Energy Efficiency, Emissions, and Policy – Strengthening the Links

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ABSTRACT

The Wisconsin Focus on Energy evaluation team uses emission factors to calculate environmental impacts from Focus on Energy net energy savings. As part of the inputs to the Focus benefit-cost analysis, the evaluation team provides updated emissions factors based on the Environmental Protection Agency's Office of Air and Radiation "Acid Rain Hourly Emissions Data." In the FY07 emissions research we noted significant changes in the factor estimates for NOx, SOx, and CO_2 relative to an earlier analysis based on 2000 EPA data. To better understand these changes, the Focus team re-estimated emissions factors on five years of EPA data, spanning 2002 to 2006. These are reported here. We also report the effect on emission rates of three different definitions of plants that are on the margin. This concept identifies the source of emissions that would be avoided or displaced by energy efficiency programs. We find that emission rate estimates are quite sensitive to the definition. We propose a definition of marginal plant based on the length of time a unit remains on once it is called on, which we term the "use rate." We also report preliminary findings on trends in emission rates over five years.

Introduction

The Wisconsin Focus on Energy (Focus) evaluation team uses emission factors to calculate environmental impacts from Focus on Energy net energy savings. As part of the inputs to the Focus benefit-cost analysis, the evaluation team provides updated emissions factors based on the Environmental Protection Agency's Office of Air and Radiation "Acid Rain Hourly Emissions Data," which derives from actual stack monitoring. Appropriate allowance prices for displaced emissions are then used for the benefit-cost and economic impact analyses, including a forecast of future prices (2007–2026). Focus on Energy estimates an annual net electric savings in 2008 of 756 GWh from activities since 2001.

In the FY07 emissions research, using 2005 EPA data, we noted significant changes in the factor estimates for NOx, SOx and CO_2 relative to an earlier analysis based on 2000 data. Between 2000 and 2005 our estimates indicated that NO_X had fallen from 5.7 to 3.2 lbs/MWh and SOx had fallen from 12.2 to 4.8 lbs/MWh. The rate for CO_2, conversely, had risen from 2,216 to 2,480 lbs/MWh. Change as dramatic as this demanded further investigation. Was it real or an artifact of our estimation process? Was it, for instance, a result of how we defined marginal plants? If real, what caused the changes?

In late 2007, the Focus team began the process of re-estimating emissions factors, this time on five years of EPA data, spanning 2002 to 2006. As before, we looked at all generation within the two NERC regions serving Wisconsin: RFC (formerly MAIN) and MRO (formerly MAPP). It is not incidental to our current findings that we also altered the method we used to analyze the data. In past years we had used a statistics package, SPSS, to obtain estimates. The size of the databases (4 to 10 million records per year) made this tool rather cumbersome and provided too narrow a window onto the data—even more so when manipulating five years of reporting. This was compounded by the complexity of the EPA data structure, with emissions data spread across multiple records, for instance, with different reporting requirements for different types of plants. By importing data into a SQL database we gained clearer insight into the relationship between emissions reporting and load reporting, which has contributed significantly to our thinking about how to define marginal plants.

What we have found is that emission rate estimates are quite sensitive to the definition of what is a marginal plant. Driving this sensitivity, of course, is the way definitions affect the mix of coal burning and gas burning plants, and among gas plants the mix of combined cycle and gas turbine units. In the past we have used two different definitions. We now see significant problems with both of these and in this report will introduce two new ones. One of them we think is quite a good definition, given the data at our disposal, and we will use it to show trends in emission rates over time. But another key finding of our research is the more basic point that definitions of marginality are critical to the estimation of emissions factors.

We now think our earlier findings overstated the rate of change in emissions factors. Adopting a definition of marginal emission rate that better captures emissions of plants on the margin, we see more modest declines in NO_X and SO_X and no clear trend in CO_2.

The decreases in emissions we do see result from the substitution of gas-fired load for coal-fired load at the margins. We no longer see clear evidence that cleaner coal generation is contributing significantly to the reduction in emissions, with the modest exception of NO_X emissions where there does seem to be a slight downward trend in rates for coal.

Method

Using EPA Acid Rain Hourly Emissions Data

In many ways, the EPA's "Acid Rain Hourly Emissions Data" series is ideal for estimating emission rates. It comes as close as any source available to being comprehensive of all emitting plants. Moreover, it would be hard to imagine a less aggregated set of data, amenable to many different forms of analysis. The data can be used to estimate emission rates for a single plant, or all plants of a particular owner, or for any regional division within the US. The EPA data include hourly measurement not only of emissions but also of load and heat rate and other critical components of the emission rate estimate, and include information about fuel types and facility technology. Much of this data derives directly from continuous emissions monitoring (CEM) systems, though a subset is estimated from other parameters. Where unit information (other than load or emissions) is missing data can be supplemented by merging with EIA data. We use EIA data, for instance, to associate the appropriate NERC region to each unit.

