PA Consulting Group

State of Wisconsin Public Service Commission of Wisconsin

Focus on Energy Evaluation

Quantifying Environmental Benefits of Focus on Energy: Emission-rate Estimates 2002 to 2006

Final Report: October 28, 2008

Evaluation Contractor: PA Consulting Group

Prepared by: Eric Rambo, Bryan Ward, and David Sumi
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ABSTRACT

This report updates ongoing work by the Focus on Energy (Focus) evaluation team to estimate emission factors for electric generation affected by Focus programs. It informs the Focus overall benefit-cost analysis and the periodic quantification of displaced power plant emissions associated with Focus energy impacts (in the Focus evaluation's Semiannual Reports). In this report we compare our approach to the recent World Resources Institute "Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects," with special attention to the identification of plants operating on the margin of system supply. We discuss an approach that uses the average duration of operation of each generating unit to identify the dispatch order and thus plants operating on the margin. We use data from 2002 to 2006 from the Environmental Protection Agency's (EPA) "Acid Rain Hourly Emissions" data series to estimate an emission rate for CO_2, NO_X, and SO_X for all monitored utilities serving on the grid that serves Wisconsin. We find that emission rates for all pollutants have declined over the study period. We trace this decline to the decreasing use of coal generation at the margin. We then look specifically at Wisconsin investor-owned utilities (IOUs) and see systematic reductions in emission rates for MG&E and a more complex picture for other utilities.

NOTE: This report version does not include reporting of estimated emission rates for mercury (included in our past reports).We will submit an addendum to this report including mercury emission rates.

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1. EXECUTIVE SUMMARY

This report updates ongoing work by the Wisconsin Focus on Energy (Focus) evaluation team to estimate emission factors for electric generation affected by Focus programs. It is part of the Focus overall benefit-cost analysis.

The Focus evaluation team uses emission factors to estimate environmental impacts from Focus on Energy net energy savings, in the form of displaced power plant emissions. Emission factors are used to accomplish basic conversions between energy inputs (i.e., fuels used to generate electricity) and generation of gases (e.g., NO_X, CO_2, and SO_2). We also strive to base our emission-factor calculations on generation data specific to the geography of the Focus energy efficiency programs. In addition, emission factors for Focus are estimated based on specific marginal generating plant(s), adding critical realism to the quantifications.[1]

As part of the inputs to the Focus benefit-cost analysis, the evaluation team provides updated emission factors based on the Environmental Protection Agency's (EPA) 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 Fiscal Year 2007 (FY07) emissions research, using 2005 EPA data, we noted significant changes in the factor estimates for NO_X, SO_X, 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 SO_X 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? In particular we wanted to know whether it was a result of how we defined marginal plants. If real, what caused the changes?

NOTE: This draft report version does not include reporting of estimated emission rates for mercury (included in our past reports). We will submit an addendum to this report including mercury emission rates.

The Focus team has re-estimated emission factors on five years of EPA data, spanning from 2002 to 2006. As before, we estimated the emission rate for all plants serving the grid that provides electricity to Wisconsin consumers. We define this grid by the two North American Reliability Corporation (NERC) reliability regions that cover the state: the Midwest Reliability Organization (MRO; prior to 2005 MAPP) and the Reliability First Corporation (RFC; prior to 2006 MAIN).

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[1] Using ***marginal*** emission factors will produce much more accurate estimates of emissions reductions than applying ***average*** rates taken from published data. This approach is also more accurate than one which relates avoided generation and emissions to a specific type of ***new*** power plant, since new capacity is often not dispatched as a marginal source.

For the current effort, however, we have adopted a new definition of emissions from generating units on the margin. In the past we have defined marginal generation as coming from either:

- The single unit in any hour with the greatest change in load from the previous hour, relative to the unit's maximum load, where that change is in the direction of the grid as a whole, up or down (referred to in this report as the "single greatest mover" approach), or
- The set of plants that are increasing their load relative to their maximum load, by an amount that puts them in the top one percent of hourly change for the year (referred to in this report as the "99 percent gainers" approach).

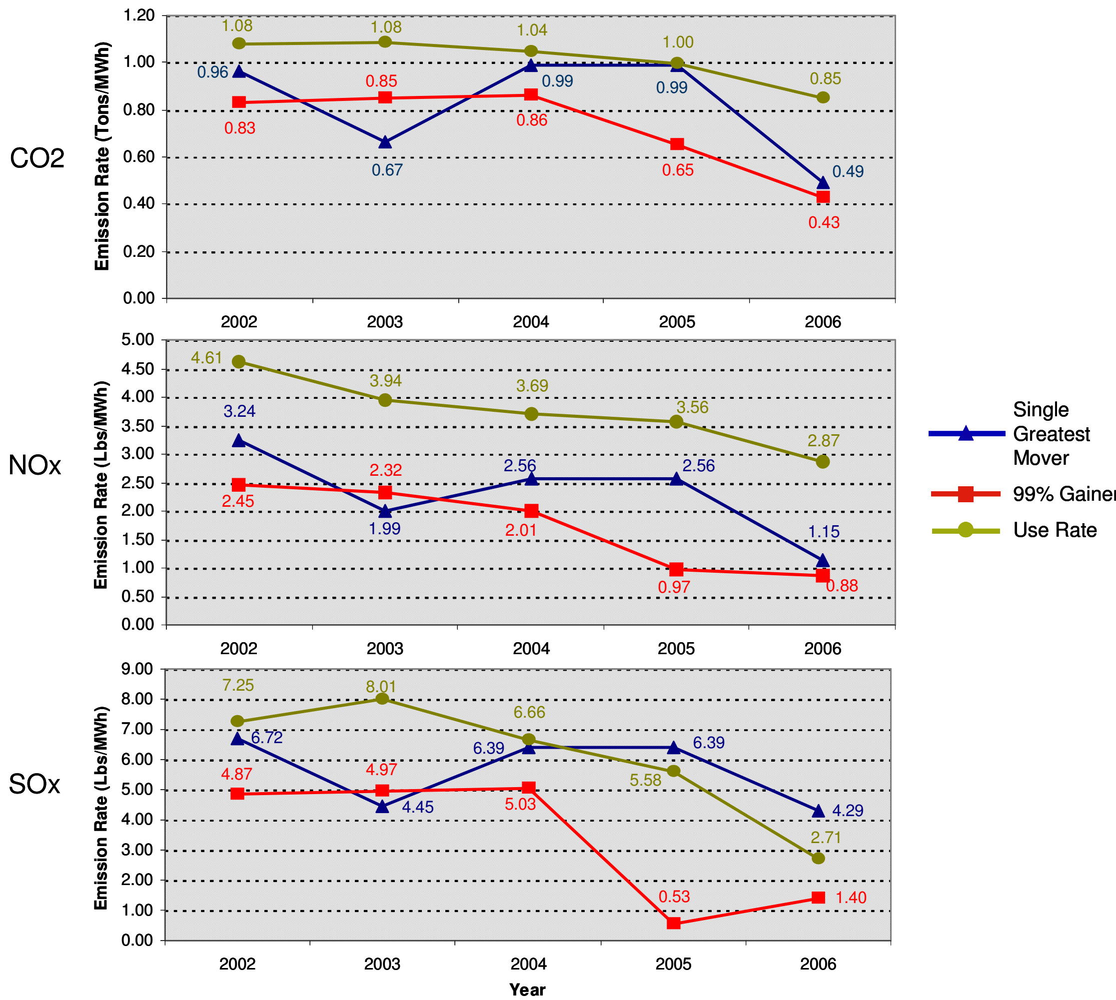
While both of those are reasonable approaches, each has its shortcomings. The single greatest mover approach is unstable because there are reasons other than demand changes that cause plants to increase or decrease load dramatically in an hour. The 99 percent gainers approach smoothes out some of this instability by averaging over several units; however the 99th percentile is an arbitrary cut-off and there are significant numbers of hours where there are no marginal plants under this definition.

We have now developed the concept of "use-rate" to identify marginal plants. Use-rate is the average length of time a generating unit remains on once it is brought online. Thus, peaking units, which are brought on for only a short time, have a low use-rate; base-load plants that remain on for hundreds of hours or more have a high use-rate. We define marginal emissions as those produced by the set of generating units in the lowest use-rate group that is operating in each hour, in each NERC region.

Another change from previous emissions estimates is the way we treat Wisconsin plants in the analysis. In FY07 we weighted emission factors to reflect in-state versus out-of-state generation. We no longer think this is appropriate. The Focus team has been working to align our emission rate estimation method with recommendations of the Greenhouse Gas Protocol Initiative. This protocol, developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD), has become the most broadly accepted accounting tool for understanding, quantifying, and managing greenhouse gas emissions. In July of 2007, the Greenhouse Gas Protocol Initiative published its "Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects" ("the Guidelines"). It is clearly stated in this protocol that the proper geographic region for estimating avoided emissions is the electrical grid. For this year we do not introduce any weights to the analysis relative to where generation is occurring.

We have found that emission rate estimates are quite sensitive to the definition of what is a marginal plant. Compared to our current approach, the FY07 findings overstated the rate of change in emission factors. Figure 1-1 compares marginal emission rates for the three definitions.

