Quantifying Emissions Reductions from New England Offshore Wind Energy Resources

by

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Submitted to the Engineering Systems Division
in Partial Fulfillment of the Requirements for the Degree of

Master of Science in Technology and Policy

at the

Massachusetts Institute of Technology

June 2006

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Abstract

Access to straightforward yet robust tools to quantify the impact of renewable energy resources on air emissions from fossil fuel power plants is important to governments aiming to improve air quality and reduce greenhouse gases at least cost. It is also important to renewable energy developers seeking to gather support and facilitate permitting of their projects. Due to the inherent complexities of the electric power system, it is difficult to determine the effects of renewable energy generators on emissions from fossil fuel power plants. Additionally, because there are a variety of methods for calculating “avoided emissions,” which differ in complexity and transparency, and which provide dissimilar results, there remains uncertainty in estimating avoided emissions. Guidance from government authorities on which method to use is too flexible to provide a robust framework to enable decision makers to evaluate environmental solutions.

This thesis informs decision making first by highlighting important issues to consider when analyzing the impact of renewable energy resources on emissions, then by reviewing current guidance on the matter, and finally by comparing existing methods of calculating avoided emissions. Several methods are further evaluated by applying them to potential offshore wind energy resources in New England, including the proposed Cape Wind project. This analysis suggests that the potential avoided emissions of the Cape Wind project are significant, though lower than previously stated by the project developers and supporters.

The usefulness of the available literature on calculating avoided emissions suggests that governments and electric industry analysts should continue to share information on different methods and work together to revise the current guidance. To further increase analytical capacity, government agencies should collect, organize, and disseminate more data on the electricity system including power plant operations and emissions. The ability to accurately quantify avoided emissions will help policymakers design programs with the right incentives to reduce emissions from power plants and will enable them to describe the environmental benefits of doing so. To facilitate development of clean energy resources, it is proposed that more weight is given to environmental benefits such as avoided emissions in environmental impact assessments. To assist in reducing emissions, it is recommended that renewable energy and energy efficiency resources are allowed to participate more directly in emissions markets.

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Acknowledgements

I would first like to thank my advisor, Stephen Connors, for his guidance, patience, and support throughout the last two years. Steve provided me with interesting and challenging work, the opportunity to present our research to several organizations, and, very importantly, funding for two years. The freedom I enjoyed allowed me to find my own path and learn from my mistakes, while the direction Steve provided kept me moving in the right direction.

I would also like to thank my colleague Kate Martin for sharing her expertise in emissions markets and for taking the time to answer questions about her and others’ previous work on avoided emissions.

Synapsee Energy Economics should be recognized for producing many reports on the topic of avoided emissions from renewable energy and energy efficiency technologies and making them publicly available (for free). I would like to thank Bruce Biewald for providing valuable and timely responses to all my inquiries.

A big thank you to Jill for her tireless encouragement and patience during this busy school year. Her reviews of my thesis drafts were most helpful and I think she is starting to understand energy systems, maybe a little too well.

Finally, thank you to my family for their love and support throughout my MIT career and my life.
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CHAPTER 1: Who Cares About Reducing Emissions from Power Plants?

Introduction

The reduction of emissions from fossil fuel power plants is important to many electricity industry stakeholders. In particular, policymakers are interested in improving air quality and reducing greenhouse gases, and in doing so meeting environmental regulations. To create smart energy programs and incentivize beneficial projects, an understanding of the complex system of power plant operation and resulting emissions is necessary. The present analysis informs the policymaking process by describing methods of quantifying the “avoided emissions” due to the operation of renewable energy generators and by highlighting important issues to be considered when designing policies to reduce emissions from power plants.

Avoided emissions are an important part of the argument for the continued development of renewable energy resources. Because many different ways to estimate avoided emissions exist, there is uncertainty over the actual environmental benefits of renewable energy generation. Reducing this uncertainty and increasing the accuracy of avoided emission calculations will help quantify the benefits of renewable energy, which will in turn address some of the current obstacles to development. These insights also have important implications for political debates over energy policy such as the inclusion of clean energy generators in emissions markets.

This analysis focuses on the potential environmental benefits of wind power. Specifically, the avoided air emissions due to operation of offshore wind power in New England will be assessed. As the first proposed offshore wind farms in the United States are undergoing reviews, a major issue in the debates surrounding these projects is what benefits they will produce. Accurately

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1 In this report, an energy “program” refers to an organized set of actions (such as deploying renewable energy technologies) and may consist of many “projects,” which are individual installations (such as a particular wind farm).

2 Energy efficiency programs, like renewable generation, have much potential for reducing emissions from power plants. While most of the analysis in this report is applicable to both demand-side and supply-side measures, renewable electricity programs are the focus of this thesis.
quantifying the avoided emissions from these wind farms is important to informing these debates.

While there are many externalities of fossil fuel electricity generation, the costs of only a few pollutants have begun to be internalized in the U.S. Calculating avoided emissions of clean energy resources such as wind power is essential to capturing this potential value. Offshore wind resources, with their significant generation potential year-round and their strong winter peaks, are well positioned to profit from any offered monetization of these environmental externalities.