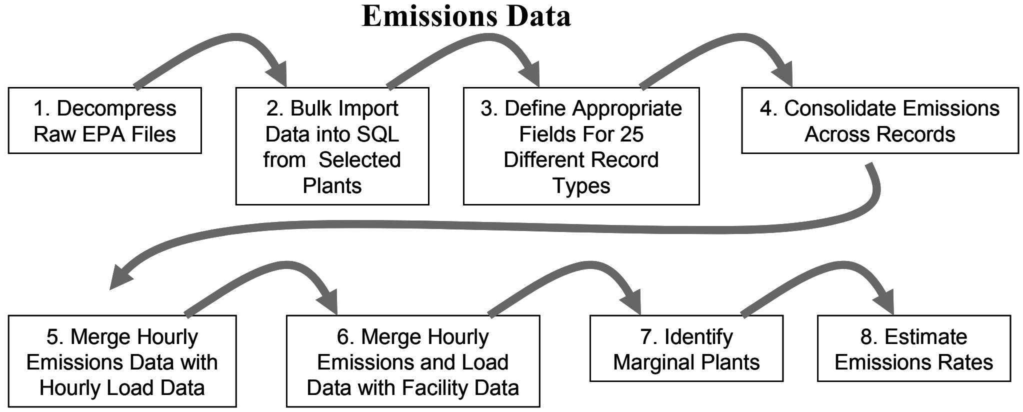
The data do not include generation from non-emitting plants. For the purposes of estimating program effects, however, this is not a problem because non-emitting load—at least to date—primarily originates from hydro-electric and nuclear sources and these are "always on" energy sources, never on the margin.

The EPA Hourly data also do not include emissions from Canadian sources, which are encompassed by some NERC regions. We have not yet addressed this issue in our research but we expect the effect on emission rates to be minimal because of the prevalence of hydro and nuclear generation in Canada and because of the small percentage of total load that originates there.

The two main impediments to using the EPA hourly data are the size of the datasets and their complexity. The research reported here, for instance--including only two NERC regions (RFC and MRO) and five years of records--currently occupies about 40 gigabytes of memory on our SQL server. The main data table for just the year 2006 has approximately 8 million rows, supported by another 15 million rows in related tables. The size of the datasets compounds difficulties inherent in a complex reporting structure. Data are reported on 91 different record types. Moreover, regulations for reporting differ depending on the circumstances of the generator, so reports for a single emission type must be consolidated from several records, care being given to render the reporting units comparable. For instance, some plants report NO_X on Record 320 in pounds per million Btus. Oil and gas burning plants have an option of reporting on Record 323. Plants that mix fuels report on Records 324, 325, and 328 in pounds per hour. Plants that have low emissions certification report NO_X on Record 360, again in pounds per hour. A small number of plants report CO_2 data only on a daily basis. Because they report an hourly heat rate, however, we can estimate an hourly rate by apportioning the daily emissions on that basis.

Figure 1 gives a high-level perspective on our method for estimating emission rates from EPA Hourly data.

Figure 1. High-Level Procedure for Estimating Emission rates from EPA Acid Rain Hourly Emissions Data



Alignment with WRI Guidelines

PA has been working to align our emission rate estimation method with the Greenhouse Gas Protocol of the World Resources Institute (WRI). Although we report on emissions other than greenhouse gasses, we consider these protocols fully applicable to them as well. In the Fall of 2007, the WRI published its “Guidelines for quantifying GHG Reductions from Grid-Connected Electricity Projects” (“the Guidelines”). This is its most recent effort to standardize measurements of the type we are undertaking with this research. Although an extended discussion of how our effort aligns with the WRI guidelines is beyond our current scope, we do want to highlight our position relative to four of the critical elements.

Building margin vs. operating margin emission factors (Guidelines section 5.1).

The Guidelines divide emissions impacts into those affecting the “Building Margin” (BM), which result in delayed construction of generating capacity, and those affecting the

"Operating Margin" (OM), which result in a reduced use of existing generating capacity. They stipulate that a base emission rate may be composed of both elements, and that impacts should be distributed in a methodical way. Insofar as either the grid affected by a program has excess capacity or the programs are not themselves a source of capacity, the weight given to BM should be 0. If the grid has chronic under-capacity, or if the programs are not a source of capacity, the BM should be factored into the emission rate.

In our research we have ignored BM in our estimate of emissions factors. This decision would appear to be generally justified by the fact that capacity in both grids serving the Focus territory have adequate supply, at least through 2010 (MRO reserve margin is approximately 15%, RFC reserve margin is about 20%) and that the majority of programs are consumption reduction programs rather than capacity generation programs. We may need to revisit this assumption in future years.

Defining the geographic area (Guidelines section 7.3.1)

The Guidelines recommend that in most cases, the extent of the electrical transmission and distribution grid where the project is situated is the proper geographic area for estimating effects. The logic is, of course, that avoided emissions in Wisconsin may be spread variously across the whole grid serving that state. Consistent with this view, we have used the NERC regions that encompass Wisconsin (MRO (MAPP), RFC (MAIN)) as the relevant grid.

