Into the Breach with Carbon: Recent Approaches for Realizing Environmental Benefits of Displaced Generation Emissions

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ABSTRACT

As the scale of energy efficiency (EE) programs continues to expand in North America, the evaluation of these programs has emphasized documenting and measuring the energy savings impacts. Until recently, a different set of impacts, environmental benefits resulting from displaced power plant emissions, had been gathering increased attention as policy and legislation related to global warming gained momentum.[1] Over a period of about 10 years, the authors have refined a method for estimating displaced emissions. Our approach makes use of the U.S. Environmental Protection Agency's (EPA's) "Acid Rain Hourly Emissions" data series and is guided by the protocols of the World Resources Institute. The goal of this paper is to present details of this approach, which effectively balances the need for precision against the cost of attaining evaluation objectives and overall public policy objectives.

In the past year, however, mounting resistance to the regulation of greenhouse gas (GHG) emissions has come to a head. Two pieces of legislation directed at the reduction of GHG emissions have stalled in the U.S. Congress and at this time seem unlikely to become law. Only the EPA, which plans to regulate GHG under the Clean Air Act (CAA), continues to push for reductions. In our concluding remarks we address the relevance of our methods in the current political and policy environment.

Introduction

As the scale of energy efficiency programs continues to expand in North America, the evaluation of these programs has understandably placed primary emphasis on documenting the energy savings impacts. Until recently, a different set of impacts, environmental benefits resulting from displaced power plant emissions, had been gathering increased attention as policy and legislation related to global warming gained momentum. Although the inability of the U.S. Congress to ratify the Kyoto Protocol signaled significant resistance to regulation, many indicators pointed toward the near-term establishment of a cap-and-trade system for carbon, if not an outright tax.

In anticipation of the likelihood that emissions benefits due to EE programs would be monetized within a market structure, and because our clients sought to account for both energy and non-energy benefits of EE programs, over a period of about 10 years the authors refined a method for estimating displaced emissions. Our approach makes use of the EPA's "Acid Rain

[1] We use the term "displaced" because it is typically not feasible to verify that power generation is reduced and associated emissions have been avoided.

Hourly Emissions" data series.[2] Moreover, this work is guided by the protocol of the World Resources Institute (WRI) and World Business Council for Sustainable Development (WBCSD) (2007), which has become the most broadly accepted accounting standard for quantifying and managing GHG emissions. Our aim has been to lend rigor to the accounting of benefits so they will withstand critical scrutiny. Many of the methodological refinements we have developed have had the effect of reducing emission benefit claims compared to less precise accounting methods; but we have viewed this as a step toward the general acceptance of EE program claims.

In the past year, however, mounting resistance to the regulation of GHG emissions has come to a head. Two pieces of legislation directed at the reduction of GHG emissions stalled in Congress and at this time seem unlikely to become law.[3] The current political climate appears to make passage of either cap-and-trade or a direct carbon tax unlikely. This leaves only one significant initiative in place to regulate GHG emissions—the EPA's determination that CO_2 is a pollutant and can be regulated under the CAA. More recently, the EPA has also signaled that it will regulate Hg emissions from power plants on the same basis. Even these efforts are coming under attack, with legislation having been drafted that would disallow the regulation of carbon as a pollutant. Most recently, the EPA has announced it will delay its publication of a CO_2 performance standard in the face of political and industry pressure.[4]

In this political climate, the *ability* to estimate displaced emissions may require additional justification as to the *value* of doing so. The main thrust of our paper is to describe our approach to estimating the effects of EE programs on air emissions from power plants. In concluding, however, we turn to the question of whether these emissions *should be* estimated and, since the answer is "yes," the rationale for doing so.

Background

As part of the evaluation of Wisconsin's Focus on Energy programs (Focus), emission factors are estimated for electric generation affected by Focus programs. These emission factors are then applied to program net energy savings to estimate displaced emissions. This is part of the ongoing development of inputs to the Focus benefit-cost analyses.

To estimate environmental impacts associated with the Focus EE program net energy savings, the authors, along with Bryan Ward, also of The Cadmus Group, have developed emissions factors that are reported in pounds of pollutant per megawatt hour of generation. The EPA acid rain data series provides stack-level data for most power generators for the pollutants CO_2, NO_x, and SO_2 (identified by company and unit name, as well as specific stack). We estimate emission factors for each of these. Additionally, we use information in the data series about emission control devices at each generating unit, together with Energy Information Administration data about the source of coal being burned, to estimate Hg emissions. The

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2 Environmental Protection Agency, Washington, DC. Office of Air and Radiation. 2002 – 2007. "Acid Rain Hourly Emissions Data." (SUB-5431).

