Emissions Factors[a]

region	CO_2 (kg/MWh) MEF	AEF	% diff[b]	SO_2 (kg/MWh) MEF	AEF	% diff[b]	NO_x (kg/MWh) MEF	AEF	% diff[b]
FRCC (Florida)	577	553	−4	1.73	1.44	−17	0.99	0.88	−11
MRO (Midwest)	786	799	2	2.13	2.57	21	1.15	1.39	20
NPCC Northeast)	477	357	−25	0.63	1.09	73	0.35	0.34	−5
RFC Mid-Atlantic)	726	648	−11	3.96	3.76	−5	0.81	0.65	−20
SERC (Southeast)	656	619	−6	2.3	2.46	7	0.57	0.56	−2
SPP (Southwest)	564	763	35	0.7	1.86	166	0.86	1.05	22
TRE (Texas)	506	568	12	0.29	1.16	295	0.3	0.33	10
WECC (West)	464	462	0	0.14	0.53	280	0.26	0.68	161

[a]With the exception of TRE and WECC, average and marginal NO_x rates are based on data from the 2007 summer ozone season (May 1−September 30). [b]Percent difference = (AEF − MEF)/MEF × 100.

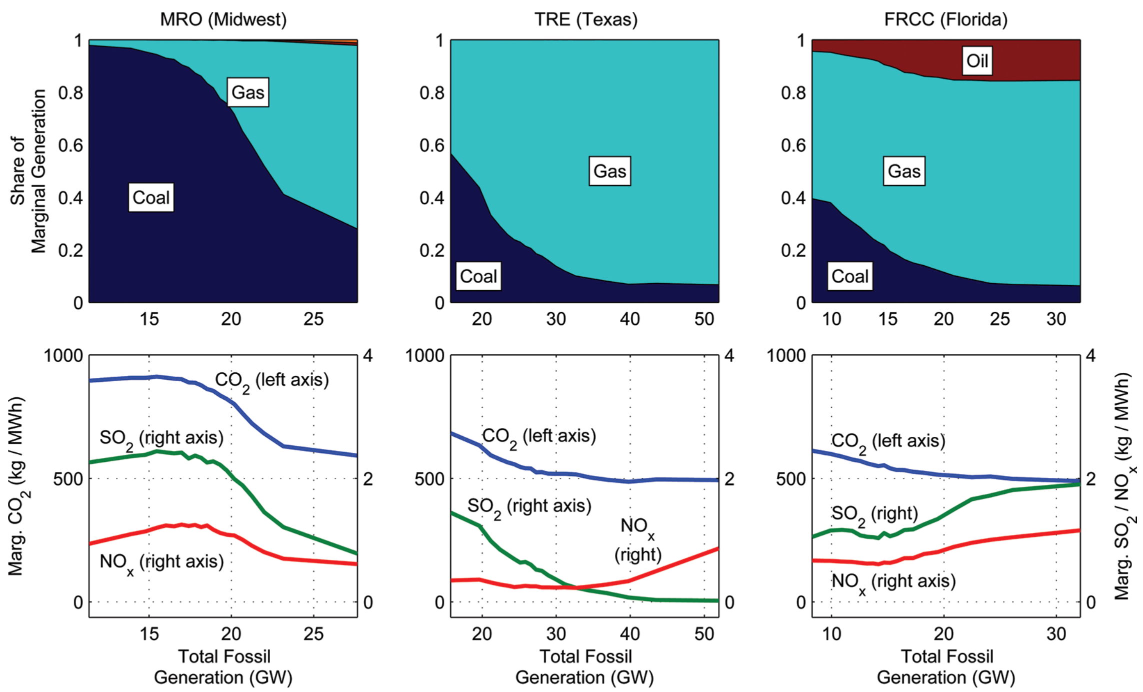

Figure 3. Share of marginal generation by fuel type (top) and MEFs (bottom) as a function of total fossil generation, a proxy for system demand. Results are based on data from 2006 through 2011, binned by every fifth percentile of total fossil generation. MEFs have two axes: the left axis applies to CO_2 and right axis applies to NO_x and SO_2.