Figure 1-1. Emission Rates Under Three Definitions of Marginal Plant, 2002–2006



Source: EPA

Adopting a definition that we believe best captures the operating margin, we see more modest declines in CO_2, NO_X, and SO_X than we saw in our previous estimates. Table 1-1 shows our current estimates of emission factors for 2002 to 2006.

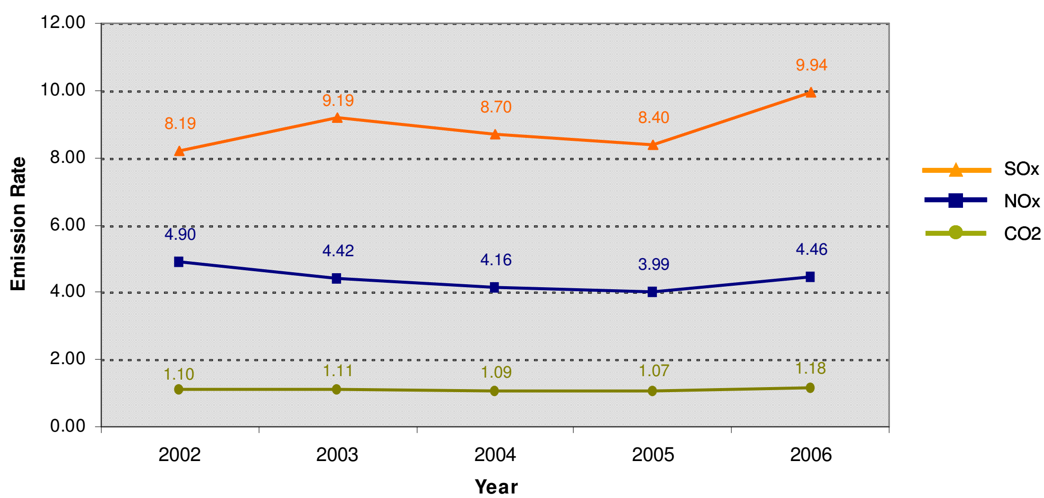
Table 1-1. Emission Rates for Wisconsin NERC Regions, 2002–2006

		2002	2003	2004	2005	2006
Marginal Plants	CO_2	1.08	1.08	1.04	1.00	0.85
	NO_X	4.61	3.94	3.69	3.56	2.87
	SO_X	7.25	8.01	6.66	5.58	2.71
Total Generation	CO_2	1.03	1.04	1.03	1.01	0.90
	NO_X	3.74	3.49	3.10	2.85	1.73
	SO_X	6.82	6.92	6.85	6.29	9.77

Emission rates for CO_2 are in tons per MWh; emission rates for NO_X and SO_X are in pounds per MWh.
Source: EPA

The decreases in emissions we 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 more than marginally to the reduction in emissions. We do note that among Wisconsin IOUs, MG&E has reduced its emissions from coal. Figure 1-2 indicates the emission rates from coal fueled plants on the operating margin from 2002 to 2006.

Figure 1-2. Emission Rates from Coal Fueled Plants on the Margin, 2002–2006

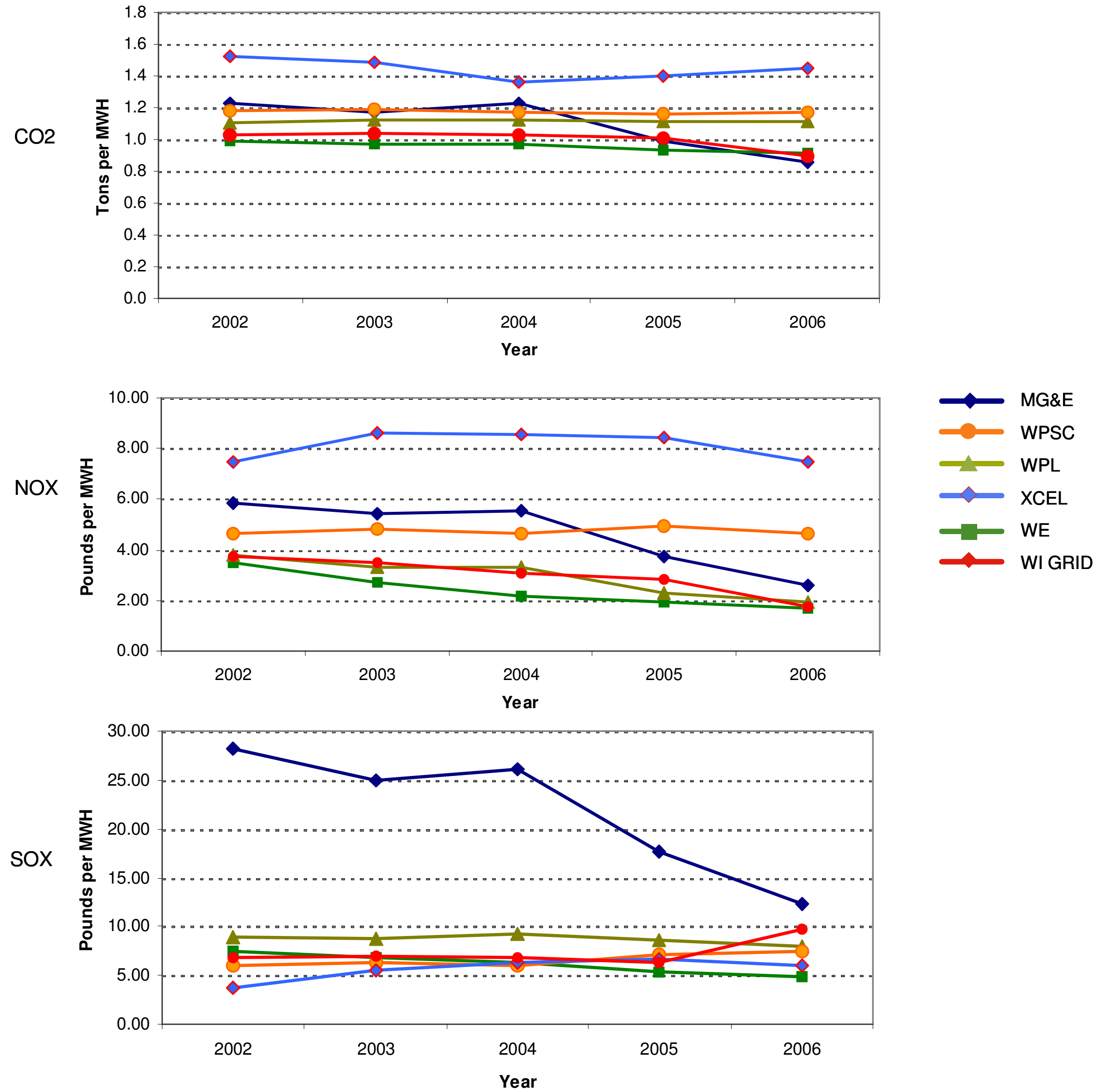


Note: CO_2 emissions expressed in tons per MWh; NO_X and SO_X expressed in pounds per MWh. Source: EPA

In our planning for this report we anticipated providing separate emission estimates for individual Wisconsin IOUs. In the course of preparing the report, however, we have come to doubt that point of view. Nevertheless, we believe there is value in knowing how Wisconsin IOU emission rates compare with the grid as a whole. Given the predominance of base load in Wisconsin IOU generation, the comparison that seems most appropriate is for total emissions.

Figure 1-3 shows the emission rates for CO_2, NO_X, and SO_X from Wisconsin IOUs' total generation. For CO_2, emission rates indicate some downward drift over the five-year study period, with the exception of WP&L. NO_X rates dropped for MG&E, We Energies, and WP&L. SO_X rates dropped significantly for MG&E.

Figure 1-3. Emission Rates for Wisconsin IOUs' Total Generation, 2002–2006



Source: EPA

2. INTRODUCTION

This report updates ongoing work by the Focus on Energy evaluation team to estimate emission factors for electric generation affected by Focus programs. It is part of the Focus overall benefit-cost analysis.

In the FY07 emissions research, using 2005 EPA data, we noted significant changes in the factor estimates for NO_X, SO_X, and CO_2 relative to an earlier analysis based on 2000 data.[2] Between 2000 and 2005 our estimates indicated that NO_X had fallen from 5.7 to 3.2 lbs/MWh and SO_X 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?

Since 2004, the Focus evaluation team has used the EPA's "Acid Rain Hourly Emissions" data series for estimating emission rates. The EPA data include hourly measurement of emissions at the boiler level and also include load and heat rate and other critical components of the emission rate estimate. The data also 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. This source is as close as any available to being comprehensive of all emitting plants. The data can be used to estimate emission rates for a single plant, all plants of a particular owner, or any regional division within the US.

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.[3]

We estimate the emission rate for all plants serving the grid that serves Wisconsin electricity consumers. We define this grid by the two NERC reliability regions that cover the state. Using NERC regions to define the grid complicates 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 if 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. Thus, changes in emissions over time include

[2] Focus on Energy Evaluation. *Method for 2006 Re-Estimation of Emission factors and Allowance Prices.* January 5, 2007.

[3] 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.

operational changes at individual plants, plant commissioning and decommissioning, and changes resulting from NERC region boundary changes.