This report informs policymakers and other stakeholders in the arena of wind power development about the challenges in and value of estimating avoided emissions. The rest of this chapter explains why this topic is important to the different stakeholders and relates how one offshore wind project developer, Cape Wind Associates, has been describing its project’s proposed environmental benefits. The next chapter explains why estimating avoided emissions is difficult and shares current government guidance on the matter. The third chapter briefly describes many commonly used methods for calculating avoided emissions and selects a few for further investigation. In the fourth chapter, those selected methods are applied to potential offshore wind energy resources in New England and the resulting avoided emissions estimates are compared. The last chapter articulates important implications from this analysis for the various stakeholders and then makes recommendations for future action.

**Why are Avoided Emissions Important?**

Electricity generation is the dominant industrial source of air emissions in the United States. According to the U.S. Environmental Protection Agency (EPA), fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide (SO2) emissions, 23 percent of nitrogen oxide (NOx) emissions, and 40 percent of carbon dioxide (CO2) emissions, as well as significant amounts of other pollutants (EPA, 2006b). These and other emissions (like mercury (Hg) and particulate matter (PM)) can lead to smog, acid rain, haze, and climate change and contribute to negative health and other environmental impacts. Given these adverse effects of
fossil fuel power plants, many argue that programs and projects that reduce these emissions should be developed and valued according to their positive impact.

Calculating avoided emissions due to the operation of renewable energy technologies will inform the debates over their benefits and will help quantify the value of those resources. This information is important to many of the stakeholders in the electricity industry, including citizens, governments, utilities, and developers. The various stakeholder interests in quantifying avoided emissions can be summarized as follows:

<table>
<thead>
<tr>
<th>Stakeholder</th>
<th>Main Benefit from Avoided Emission Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Citizens</td>
<td>Understand environmental benefits and value of “green” power</td>
</tr>
<tr>
<td>Governments</td>
<td>Meet environmental regulations at least cost</td>
</tr>
<tr>
<td>Utilities</td>
<td>Meet environmental regulations at least cost</td>
</tr>
<tr>
<td>Developers</td>
<td>Support project approval and ease permitting</td>
</tr>
</tbody>
</table>

Citizens benefit from reduced emissions by enjoying improved air and water quality and decreased greenhouse gases (GHG). Analysis of avoided emissions is essential to estimating the health and environmental benefits (such as lower health costs) of energy programs and projects will help citizens better understand the positive impacts of clean energy resources. This will help citizens understand the value proposition of “green” power, and will inform their decisions on proposed energy legislation and project development.

State and local governments are interested in clean energy sources to meet external and internal regulations and voluntary programs regarding environmental quality and renewable electricity. Renewable power plants help states comply with federal legislation such as the Clean Air Act and EPA regulations like the Clean Air Interstate Rule. EPA has said the benefits of calculating emissions reductions of clean energy sources include helping agencies choose the best investments in a clean energy program, reducing compliance costs, and adding new options for environmental solutions (EPA, 2006c, pp. 3–47-48).
Utilities and other load-serving entities and power plant operators, because they must comply with federal, state, and local regulations, follow the incentives of governments. Avoided emission assessments help these stakeholders determine the best environmental solutions.

There are many policies at the state level that encourage renewable energy development, and quantifying the environmental benefits of these policies helps justify their existence. As of March 2006, 20 states including four New England states (Massachusetts, Maine, Connecticut, and Rhode Island) had Renewable Portfolio Standards (RPS) that require some minimum amount of electricity to be supplied by renewable sources (DSIRE, 2006). As of May 2004, 28 states including all of the New England states had voluntarily completed state climate change action plans, which encourage development of renewable energy resources as a way to reduce GHG emissions (EPA, 2005). In December 2005, seven states including Connecticut, Maine, New Hampshire, and Vermont launched the Regional Greenhouse Gas Initiative (RGGI), a regional cap and trade program covering carbon dioxide emissions from power plants in the region (RGGI, 2006). A major justification for these policies has been to improve environmental quality. Quantifying the avoided emissions from renewables is essential to assessing the degree of environmental enhancement from these policies.

Environmental benefits analysis also informs policymaking. Having detailed information on electricity grid operation and unit interaction will allow decision makers to create programs that achieve maximum benefit. Useful methods and tools to analyze the impacts of clean electricity production are essential to informing decisions on programs designed to improve air quality and meet other regulations. Due to the complexities of the electricity system, limited knowledge of its dynamics may serve the creation of counterproductive policies.

Developers of renewable energy projects are also interested in calculating avoided emissions. For example, Cape Wind Associates, Long Island Offshore Wind Park, and other wind developers share much information on their websites about their projects’ projected environmental benefits (the Cape Wind proposed benefits will be discussed in the section

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3 In June 2005, VT enacted a renewable portfolio goal and will consider a RPS (DSIRE, 2006). NH is considering the issue (RenewableEnergyAccess.com, 2005).
below). These developers publish this information on expected avoided emissions, along with amounts of dollars and lives saved from reduced pollution, to help quantify their projects’ benefits and increase approval and ease the permitting process.

By enabling the quantification of a project’s environmental benefits, calculation of avoided emissions facilitates the completion of environmental impact assessments. Professor of Law Dorothy Bisbee maintains that environmental impact assessments to meet National Environmental Policy Act (NEPA) requirements should focus more on the environmental benefits of proposed projects (Bisbee, 2004). Calculations of avoided emissions allows one to compare the likely environmental and health impacts of the alternatives to the proposed project. Such comparisons of environmental performance will likely favor renewable energy projects, helping the case for their development.