In 2007 we attempted to refine the effect of geography on our estimate. We calculated separate emission factors for Wisconsin generation and for non-Wisconsin generation in the MAIN and MRO regions, then weighted emissions by each region's net contribution to Wisconsin consumption. This did have a significant effect on emission rates relative to the un-weighted estimate, reducing NO_X and SO_X by roughly 10% and CO_2 by about 2%. Geographic weighting is not consistent with the Guidelines, however, and we no longer believe it is appropriate. Even on days when demand peaks within Wisconsin, Wisconsin-based generators are both exporting and importing energy. Thus, the grid is the most appropriate region for estimating effects.

Using NERC regions to define the grid does complicate the comparison of emission rates from one year to the next because the boundaries of NERC regions have shifted several times in the past five years. On January 1, 2005, the Midwest Reliability Organization (MRO) replaced MAPP as the NERC council. Likewise, beginning in 2006, the Reliability First Corporation (RFC) replaced MAIN as the NERC council that serves the southeast corner of Wisconsin, which includes Milwaukee. Each of these changes has brought a new set of region boundaries and a different set of plants that constitutes the Wisconsin grid. For instance, the MAIN region encompassed southern Wisconsin, most of Illinois, and parts of Missouri. Its replacement, the RFC, covers much less of Illinois, none of Missouri, but extends eastward to include Michigan, Indiana, Ohio, Pennsylvania, West Virginia, Maryland, Delaware, New Jersey and parts of North Carolina and Kentucky. We consistently use the NERC region boundaries to define the relevant grid so when they change the set of emitting units changes as well. Thus, changes in emissions over time include operational changes at individual plants, plant commissioning and decommissioning, and changes resulting form NERC region boundary changes.

Ex ante or ex post emission factors (Guidelines section 10.2)

The Guidelines distinguish between *ex ante* and *ex post* estimation of emissions factors. *Ex ante* factors are calculated at the beginning of a program and applied for the duration of the program. *Ex post* factors are more dynamic in that they are recalculated on an ongoing basis during the program. The Guidelines give clear preference to ex post emissions factor estimates where they can be obtained and in particular when grid conditions are changing from year to year.

That the Focus team is conducting its third estimation of emissions factors in four years is clear indication that we are moving to an *ex post* calculation of emissions factors. It is one of the important byproducts of our research that we are quantifying the extent to which grid conditions are, indeed, changing annually.

Operating margin calculation method (Guidelines section 10.4.5)

The Guidelines identify four different methods for estimating emissions factors at the operating margin. In the order of increasing precision and stringency, and including the data requirements of each, they are:

Method 1 -- Averaging annual emissions for load following plants (*Guidelines 10.4.2)*
- Total annual generation
- Total annual emissions
- List of base, must-run, and intermittent plants OR
- Total consumption by fuel type

Method 2 -- Weighted average by resource type on the margin at specific time periods (*Guidelines 10.4.3)*
- Total demand by hour for specific time periods
- Total generation by fuel type for specific time periods
- Total emissions by fuel type for specific time periods

Method 3 -- Historical data to calculate marginal emission rates by hour (*Guidelines 10.4.2)*
- Total generation by hour for each plant on the grid
- Total emissions by hour for each plant on the grid
- The system dispatch order

Method 4 -- Dispatch modeling to calculate marginal emission rates by hour (*Guidelines 10.4.2)*
- Dependent on model

We believe our current approach is at least at the level of Method 3: we use load data to identify set of plants that are at the margin in any given hour of the day. We do not use external data on the system dispatch order, however; instead, we model the order from actual plant performance. In this sense our approach may be closer to Method 4. We devote the following section to this critical question of identifying emissions at the margin.

Identifying Marginal Plants

In 2004, emissions factors for NO_X, SO_X, and CO_2 were based on the mass of emissions per hour, per MWh of generation for all plants within the MAPP (now MRO) and MAIN (now

RFC) transmission regions in 2000.[1] Emission factors were calculated on marginal plants only, averaged over the NERC regions that supply Wisconsin. We defined the marginal plant for any hour as the single plant with the most change in MWh since the previous hour. The logic, of course, is that there can only be one plant actually *on the margin* at any given time, and that it must be the one moving the most. The relevant pool was considered to be among plants increasing their load when the total system load was increasing, or decreasing their load when the total system load was decreasing—i.e. plants that are "following the load." Load change from the previous hour was introduced not as an absolute difference but relative to each plant's capacity. This has the effect of neutralizing size differences between base load and peaking plants.

In 2007 we replicated the prior work—which we will refer to as the *single greatest mover* definition--but also introduced estimates based on a new definition of a marginal plant. We had come to the view that defining as marginal the single plant with the largest change in energy production--up or down depending on total system load--was too broad. It included as marginal a large number of plants that were already reducing output during the hour, violating the notion that energy savings implies production foregone. Indeed, many of the large downward movers were apparently in the process of shutting down altogether because their load became zero during the hour in question or during the subsequent hour. On the other hand, in any hour there would seem to be multiple plants that would be candidates for reducing output under reduced consumption. EPA emissions data are hourly. Though this is an excellent level of granularity, it is still the case that multiple plants come on line and go off line during a measurement period. Given the complex set of factors that guide the dispatch process, we cannot be sure it would always be the largest mover that would not have been turned on in the presence of program savings.