In late 2007, the Focus team began the process of re-estimating emission factors, this time on five years of EPA data, spanning 2002 to 2006. 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 cumbersome—both too slow and a more difficult environment for keeping track of the multiple data tables needed for the analysis. At the core of the difficulty is 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. In the process of importing data into a SQL database we gained a more systematic and more stable platform for making data inquiries. We thus increased the number of diagnostic inquiries into the data and obtained, for example, clearer insight into the relationship between emissions reporting and load reporting. This has contributed significantly to our thinking about how to define marginal plants—i.e. plants that respond to changes in demand.

We have found that emission rate estimates are quite sensitive to the definition of 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 related to both of these definitions. This report will introduce a new definition that we believe is more appropriate, given the data we now observe and additional thought about how to best model the operating margin. We will use this definition to show trends in emission rates over time.

Compared to our current approach, the FY07 findings overstated the rate of change in emission factors. Adopting a definition that better captures the operating 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. We do note that among Wisconsin IOUs, MG&E has reduced its emissions from coal.

Another change for this year is in the way we treat Wisconsin plants in our analysis. In FY07 we weighted emission factors to reflect in-state versus out-of-state generation. We no longer think this is appropriate, as we explain below. We do, however, report emission factors separately for Wisconsin IOUs.

3. METHOD

3.1 ALIGNMENT WITH GREENHOUSE GAS PROTOCOL GUIDELINES

The Focus team has been working to align our emission rate estimation method with recommendations of the Greenhouse Gas Protocol Initiative. This protocol, developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD), has become the most broadly accepted accounting tool for understanding, quantifying, and reporting greenhouse gas emission reductions.[4] Although we report on emissions other than greenhouse gasses, we consider this protocol fully applicable to those emissions as well. In July of 2007, the Greenhouse Gas Protocol Initiative 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. In what follows we highlight our position relative to four of the critical elements.

3.1.1 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 a source of capacity, the BM should be factored into the emission rate.

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

3.1.2 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 a project is situated is the proper geographic area for estimating effects. The logic is 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 (formerly MAPP) and RFC (formerly MAIN)) as the relevant grid.

[4] Launched in 1998, the Initiative’s mission is “to develop internationally accepted GHG accounting and reporting standards and protocols, and to promote their broad adoption” (*Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*, page 5). These Guidelines may be downloaded from the following website: www.wri.org.

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 ten percent and CO_2 by about two percent. Geographic weighting is not consistent with the Guidelines, however, and we no longer believe it is appropriate. Even on days when demand is at its annual maximum within Wisconsin, Wisconsin-based generators are both exporting and importing energy, responding to demand on the grid as a whole. For this, the grid is the most appropriate region for estimating effects.

3.1.3 *Ex ante* or *ex post* emission factors (Guidelines Section 10.2)

The Guidelines distinguish between *ex ante* and *ex post* estimation of emission 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 emission factors in four years is a clear indication that we are moving to an *ex post* calculation of emission 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.

3.1.4 Operating margin calculation method (Guidelines Section 10.4.5)

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

Method 1—Averaging annual emissions for load-following (i.e., on the margin) 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 averaging 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—Using 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 dispatch model.

We believe our current approach is *at least* at the level of Method 3. We use load data to identify a set of plants that are at the margin in any given hour of the day. We do not use external data about the system dispatch order, however. Instead, we model the order from actual plant activity—the number of operating hours and the number of operating cycles per year. 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.

3.2 IDENTIFYING MARGINAL PLANTS

3.2.1 Single greatest mover (2004)

In 2004, emission factors for NO_X, SO_X, and CO_2 were based on the mass of emissions per MWh of generation for all plants within the MAPP (now MRO) and MAIN (now RFC) transmission regions in 2000.[5] Emission factors were calculated on marginal plants only, then 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 MW since the previous hour. The logic is that there can be only 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 had the effect of neutralizing size differences between base load and peaking plants.

In 2007 we replicated the prior work—which we 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 the single plant with the largest change in energy production as marginal—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.

[5] See Focus on Energy Public Benefits Evaluation, *Estimating Seasonal and Peak Environmental Emission Factors,* May 21, 2004. This report also includes mercury emissions; however, this part of the analysis has not been completed in time for the current report.

On the other hand, in any hour there would seem to be multiple plants that would be candidates for reducing output under reduced consumption—for example, the second and third greatest movers. EPA emissions data are reported on an hourly basis. Though this is an excellent level of granularity, it is still the case that multiple plants come on-line and go off-line during an hourly 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 have been "spared" by program savings.

3.2.2 99th percentile gainer (2007)

Thus, in 2007 we developed a definition of marginality based on units that have large increases in output in a given hour, whether or not other plants also have 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 one percentile of movement was represented by an increase in output from the previous hour of 19 percent of the annual maximum output. Therefore, as an 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 gainer* definition.

Table 3-1 presents a comparison of emission factors based on 2000 and 2005 EPA data. Over this period, according to our analysis, coal-fired generation dropped from 97 percent to 87 percent of the total Wisconsin generation and coal-emission rates simultaneously declined. Comparing the approaches for 2005 data, the 99th percentile approach reduced the emission-rate estimates for all types of emissions.

Table 3-1. Hourly Emission-rate Estimates, 2000 and 2005

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

Sources: 2000 data, *Focus on Energy Evaluation, Estimating Seasonal and Peak Environmental Emission Factors.* May 21, 2004; 2005 data, *Focus on Energy Evaluation, Method for 2006 Re-Estimation of Emission Factors and Allowance Prices.* January 5, 2007.

Moving the data into a SQL database has allowed us to look carefully, hour by hour, at the composition of marginal units. In so doing we confirmed our previous concern that the single greatest mover approach includes units that clearly are not on the operating margin in any reasonable interpretation of that term. Often a sister unit at the same facility is powering up at the same time the single greatest mover is coming down. Also, we have identified a small set of unit operating hours for large coal-fired plants that have very low loads but report high emissions in the hour. These occur when units are shutting down or ramping up. They create a set of low-load (below one or two MWh) emission rates that are hundreds or even thousands of times higher than the average. These are but two factors that support our general conclusion that the complexity of causes that render a given plant the single greatest mover in any hour inserts too much random variance into the data. At the least, an approach that averages a set of candidates for avoided load provides a more stable estimate because it reduces the effect of anomalous data points.

The *99th 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, as many as half the hours in the year do not have any plants in the 99th percentile of gainers, so there are essentially no marginal plants in those hours. Since energy efficiency programs could potentially 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 99th percentile, but that immediately highlights the problem that any threshold is somewhat arbitrary. Furthermore, with additional years of data we can now see that the 99th percentile changes significantly from year to year. For instance, in 2002 a plant had to increase load by 28 percent of its maximum to fall into the 99th percentile. By 2006 that cutoff was 40 percent of maximum load.[6]

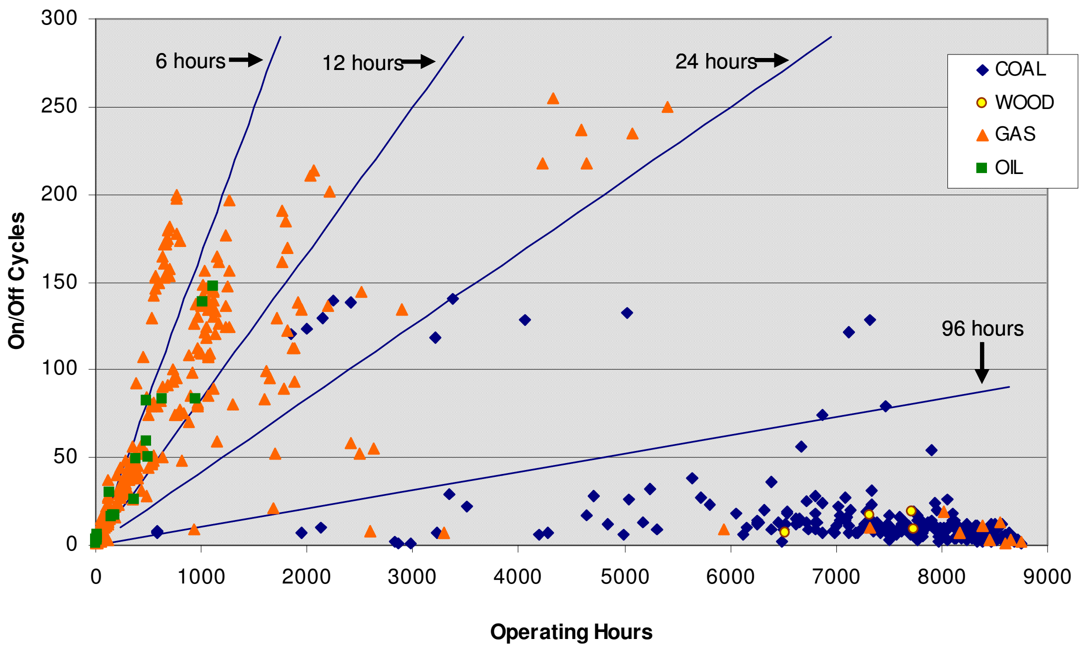
A problem that pertains to both of our previous approaches is that movement is defined relative to the size of the plant. This improves the representation of peaking plants in the marginal group but only by introducing a consideration that is, at best, an indirect indicator of the likely dispatch order.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

3.2.3 Use-rate (2008)

The WRI 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 each 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 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 3-1 shows a plot of on/off cycles and operating hours for the year 2005, and a demarcation for use-rates of 6, 12, 24, and 96 hours. We have used these use-rates to define and bound five different groups of plants.