Markets for emissions permits may provide an additional opportunity for developers of renewable energy projects to secure revenue. In the U.S., there are currently values for SO2, NOx, and CO2 emissions offsets. A national “cap and trade” program exists for emission allowances for SO2 (Title IV Acid Rain program) and a regional one exists for NOx in the eastern U.S. (SIP Call). While there currently is no national regulation for CO2, a market for CO2 emissions reductions has been created in the Chicago Climate Exchange (CCX) and some states and regions have developed GHG cap and trade programs (e.g. RGGI in the northeastern U.S.). Therefore, the emissions markets provide another potential source of revenue for renewable energy generators such as wind plants.

Despite the existence of these emission markets, their structure generally does not allow renewable power plants to participate (at least directly). The national SO2 market currently discourages renewable participation, and only seven states (including MA and NH) currently allow participation in NOx programs (Holt and Bird, 2005, pp. 52-54). In CO2 markets, renewables can participate in the CCX only under certain circumstances and it is not yet determined whether renewables may become eligible for CO2 permits in RGGI. Being able to

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4 EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005, which will phase in new caps for NOx and SO2 emissions beginning in 2009 (EPA, 2006).
quantify the emission offsets of renewables will allow developers and policymakers to discuss
the pros and cons of including renewable technologies in these programs.

**Statements about the Environmental Benefits of Cape Wind**

Cape Wind Associates, on its website and in its permit application materials including the Draft
Environmental Impact Statement (DEIS), makes statements about how much emissions will be
avoided by the proposed wind farm. The Cape Wind DEIS states that the wind farm would have
offset 4,000 tons of SO2, 1,180 tons of NOx, and 949,000 tons of CO2 had it operated in 2000
(USACE, 2004, p. 5–254). The source of the emission rates used in this estimation is cited as the
Rate Analysis.” The DEIS acknowledges that emission offsets may change over time and, in
fact, the amount of emissions that would have been avoided by the Cape Wind project in 2000 is
likely higher than the amount that would have been offset in more recent years (as will be shown
later).

On its FAQs website, Cape Wind Associates addresses the question “How would Cape Wind
reduce air pollution and greenhouse gasses?” by stating,

[W]ind farms provide even greater environmental benefits because their operations
reduce the amount of fossil fuel power that needs to be generated, thereby reducing the
amount of pollution that goes into the air. Using the methodology Massachusetts State
agencies use to estimate air pollution reductions from wind farms, Cape Wind would
reduce by several thousand tons per year air pollutants that harm human health. Cape
Wind would also reduce about 880,000 tons of carbon dioxide emissions in New
England, a greenhouse gas causing climate change. [emphasis added] (Cape Wind,
2006c)

The differences in the amounts of avoided emissions between the two statements are likely due
to the use of different methods of calculation. Another set of estimates is available from Clean
Power Now, an organization formed in support of Cape Wind, which states that the project will
offset 2,400 tons of SO2, 800 tons of NOx, and 1,000,000 tons of CO2 (Kleekamp, 2006a and
2006b). The Clean Power Now calculations rely on the ISO-NE “2002 NEPOOL Marginal
Emission Rate Analysis.”
For all stakeholders in the electricity industry, especially those debating the value of renewable energy programs and projects like Cape Wind, the issue of emissions reductions is important. Therefore, the accuracy of avoided emissions calculations is important to ensure valid arguments are being made in the debate. The next chapter explains some of the major issues with estimating avoided emissions from renewable energy and describes current guidance for making these calculations.
CHAPTER 2: One Complex System Plus Soft Guidance Equals a Tough Task

Quantifying avoided emissions from renewable energy programs and projects requires an understanding of the dynamics of the electricity system. Because this system is complex, it is not a trivial task to accurately calculate avoided emissions. To help regulated entities with this challenge, government organizations have issued guidance on how to estimate avoided emissions. This guidance is as detailed as is possible given the uncertainty in estimating operations of the electricity system, but regulated entities retain a great deal of freedom to choose from a variety of methods to calculate avoided emissions. The current guidance is too flexible to provide a robust framework to enable decision makers to evaluate the best environmental solutions. This chapter first highlights important issues that create complexity in this system and then reviews the existing guidelines on calculating avoided emissions.

Complexities of the Electricity System

There are many issues to consider when calculating avoided emissions because the operation of the electric power system is complex and many impacts are hard to determine. For example, it is often difficult to identify which generating units will reduce output as a response to increased renewable generation. Faced with lower demand, local companies may sell more power out of the region, as long as transmission capacity is sufficient. Not only do generating unit operations change on an hourly and seasonal basis according to demand swings, operating costs, and availability, but the makeup of the system supply changes over time as plants get built and retire.

For an accurate analysis of avoided emissions, one must identify which generating units will reduce output (or not get built) as a response to increased renewable generation or reduced demand. The identification of these “marginal” units can be accomplished in any of several ways, which differ in terms of sophistication and effort required (the next chapter provides a

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5 For a brief explanation of how the electricity system operates, see EPA’s “Clean Energy-Environment Guide to Action” (EPA, 2006c, p. 3-50).
discussion of methods). Methods based on average, system-wide emission rates are criticized for failing to identify the displaced generation or units, and are usually inaccurate.