Thus, in 2007 we developed a definition of marginality based on units that had large increases in output in a given hour, whether or not other plants also had large increases during that hour. Increase was again defined as a percentage of each unit's annual maximum. To identify what constitutes a *large* increase, we examined the entire distribution of movement and selected the 99th percentile as the critical value. Marginal units were defined as those at or above the 99th percentile. The top 1 percentile of movement was represented by an increase in output from the previous hour of 19% of the annual maximum output. Thus, for example, a unit that had a maximum hourly output of 100 MW during 2005 would be a marginal unit in any hour where its output increased by 19 MW. We will refer to this as the *99th percentile mover* definition.

Table 1 presents a comparison of emissions factors we estimated in previous years, based on 2000 and 2005 EPA data. Over this period, according to our analysis, coal-fired generation dropped from 97% to 87% of total Wisconsin generation, and that simultaneously coal emission rates had declined. The 99th percentile approach reduced the emission rate estimates for all types of emission.

[1] We also report on Hg emissions; however, this part of the analysis has not been completed in time for the current report.

Table 1. 2000 and 2005 Emission Rate Estimates

		Pounds / MWh		
Year	**Definition of Marginal Unit**	**NOx**	**SOx**	**CO_2**
2000	Single Greatest Mover	5.7	12.2	2,216
2005	Single Greatest Mover	3.2	4.8	2,480
	99^{th} Percentile Gainer	2.2	4.1	1,734

Sources: Wisconsin Department of Administration, Focus on Energy Public Benefits Evaluation (2004); Wisconsin Department of Administration, Focus on Energy Public Benefits Evaluation (2007)

Moving the data into a SQL database has allowed us to look carefully, hour by hour, at the composition of marginal plants. In so doing we confirmed our previous concern that the single greatest mover approach included plants that clearly are base load units coming off-line for reasons having nothing to do with demand. Often a sister unit at the same plant is powering up at the same time the single greatest mover is coming down. Also, we identified a small set of plants that had very low loads but continued to report high emissions in the hour. This creates a set of low-load emission rates that are hundreds or even thousands of times higher than the average. Overall, the complexity of factors that render a given plant the single greatest mover in any hour inserts too much random variance into the data. An approach that averages a set of candidates for avoided load will provide a more stable estimate.

The *99^{th} percentile gainer* approach to identifying marginal plants has the benefit of evening out some of the random variance by averaging the emission rates of multiple plants in a given hour. However, we have realized that as many as half the hours in the year do not have any plants in the 99^{th} percentile of load gainers, so there essentially are no marginal plants in those hours. Since programs could be displacing load in those hours there is a disconnection between the estimate of emission rate and the effect of programs. This could be changed by lowering the movement threshold below the 99^{th} percentile; but that immediately highlights the problem that any threshold is somewhat arbitrary. Secondly, with more years of data we can now see that the 99^{th} percentile changes significantly from year to year. For instance, in 2002 a plant had to increase load by 28% of its maximum to fall into the 99^{th} percentile. By 2006 that cutoff was 40% of maximum load.[2]

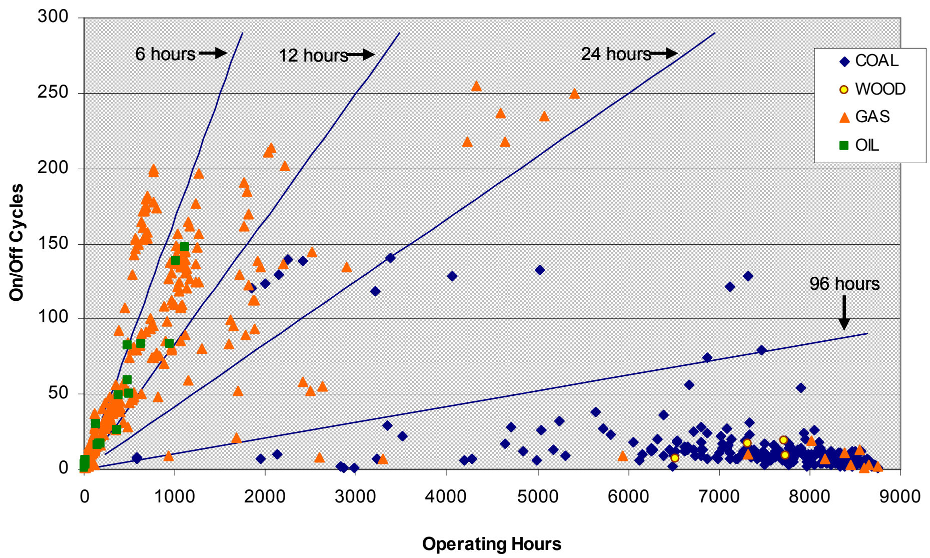
A problem that pertains to both of our previous approaches is that movement is defined relative to the size of the plant. This improves the representation of peaking plants in the marginal group but only by introducing a consideration that is at best an indirect indicator of the likely dispatch order. We have no clear theoretical argument to support this approach to calculating hourly movement.

