Peak Demand Reduction vs. Emission Savings: When Does It Pay to Chase Emissions?

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ABSTRACT

Public benefit programs may have multiple objectives including saving energy, reducing peak demand, system reliability, and reducing emissions. Optimizing programs to address one objective implies less than optimal performance on other objectives. Thus policy makers and program designers must weigh the relative importance of competing objectives to design programs that do the best job possible of meeting all objectives. For Wisconsin public-benefit programs, the tradeoffs are particularly apparent for two objectives: reducing peak demand and reducing emissions. The statewide evaluation team created a model to calculate peak and off-peak, winter and summer emission factors for the power plants supplying Wisconsin's electricity grid. The team also estimated season and peak energy savings by the statewide programs. Multiplying the savings by the emission factors produces estimates of the pounds of pollutants avoided by season and peak. The results indicate that energy savings in off-peak hours and particularly winter off-peak hours produce the highest emissions savings. This places the objectives of demand reduction and emission savings in direct opposition. This paper will present the results of the energy and emissions analysis in particular focusing on the dollar value of emissions avoided (assuming a system of tradable allowances for avoided emissions) compared to the dollar value of peak demand reduction.

Introduction

Energy efficiency technologies can produce a variety of benefits besides saving energy. They can reduce peak demand, power plant emissions, and on-site emissions. They can improve operating conditions, reduce maintenance needs, and produce a variety of other benefits. In this paper, we are interested in two of those benefits, peak demand reduction and reducing pollution. Do technologies that produce the greatest demand savings also produce the best emissions savings? Or is there a tradeoff between demand savings and emissions savings. If so (and this is the case in Wisconsin), how do program designers and those defining policy choose the appropriate balance between the two?

To help answer this last question, we first address two issues: 1. When are the marginal power plants at their dirtiest? That is, when are the power plants that are producing power at the margin also emitting the most emissions? 2. What is the value of an avoided pound of one of the substances emitted by utility power plants?

Once we have answers to those two questions, we have the information we need to be able to balance the competing benefits of peak demand and emissions reduction. However, this information alone is not enough. We also need a way to compare the two benefits on an equal footing so that policy makers can decide on the appropriate tradeoffs. How do you compare kW to pounds of NOx and SOx to decide on an appropriate balance? Our answer was to convert both to dollars. We converted demand reduction to dollars using an estimate of the value to society of reduced demand. We converted pounds of emissions avoided to dollars using estimates of the market value for emissions allowances from cap and trade regimes.

Because there are no clearly defined ranges for the values of demand and emissions savings, we did a sensitivity analysis to see how sensitive our conclusions were to the input assumptions. What would the conclusions be if our estimate of the value of emission allowances were too high by an order of magnitude? What would they be if we used a more generous definition of the value of demand?

The value for emissions savings in this paper assumes that the market value defined in an allowance trading system created for an emissions cap and trade program is a fair way to define the value to society of the presumed emissions savings from energy efficiency activities.

SOx emissions nationwide, and NOx emissions in some states, are subject to ceilings defined in cap and trade programs. Each generator is allocated allowances, and at the end of the year they must possess enough allowances to cover the emissions they have generated during the course of the year. To achieve that balance they must manage their emissions and/or purchase allowances from someone else. Thus the market value of the emission allowances reflects the cost to utilities of meeting their caps. As a result, the value to society of emissions reduction is reflected in the value of emissions allowances only to the degree that policy makers in creating the caps have accurately reflected the costs to society of the emissions. In addition, because of the nature of the cap and trade system and the utility grid, reduced demand for electricity created by an energy efficiency program may not actually produce emissions savings in the vicinity for the local utility may choose to maintain their level of emissions by selling power outside the region. Thus the emissions-related value the nearby residents experience from the energy efficiency program might only be experienced through financial means (say in ultimately holding down utility rates) rather than through an improved environment.

We created the model discussed in this paper to estimate emissions savings from Wisconsin's Focus on Energy program, which is a statewide energy efficiency and renewable energy program run through the state Department of Administration, Division of Energy.