The best technique to accurately identify the marginal units depends in part on the time frame under consideration. The short term is usually taken to be the time over which the electricity system components will not change dramatically – no plants get built or retired (that have not already been announced) – the present to several years in the future. The long term refers to the period for which the system may change dramatically from additions and retirements. For maximum accuracy for short-term avoided emissions, one should identify the marginal operating units (to calculate the operating margin) by matching generation to load for each hour, but many analysts agree that using several time periods in a year may also work (as will be shown in the next chapter). For maximum accuracy for the long term, one should specify which units retire or do not get built as a result of the program or project being analyzed (to calculate the build margin).

The major challenge in quantifying avoided emissions is that identification of the marginal units is complicated. Simply getting access to the necessary data on the existing set of generating units (operating costs, emission rates, etc.) is often difficult. Accurate information about the future is also hard to come by. Many of the useful data are proprietary or are contained in large databases that are hard to access. Data that are available are often old and less applicable to a rapidly changing system. For example, the EPA Emissions & Generation Resource Integrated Database (eGRID) has data only through 2000, although more recent data (yet less organized) are available through other databases.

Even with data on existing generators, their reaction to increased renewable generation or reduced demand is hard to determine because of the interconnected nature of the electricity grid. For example, many generators are dispatched for reliability and not economic purposes and may not reduce output as renewable generation increases. Also, taking advantage of long-distance
transmission capacity, local generators may export surplus power to neighboring regions rather than reducing output. Similarly, local demand may be met by imports from neighboring regions (depending on the status of electricity competition) and it is those neighboring generators that will be backed down. If either situation is the case, then the marginal units may be outside of the boundaries of the region with the renewable generation. These issues, and any transmission constraints, are important to keep in mind when defining the geographic boundaries of the system.

These issues are particularly important to New England, which is currently a net exporter of power to New York (though it used to be a net importer, and may become one again). Because marginal generation (and therefore marginal emission rates) is dirtier in New York than in New England, it is important to include both regions in an analysis of New England avoided emissions (Keith et al., 2002).

In addition to geographic issues, timing of demand and supply is important. At different times of the day and of the year there are varying levels of electricity demanded, due mainly to human behavior and weather. To meet fluctuating demand, different kinds of generating units are relied on at different times. The figure below shows the electricity demand of New England in 2002. One should notice the annual peak in the summer as well as the general trend of higher demand during the day and during the summer.
Now that the demand profile is clear, we next turn to the supply profile. The figures below show the New England supply curve in 2002 with the generating units’ SO2 and NOx emission rates plotted along the vertical axis (Keith et al., 2002). The first 7,000 MW in the New England system is hydroelectric and nuclear baseload capacity and therefore has zero emissions. From 7,000 to about 13,000 MW are the region’s fossil-fueled baseload and load-following plants, with units with high emission rates. From 13,000 to 21,000 MW are mostly relatively new gas-fired combined cycle combustion turbine (CCCT) plants (with very low emission rates) as well as some oil- and gas-fired steam units. Above 21,000 MW lie higher cost oil- and gas-fired steam units and peaking units (gas-fired combustion turbines (CT)) with high SO2 and/or NOx emission rates.

These two figures show that the emission rates of New England generators vary widely across different types of units. Because the generating units at the intersection of the demand and supply curves are typically the marginal units, marginal emission rates will change over the course of a

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8 The emission rates along the New York and PA-NJ-MD-DE (PJM) supply curves follow a similar shape, except that the rates are higher in New York and even higher in PJM.
year because the demand curves fall on different areas of the supply curve during different periods. To help illustrate this, the minimum, average, and maximum hourly electricity demands for New England in 2002 are also shown below. The minimum hourly load was about 9,300 MW, the average was about 15,000 MW, and the maximum was about 26,000 MW. The marginal emission rates for New England generators (not taking into account imports or exports) for 2002 likely were between 0 and 10 lbs/MWh for SO2 and between 0 and 6 lbs/MWh for NOx. As these are very wide ranges, the next chapter will look to various published methods for help in identifying which units are affected by renewable generation and in estimating the marginal emission rates.

Figures 2-2a. and 2-2b. SO2 and NOx Emission Rates Along the New England Supply Curve in 2002

The above figures illustrate the importance of timing in estimating avoided emissions. Within a year, hourly and seasonal factors such as demand swings and fuel costs, as well as environmental
regulations such as the summer limits on NOx emissions, must be taken into account when determining the marginal generation and the marginal emission rates. Additionally, the generation profile of the renewable energy project to be assessed needs to be accurately described. In the case of offshore wind power, there is great variation of wind speeds over a day and over a year (as will be shown later), which should be taken into account to accurately predict the impact of the wind energy on the electricity system.

Even if intra-annual factors are addressed, accuracy of marginal emission analysis is not guaranteed unless the dynamic nature of the electricity system is accounted for. Features such as increasing electricity demand and plant additions and retirements cause marginal emission rates to change on an inter-annual basis. For short-term analyses (of two to three years), the main task is discerning which existing generating units will be affected by the renewable generation. For long-term analyses, the key task is to predict what types of generating units will be added and retired as a result of the operation of the renewable resources. As will be shown, different tools and methods are better suited for each time horizon.

As an example of the long-term trend for marginal emission rates, New England rates have been coming down over time (see the figure below).