3 Waxman-Markey would have, among other things, established a cap-and-trade system for CO_2. Kerry-Liebermann would have set emission reduction targets.

4 Reuters. "UPDATE 2-U.S. EPA delays rollout of CO2 rule on power plants." June 13, 2011.

primary challenge in developing the factors is the volume of data involved and the complexity of the EPA data structure.

As noted, we have aligned our method with recommendations of the Greenhouse Gas Protocol Initiative (GHG Protocol). One implication of adherence to the GHG Protocol is that emission factor calculations are based on generation data specific to the geography of EE programs. The relevant set of plants from which emissions are displaced are those that serve the electric grid from which EE program participants receive electric power. A second implication of following the GHG Protocol is that emission factors are estimated only for plants that are operating on the margin. These are the plants affected by a reduction in demand/consumption resulting from EE programs.

To identify marginal plants we calculate the average length of time, in hours, that a generating unit remains on once it has been brought online. Peaking units, which are brought on for only a short time, have a short average time on; base-load plants that remain on for hundreds of hours or more have a long average time on. We divide the population of generating units into five groups: those averaging less than 6 hours on, 6 to 12 hours on, 12 to 24 hours on, 24 to 96 hours on, and more than 96 hours on, for each time they are dispatched. Depending on the hour of the year, any of these groups might be on the margin. We define marginal emissions in each hour as those produced by the set of generating units in the group with the shortest average time on. These are units that are modulated to follow demand at any time.

Annual Average Emission Factors

In our initial efforts to estimate emission factors, we calculated the average marginal emission rate for each hour of the year and then averaged across hours for an annual emission factor that could be applied to all energy savings. The emission factor is estimated to be the average displaced emissions divided by the average energy savings. We have since refined this approach, as we show below; but the refinement requires additional information.

Table 1 shows our estimated annual average emission factors across two North American Energy Reliability Council (NERC) regions: the Midwest Reliability Organization (MRO; prior to 2005 MAPP) and the Reliability First Corporation (RFC; prior to 2006 MAIN) for the years 2002 to 2007.

Table 1: Annual Average of Hourly Emissions at the Generating Margin, 2002 to 2007, by Pollutant (Lbs/MWh)

Year	CO_2	NO_x	SO_2	Hg
2002	2,031	3.6	5.8	0.000015
2003	2,194	3.9	6.9	0.000012
2004	2,088	3.1	3.7	0.000007
2005	1,757	2.3	2.5	0.000006
2006	1,957	3	4.8	0.000007
2007	1,821	2.7	4.2	0.000015

Note that the general tendency over this time period was a decline in emission factors. The increase from 2005 to 2006 is related to shifting NERC boundaries, which brought older, more polluting coal generation onto the margin in the RFC region.[5]

Time of Savings Emission Factors

The weakness of the average hour approach is that energy savings from EE programs are not, as the approach assumes, equally allocated across hours. Since the EPA data allow an 8,760-hour accounting of pollutants, insofar as energy savings can be assigned to hours of the day and days of the year, a more accurate emission rate can be estimated by matching the amount of energy savings in a given hour to the emission rate for that hour. We have come to call this approach *time of savings* (TOS) emission factors.

The availability of accurate savings loadshapes, which allocate energy savings as a percentage across the hours of the year, is essential to this refinement. Savings loadshapes often are developed by utilities for use in planning tools such as PortfolioPro™ and DSMore™. We acknowledge that the only savings loadshapes we have used are at a rather coarse level of aggregation. For instance, for residential programs the available loadshapes typically are lighting, heating, cooling, and possibly HVAC heating-and-cooling loadshapes, as well as an aggregate or total residential loadshape. This is a significant improvement, however, compared to the flat savings loadshape implied by the average hour approach.

Renewables pose some special problems in the allocation of savings over the year. For solar hot water, the energy savings occur when energy would have been consumed and not when the energy is collected or generated. Where we do not have a residential hot water loadshape, we substitute the residential lighting loadshape. Though not a perfect fit, it seems better than the residential total loadshape—which would be the other option—because it is not so much dominated by cooling load and generally reflects hours of the day when household consumption takes place. For solar electric, we estimate an insolation loadshape from the National Solar

[5] Changes in NERC regions have had a significant effect on emission factors because these changes redraw the boundaries of the grid and incorporate a new mix of fuels. The table below shows the number of operating units by NERC region and fuel type from 2002 to 2007. We have used shading to show where the change in regions takes place. Clearly, the change from MAIN to RFC was dramatic in the increase in the numbers of units factored into emission rates.