Seasonality of Generation Emissions

Given the moderate size of the energy efficiency programs in Wisconsin, their effects are probably felt at the margin; that is, they reduce the need for power from the marginal producer – the last power plant put on line at any point in the day. In the short run they probably do not significantly change the characteristics of baseload generation. So if we are to target our energy efficiency programs to technologies that produce the best emissions impacts, we need to know when the marginal power plants are at their dirtiest – when are they producing the most emissions for the last kWh generated? To answer this question, we had to model the hourly generation and emissions characteristics of the power plants serving Wisconsin. Our model allows us to calculate emission factors expressed as pounds of nitrogen oxides (NOx), sulfur oxides (SOx), carbon dioxide (CO_2), and mercury (Hg) per MWh. The model allows us to calculate emission factors for the entire year or for any subset of the year. For example, our base specification produced factors for peak (8 am – 10 pm weekdays) and off-peak periods for the summer (April – September) and winter. We also calculated factors for shoulder periods and for a narrower definition of peak (1 – 4 pm, June – August).

Method

The driving factor for the design of the emissions model was the need to calculate emission factors for specific times of the year. We wanted to be able to characterize the emission characteristics of the generators operating on the margin for winter and summer months, during peak and off-peak hours. To do that, we had to have **hourly** data on all of the generators that might feed demand in Wisconsin. The only hourly data available that would meet our needs is data EPA collects to monitor emissions at power plants (EPA 2000). This data is primarily an emissions data set—it contains hourly data on actual emissions of pollutants from all large generators in the country.[1] Fortunately, it also contains energy generation information. Thus we could use the combination to calculate the actual emissions of each generator and predict when it was operating on the margin. Summing the emissions from marginal generators in a given time period, then dividing by their energy production, gave us emissions factors for the marginal producers in that time period.

We estimated when each generator was operating on the margin by using its capacity factor. This approach is based on the assumption that plants with lower capacity factors were more likely to be marginal plants than those with higher capacity factors. (Of course, this will not always be true but should be a reasonably accurate assumption.) For any given period of the year (e.g., on-peak summer hours), we calculated each plant's capacity factor as (Sum of MWh in period) * (Maximum MW for period * hours in the period). The model then fills a load duration curve starting with the plants with the highest capacity factor. The last plant necessary to meet demand at each hour in the load duration curve for the period is the marginal plant, and its emissions were used to calculate emissions factors. (For a more complete description of the model see Erickson 2002, 2004.)

This model has several advantages over the generic averages often used when calculating emissions savings:

- The model calculates emission factors from plants operating on the margin in the specified seasons and times and in the distribution region serving Wisconsin, rather than using averages including all generators in Wisconsin.
- The model calculates emissions factors using actual plant emissions, not estimated emissions based on emission rates and control technologies.
- The model uses true time-of-use data, not estimates.

One other significant advance of the emissions model over other models is that it can calculate an emissions factor for mercury. Mercury emissions are not tracked in the EPA hourly data, but detailed information on fuels and emissions cleaning technologies are available. Using that data, we were able to estimate hourly mercury emissions, which enabled us to calculate mercury emission factors using the same basic methods as those used for CO_2, NOx, and SOx.

The model calculates emission factors for less than a full year and less than a full 24-hour day. The model was designed to run with any subset of hours and days. For example, it could calculate emission factors for each month of the year, for weekends vs. weekdays, or for winter and summer without specifying peak hours.

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[1] Generally, units required to report to this system burn fossil fuel (coal, oil, natural gas, or any fuel derived from those fuels) to generate and sell electricity and serve a generator that is greater than 25 MW in capacity. See http://www.epa.gov/airmarkets/business/chicagowkshp/presents/1_programappliability.ppt.

Emission Factor Results

We ran the model on four basic scenarios named "Yearly," "Broad Peak," "Narrow Peak," and "Shoulder" with the parameters shown in Table 1. The emissions factors calculated by our emissions model using data from 2000 are shown in Table 2.

Table 1. Season and Peak Scenarios

Scenario	Season	Summer Peak Hours*	Winter Peak Hours*
Broad Peak (Base Case)	April–September = Summer Months	8 am–10 pm	7 am–10 pm
Narrow Peak	June–August = Summer Months	1 pm–4 pm	None
Shoulder	March, April, October = Shoulder Months	7 am–10 pm	7 am–10 pm
Yearly	January – December	No peak hours defined	

* All peak hours are for workdays only, not including weekends.