The Guidelines are expansive on the point that marginal plants are identified by the dispatch order, i.e. the order of priority for turning plants on and off as load changes. In our current approach we model the dispatch order using data available in the EPA dataset. We calculate for each plant an average amount of time it tends to *stay* on once it is called on-line. The total number of hours a plant operates per year, divided by the number of on/off cycles, gives this information. We refer to this as the *use-rate* of a plant. We note that use-rates tend to fall into distinct patterns, with one group of plants coming on for about 5 hours, another set for

[2] We have not done extensive analysis to explain this change since we are currently recommending a new definition of marginal plant. We believe the increasing threshold is the result of new peak supply coming on-line that ramps up and down faster in response to demand.

about 9 hours, a smaller group coming on for roughly 18 hours, and a large group coming on for hundreds or thousands of hours. Figure 2 shows a plot of on/off cycles and operating hours for the year 2005, and shows a demarcation for use-rates of 6, 12, 24, and 96 hours. We have used these use-rates to bound five groups of plants.

Figure 2. Plant On/Off Cycles and Annual Operating Hours by Fuel Type for 2005



Source: EPA

Plants in the less-than-6 hour category are peaking plants. Plants in the more-than-96 hour category are base load plants. In between are plants with intermediate characteristics: the shorter the average use-rate the more sensitive to demand.

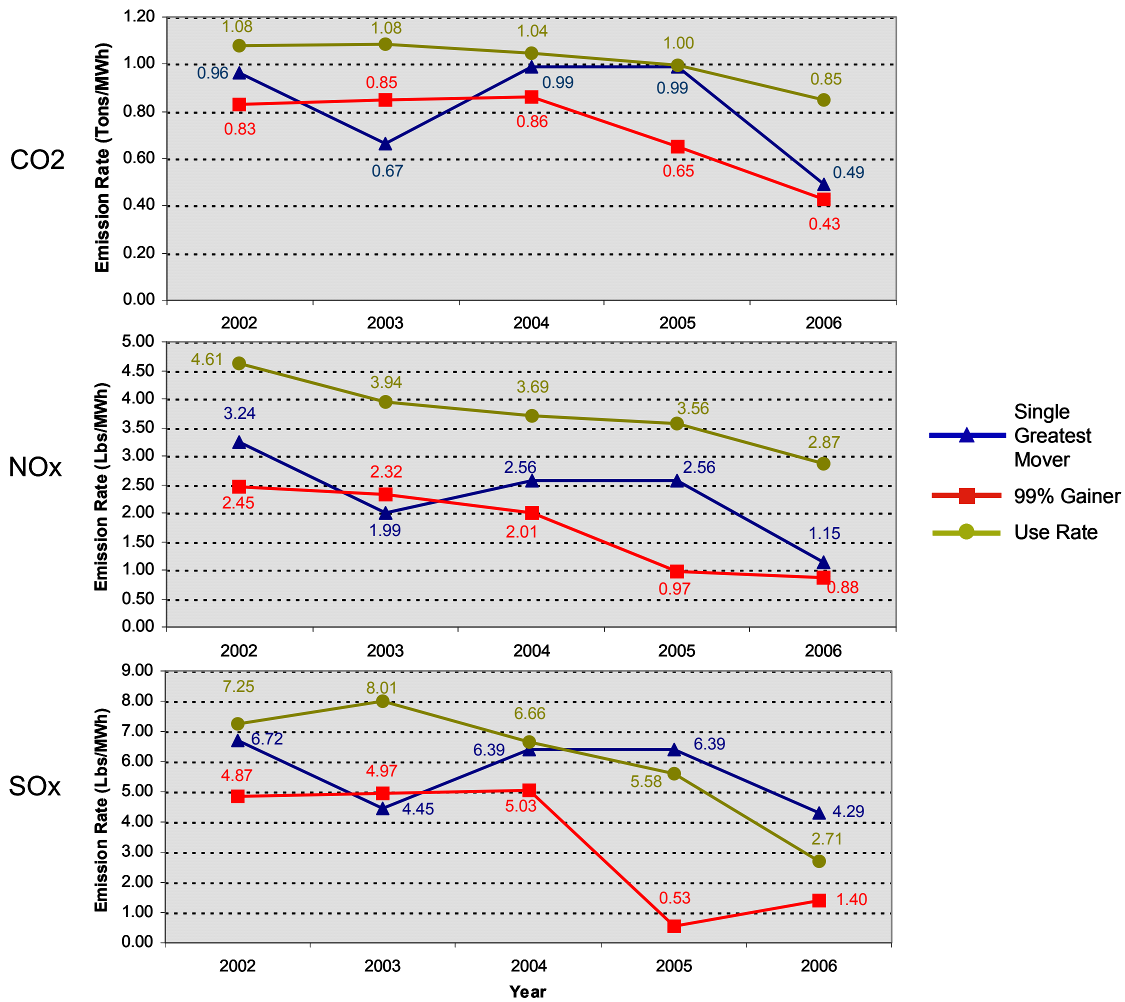
Following this logic, we define marginal emissions as those produced by the set of plants in the lowest use-rate group that is operating in each hour, in each NERC region. So, at peak times in the mid-summer the marginal emission rate is defined by the shortest cycling plants, which tend to remain on about 5 hours once they are called up. In mid-winter in the middle of the night, the marginal emission rate is defined by what are essentially base load plants—because these are the only plants in operation. We eliminate from the estimate plants that are generating less than 1 MW because these typically are shutting down in the hour and are subject to low-load emissions problems, mentioned above. We average emission rates across all marginal plants in each hour, and then average across hours of the year, to get an annual average.