[6] 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.

Figure 3-1. Plant On/Off Cycles and Annual Operating Hours by Fuel Type—2005



Plants in the less-than-6-hour category—*i.e. low use-rate*—are peaking plants. Plants in the more-than-96-hour category—*i.e. high use-rate*—are base load plants. In between are plants with intermediate characteristics: the shorter the average use-rate the more sensitive to demand. Table 3-2 shows the percentage of load by fuel type for each use-rate group. As expected, natural gas dominates the low use-rate group and coal dominates the high use-rate group.

Table 3-2. Distribution of Units by Use-rate Group and Fuel Type*

Use-rate Group	Fuel	Percent of Load	Number of Units
1	Oil	7%	34
	Natural Gas	93%	64
2	Coal	5%	1
	Oil	5%	16
	Natural Gas	90%	68
3	Coal	7%	10
	Oil	9%	11
	Natural Gas	84%	33
4	Coal	23%	7
	Oil	6%	6
	Natural Gas	71%	12
5	Coal	96%	191
	Oil	1%	3
	Natural Gas	2%	14

*Fuels representing less than 0.5% of total load are not included.

Following this logic, we define marginal emissions as those produced by the set of generating units 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 average emission rates across all marginal plants in each hour, and then average across hours of the year, to get an annual average.

There are two complications to this approach.

1. We eliminate from the estimate plants that generate less than 1 MW during the hour because these typically are shutting down and are subject to low-load emissions problems, i.e., emissions rates that are orders of magnitude higher than normal because of the tiny denominator.

2. In an hour where the lowest use-rate group accounts for only a small amount of total generation in a given NERC region, we fold that group into the next highest use-rate group and average both. This happens in about 5 percent of hours where, for example, only one or two plants from use-rate group 1 are operating and are generating less than 11 MWh. In this case we average the emission rate from groups 1 and 2. Since Focus programs claim an hourly average savings of about 22 MW, and there are two grids providing electricity to Wisconsin in roughly equal proportions, we use 11 MWh as the point at which we combined a use-rate group with its next lowest neighbor. In fact, this adjustment has almost no effect on the annual emission rate.

One refinement of this approach that we will pursue in future research is the identification of plants that are called up for reliability reasons rather than 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 as plants called on for system reliability—i.e., in response to changes in availability of generation units rather than in response to load. These should not factor into the emission-rate estimates, though we do not believe their effect on the overall estimate is large.

In summary, we believe all of the approaches we have used over the past several years represent an improvement over any approach that ignores generation on the grid to focus only on in-state units. They are also an improvement on any approach that looks at total generation rather than generation on the operating margin. As we have developed our approach, however, we have refined our understanding of how to model generation on the margin. The findings of this report represent our most recent developments.

4. FINDINGS

In our findings section we first report on emission rates at the grid level. For this we use the NERC regions that encompass Wisconsin: MRO (formerly MAPP) and RFC (formerly MAIN). This is the geographic region recommended by the WRI Guidelines for estimating effects from Focus programs. We then look at the performance of Wisconsin-based IOUs. We take this look not because these units contribute substantially to generation on the operating margin, but because these are the entities that have the closest relationship to Focus programs (e.g., geographic and regulatory proximity).

4.1 NERC REGION ANALYSIS

Employing the use-rate definition of marginal plants, the emission rates for CO_2, NO_X, and SO_X decreased substantially between 2002 and 2006. As indicated in Table 4-1, the sharpest decline was between 2005 and 2006, where rates dropped 15 percent for CO_2, 19 percent for NO_X, and 51 percent for SO_X. As we mentioned, this change may in principal reflect several factors, including a changing mix of fuels at the margin, a changing set of facilities in the NERC regions supplying Wisconsin, and a systematic trend toward greater use of gas plants, especially on the margin. In fact, the large decrease in emission rates between 2005 and 2006 seems primarily to reflect the shift from the MAIN to the RFC NERC region for emissions from the southeast corner of Wisconsin. Emission rates from MRO actually showed a slight increase during that period. However, unlike the MAIN NERC region, the RFC has very little generation on the margin from coal-burning units so the blended rate went down dramatically. This effect was offset somewhat by the fact that RFC coal generation is, on average, “dirtier” than either MAIN or MRO. We will look further into the mix of fuels, below.

Table 4-1. Emission Rates for Wisconsin NERC Regions, 2002–2006

		2002	2003	2004	2005	2006
Marginal Plants	CO_2	1.08	1.08	1.04	1.00	0.85
	NO_X	4.61	3.94	3.69	3.56	2.87
	SO_X	7.25	8.01	6.66	5.58	2.71
Total Generation	CO_2	1.03	1.04	1.03	1.01	0.90
	NO_X	3.74	3.49	3.10	2.85	1.73
	SO_X	6.82	6.92	6.85	6.29	9.77

Emission rates for CO_2 are in tons per MWh; emission rates for NO_X and SO_X are in pounds per MWh.
Source: EPA

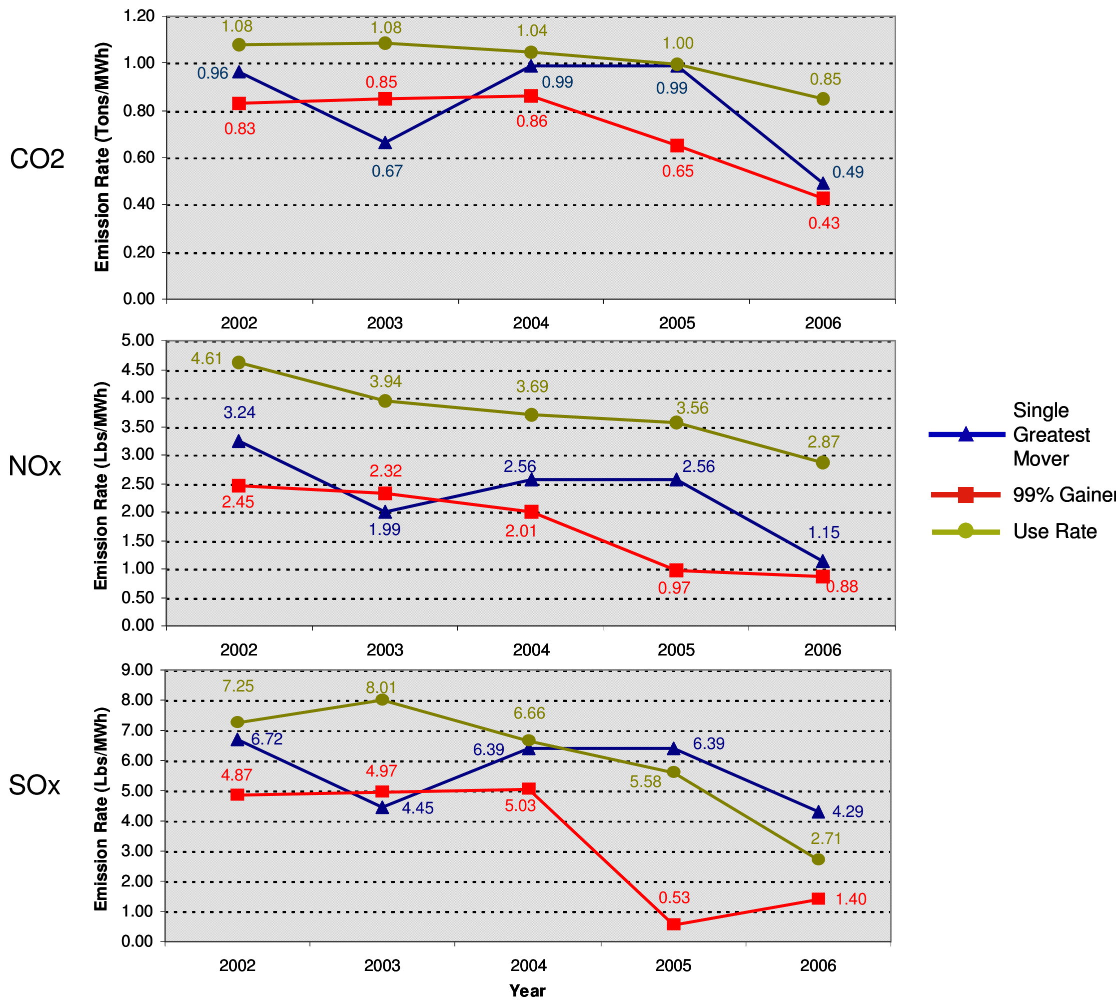
4.1.1 Comparing definitions of marginal load

Figure 4-1, below, shows the annual emission rate of CO_2, NO_X, and SO_X for marginal plants in the years 2002–2006 using the three different definitions of marginal plant discussed above. We initially posed the question whether the changes we had seen last year were real or an artifact of the estimation procedure. It now seems 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 have used have created different pictures of emission rates.

For emissions of CO_2, the 99th percentile and use-rate approaches move together, with the use-rate approach indicating an emission rate of between 0.25 and 0.40 additional tons CO_2

per MWh. 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. NO_X emissions show a pattern similar to CO_2.