Table 2. Marginal Emissions Factors–Summary

	Pounds /MWh			Pounds /GWh	Percent of Yearly Value †			
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**	**NOx**	**SOx**	**CO_2**	**Mercury**
Yearly	5.7	12.2	2,216	0.0489	100%	100%	100%	100%
Broad Peak Scenario								
Winter Peak	5.9	13.9	2,027	0.0427	104%	114%	91%	87%
Winter Off-peak	5.8	14.5	2,287	0.0536	102%	119%	103%	110%
Summer Peak	4.6	9.8	1,788	0.0346	81%	80%	81%	71%
Summer Off-peak	5.4	11.1	2,233	0.0524	95%	91%	101%	107%
Narrow Peak Scenario								
Winter Peak				No winter peak hours				
Winter Off-peak	5.1	11.0	2,076	0.0461	89%	90%	94%	94%
Summer Peak	2.9	6.0	1,476	0.0181	51%	49%	67%	37%
Summer Off-peak	5.4	11.2	2,073	0.0431	95%	92%	94%	88%
Shoulder Scenario								
Shoulder Peak	5.0	10.4	2,186	0.0510	88%	85%	99%	104%
Shoulder Off-peak	7.1	16.2	2,269	0.0547	125%	133%	102%	112%
Non-shoulder Peak	4.8	11.1	1,945	0.0395	84%	91%	88%	81%
Non-shoulder Off-peak	5.9	13.5	2,260	0.0517	104%	111%	102%	106%

† Percent of Yearly Value = Scenario emission factor divided by the yearly emission factor.

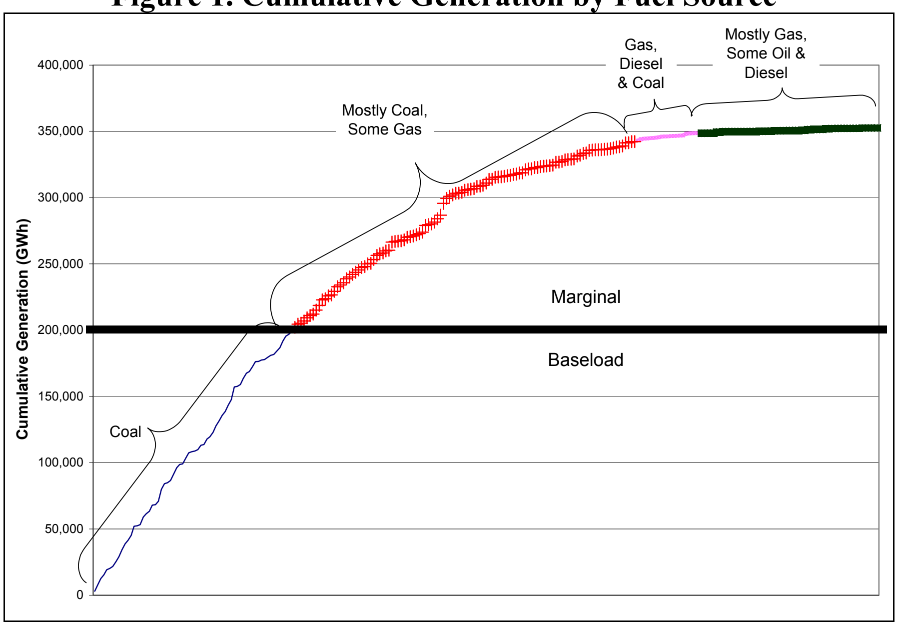
The lowest emissions rates of any scenario are in the summer peak hours in the Narrow Peak scenario—or between 1 pm and 4 pm, June through August—which is the definition of the peak season defined by the Division of Energy for the Focus on Energy program. Our interpretation of this result is that during summer peak times the marginal plant is more likely to use natural gas, which implies lower emissions than the average plant, which is more likely to use coal. The highest emissions rates are in the shoulder off-peak hours of the Shoulder scenario—or nighttime in March, April, and October. The most likely explanation for this result is that during times of lowest demand (such as in off-peak hours in shoulder months) the only generators running are probably large, baseload coal plants. The highest emissions rates in the Broad Peak scenario are in the winter off-peak hours, again probably because coal plants predominate at the margin. There the CO_2 rate is the highest of any scenario and the mercury rate is close to the highest in the shoulder off-peak hours. The lowest rates in the Broad Peak scenario are still well above the lowest in the Narrow Peak scenario.

The key determinant of the emissions rates is the amount of power supplied by natural gas burning plants. Coal is the predominant fuel source in all hours and seasons (Table 3 and Figure 1), but natural gas provides a significantly larger fraction of total power during times of high system peak compared to other times of the year. Coal produces over 90% of the CO_2 emissions in many season/hour combinations across the three scenarios. However, it produces only 51.6% of the CO_2 emissions in the Narrow Peak scenario during Summer Peak hours. Other fuels, such as residual oil and diesel, generally provide a very small portion of the power at any time of the year and have a small effect on the emissions rates.