One refinement on this approach that we will pursue in future research is the identification of plants that are called up for reliability reasons rather than to meet demand changes. Currently we do not discriminate between the two uses. We will explore the idea that plants with short use rates and few total hours in a year are likely candidates for plants called on for system reliability, and this should not factor into the emission rate estimates.

Findings

Figure 3 shows the annual emission of CO_2, NO_X and SO_X for marginal plants in the years 2002 – 2006, estimated in three different ways. We initially posed the question whether the changes we had seen last year were real or an artifact of the estimation procedure. It now seem clear that our estimation procedure—and in particular our definition of the margin—did indeed play a role in our previous findings. The three different methods we use have created rather different pictures of emission rates.

Figure 3. Emission Rates under Three Definitions of Marginal Plant, 2002 to 2006



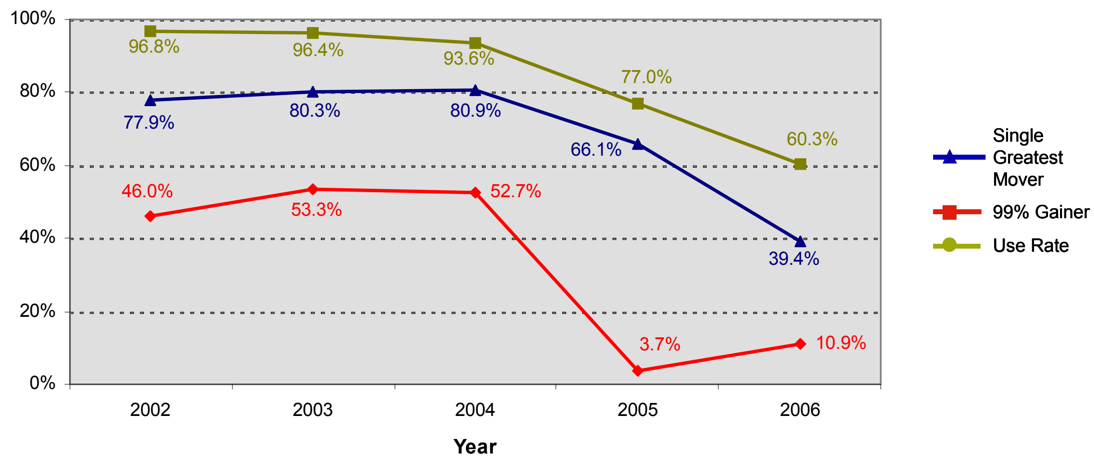
Source: EPA

We note in particular that the single marginal unit approach moves against the trend of the other two, and makes an off trend reversal of direction, lending support our concern about whether this definition yields stable results. The 99th percentile and use rate approaches move together for CO_2 and NO_X, though the rates are consistently higher for the use rate approach. For SO_X, however, the consistency of pattern disappears, with the 99th percentile rates holding steady over three years, then dropping steeply. The use rate approach again shows a steady decline.

Emission Rate Drivers

It is no surprise that the most important driver of these differences in the emission rate is the difference in the ratio of coal and gas-fired plants. (Oil and wood together make up less than 1% of the load under all definitions of marginal plant.) Coal, overall, is a much dirtier fuel than gas, especially with respect to SO_X. In our sample, for instance, for total emissions coal averages 10.29 lbs. SOX per MWh, while gas averages 3.26 lbs. It is interesting to observe, however, how the different definitions of marginal plant capture different ratios. Figure 4 shows the proportion of coal-fired load in each year's estimate of the emission rate. The percentage of coal is essentially steady from 2002 to 2003 and then begins to decline. The steep decline we saw in SO_X between 2004 and 2005 under the 99% gainers definition is easily explained by the big drop in coal-fired load.