Figure 2-3. Historical New England Marginal Emission Rates

![Figure 2-3. Historical New England Marginal Emission Rates](image)


9 The NOx compliance period or “ozone season” ran from May 1 to September 30 each year until 2004, when it changed to May 31 through September 30 each year (EPA, 2006e).
New England marginal SO2 and NOx emission rates have come down 84% between 1993 and 2003, while CO2 rates have come down 28% (ISO-NE, 2004). This has been mainly due to the tightening of environmental regulations and the construction of cleaner power plants, including the addition of several thousand MW of natural gas-fired CCCT plants between 2000 and 2003. This shows that historical and possibly even current marginal emission rates may not be indicative of future rates.

Continuing this trend, Synapse Energy Economics has produced a set of default marginal emission rates to use in their OTC Emission Reduction Workbook for analysis of avoided emissions in New England for 2002 through 2020 (Keith et al., 2002). As one can see in the figure below, while rates are expected to continue to decline initially, they level off as the likely best (and cleanest) technology is introduced and becomes the standard. Synapse’s near-term marginal emission rates are the result of some electric power system simulation modeling, while their medium- and long-term emission rates are derived from a blending of existing plant expected operation (as characterized by their model) and likely future plant additions and retirements.

Figure 2-4. Possible Future New England Marginal Emission Rates

[Graph showing emission rates for SO2, NOx, and CO2 from 2002 to 2014]

* CO2 rates in Lbs/kWh


When using the OTC Emission Reduction Workbook default emission rates or any other method to estimate avoided emissions, one should be aware of the size of the program or project for
which the method is valid. Some methods may only be applicable for small changes to a system (on the order of megawatt hours (MWh)) while other methods may better suit large changes (in terawatt hours (TWh)).

As can be seen, there are a great number of issues to address when attempting to quantify avoided emissions from renewable energy projects. The next section describes current guidance from government authorities on calculating avoided emissions.

**Current Guidance on Calculating Avoided Emissions**

In the U.S., the Environmental Protection Agency (EPA) provides official guidance on calculating avoided emissions from renewable energy and energy efficiency resources. Internationally, the United Nations Framework Convention on Climate Change (UNFCCC) has set guidelines for calculating avoided greenhouse gas (GHG) emission credits for the Kyoto Protocol. Both organizations provide detailed, yet flexible guidelines for estimating avoided emissions that address many of the complexities of the electricity system. Given the complexities of the electricity system and the uncertainties in estimating avoided emissions, the current guidance is too flexible to enable decision makers to evaluate the best environmental solutions.

EPA discusses calculating avoided emissions from renewable energy resources in its guidance documents on incorporating energy efficiency and renewable energy measures into State Implementation Plans (SIP).\(^\text{10}\) Although these guidance documents focus on NOx emissions reductions to meet ozone standards, the procedures to quantify and validate emissions reductions are applicable to other pollutants.

The EPA guidance specifies four criteria for crediting emission reductions: Quantifiable, Surplus, Enforceable, and Permanent (EPA, 2004a, pp. 5-7). To meet each of these criteria, some degree of quantification of avoided emissions is required.

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The procedure for meeting the Quantifiable criterion has four steps (EPA, 2004a, pp. 11-12):

1. Estimate the energy savings or amount of renewable generation
2. Convert energy impact into an emissions reduction
3. Determine the effect on air quality
4. Validate the effect

While the first step is relatively straightforward, the “critical” second step, accurately converting energy impact into an amount and a location of emissions reduction, is quite difficult because the electricity system is very complex. However, EPA provides a simple procedure to follow.

To convert energy impact into an emissions reduction, EPA explains that one first identifies which facilities will likely reduce their energy output as a result of the measure and then determines the emission rate in pounds per kilowatt-hour (lbs/kWh) of those facilities (EPA, 2004a, pp. 14-15). The emissions reduction is calculated by multiplying the decrease in the facilities’ energy output by the emission rate for the group of facilities. If the affected facilities are of different sizes or have different emission rates, the use of an average emission rate is unreasonable and one should instead calculate the emission reduction for each facility and then add them (EPA, 2004b, p. 16).

Unfortunately, these procedures are oversimplified given the complexity of the electricity system, as explained in the previous section. EPA does concede that in some cases it might not be possible to identify the specific facilities affected (EPA, 2004a, pp. 14-15). In those cases, approaches such as simulating the expected plant dispatch with computer modeling or making reasonable assumptions based on historical or projected information may be used. Although the guidance notes that dispatch models are not necessary for acceptable quantification of expected emission reductions, projections of avoided emissions based on historical data or using very simple methods may prove difficult to accurately estimate avoided emissions.

To handle uncertainty, EPA suggests using a variety of tools and techniques to reduce the uncertainty to a manageable factor. EPA maintains that by “using conservative assumptions, appropriate discount factors or verification techniques,” one may “apply existing tools with
sufficient rigor to be able to quantify estimated emission reductions with acceptable certainty” for SIP purposes (EPA, 2004a, p. 11). In the next chapter, we will take a look at the existing tools and determine how rigorous their application has been.

The Surplus criterion for emission reductions is met as long as the reductions are not in a “baseline” or otherwise relied on to meet related regulations (EPA, 2004a, p. 5). This requirement is especially important in areas subject to a “cap and trade” program. If the allowable amount of emissions in a system is capped and permits to emit are tradable, there may be no system-wide net reduction from energy efficiency and renewable energy measures because polluting plants may transfer pollution in time and/or space as permits may be sold or banked. In such a system, while these measures may not reduce emissions, they may reduce system costs of meeting the caps. EPA notes that the estimated emission reductions can be maintained even under a cap and trade program by retiring allowances that account for the emission reductions expected from the measure or by proving that emissions decrease despite the cap and tradable permits (EPA, 2004a, p. 10).