Table 3. Coal Contribution to Marginal CO_2 Emissions by Scenario

	Percent of Total Marginal CO_2 Emissions Produced by Coal-burning Power Plants			
Scenario	**Summer or Non-shoulder Peak**	**Summer or Non-shoulder Off-peak**	**Winter or Shoulder Peak**	**Winter or Shoulder Off-peak**
Broad Peak	76.3%	93.9%	98.8%	99.9%
Narrow Peak	51.6%	82.8%	NA	88.2%
Shoulder	78.4%	93.9%	95.1%	100.0%

Figure 1. Cumulative Generation by Fuel Source[a]



[a] Does not include non-emitting sources such as nuclear, hydro, and wind.

Value of Emissions

To compare peak demand savings and avoided emissions, we need to value both in dollars. We value emissions in dollars per ton, or dollars per pound for mercury. Value could be established in several ways. One option would be to use values from existing or projected markets for emission allowances under cap and trade systems. The allowance values would reflect the cost of meeting the mandated emission caps. Another option would be to use calculated values that take into account externalities such as health and environmental effects. Policy makers and program designers must make the ultimate choice of a basis for valuing emissions. For this paper, we used market values based on emission allowances for substances where markets exist (SOx and NOx) and estimates of those values for substances without current markets but for which markets could form in the future.

Markets exist for emission allowances for SOx and NOx. The SOx market began in 1995 as a result of the Clean Air Act Amendments of 1990. It serves a national cap and trade program developed with a goal of reducing emissions from power generation by 50 percent. The NOx market serves the Ozone Transport Commission (OTC) NOx Budget Program, a cap and trade program developed in the northeastern United States. The NOx market also serves the NOx SIP Call[2] from EPA and the Federal NOx Budget Trading Program. Trading of NOx allowances under OTC began in 1999 to reduce NOx emissions during the summer months when smog forms. (Kinner and EPA 2002) Under emission allowance programs, utilities are allocated allowances for emitting SOx and NOx, one allowance per ton of NOx or SOx. The reduction in emissions sought determined the number of allowances allocated. At the end of a year, each utility must have enough allowances to cover the amount of NOx and SOx they emitted during the year. They must either reduce their level of emissions or purchase allowances from other utilities to meet their goals. Many allowances are moved internally to individual utilities as they balance the efficiency of their stable of generators. However, enough allowances are traded on the open market between utilities to provide a valid estimate of the market value of allowances.[3]

In the United States, there is no cap and trade regulation or regional agreement for CO_2 as there is for NOx and SOx. However, a market does exist for CO_2 emissions, as created under the Chicago Climate Exchange (CCX). CCX is a self-regulatory, voluntary pilot program designed to develop a trading program for greenhouse gasses. Its members have signed legally binding agreements to reduce their emissions of greenhouse gases by four percent below the average of their 1998-2001 baseline by 2006, the last year of the pilot program. (http://www.chicagoclimate exchange.com/about)

There is currently no market for mercury emission allowances in the United States. The Energy Information Administration (EIA) modeled the potential value of mercury allowances to analyze the potential costs and effects of legislation for establishing a national cap and trade system for NOx, SOx, and mercury (EIA 2001). EIA's estimated values for mercury in 2010 varied from \$12,500 per pound to \$34,500 per pound, depending on the scenario analyzed. We used a middle-range value of \$16,000/pound for the base case analysis in this paper.

Table 4 shows current and projected prices for tradable allowances. For 2004, the table shows current market prices in the markets discussed above for SOx, NOx, and CO_2. For 2010, we used prices from PA Consulting Group's "Multi-pollutant Optimization Model," which assumes enactment of the Bush Administration's "Clear Skies" proposal. We used the lower bound of the 2010 prices later in this paper when we report the dollar values of avoided emissions.

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[2] The NOx SIP Call required 22 states and the District of Columbia to submit State Implementation Plans providing NOx emission reductions to mitigate ozone transport in the eastern United States.

[3] In 2001, approximately 41 percent of the SOx allowances were traded between companies according to Clean Air Markets Update #1 September 2001.