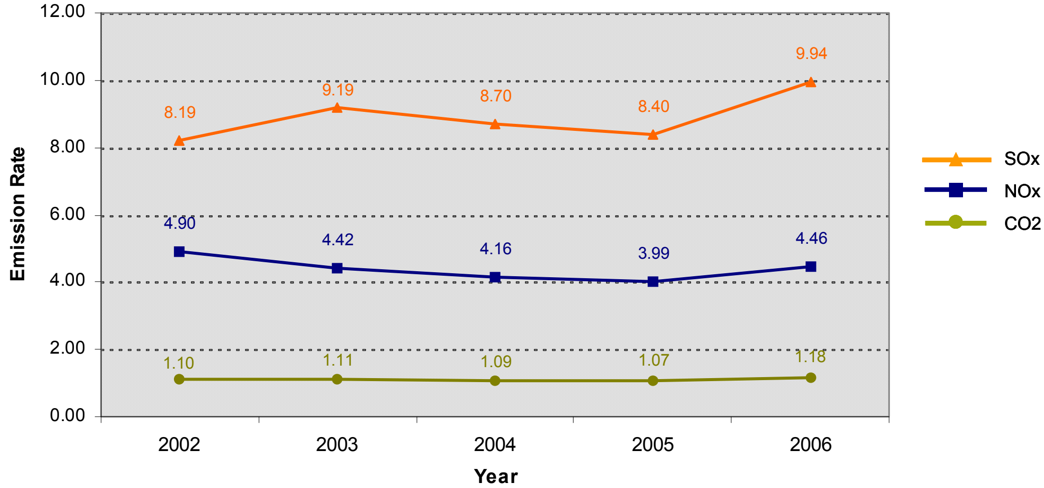
Figure 4. Percentage of Marginal Load Deriving from Coal Fuel Under Three Definitions of Marginal Plant, 2002 to 2006



Source: EPA

In the past we have argued there is a second reason for the declining emission rates: cleaner burning coal plants. Our current research raises doubt about whether this is the case. Figure 5 indicates that the CO_2 emission rate actually increases between 2005 and 2006, most likely resulting from the changing definition of the grid. The rates for NO_X and SO_X show little in the way of a trend. This analysis uses the use-rate definition of the margin.

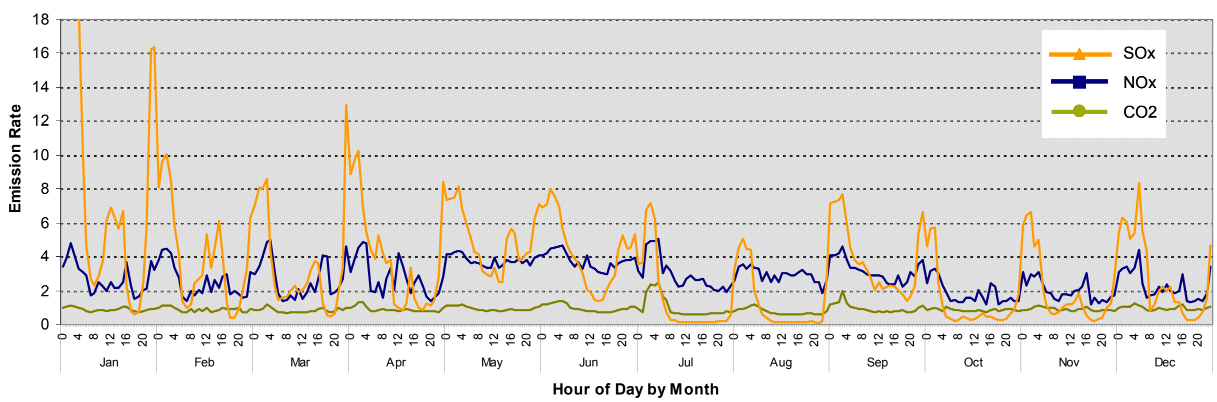
Figure 5. Emission Rates from Coal Fueled Plants on the Margin, 2002 to 2006



Note: CO2 emissions expressed in tons per MWH; NOX and SOX expressed in pounds per MWH. Source: EPA

Because the mix of fuels plays such an important role in the emission rate, the emission rate moves inversely to demand. When demand is high, relatively clean gas burning plants are at the margin; when demand is low the dirtier coal plants are at the margin. Figure 6 represents the emission rate in 2005 by hour of the day and by month of the year for CO_2, NO_X, and SO_X. We believe this graphic shows very clearly the need to assess program impacts not only on a seasonal or monthly basis but, indeed, on an hourly basis. The EPA Acid Rain data make this feasible.