(Mid-Atlantic) is expected to displace sixteen times more SO_2 than an equivalent measure in WECC (West). In several regions the R^2 values are quite low—11% in WECC, for example. This indicates that changes in demand are a very weak predictor of changes in SO_2 emissions, which is consistent with our finding that coal power plants—the primary source of SO_2—are rarely on the margin in WECC. In coal-heavy regions, such as MRO (Midwest), RFC (Mid-Atlantic), and SERC (Southeast), R^2 values range from 73% to 78%.

In most cases, marginal NO_x rates are shown separately for the summer ozone season (May 1−September 30) and the offseason (the remainder of the year). The majority of the eastern states have stricter NO_x regulations in the summer, affecting all NERC regions except TRE (Texas) and WECC (West). The effect of seasonal NO_x regulation is most pronounced in RFC (Mid-Atlantic), where the ozone-season MEF is approximately 35% lower than that of the off-season.

Overall, there are significant regional differences. Compared to WECC (West), displacing one megawatt-hour in MRO (Midwest) is expected to avoid roughly 70% more CO_2, 12 times more SO_2, and 3 times more NO_x emissions.

Comparison between Marginal and Average Emissions Factors. In both scholarly research and policy implementation, average emissions factors (AEFs) are commonly used to assess the avoided emissions resulting from an intervention, though it is widely acknowledged that MEFs are the more appropriate metric for such an analysis.[1,2,11,12,17]

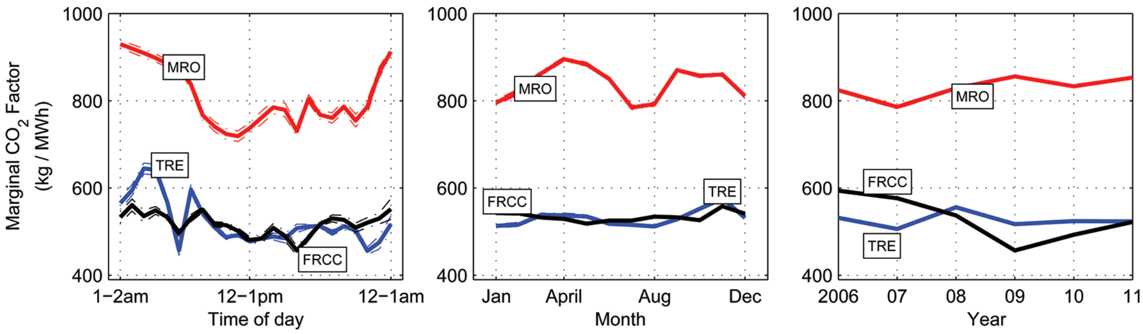

Figure 4. Temporal variations in marginal CO_2 factors for MRO (Midwest), TRE (Texas), and FRCC (Florida) based on data from 2006 through 2011. Dashed lines give the 95% confidence intervals, which are so narrow that they are not visible in most cases.

Table 2 shows a comparison between AEFs and MEFs by NERC region. AEFs are the annual emissions divided by the annual generation, based on 2007 data from the eGRID database.[14] For consistency, we also calculate MEFs based on only 2007 data.

AEFs are not consistently higher or lower than MEFs. Average CO_2 rates are 25% lower than marginal in NPCC (Northeast), where hydro and nuclear power significantly lower the average. In SPP (Southwest), large amounts of base-load coal increase the average CO_2 rate to 763 kg/MWh—35% higher than marginal. In the remaining six regions, average and marginal CO_2 rates are within 12%.

Average SO_2 emissions factors are, in some cases, much higher than marginal. In SPP (Southwest), WECC (West), and TRE (Texas), average SO_2 rates are more than 150% higher than marginal. This suggests that using AEFs may significantly overstate the avoided SO_2 resulting from an intervention. FRCC (Florida) is an exception, where marginal SO_2 rates are higher than average due to oil-fired plants operating on the margin, as discussed in the following section.