Figure 4-1. Emission Rates Under Three Definitions of Marginal Plant, 2002–2006

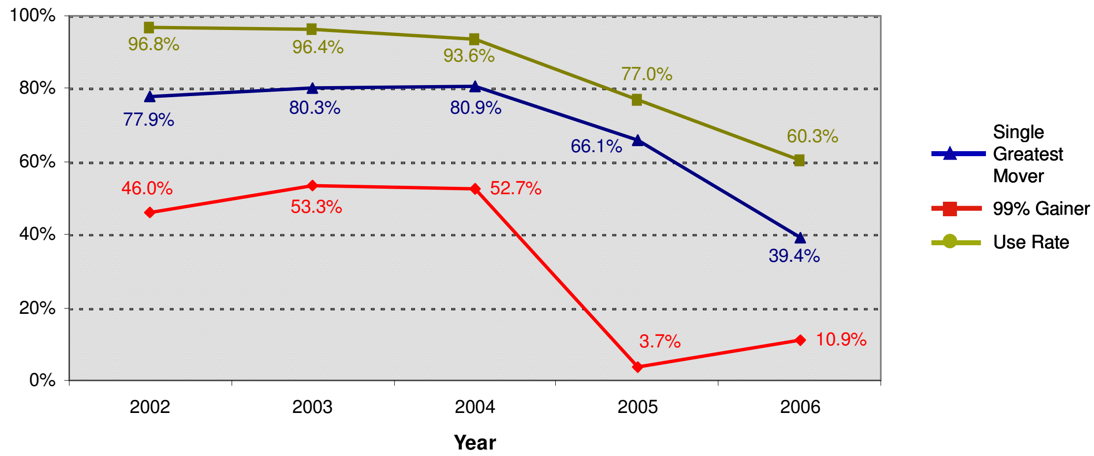


Source: EPA

4.1.2 Emission-rate drivers

The most important driver of these differences in the emission rate for different definitions of marginal load are differences in the ratio of coal- and gas-fired plants (oil, wood, and other fuels together make up less than one percent of the load under all definitions of marginal plant). Figure 4-2 shows the proportion of coal-fired load in each year's estimate of the emission rate. The percentage of coal is steady or even rises slightly from 2002 to 2004 and then begins to decline. The steep decline we saw in SO_X between 2004 and 2005 under the 99 percent movers definition is easily explained by the big drop in coal-fired load.

Figure 4-2. Percentage of Marginal Load Deriving from Coal Fuel Under Three Definitions of Marginal Plant, 2002–2006



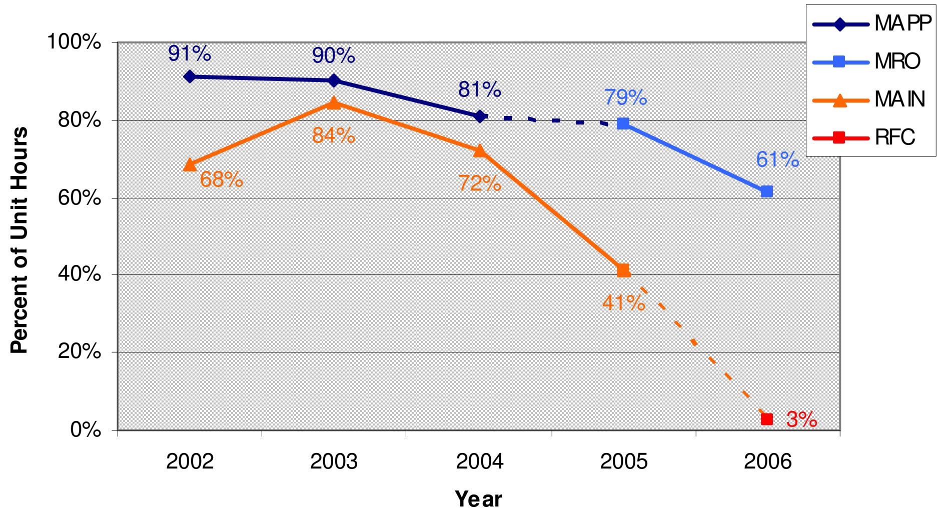
Source: EPA

The use-rate definition holds onto more coal generation as marginal load because of the way it treats load in off-peak periods when base-load is at the margin. The 99 percent mover definition includes base-load only when it is significantly ramping up and in many hours when base-load is at the margin includes no marginal load at all. The single greatest mover definition is more likely to include gas generation because it essentially favors small plants over large ones by defining movement relative to each plant's maximum generation.

Unlike the other definitions of marginal plants, use-rate does not weight emission rate by the size of the load but rather averages it for all marginal plants in each hour. This is done because the emission rate of a plant providing 500 MW with load weighting has 10 times the value of a plant generating 50 MW—*when the likely displaced load is only about 10 MW*. We do not believe there is any basis for this kind of weighting. In the absence of other information we weight all marginal plants in the hour equally.

The broader point we are making is that looking at changes in coal generation as a percentage of load does not really capture the way change factors into the emission rate under this definition of marginal load. Instead, we should look at the *percentage of unit hours* on the margin that derive from coal. Here, it becomes necessary to separate NERC regions. Figure 4-3 shows that the net change between 2002 and 2006 was a decrease in coal hours on the margin. The decrease was much larger on the MAIN/RFC portion of the grid than on the MAPP/MRO portion.

Figure 4-3. Percent of Marginal Unit-hours with Coal Generation, by NERC Region

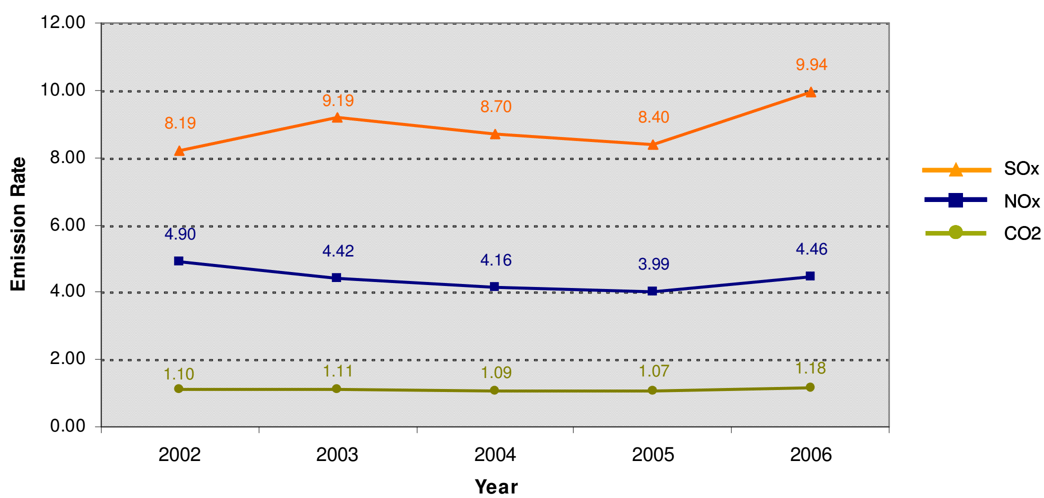


Source: EPA

4.1.3 Changes in coal emissions

In the past we argued a second reason for the declining emission rates is cleaner-burning coal plants. Our current research raises doubt about whether this is the case. Figure 4-4 indicates that none of the emissions shows a clear downward trend. Once again, the increase in rates between 2005 and 2006 reflects the shifting of boundaries for the NERC regions. Although only a small percentage of marginal load in the RFC comes from coal, the emission rates for RFC coal generation—especially CO_2 and SO_X—are higher than for either MAIN, which it replaced, or for MRO.

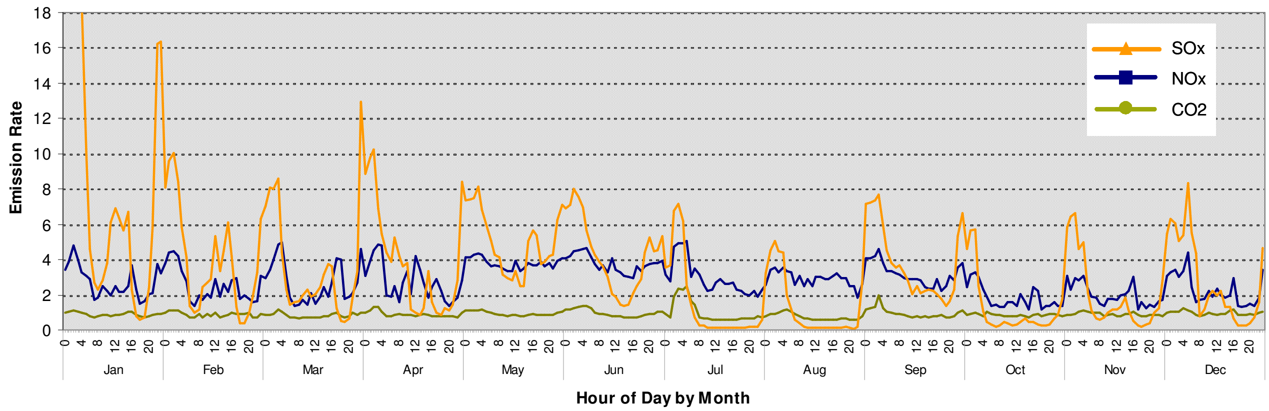
Figure 4-4. Emission Rates from Coal Fueled Plants on the Margin, 2002–2006



Note: CO_2 emissions expressed in tons per MWH; NO_X and SO_X 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 4-5 indicates the emission rate in 2006 by hour of the day and by month of the year for CO_2, NO_X, and SO_X. One implication of this is that programs that curtail load when demand is low have a larger effect on the overall emission rate than programs that curtail peak load. We note that this implies a tension between the policy objectives of mitigating the need for new power plants and reducing emissions.