The requirements of the Enforceable criterion include the emission reduction measure must be “independently verifiable,” violators can be identified, and citizens must have access to information on the emissions and the reduction measure (EPA, 2004a, pp. 6-7).

This brings up the issue of ownership of emission reductions. Just as violators must be identified, so must benefactors. Unless determination of ownership is clear, there will be conflict between the entity that creates the emission reduction and the facilities that are the ultimate source of the emissions because each will want the benefit of the offset (Erickson et al., 2004, p. 7-6). To address this issue, EPA has provided guidance on “set-asides” for energy efficiency and renewable energy measures whereby some emission allowances may be distributed to such projects instead of to polluting facilities (EPA, 2004a, p. 19).

The Permanent criterion requires that the emission reduction last for as long as the credit is granted (EPA, 2004a, p. 7). This requires monitoring and verification that the reductions remain constant. The verification process should make sure that the emission reduction measures in one
state or region do not result in an increase in electricity exports to neighboring areas and no real change in the emissions from the local power plants.

Overall, EPA is quite flexible in its guidance on how to quantify avoided emissions from energy efficiency and renewable energy measures. The emphasis on accurately identifying the location of the affected facilities and the displaced emissions promotes analytical rigor. EPA also lists other important issues to consider when estimating avoided emissions, such as status of deregulation and transmission line losses (like those discussed in the previous section). However, given the complexities of the electricity system and the uncertainties in estimating avoided emissions, the current guidance is too flexible to guide decision makers to choosing the best environmental solutions in terms of greatest impact or least cost.

The enactment of the Kyoto Protocol has generated a good deal of literature on quantification of GHG emission reductions. Guidance on how to estimate avoided GHG emissions from renewable resources ranges from the very general to the very specific. For example, the Greenhouse Gas Protocol Initiative (GHG Protocol), while it lists important accounting issues like making sure that the emission reduction is in addition to what would have happened in the absence of the project, does not mention specific quantification methods (WBCSD and WRI, 2005). However, the UNFCCC is quite specific in describing acceptable methods for estimating GHG emission reductions under the Kyoto Protocol’s Clean Development Mechanism (CDM) (UNFCCC, 2006).

The current method for calculating CDM credit for GHG emission reductions from renewables is to use a weighted sum of the “operating margin” (OM) and the “build margin” (UNFCCC, 2006, p. 5). These margins may be calculated using any of several approved methods.

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11 The GHG Protocol is initiating a task force to develop guidance on accounting for project-based reductions and expects to release a “GHG Protocol Project Quantification Standard” (WBCSD and WRI, 2005).
12 Operating margin is the effect of a resource on the operations of current power plants. Build margin is the effect on future plants, in terms of additions or retirements.
There are four acceptable methods for estimating the operating margin (UNFCCC, 2006, pp. 5-9):

a. Average OM – use an average emission rate for all power plants including low-operating cost and must-run power plants
b. Simple OM – use a generation-weighted average emission rate of all generating sources in the system, excluding low-operating cost and must-run power plants
c. Simple Adjusted OM – use a generation-weighted average emission rate of generating sources that are marginal, identified by matching the supply curve of the generators in the system to the annual load duration curve\(^{13}\)
d. Dispatch Data Analysis OM – use hourly generation-weighted average emission rates of the power plants in the top 10% of the system dispatch order during each hour

The Dispatch Data method is the preferred method of the UNFCCC because it most closely represents the emission rates of the units on the margin in each hour. It is challenging to use, though, as it requires data on the system dispatch order that are likely inaccessible and therefore subject to approximation. The Simple Adjusted method is the next most rigorous method, as it attempts to identify the marginal units, but on an annual basis. The Simple method is only more robust than the Average method in that the Simple method excludes low-operating cost and must-run power plants, which are unlikely to be marginal.

To calculate the build margin, the UNFCCC guidance suggests using generation-weighted average emission rates either from the five most recently built power plants or from the most recently built power plants that comprise 20% of the system generation (UNFCCC, 2006, p. 9). As discussed in the previous section, the recently built plant may not represent the plants likely to be built in the future.

Once the operating margin and build margin have been calculated, they are weighted,\(^{14}\) and then summed together to give the combined emission factor to be used in crediting projects. This approach is interesting in its attempt to simultaneously account for the operating and build

\(^{13}\) A duration curve is sorted highest to lowest.

\(^{14}\) The default weights are 50/50.
margins. In contrast, the EPA guidance allows a regulated entity to choose either a historical or prospective method and justify its use in requesting credit for present or future emission reductions.