Table 4. Emission Allowance Prices

Type of Emission	Historical Price (3/2003 – 2/2004 Average)	Current Price (2004)	Projected Price (2010)
SOx	$194/ton	$269/ton 2/2004	$295-$348/ton
NOx	$2,581/ton	$2,400/ton 2/2004	$1,573-$1,643/ton
CO_2	N/A	$0.95/ton 2/2004	$5-$10/ton
Mercury	N/A	N/A	$16,000-$118,053/lb

Source: Current prices for NOx and SOx: Cantor Environmental Brokerage Market Price Indices. Current price for CO_2: Chicago Climate Exchange. Projected Prices: PA Consulting Group M-POM model.

When we use the annual emissions rates to estimate the potential value of avoided emissions, CO_2 represents 44% of the total value of avoided emissions for each MWh avoided. NOx represents 36%, SOx 14%, and mercury 6%. Thus the results discussed in the remainder of this paper will vary more with changes in assumed prices for CO_2 and NOx than the other substances.

Balancing Emissions and Peak Reduction

Basic Model Specification

To compare the value of emissions avoided to the value of demand avoided by a potential energy efficiency action or measure, we need to convert both emissions and demand to a common unit. In this case, we used the annual dollar value of the demand savings from the customer's perspective and the annual dollar value of emissions avoided (assuming there is a market for emission allowances emanating from energy efficiency actions, as discussed above). The value of emissions avoided is the sum across the four substances (NOx, SOx, CO_2, or Hg) of kWh saved times the emissions factor (pounds/kWh) times the value of the emissions ($/pound as the market value for emissions allowances). The value of demand reduction is simply the coincident peak demand reduced for the measure (kW) times the value of avoided demand ($/kW).

This approach is dependent on the assumption that the energy efficiency measure in question affects the customer's peak demand. That is, we assume that the measure contributes its maximum to peak reduction during the system peak time. If the measure contributes nothing to reducing peak demand then the value of demand savings would be zero.

The formulas above contain several variables that could take a wide range of values. However, four factors play a central role in determining and understanding the results:

- The ratio of energy saved to peak demand reduced for a given measure (kWh/kW).
- The value of peak demand ($/kW)
- The value of emissions ($/pound)
- The ratio of emissions savings in dollars to demand savings in dollars (an output of the calculations).
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Because it forms the x axis in the following graphs, the ratio of energy saved to peak demand reduced needs some explanation. The ratio for a given measure can be defined as:

$$\text{Ratio of energy saved to peak demand reduced} = \frac{\text{kWh Saved per Year}}{\text{Coincident kW Reduced}}$$

This ratio will always be larger than 1 and could be a very large number if coincident demand reduction is significantly less than average demand reduction. But to illustrate the model we will assume the maximum for the ratio is 8760. Consider a measure that is running 24 hours a day 7 days a week every day of the year, such as LED exit lights. The amount of coincident demand reduced will equal the average demand reduced; therefore, “kWh Saved per Year” will be kW reduced*8760 (where 8760 is the number of hours in a year, except in leap year) and kW*8760/kW = 8760.

Measures that run much of the time, e.g., refrigeration or LED traffic lights, usually have ratios in the upper range (above 5,000). Seasonal measures, e.g., residential heating or cooling, have ratios in the mid-range (in the 3,000s), as do most commercial or industrial lighting. For example, lighting in a one-shift establishment for 10 hours a day most days of the year would produce a ratio around 3,650.