Number of Operating Units by Fuel Type and NERC Region, 2002 to 2007

NERC Region	Fuel	2002	2003	2004	2005	2006	2007
MAIN/RFC	C	105	106	107	83	273	280
MAIN/RFC	NG	180	181	187	207	396	555
MAIN/RFC	OIL	14	24	23	21	130	147
MAPP/MRO	C	69	71	70	89	114	98
MAPP/MRO	NG	26	31	41	66	80	85
MAPP/MRO	OIL	1	1	1	4	3	3

Radiation Database.[6] For the renewable measure categories wind, biomass combustion, biogas and other, a flat loadshape is assigned. For these savings we apply the average annual emission rate for the appropriate sector, business or residential, depending on which sector predominates program activity for a given technology.

Using these loadshapes, emission factors for the relevant NERC region are calculated in the following way. Annual energy savings for the year (in this example, 2007), for each measure category, are multiplied by the annual percent savings in each hour of the appropriate loadshape. Those hourly savings are multiplied by the emission factor in each hour to obtain a quantity of displaced emissions in each hour. The emission factor is estimated to be the total displaced emissions divided by the total energy savings. These loadshape-based TOS factors, expressed in pounds of pollutant per MWh energy savings, can be aggregated across programs to represent a portfolio-level rate. Table 2 shows emission factors by loadshape for one set of residential programs.

Table 2: Emission Factors by Loadshape, 2007

Loadshape	CO2	NOx	SO2	Hg
RES_COOL	1,641	2.7	4.5	0.0000109
RES_FLAT	1,817	2.7	4.1	0.0000147
RES_HEAT	1,908	2.6	3.6	0.0000158
RES_HVAC	1,783	2.6	3.9	0.0000134
RES_LGHT	1,801	2.6	3.8	0.0000135
RES_SOLAR	1,662	2.5	3.3	0.0000092
RES_TOTL	1,783	2.6	3.9	0.0000135

Emission factors for NO_x vary relatively little from one load shape to another—only about 0.1 pounds per MWh around the mean. This pollutant is less sensitive to the fuel that is predominant on the margin. The values for CO_2, SO_2, and Hg vary somewhat more by loadshape, on the order of 7 to 8 percent around the mean for CO_2, 15 percent for SO_2 and 22 to 30 percent for mercury. These pollutants vary according to the predominant fuel on the margin. In particular, coal generation produces more pollutants than natural gas and oil, wood, and other fuels. When coal-powered generation is on the margin, emission rates are higher. Hence, the timing of savings drives the emission factor for each end use.

The TOS approach is an intrinsically more precise way to represent the emission factor than the other approach, which averages across all units and all hours. What effect does it have on emission factors? Table 3 shows a comparison among three different approaches to estimating emission factors.[7] The top row shows rates calculated as an hourly average of all

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[6] We gathered hourly insolation data in watts per square meter from three data gathering stations located in cities where the majority of residential photovoltaic projects had been installed . We averaged the hourly data across all locations and years to obtain an average hourly insolation in watts per square meter. We then calculated the percentage of annual watts occurring in each hour of the year to estimate an insolation loadshape. See: http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/hourly/list_by_state.html.

[7] These data reflect the same TOS study reported above, but include the full portfolio of programs, not just residential programs.

generation, without accounting for the margin. The second row shows the rate as calculated at the beginning of this memo, as an average across all units on the margin in any hour, and then across all hours. The third row shows the TOS emission rate calculated as the kWh saved in every hour times the emission rate for that hour.

Table 3: Emission Factors from Three Different Accounting Approaches (Lbs per MWh)

Estimation Approach	**CO_2**	**NO_x**	**SO_2**	**HG**
Average of all load	2,346	4.1	10.9	0.0000570
Average of marginal load	1,957	2.7	4.2	0.0000153
Time of savings	1,801	2.6	3.8	0.0000080

The effects of the estimation approach vary quite significantly by pollutant. Going from *all load* to *average marginal load* (which are the 2007 factors reported in Table 1) results in a 61 percent reduction in the emission rate for SO_2 and Hg, about a 52 percent reduction for NO_x, and a 17 percent reduction for CO_2. Going from *average marginal* to *TOS* yields a smaller but still meaningful reduction in the emission rate: 22 percent for mercury, 10 percent for SO_2, 4 percent for NO_x and 8 percent for CO_2.