For regions affected by seasonal NO_x regulations, we report MEFs and AEFs for the summer ozone season, when NO_x emissions are of greater concern. In these cases, both average and marginal NO_x rates were calculated using data from May 1 through September 30, 2007. In seven of the eight regions, average and marginal NO_x rates are within 25%. In WECC (West), average NO_x rates are 160% higher than marginal.

Dispatch Order, Marginal Fuel Source, and MEFs. Figure 3 shows the share of marginal generation by fuel type (top) and MEF (bottom) according to the level of fossil generation, a proxy for system demand. We present results for three regions, discussed below. Results for the remaining regions are included in the SI.

MRO (Midwest). MRO is the most coal-heavy NERC region in the U.S. When demand is low, coal is the dominant marginal fuel, resulting in relatively high MEFs. At higher demand, MEFs fall as gas accounts for a larger share of marginal generation.

TRE (Texas). TRE is the most gas-heavy NERC region in the U.S., where gas-fired generators account for half of all electricity production, and coal accounts for a third. Overall, gas is the dominant marginal fuel source. When demand is low, coal accounts for roughly 60% of marginal generation, falling to roughly 7% at peak demand. As a result, marginal CO_2 and SO_2 rates fall as demand increases.

The marginal NO_x rate increases with demand. We attribute this to the use of older, dirtier gas turbines as peakers. This theory is supported by a comparison of NO_x rates from gas generators in TRE. We sort gas generators by capacity factor, with the assumption that peakers will have a low capacity factor. The average NO_x emissions rate of the bottom quartile (peakers) is six times higher than that of the top quartile (base-load gas generators).[14]

FRCC (Florida). Like TRE, electricity generation in FRCC is dominated by gas (47%) and coal (27%), so it is not surprising that marginal CO_2 rates are nearly identical in the two regions. However, FRCC is unique in that 9% of electricity is supplied from oil-fired generators. As demand increases, oil accounts for a larger share of marginal generation, causing an increase in marginal SO_2 rates.

Temporal Trends. Figure 4 shows temporal trends in marginal CO_2 factors for MRO (Midwest), TRE (Texas), and FRCC (Florida). Results for the remaining pollutants and regions are included in the SI.

Time of Day. In MRO (Midwest), marginal emissions rates are consistently higher during late-night and early-morning hours: the marginal CO_2 factor is approximately 30% higher at midnight compared to noon. In TRE (Texas), marginal CO_2 rates are highest in the early-morning hours. There is a notable drop at 7 a.m. (based on the delta between 7 and 8 a.m.). We attribute this to the morning ramp. On average, there is a 2000 MW increase in demand between 7 and 8 a.m., giving an average ramp rate of 33 MW/min. It is likely that gas-fired generators, which are more amenable to such ramp rates, are disproportionately on the margin during these times, resulting in lower marginal CO_2 factors. In FRCC (Florida), time-of-day differences are very minor. In the SI, we include time-of-day trends by season, which show that time-of-day differences are, in the majority of cases, most pronounced in the summer.

Monthly. In both TRE (Texas) and FRCC (Florida), monthly differences in marginal CO_2 factors are insignificant. In MRO (Midwest), marginal CO_2 rates are highest in spring and fall, when demand is low and coal is more often on the margin. Generally, marginal SO_2 factors have more pronounced temporal variations, particularly in coal-heavy regions (see SI).

Annual. From 2006 through 2011, marginal CO_2 rates have been relatively stable. In both TRE (Texas) and MRO (Midwest), the net difference between 2006 to 2011 is a few percent, and the maximum difference is less than 10%, which is consistent with the five regions not shown (see SI). FRCC (Florida) is the exception, with a 20% drop in the marginal CO_2 rate between 2006 and 2009. As shown in the SI, marginal SO_2 rates have dropped significantly (>45%) in FRCC (Florida), RFC (Mid-Atlantic), and SERC (Southeast). In five of the eight regions, marginal NO_x rates have dropped by more than 25% between 2006 and 2011.