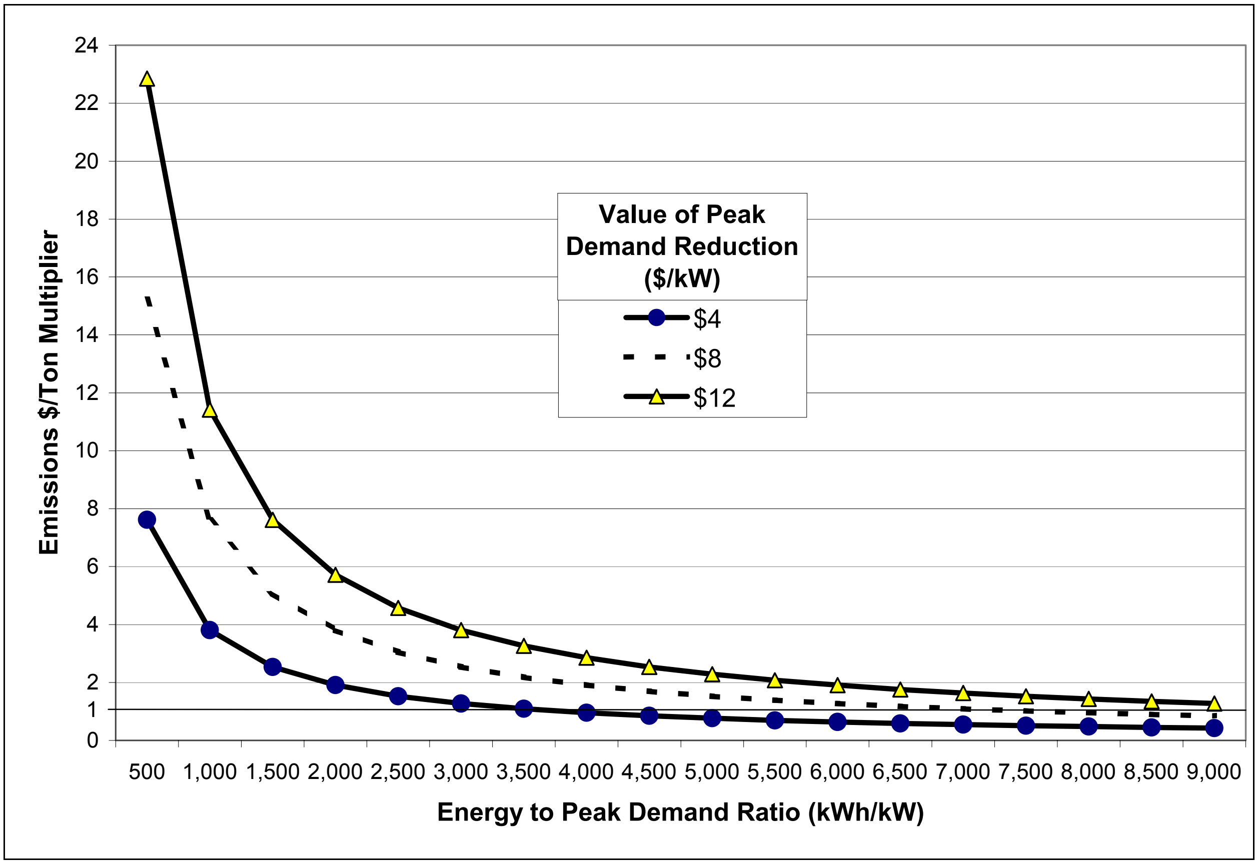
Sensitivity Analysis – Identifying Equilibrium Points

The task now is to identify equilibrium points where the value of emissions savings equals the value of demand reduced for a range of values for peak demand and emissions allowances. Assuming a given value for peak demand reduction, what energy-to-demand ratios and values for emission allowances produce emission savings greater than the value of demand savings? Assuming a given value for emissions allowances, what energy-to-demand ratios and values for demand reduction produce emission savings greater than the value of demand savings? To answer this, we model ranges of values for the key parameters ($/ton emission values, $/kW demand values, and kWh/kW measure characteristics) to identify when emissions savings are greater than the value of demand reduction. The results are shown in Figure 2.

In Figure 2, each line represents the equilibrium point for the given conditions. Any point on the line produces emissions savings that are equal to the value of demand reduction. Any energy efficiency measure that falls below the line will produce more value from emissions savings than from demand reduction. Any measure that falls above the line will produce the opposite.

If emission factors are held constant at base case amounts and if the value of demand is $8.00/kW, then measures with an energy to demand ratio of 7,500 or more will produce more value from emission savings than from demand reduction (in Figure 2, the $8 demand line crosses the $/Ton Multiplier line of 1 [base case] when the energy to demand ratio is around 7,500). If value of demand is only $4.00/kW, then technologies with an energy to demand ratio as low as 4,500 will produce more value from emission savings than from demand reduction (the $4 demand line crosses the $/Ton Multiplier line of 1 when the energy to demand ratio is around 4,500). If the value of demand is $12.00/kW, then no technologies will produce more value from emission savings than from demand reduction (the $12 line never crosses the line where the multiplier equals 1).