Despite the varying guidance and the existence of many methods to estimate avoided emissions, there are several common attributes in determining a given technique's appropriateness. To assess avoided emissions methods, I have adapted the GHG Protocol's five guiding principles for emission accounting systems (see WBCSD and WRI, 2005), listed below:

- **Accuracy** – the method addresses all relevant issues in a factual and coherent manner, to ensure that the quantification of emission reductions is systematically neither over nor under actual reductions (as far as can be judged), and that uncertainties are reduced as far as practicable, to enable users to make decisions with reasonable assurance as to the integrity of the reported information

- **Relevance** – appropriately accounts for the complexities of the particular system under review and serves the decision-making needs of users

- **Completeness** – accounts for all emission sources, reduction activities, and dynamics within the system and discloses and justifies any specific exclusions

- **Transparency** – discloses any relevant assumptions such as system boundaries and makes appropriate references to data sources and accounting and calculation methodologies

- **Consistency** – uses consistent methodologies to allow for meaningful comparisons of emissions reductions over time

In the next chapter, I invoke these principles to assess different methods that may be used to calculate avoided emissions from offshore wind power in New England.
CHAPTER 3: Today’s Menu of Methods for Quantifying Avoided Emissions

Now that the major issues involved in calculating avoided emissions have been discussed, we can review existing methods and select those applicable to assessing emissions reductions from offshore wind power in New England. This chapter describes and compares on a qualitative basis the wide variety of existing methods. The following chapter compares a few selected methods on a quantitative basis for offshore wind in New England.

I classify avoided emissions methods into three different categories: Modeling, Non-modeling or Accounting, and Hybrid. Descriptions of existing methods have been collected from publications by EPA and various research and consulting organizations. These methods differ most in terms of relevance, completeness, and transparency, when applied to calculating avoided emissions from renewable generation in a region such as New England.\(^\text{15}\) The methods reviewed in this chapter are listed below:

Methods

A. Modeling
   1. Dispatch Models
   2. Forecasting / Optimization Models

B. Non-Modeling / Accounting
   1. Geography
   2. Unit Type
   3. Load Curve
   4. Capacity Factor
   5. Dispatch Data

C. Hybrid

\(^{15}\) Although listed as a guiding principle, accuracy is difficult to determine \textit{a priori}, and will only be loosely judged in this paper. Consistency, while useful over time, is not a practical principle in the present analysis.
A. Modeling

Because the operations of the electricity system are so complex, analysts often employ computer models to simulate it. Such tools are often classified as either dispatch models or forecast / optimization models (Keith and Biewald, 2002).

Dispatch models incorporate a detailed representation of the existing electricity system and simulate unit dispatch to meet hourly loads, often in a chronological way (but sometimes using a load duration curve). They usually involve shorter time periods, on the order of a few years, and often do not cover large geographic areas, instead focusing on one or several regions of a country.

Forecast / optimization models are designed to predict capacity additions and retirements over longer time frames (up to many decades), but often in larger time steps (seasons or years). They are broader in scope than dispatch models, often covering several energy sectors, larger geographic areas, while aggregating units and transmission system components. They usually operate iteratively, eventually converging on an optimal solution.

To use such tools to estimate avoided emissions, modelers often first run a “Base Case” without the program or project in question, and then run an “Alternative Case,” which is sometimes called a decrement run (if reducing demand due to an efficiency program) or an increment run (if adding renewable generation). The modeler then subtracts the results of one run from the other to calculate the change in emissions and generation.

While such tools are powerful, there are always limits to model capability and modeling techniques. Many databases underlying models need to be revised or updated and there is a lack of up to date and useful publicly available information. Also, different analyses require different geographic resolutions and some models may be less applicable to certain system sizes. Models differ in how they handle dispatch and emission trading and uncertainties like future plant construction, duration of emission offset credits, fuel prices, and policy constraints. As a result of these challenges, there is usually a tradeoff between model accuracy and cost.
As cost generally increases with model sophistication, many non-modeling alternatives have been developed. Synapse distinguishes “dynamic models” like dispatch and forecast/optimization models from “static methods based on data sorting and arithmetic” (Keith et al., 2004). I label these static methods as “accounting” techniques because of their reliance on databases and simple calculations, and describe them later in this chapter. We now review some methods of calculating avoided emission using dynamic models.

1. Dispatch Models

The most common method of estimating avoided emissions involves the use of a dispatch model. Some commonly used dispatch models include PROSYM/MULTISYM, General Electric’s Multi-Area Production Simulation (GE-MAPS), PROMOD, and ELFIN. PROSYM and GE MAPS simulate dispatch chronologically, while PROMOD and ELFIN do not.

One case of using a dispatch model to calculate avoided emissions is the Independent System Operator of New England (ISO-NE) Marginal Emissions Analysis (MEA). ISO-NE developed the yearly “NEPOOL Marginal Emission Rate Analysis Report” to assess the impact that demand-side management (DSM) programs have on power plant emissions of SO2, NOx, and CO2 (ISO-NE, 2004). The 2002 Report, and previous reports, used the PROSYM dispatch model.16 PROSYM is a highly detailed chronological dispatch model simulating demand and supply constraints as well as ISO rules such as operating reserves for one control area or for a group of control areas.

The PROSYM model was run twice for ISO-NE, producing a “Reference Case” and a “Marginal Case.” The Reference Case served as a baseline by simulating the actual loads of each day for the single year of study. The Marginal Case was an increment run with all hourly loads increased by 500 MW to simulate the effect of not having DSM programs in place. Results of New

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16 The ISO-NE Marginal Emission Rate Analysis for 2003 used the Inter-Regional Electric Market Model (IREMM) dispatch model, which is similar to PROSYM (ISO-NE, 2004). The 2004 report published in May 2006 uses a new method to calculate marginal emission rates (not a dispatch model), but was released too late to be assessed in this thesis.
England region-wide marginal emission rates were reported for five time periods for the year, including an annual average. The figures below show the results of this method for 2000 and 2002.