This finding underscores the point that emission factors derived from an average of all generation tend to exaggerate displaced emissions. The reason is that the emissions of all base load generation are included in the estimate even though they are not displaced by energy savings during a large portion of the year. This base load generation is generally higher in pollutant emissions than is gas-fired generation that follows the load during most of the year. We have consistently sought better ways of identifying the operating margin in order to improve the accuracy of the emission factor estimate.

A more salient question is whether the added effort of matching savings with emissions on an hourly basis—thus moving from an average across all hours to a TOS estimate—is worth the additional effort. The findings reported in Table 3 would suggest the value is perhaps not worth the effort if loadshapes must be developed specifically for the displaced emissions estimate. However, for Focus, these loadshapes already existed as an important input to the benefit-cost analysis, where they were used to assign avoided costs to energy savings. Once loadshapes have been developed, it is relatively easy to apply them to displaced emissions as well. Hence, there is no strong argument against the resulting added precision, however small it may be. On balance, we believe the TOS approach represents a worthwhile improvement in emissions estimates and should become standard for Focus evaluations. To a large extent the value of this additional effort hinges on the quality of the loadshapes that are available for apportioning savings. The approach also benefits from improved knowledge of which plants are on the margin, future efforts to control emissions through retirement of older, high-emissions plants, and the installation of emissions controls on existing plants.

Including Program Emissions Impacts in Benefit-Cost Analyses

A central objective of benefit-cost analyses is to provide relevant information to policymakers, regulators, utilities, and other stakeholders on the savings gained from the past, current, and future investments in energy efficiency and renewable energy. The analysis focuses on the value to the public of energy efficiency and renewable energy measures implemented as a result of EE programs. This value includes savings on energy bills, associated benefits of the measures not related to energy bills, economic impacts, and the mitigation of environmental externalities—quantification and monetization of the displaced power plant emissions associated with direct energy impacts.

The benefit-cost analysis is one very tangible way that the emissions effects can be credited to the programs. Because the analysis takes a societal perspective to counting benefits and costs with an "expanded" test of cost-effectiveness (as well as a more conservative "simple" test), the important emissions effects of the programs are identified.

For the most recent benefit-cost analysis for Wisconsin's program, we updated prices for displaced emissions and calculated different emission factors for each electric cost period using the TOS emission factors. This had differing impacts on program estimates of displaced emissions depending upon the savings loadshape. We treated NO_x and SO_2 as *economic emissions* because values are set in real markets; that is, utilities can, in principle, gain direct economic benefit from trading reductions in these pollutants. In the case of CO_2, we have been treating it as an economic emission but have set its value to zero until 2012, using our allowance price projections. We treated mercury as a *non-economic emission* because we had to impute the value of its displaced emissions. Whether treated in the benefit-cost analysis as economic or non-economic benefits, the effects of the Focus on Energy program on emissions support the State's environmental initiatives to reduce these air pollutants (see the Conclusion section for additional discussion).

Examining and Interpreting Trends in Emission Factors over Time

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 involved in estimating 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 the availability of measurements taken over time. First, we have been observing emissions during a period in which the conversion from coal to gas fuel has been particularly vigorous. The U.S. Department of Energy (DOE) estimates this trend will taper over the next 10 years. Second, shifting NERC boundaries and our decision to follow those shifts as we define marginal emissions means changes over time are a complex result of both operating changes and the mix of facilities on the grid.[8]

To explore emission-rate trends indicated by our data we estimated a time-series regression equation for each emission type, CO_2, NO_x and SO_x. The resulting models for all three emissions are strong, with good R^2 values and significance levels. During our study period, from 2002 to 2006, the emission rate for CO_2 declined at an average rate of about 7 pounds (0.0034

[8] Forecasting trends in power generation conversions from coal to gas is difficult, perhaps primarily because of the need to predict relative price differentials between coal and gas as well as future price and availability.

tons) per MWh per month.[9] NO_x declined at a rate of about 0.03 pounds per MWh per month and SO_2 declined at a rate of about 0.07 pounds per MWh per month.

Table 4 shows the fit of the three models.