Figure 4-5. Emission Rate by Hour of the Day by Month—Marginal Plants—2006



4.1.4 Emission rate forecast

One of the benefits of observing a series of measurements over time is the ability to forecast trends. This is important because of the effort to estimate a present value for energy efficiency measures that continue to generate savings for a number of years into the future.

Two factors in our current data make an estimate of emission trends difficult to obtain, despite having taken measurements over time. First, we have selected a period of years where the conversion from coal to gas fuel has been particularly vigorous. DOE estimates suggest this trend will taper over the next ten years. Second, shifting NERC boundaries and our decision to follow those shifts in the definition of marginal emissions means changes over time are a complex result of operating changes and the mix of facilities on the grid.

To explore emission-rate trends indicated by our data we estimated a time-series regression equation on each emission type.[7] The resulting models for all three emissions are strong, with good R^2 values and significance levels. Table 4-2 shows the fit of the three models.

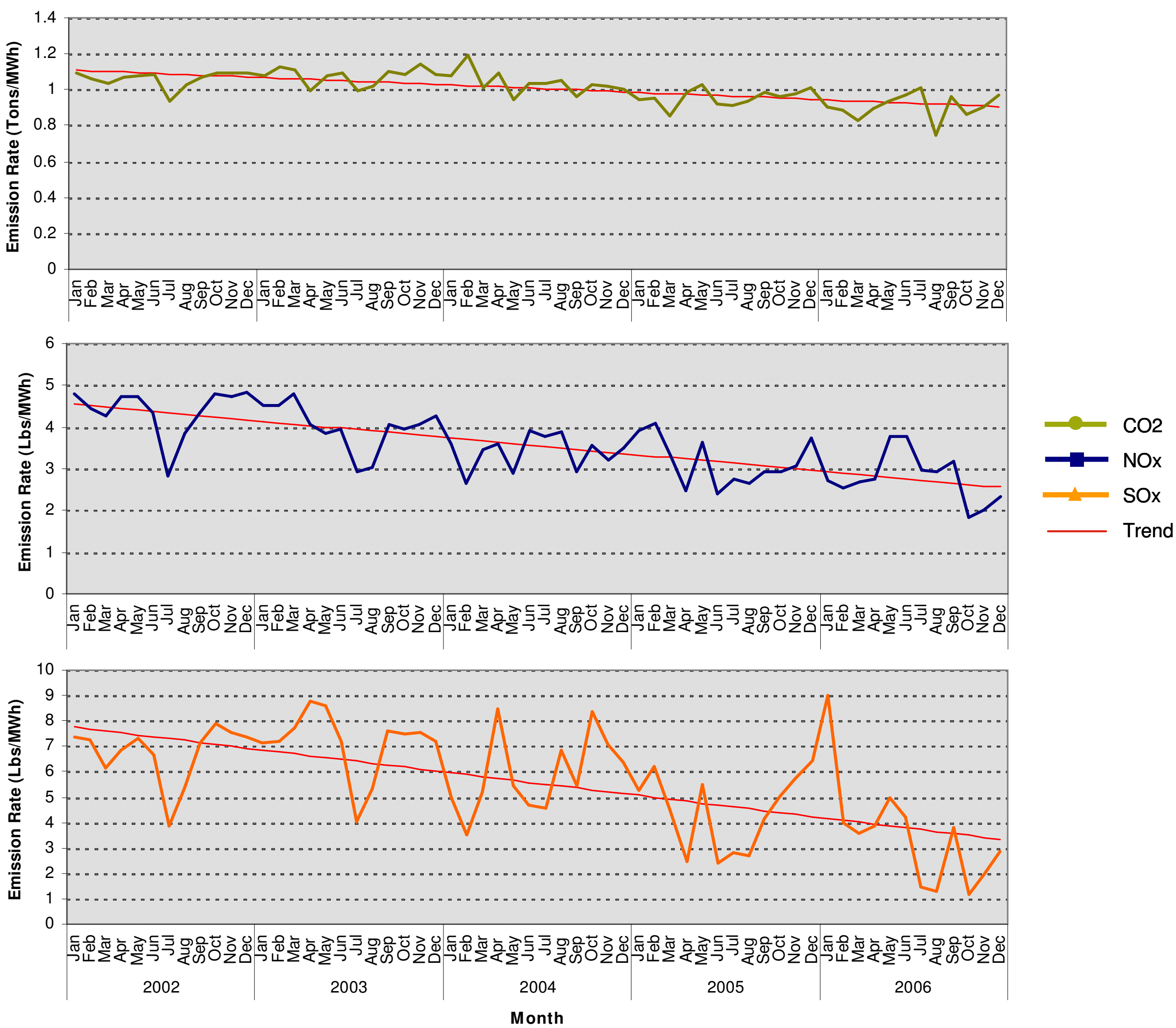
[7] We used SAS PROC AUTOREG, which can account for autocorrelation in residuals. In fact, we found no such autocorrelation. We regressed emission rate on time, designated as number of months since December 2001.

Table 4-2. Times Series Regression Models for Emission Rate Trends

	R^2	Intercept	P-value	Time	P-value
CO_2	0.49	1.11	< 0.0001	-0.0034	< 0.0001
NO_X	0.56	4.58	< 0.0001	-0.0336	< 0.0001
SO_X	0.40	7.82	< 0.0001	-0.0747	< 0.0001

Figure 4-6 shows the emission rate and trends for CO_2, NO_X, and SO_X from 2002 to 2006, using EPA data and the use-rate definition of marginal plant. During our study period the emission rate for CO_2 declined at an average rate of about seven pounds per MWh per month. NO_X declined at a rate of about 0.03 pounds per MWh per month and SO_X declined at a rate of about 0.07 pounds per MWh per month.

Figure 4-6. Emission Rate Trends by Month, 2002–2006



Source: EPA

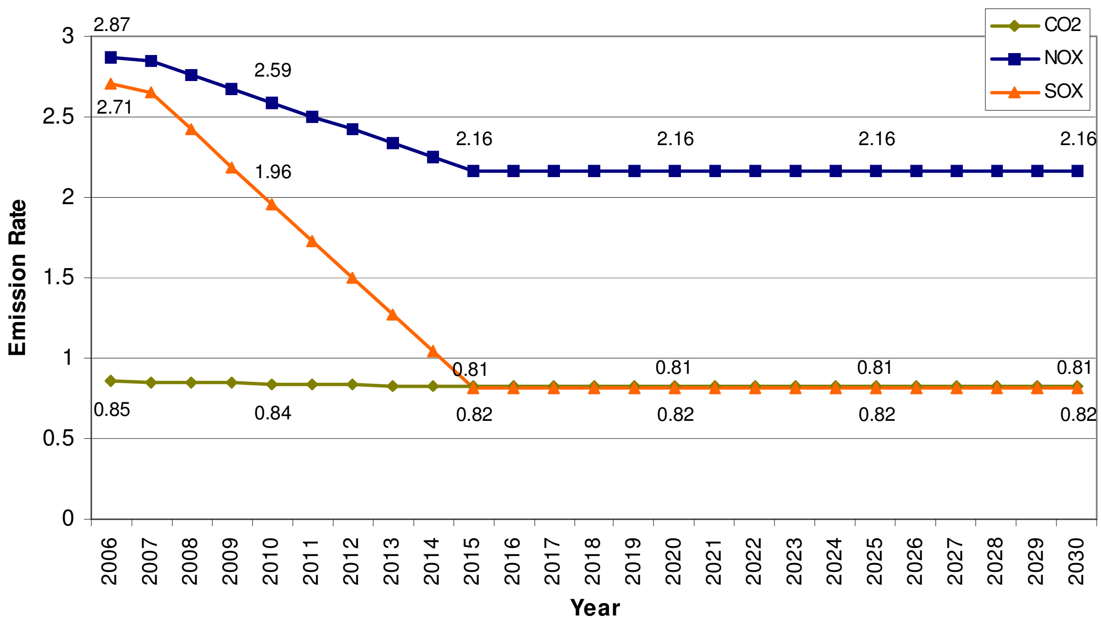
If these rates of declining emissions were to persist, marginal CO_2 emissions would reach 0.79 tons per MWh by 2010 and 0.58 tons per MWh by 2015. Marginal NO_X emissions would reach 1.35 lbs per MWh by 2010 and would become zero in 2013. Likewise, marginal SO_X emissions would reach zero by 2010. The implausibility of the latter two projections, which derive from the steep descent of emission rates over the five-year study period, sends us first to search for a better model of change.

For the purpose of long-term forecasting of emission rates, the way out of this difficulty lies in the fact that rates are not trending toward zero emissions but toward the emission rates of the cleaner of the two primary fuels serving the margin, i.e., natural gas. We saw in Figure 4-3 that by 2006 the grid serving southeastern Wisconsin (MAIN/RFC) had replaced almost all coal generation on the margin with natural gas. Only 3 percent of unit hours on the margin are fueled by coal. In the other half of Wisconsin generation, the MAPP/MRO is likewise trending toward more gas on the margin, but at a slower rate.