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Application of MEFs. To illustrate an application of MEFs, we consider efficiency improvements in (1) a lighting system that operates from 8 a.m. to 5 p.m. Monday through Friday (e.g., interior lighting in an office) and (2) a lighting system that operates from 7 p.m. to 7 a.m. every day (e.g., exterior lighting). While it would be straightforward to use time-of-day MEFs to calculate the avoided emissions, the level of electrical demand better reflects the underlying operation of the system (generator dispatch). We calculate avoided emissions by determining the avoided energy in each hour of the year, then applying the appropriate MEF based on the level of demand at that hour (using total fossil generation as a proxy for demand; see Figure 3).

For each NERC region, we calculate the avoided CO_2, SO_2, and NO_x resulting from the two interventions. Results highlight three important points. First, there are significant regional differences in the avoided emissions resulting from the same intervention. Second, assessing the interventions using AEFs would, in some regions, grossly misestimate the avoided emissions. Third, surprisingly, the temporal differences between the two interventions have a modest impact on avoided emissions. Simply using the average MEF, thus ignoring temporal differences, is within 7% of the more detailed assessment for CO_2, 20% for NO_x, and 30% for SO_2 (see SI).

DISCUSSION AND CONCLUSIONS

The avoided emissions resulting from an intervention in the electricity system will depend on the generators that are displaced, which vary depending on the timing and location of the intervention. Marginal emissions factors give a consistent metric for assessing avoided emissions.

Lacking a database of MEFs, studies may revert to using system-average emissions factors, which can significantly misestimate the avoided emissions resulting from an intervention. AEFs may misestimate avoided CO_2 emissions by as much as 35% (in SPP), SO_2 by nearly 300% (in TRE), and NO_x emissions by more than 150% (in WECC).

On average, coal-fired generators emit more CO_2, NO_x, and SO_2 than other generators. As a result, displacing demand in coal-heavy regions will have greater emissions savings. Compared to WECC (West), avoiding one megawatt-hour of electricity in MRO (Midwest) is expected to avoid roughly 70% more CO_2, 12 times more SO_2, and 3 times more NO_x emissions.

Several regions show consistent temporal differences in marginal emissions factors. In coal-heavy regions, MEFs tend to be higher during the spring, fall, and late-night hours—when demand is low and coal is more often on the margin. Temporal differences in marginal CO_2 factors are modest, and using an average MEF is reasonable for most applications. When considering avoided NO_x and SO_2 emissions, analysts must weight the need for accuracy with the simplicity offered by average MEFs.

We note that existing set-aside programs for NO_x allowances err on the side of simplicity. These programs credit energy efficiency and renewable energy projects for avoiding NO_x emissions. Existing set-aside programs assume that 1 kg of NO_x is avoided for every megawatt-hour displaced.[17,18] By neglecting temporal and regional differences in avoided emissions, these policies risk incentivizing inefficient investments in renewable energy and energy efficiency.

From 2006 through 2011, marginal CO_2 rates have changed very little. Given the long life of the electricity infrastructure, it is likely that the marginal CO_2 factors presented here are reasonably valid for the next several years. Rapid changes in the generation fleet or new environmental regulations may warrant more frequent updates. In several regions, marginal SO_2 and NO_x rates have decreased substantially in the past six years. In such cases, practitioners should be cautious when applying MEFs to future scenarios. We recommend that a database of MEFs be maintained so as to facilitate effective policy and investment decisions. Independent System Operators (ISO) and Regional Transmissions Operators (RTO)—the entities responsible for dispatching generators—could greatly help by publishing MEFs for their respective areas. However, much of the U.S. is not covered by an ISO or RTO. Therefore, an agreed-upon method is needed to estimate MEFs consistently across the U.S. electricity system.

ASSOCIATED CONTENT

Supporting Information

Map of NERC regions and regional generation mix, details of plants omitted from CEMS data, comparison of marginal fuel estimates with published values from SPP, example application of MEFs, and full results by region. This material is available free of charge via the Internet at http://pubs.acs.org. A spreadsheet of all results is available from the corresponding author upon request.

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Notes

The authors declare no competing financial interest.

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