Table 4: Times Series Regression Models for Emission Rate Trends

Pollutant	R^2	Intercept	P-value	Time (Months)	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_2	0.40	7.82	< 0.0001	-0.0747	< 0.0001

If these rates of declining emissions were to persist, marginal CO_2 emissions would reach 0.58 tons per MWh by 2015. Marginal NO_x emissions would become zero in 2013. Likewise, marginal SO_2 emissions would have reached zero by 2010. The implausibility of the first, and the know impossibility of the second projection, which derive from the steep descent of emission rates over the 5-year study period, sends us 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. In 2006, the RFC NERC region had replaced almost all coal generation *on the margin* with natural gas. Only 3 percent of unit hours on the margin were fueled by coal. The MRO NERC region was likewise trending toward more gas on the margin, but at a slower rate. We acknowledge that this simple model of continuing trends ignores a number of factors that will shape marginal emission-rates in the future:

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.[10] 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_2 by catalytic reduction and flue gas desulfurization equipment. Emissions of CO_2 are not reduced. Figure 1 shows DOE projections of total emissions of NO_x and SO_2 to 2030.[11] These data suggest total emissions will level off at rates that are about 40 percent

[9] Data for 2007 were not available in time for this analysis.

[10] This is down 6 percentage points from its peak of 22 percent and down 3 percentage points from the current 19 percent. See DOE/EIA-0383(2007), p. 82 and p. 110.

[11] DOE/EIA-0383(2008)

below 2006 levels for NO_x and about 60 percent below 2006 levels for SO_2.[12] 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.

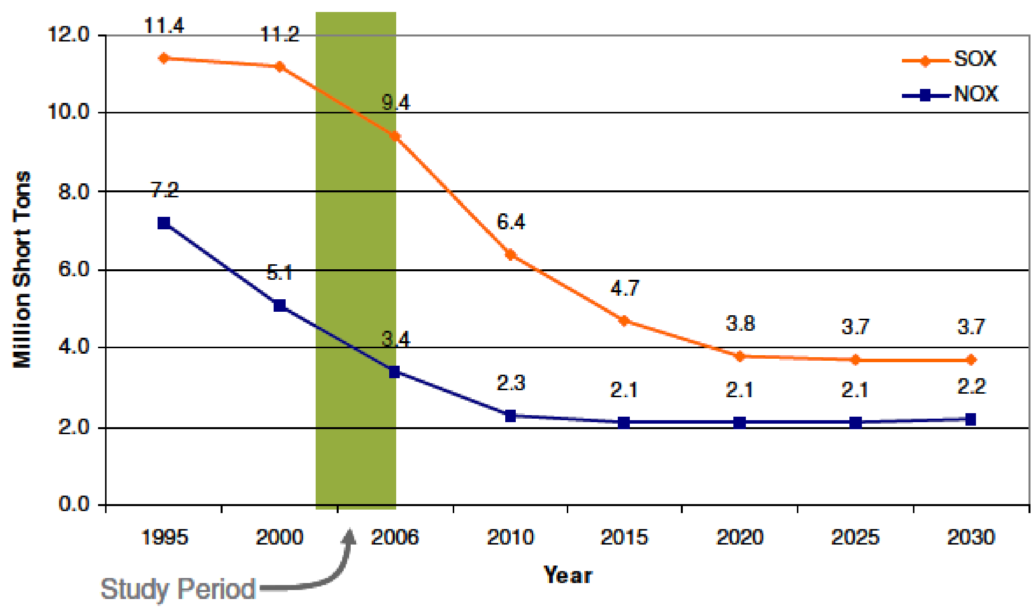

Figure 1: SO_x and NO_x Total Emission Trends

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 hydroelectric) 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.[13] 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

[12] "The reduction [in SO_x emissions] results from both use of lower sulfur coal and projected additions of flue gas desulfurization equipment on 143 GW 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 Clean Air Interstate Rule-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 5-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 NO_x emissions." DOE/EIA-0383(2007), pp 102–103.

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

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.

Mercury Emissions

The majority of mercury emissions from electric generation come from coal-burning facilities. The mercury content of coal varies depending on the geological formation from which the coal is extracted. To estimate mercury emission factors, we use fuel source information for coal-burning facilities that serve the Wisconsin grid. This data, submitted to the Federal Energy Regulatory Commission (FERC) by electric utilities on form FERC 423 (also EIA 423), includes the state of origin of coal and its energy content. We combined this information with data on the mercury content of coal collected in an extensive study conducted by the EPA in 2000. We estimate average mercury content per trillion BTUs of fuel consumption for coal consumed by utilities serving the MRO and RFC NERC regions. Average mercury content by year is represented in Table 5.