Figure 2. Equilibrium Where Value of Emissions Savings Equals Value of Demand Reduction – Value of Peak Demand Scenarios



Base Case Assumptions: Lower Bound of Projected 2010 Prices and Emission Factors

	NOx	SOx	CO2	Hg
$/ton	1,573	295	5	16,000
Pounds/MWh	5.7	12.2	2,216	0.0489
Value of Demand	Varies with Scenario			

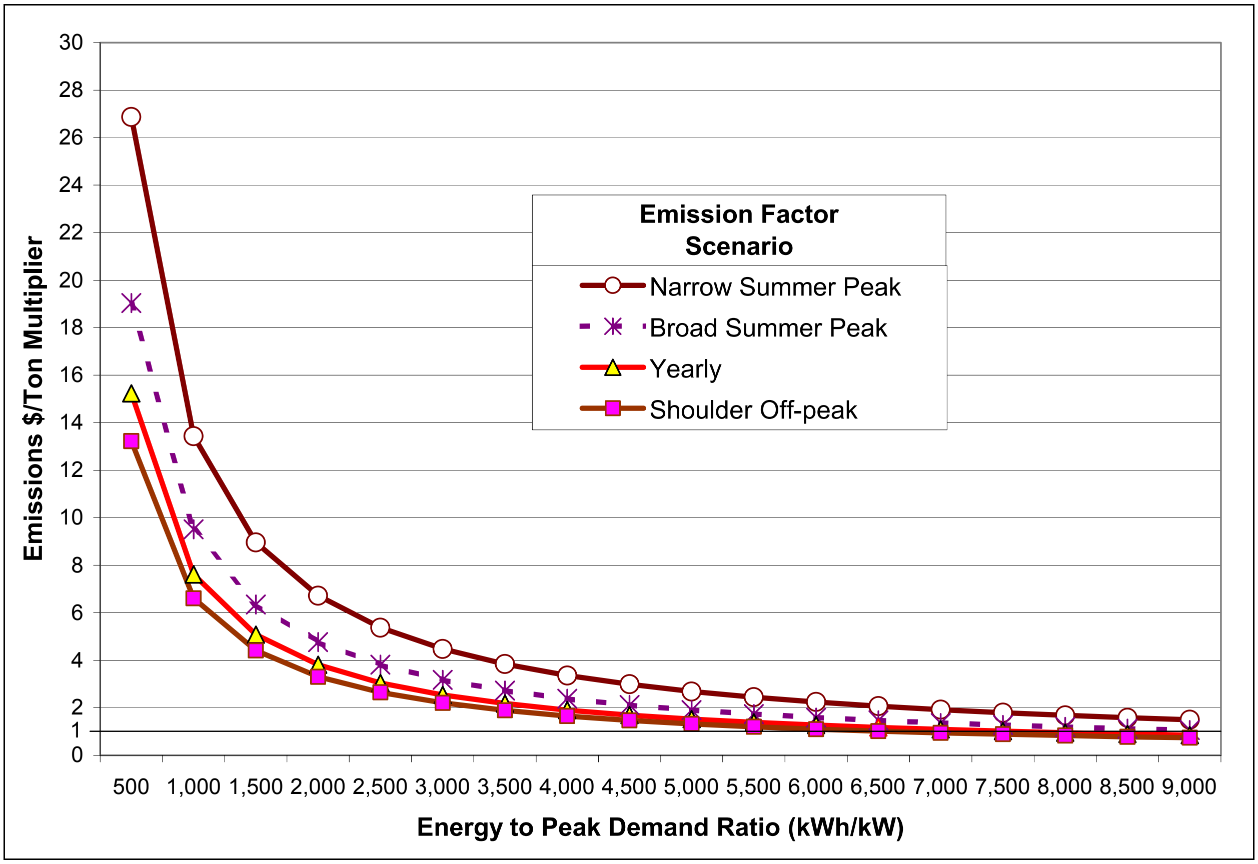
Mercury values are $/pound and pounds/GWh

If the value of emissions allowances is twice our base case assumption (represented by the $/Ton Multiplier line at 2) then measures with an energy to demand ratio of 6,000 or more will produce more value from emission savings than from demand reduction. The value of emissions allowances would have to be four times our base case assumptions for measures with energy to demand ratios of 3,000 to produce more emission savings than demand savings at $12/kW. Using the maximum projected prices for emissions allowances from Table 4 produces results roughly in line with doubling the emissions as shown by the $/Ton Multiplier line at 2.

Sensitivity to Emission Factors

How much do the emission factor scenarios discussed earlier affect the results? Figure 3 shows the effect of holding the price for demand constant while varying the emission factors according to the scenarios presented earlier in this paper. As with Figure 2, each line represents the equilibrium point for the given conditions. Figure 3 shows four of the scenarios: Yearly, Broad and Narrow Summer Peak, and Shoulder Off-peak. The graph lines for all other scenarios fall between the Broad Summer Peak and Shoulder Off-peak scenarios and most are closer to the Yearly scenario. (Emission factors for the Yearly scenario were used in Figure 2 so the Yearly line in Figure 3 is the same as the $8/kW line in Figure 2.)