If we assume the trend toward gas fuel on the margin continues—and we will discuss reasons why it may not continue shortly—we could expect emission rates to 2030 as represented in Figure 4-7. By 2015, all but about 3 percent of marginal load will be fueled by gas.[8]

We acknowledge that this simple model of continuing trends ignores a number of factors that will shape marginal emission-rates in the future:

Figure 4-7. Emission Rates to 2030 Assuming Continuation of Current Fuel Mix Trends



Note: CO_2 emissions expressed in tons per MWH; NO_X and SO_X expressed in pounds per MWh. Source: DOE

[8] We preserve this margin because there is no data to suggest coal will ever be entirely replaced at the margin. Even three percent coal-fueled generation at the margin seems too little; however, we have no other evidence of a settle point in the data we have seen to date.

1. *Natural Gas Prices:* The shift toward gas fuel that our study period partially captures has already driven up the price of natural gas, tilting the economic equation back toward coal. The DOE predicts that price increases will reduce the growth rate of gas-fueled electricity generation; but total consumption of gas will continue to rise through about 2020 and even in 2030 it will account for 16 percent of total generation.[9] What we cannot know at this point is how this will affect generation at the margin. The shorter start-up and shut-down times of gas-fueled generation may cause it to remain the technology of choice at the margin.

2. *Cleaner Coal Technology:* If cleaner coal technology is widely implemented in the construction of new generation it will partly offset the effect of any return to coal-fueled generation at the margin. Cleaner coal technology achieves lower emissions of NO_X and SO_X by catalytic reduction and flue gas desulphurization equipment. Emissions of CO_2 are not reduced. Figure 4-8 shows DOE projections of total emissions of NO_X and SO_X to 2030.[10] This data suggests total emissions will level off at rates that are about 40 percent below 2006 levels for NO_X and about 60 percent below 2006 levels for SO_X.[11] That would be equivalent to an emission rate of about 2.7 pounds per MWh for NO_X and 3.4 pounds per MWh for SO_X—still substantially above natural gas emission rates.

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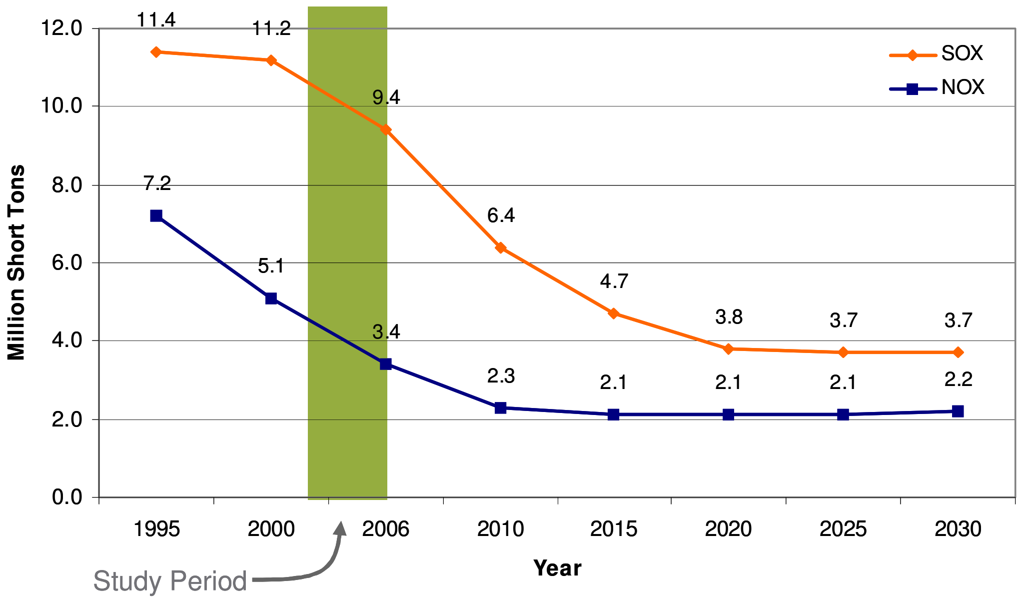
[9] This is down six percentage points from its peak of 22 percent and down three percentage points from the current 19 percent. See DOE/EIA-0383(2007), http://tonto.eia.doe.gov/FTPROOT/forecasting/0383(2007).pdf, p. 82 and p. 110, last accessed 28 October 2008.

[10] DOE/EIA-0383(2008), see http://www.eia.doe.gov/oiaf/aeo/emission.html, last accessed 27 October, 2008.

[11] "The reduction [in SOX emissions] results from both use of lower sulphur coal and projected additions of flue gas desulfurization equipment on 143 gigawatts of capacity. SO_2 allowance prices are projected to rise to $900 per ton in 2015, remain between $900 and $1,100 per ton until 2025, and then fall to $800 per ton in 2030… As with the CAIR-mandated SO_2 reductions, each State can determine a preferred method for reducing NO_x emissions. Options include joining the EPA's cap and trade program and enforcing individual State regulations. Each State will be subject to two NO_x limits: a five-month summer season limit and an annual limit. In the reference case, national NO_x emissions from the electric power sector are projected to fall from 3.6 million short tons in 2005 to 2.3 million short tons in 2030. Because the CAIR caps are inflexible, different assumptions in the high and low growth and high and low fuel price cases do not affect the projections for aggregate NOx emissions." DOE/EIA-0383(2007), pp 102–103.

Figure 4-8. NO_X and SO_X Total Emission Trends to 2030



Source DOE/EIA-0383(2008)

3. *Renewable Energy*: Renewable energy does not factor into current emission-rate estimates because it is not affecting the operating margin. Not only is supply (other than hydro-electric) too small to register, most sources are not currently under dispatch control because they depend on intermittent environmental factors. The DOE projects a rather modest 0.5 percent annual increase in non-hydro renewable generation to 2030.[12] With state and federal regulators pushing for greater reliance on renewable energy, however, the DOE's estimate may be too low. As renewable energy generation expands and technology improves, it may come to play a role in generation at the margin.

A model that would incorporate these three factors would require additional analysis. The current simple model arrives at what we believe is a floor on emission rates, unless renewable energy becomes a more significant factor at the margin. Continuing the series of emission rate estimates using EPA acid rain data will help to inform trends in the future.

4.2 WISCONSIN INVESTOR-OWNED UTILITIES

In our planning for this report we anticipated providing separate emission estimates for individual Wisconsin IOUs. Our thinking was that, on balance, Wisconsin generation was the most important source of displaced emissions, and that Wisconsin displaced emissions would have the greatest impact on Focus territory customers. In the course of preparing the report, however, we have come to doubt that point of view. The logic established in the WRI Guidelines is that emissions displaced by energy-efficiency programs will affect generation at plants on the margin anywhere on the grid that serves the territory where the programs

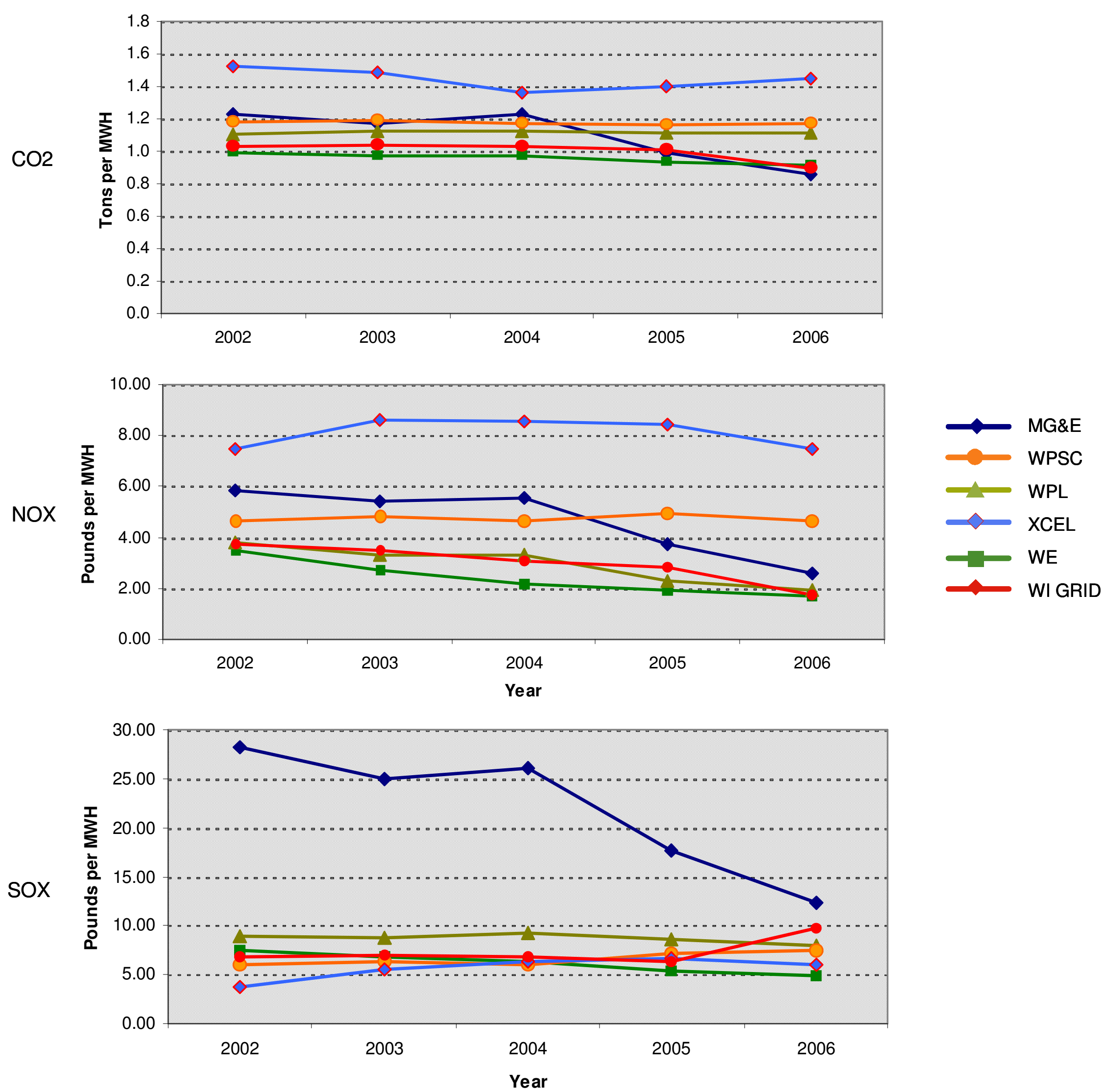
[12] DOE/EIA-0383(2007), p. 153.