Table 5: Mercury Content of Coal Consumed on MRO and RFC Grid, 2002 to 2007

Year	Trillion BTUs (Tbtu)	Pounds	Lbs / Tbtu
2002	742	2,960	3.99
2003	793	3,167	3.99
2004	837	3,314	3.96
2005	772	3,059	3.96
2006	2,273	21,688	9.54
2007	2,158	20,377	9.44

The large increase in all values between 2005 and 2006 reflects the change in NERC boundaries.

The amount of mercury emitted by coal-fueled facilities is affected by the type of boiler used and by emission control devices installed for NO_x and SO_2 emission reduction. This information is recorded in EPA's acid rain data. The EPA has summarized these effects with the development of emission modification factors (EMF). An EMF reflects the ratio of outlet mercury concentration to inlet mercury concentration and depends on the type of boiler, the control technologies installed at the plant, and in some cases the type of fuel. The percentage of mercury reduction achieved compared to the inlet rate during combustion and flue-gas treatment is calculated as (1 - EMF). For example, an EMF of 0.85 means that the mercury released is 15 percent less than mercury entering the system. An EMF of 1 means the same amount of mercury that entered the system was released to the atmosphere. We assumed that all of the mercury in the fuel is released into the flue gas, prior to removal by control technologies. Each year, we update the emission factor estimates by using current-year source coal reporting and by using our refined approach to identification of marginal plants.

Conclusions: What is the Value of Estimating Displaced Emissions in the Current Political Climate?

In the current political climate—with the EPA, for instance, slowing the implementation of CO_2 regulation in the face of significant resistance—a question arises as to whether the estimation of displaced emissions from energy efficiency program activity has any value. We raise this question not to convince an audience we believe is generally understanding of that value, but to sharpen the logic for the more mixed community at large.

First, it seems clear that in any scenario where the EPA does regulate greenhouse gas emissions, or mercury emissions, the argument for estimating displaced emissions is made *prima facie*. If there is doubt that the EPA will be allowed to impose regulations, however, what is the argument? To us, the answer devolves to a matter of risk mitigation for utilities. Given the uncertainty about future regulation, it is essential that utilities recoup not only the current value of reduced consumption and demand but that they also establish a claim to value that may exist in the future in the event of regulation. In most likely scenarios where emissions are regulated, two key facts will emerge about each emitter:

- A baseline of emissions
- A track record of efforts to reduce emissions

If emissions credits are established, utilities will want to claim credit for reductions they have already made and factor these efforts into their baselines. An ongoing program of estimating these environmental benefits will solidify the connection between energy and non-energy benefits of programs and support a claim that emission savings have been an ongoing consideration in the support for programs. Estimation of emission impacts could be completed for prior program activity; however, this approach does not support a track record of consideration in program development. Moreover, the methodology is complex enough, with emission factors changing annually, that it may be difficult to re-establish emission factors over a period of several years.

If the EPA regulates CO_2, it will be as a criterion air pollutant under the Clean Air Act's National Ambient Air Quality Standards (NAAQS). Energy efficiency programs have significantly reduced two NAAQS criteria pollutants emitted in the process of generating electricity: sulfur dioxide and nitrogen oxides. The EPA will regulate CO_2 and other greenhouse gases based on a finding that they are related to global warming and that global warming has health effects. Thus, with greenhouse gases linked to global warming and climate change, and EE programs contributing to decreased power production, these programs can and should be credited with impacts on GHG mitigation. How much credit will depend on estimation of the impacts.

A leading prospect for demonstrating emissions credit is EPA's plan to designate energy efficiency programming a "best available control technology" (BACT) for GHG mitigation. If EPA chooses to exercise regulatory authority in GHG mitigation, major emitting sources—prominently including electric generators—will be required to implement BACTs. This will lead to value in estimating emission impacts of EE programs because these programs will be a formally recognized and mandated GHG control technology. The proposed regulation of Hg will likely reinforce this BACT designation.

In closing, we note other rationales for estimating the effects of EE programs on emissions.

- The use of expanded benefit-costs tests readily accommodates the estimation of power generation emission impacts. Cost-effectiveness analysis is a tangible way that the emissions effects can be included as program benefits.

- State-level efforts to manage Hg emissions are served by the ability to measure reductions achieved by energy efficiency programs.

- Calculation of program-attributable emission effects could assist utilities with planning for compliance with renewable portfolio standard (RPS) requirements.

We do not imagine we have exhausted the rationale for estimating emission effects from energy efficiency programs. Clearly, estimating these effects is not entirely associated with regulation of greenhouse gases because other emittants are involved. Though CO_2 regulation had been expected to make the need unavoidable, the political headwinds regulation currently faces still do not eliminate the value of capturing this information.

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