Figure 3. Equilibrium Where Value of Emissions Savings Equals Value of Demand Reduction – Emission Factor Scenarios



Base Case Assumptions: Lower Bound of Projected 2010 Prices

	NOx	SOx	CO_2	Hg
$/ton	1,573	295	5	16,000
Pounds/MWh	Varies with scenario			
Value of Demand	$8.00			

Mercury values are $/pound and pounds/GWh

If the values of emission allowances are held constant and value of demand is $8.00/kW, then no measures will produce more value from emission savings than from demand reduction if we use the Broad or Narrow Summer Peak emission factors (in Figure 3, neither scenario line ever crosses the $/Ton Multiplier line of 1). This makes intuitive sense for Wisconsin because the emission factors for both scenarios are lower, primarily because of more natural gas generation during peak times.

At the other end of the spectrum, measures saving energy in the Shoulder Off-peak hours are more likely to produce more value from emissions savings than from demand reduction. The

Shoulder Off-peak line crosses the $/Ton Multiplier line of 1 when the kWh/kW ratio is 6,500 compared to 7,500 for the Yearly scenario.

These results illustrate the conclusion that, in Wisconsin, measures that save energy predominantly in the off-peak hours will produce more value from emissions allowances relative to demand savings.

Example Energy Efficiency Measures

Now that we know under what conditions an energy efficiency measure can produce more value from emissions savings than from demand reduction, we can ask "Which energy efficiency measures fit those conditions?" Two measure-specific factors help determine the relative value of emissions savings. First, some measures are more likely to save energy in times when the marginal electric generators produce more emissions. As we discussed above, in Wisconsin this means off-peak periods, particularly in the shoulder months. Probably the best example of such a measure in Wisconsin would be residential space heating.

Second, some measures are more likely to have relatively high energy use compared to their demand, so the value of emissions savings, which is driven by energy use, will be relatively higher compared to the value of demand reduction. Technologies that run most or all of the time are likely to have high energy use relative to demand and should present attractive options for targeting for emissions reductions. Table 6 presents some examples.

Table 6. Measures with High Hours of Operation

Description	Hours/Year	Description	Hours/Year
LED Exit Fixtures	8,760	Office Ventilation Fan	6,192
Pool Pump	8,760	Refrigerator Turn-In	5,947
Vending Miser	8,760	Hotel/Motel HVAC pump (heating)	5,775
Hospital Ventilation Fan	8,374	Freezer Turn-In	5,257
LED Traffic Lights	7,175	Fluorescent lights (commercial)	3,667
Grocery Ventilation Fan	6,389		

Source: PA Consulting Group analysis of Focus on Energy program tracking systems and New Jersey protocols.

Summary and Conclusion

The analysis behind this paper was designed to provide information to policy makers and program designers to aid them in deciding whether and (if yes) how to target energy efficiency measures to achieve emissions reduction. We created a model and approach for estimating the conditions under which an energy efficiency measure would produce more value from emissions savings than from demand reduction. In Wisconsin, public benefits programs are charged with saving energy, improving system reliability (which brings with it the goal of reducing peak demand), and mitigating the environmental impacts of energy use. Our emissions model demonstrated that energy savings in off-peak hours and particularly winter off-peak hours produce the highest emissions savings in Wisconsin. This places the objectives of demand reduction and emission savings in direct opposition. As a result, we extended the analysis to compare the value of emissions avoided to the value of demand reduction to provide a means of comparing the two goals using the same terms.

Under a reasonably plausible set of conditions, it is possible that energy efficiency measures can produce more value (expressed in dollars) from emissions savings than from demand reduction. If demand reduction is valued at $8/kW, only measures that are operating at their peak for 7,000 hours or more each year will produce more value from emissions savings than from demand reduction. However, if demand reduction is valued at $4/kW, that number drops to 3,500 hours. Similarly, if the price per pound for avoided emissions is twice our estimates (and demand is at $8/kW), measures that are operating at their peak for 4,000 hours or more each year will produce more value from emissions savings than from demand reduction.

CO_2 and NOx account for 80% of the value of emissions savings, using yearly emissions factors for Wisconsin. As a result, any significant difference in their price from our base model ($5 and $1,573/ton respectively) will have a significant effect on the ratio of emissions savings to demand savings.

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