Figure 6. Emission Rate by Hour of the Day and Month for Marginal Plants, 2006



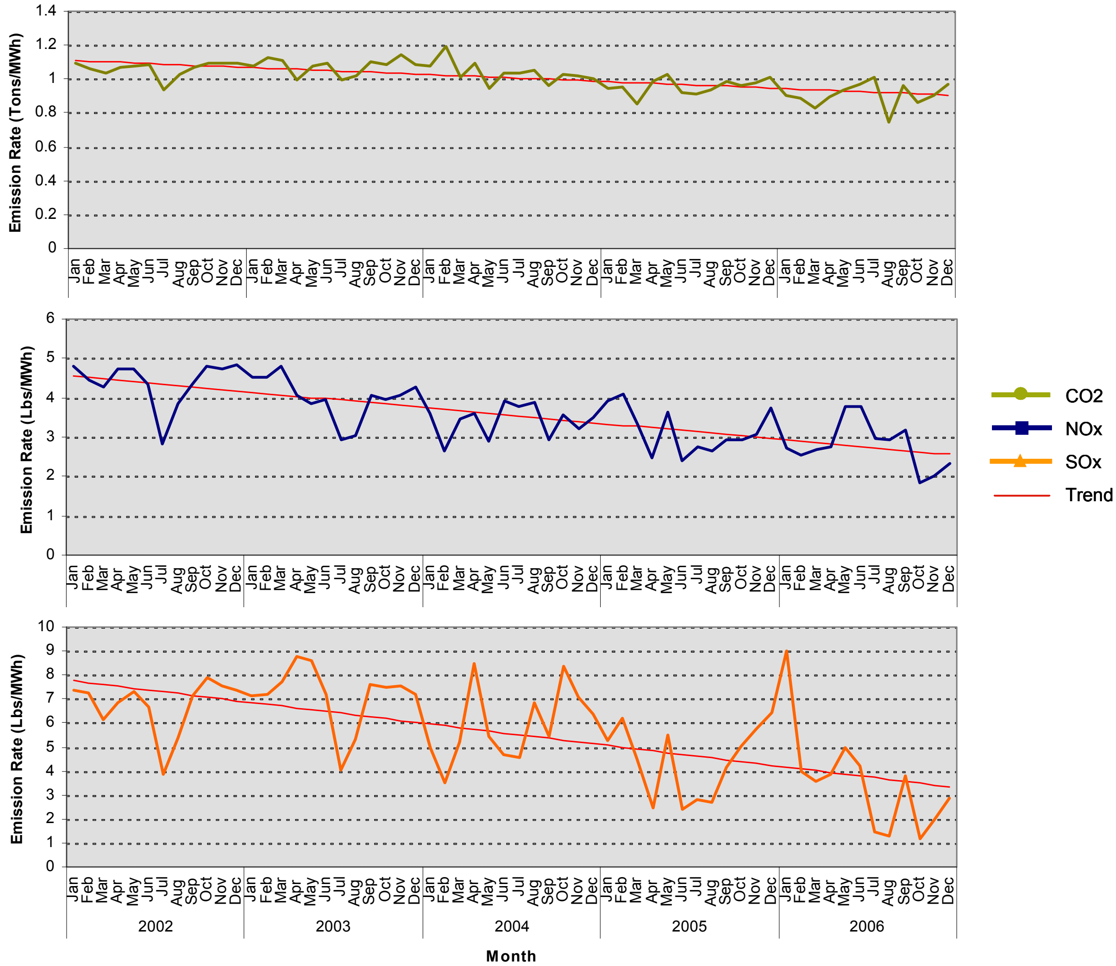
Note: CO2 emissions expressed in tons per MWH; NOX and SOX expressed in pounds per MWH. Source: EPA

Emission Rate Trends

Another key tenet of the WRI guidelines is that emission rate estimates are best done on an ongoing basis because they change over time. Our research strongly underscores this point. Between 2002 and 2005 there has been a downward trend in all three emissions we are observing. Figure 7 shows the emission rate and trends for CO_2, NO_X, and SO_X from 2002 to

2006. During our study period the emission rate for CO_2 declined at an average rate of about 7 pounds per month per MWh. NO_X declined at a rate of about 0.03 pounds per month and SO_X declined at a rate of about 0.07 pounds per month. The EPA Acid Rain data series provides an excellent source for recalculating emission rate estimates on an annual basis.

Figure 7. Emission Rate Trends by Month, 2002 to 2006



Source: EPA

Discussion and Recommendations

As regulators, program implementers, and program evaluators struggle to make an accurate assessment of the effects of energy efficiency programs on the environment, the quantification and attribution of emissions from power plants that have been either avoided or displaced will be at the forefront of issues. This is even more the case given current concerns about greenhouse gases and debate about the role energy efficiency can play in their reduction. An estimation of annual emission rate averages will continue to provide a benchmark for progress over time; but the assignment of avoided emissions to programs will necessarily move to a much finer-grained analysis, down to hour-by-hour impacts. The EPA's Acid Rain Hourly Emissions Data series is a valuable tool for moving in this direction.

As our research shows, however, a degree of consensus will be needed on the best way to identify the operating margin because different definitions yield quite different rates. We believe our current approach—averaging emission rates for each hour across the units with the shortest operating cycle--is supported both conceptually and by the data. It is, of course, still only an approximation and as we've noted there is room for refinement. That may be accomplished either within the data available from the EPA or by supplementing it from other sources.

In any case, finer granularity in the estimate of the emission rates will combine well with an effort to attribute energy program savings to specific hours of the day. In combination the two will increase the accuracy of environmental impacts evaluation.

Based on our research we draw the following conclusions about emission rate calculations.

- We agree with WRI Guidelines that stipulate emission rate estimates should be based on marginal generation on the operating grid.
- Identifying marginal plants using the *use-rate* definition provides a good estimate of the dispatch order and is more defensible than either the *single largest mover* or *99th percentile gainer* approaches.
- Variations in emission rates over time indicate the need to target program effects to specific hours of the year
- Emission rate trends suggest the need to recalculate emission rates on a periodic basis.
- The EPA Acid Rain Hourly Emissions dataset is the best generally available resource for making emission rate estimates using the approach we have adopted.

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