operate. Thus, in principal, energy savings in Wisconsin affect generation in a region that stretches from Montana to Maryland.

One reason for not linking Wisconsin IOU emissions with Focus program impacts is that there is no “Wisconsin” operating margin. Looking at the Wisconsin grid—i.e., MRO and RFC—only about 5 percent of unit-hours of generation by Wisconsin IOUs are on the margin. Nevertheless, we believe there is value in knowing how Wisconsin IOU emission rates compare with the grid as a whole. Given the predominance of base load in Wisconsin IOU generation, the comparison that seems most appropriate is total emissions.

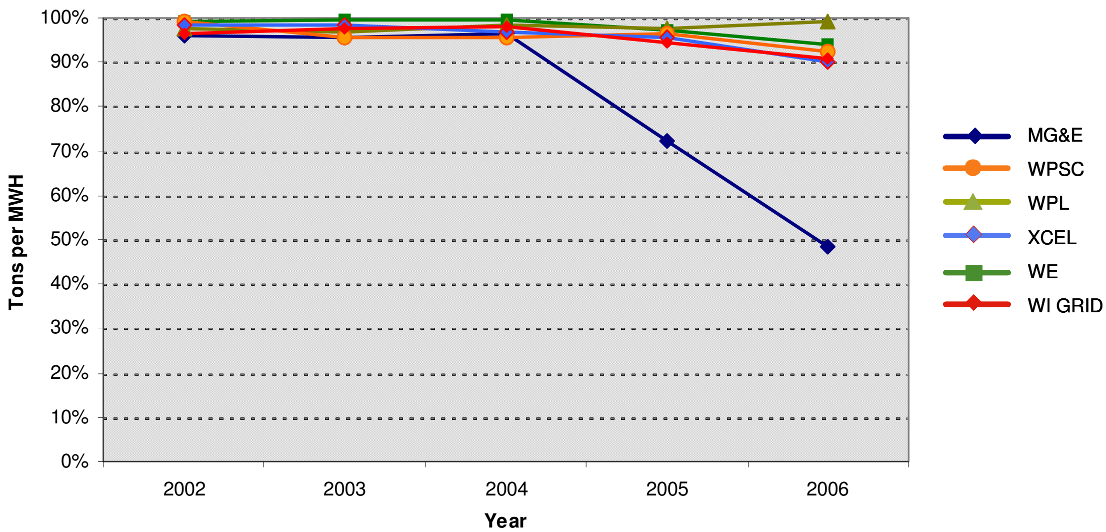
Figure 4-9 shows the emission rates for CO_2, NO_X, and SO_X from Wisconsin IOU’s total generation. For $CO_{2,}$ emission rates indicate some downward drift over the five-year study period, with the exception of WP&L. NO_X rates dropped for MG&E, We Energies, and WP&L.SO_X rates dropped significantly for MG&E.

Figure 4-9. Emission Rates for Wisconsin IOUs, Total Generation, 2002–2006



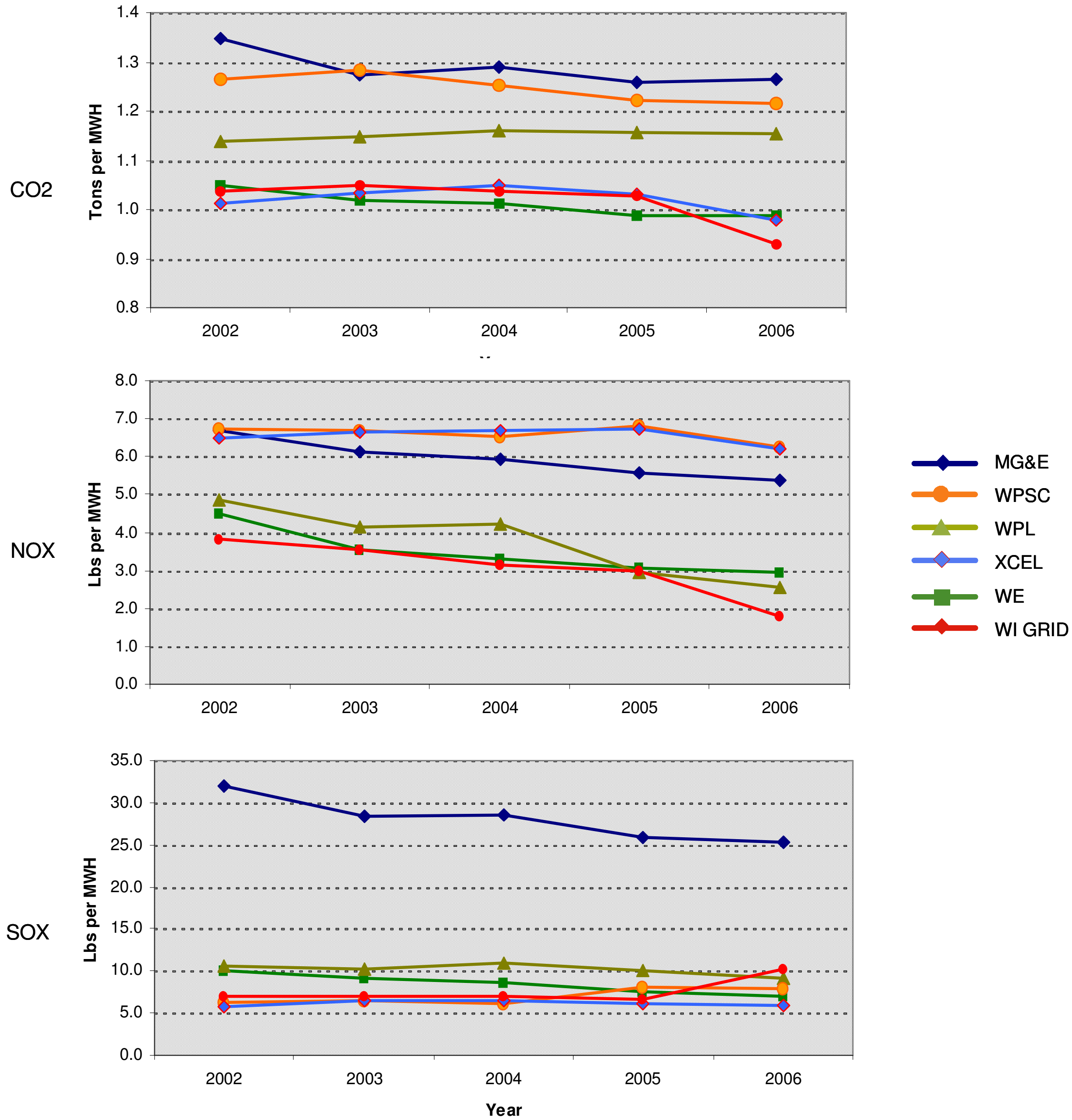
The declining emissions rate for MG&E can be shown to reflect the declining use of coal as a fuel, which dropped from 96 percent to 49 percent of total load between 2002 and 2006 (see Figure 4-10). Other utilities slightly reduced their reliance on coal after 2004.

Figure 4-10. Percent of Total Load from Coal-Burning Plants, 2002–2006



Although most IOUs did not substantially reduce their reliance on coal-fired generation, they did make some gains in the emissions from their coal generation. Figure 4-11 shows emissions from coal generation for Wisconsin IOUs and the Wisconsin grid.

Figure 4-11. Emission Rates from Coal-Burning Plants, Total Load, 2002–2006



5. DISCUSSION

As Focus regulators, program implementers, and program evaluators strive 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 considerations. This will be particularly true given current concerns about greenhouse gases and the debate about the role energy efficiency can play in reducing them. 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, 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. Of course, it is still only an approximation and as we have noted there is room for refinement. This may be accomplished within either 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 evaluating the associated environmental impacts.