**Figure 3-1. New England Marginal Emission Rates for 2000 (Lbs/MWh)**

<table>
<thead>
<tr>
<th>Emission</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
<th>Annual</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On-Peak</td>
<td>Off-Peak</td>
</tr>
<tr>
<td>SO2</td>
<td>6.6</td>
<td>6.0</td>
<td>6.3</td>
<td>5.9</td>
</tr>
<tr>
<td>NOx</td>
<td>2.0</td>
<td>1.8</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>CO2</td>
<td>1,545</td>
<td>1,505</td>
<td>1,463</td>
<td>1,440</td>
</tr>
</tbody>
</table>

Source: 2000 NEPOOL Marginal Emission Rate Analysis (ISO-NE, 2002)

Note: Ozone season is defined as May 1 to September 30. Non-ozone season consists of all other days. On-peak is defined as 8AM - 10PM weekdays. Off-peak consists of all other hours.

**Figure 3-2. New England Marginal Emission Rates for 2002 (Lbs/MWh) and Change from 2000 (%)**

<table>
<thead>
<tr>
<th>Emission</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
<th>Annual</th>
<th>Average</th>
<th>Ozone</th>
<th>Non-Ozone</th>
<th>Annual</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On</td>
<td>Off</td>
<td>On</td>
<td>Off</td>
</tr>
<tr>
<td>SO2</td>
<td>3.7</td>
<td>2.0</td>
<td>4.9</td>
<td>3.0</td>
<td>3.3</td>
<td>-44%</td>
<td>-67%</td>
<td>-22%</td>
</tr>
<tr>
<td>NOx</td>
<td>1.4</td>
<td>0.8</td>
<td>1.5</td>
<td>1.0</td>
<td>1.1</td>
<td>-30%</td>
<td>-56%</td>
<td>-17%</td>
</tr>
<tr>
<td>CO2</td>
<td>1,412</td>
<td>1,171</td>
<td>1,536</td>
<td>1,300</td>
<td>1,338</td>
<td>-9%</td>
<td>-22%</td>
<td>5%</td>
</tr>
</tbody>
</table>

Source: 2002 NEPOOL Marginal Emission Rate Analysis (ISO-NE, 2003)

The 2000 values were referenced in the Cape Wind DEIS (see USACE, 2004, p. 5–254) while the 2002 annual values have been used in Clean Power Now statements about the emission impacts of the Cape Wind project (see Kleekamp, 2006a and 2006b). It is important to note that the 2002 values are substantially lower than the 2000 values; the SO2 values are about 50% lower, NOx values are about 40% lower, and CO2 values are about 10% lower.

This method is likely complete because it uses a highly detailed chronological dispatch model covering the entire New England region and accounts for transfers with neighboring regions. Although this method does not take into account changes in generation on neighboring regions, as a retrospective analysis it is likely more accurate than prospective modeling. The method is less relevant to a projection of avoided emissions because it looks backwards and at only one year at a time, given the downward trend of marginal emission rates over time. Also, because this method was developed to assess the emission impacts from DSM programs, it is not perfectly appropriate to estimate potential avoided emissions from renewable energy projects such as Cape Wind. However, as the reports feature transparent documentation and provide easily accessible marginal emission rates for New England, it has been used for many of the
estimates of the Cape Wind project’s potential emissions impact and will be analyzed in more
detail in the next chapter.

Synapse Energy Economics used the PROSYM model to develop a tool for the Ozone Transport
Commission (OTC) to estimate emissions impacts of energy efficiency and renewable energy
projects in the northeastern U.S. (Keith et al., 2002). The model was used to calculate default
marginal emission rates for the years 2002 through 2020 for SO2, NOx, CO2, and Hg for New
England, New York, and the PA-NJ-MD-DE system (PJM), though users have the option of
inputting their own marginal emission rates into the tool. The default rates for the near-term
(2002 through 2005) are based on operation characteristics of existing electricity systems; the
rates for the medium-term (2006 through 2010) are a blend of the near-term factors and
new/retired plant emission rates; while the factors for the long-term (2011 through 2020) are
based purely on new/retired plant emission rates. Typical load profiles are provided as a default
or input by the tool user. The user allocates projected energy production or savings to six
different time periods and the tool calculates the avoided emissions. The figure below shows the
annual average default rates of this method (see the Appendix for all of the default rates for New
England).

![Table showing annual average default marginal emission rates for New England (Lbs/MWh) and change from 2002 to 2010 (%)]

Source: OTC Emission Reduction Workbook 2.1: Description and Users Manual (Keith et al., 2002).
Annual Averages.
Note: Although not shown here, this table extends through 2020.

This method is likely complete because it uses a detailed dispatch model covering the
northeastern U.S. and eastern Canada and accounts for transfers between neighboring regions. It
also takes into account both existing unit operation and future unit additions and retirements. The tool description and users manual provides sufficient transparency. The tool is very relevant to a projection of avoided emissions in New England because that is what it was designed for, and so it will be assessed quantitatively in the next chapter.

La Capra Associates also used PROSYM as part of their “La Capra Emission Model” to examine the emissions impact of renewable energy programs in New England (La Capra Associates, 2003). Looking at a few future years, and running several scenarios, La Capra estimated marginal emission rates for New England and its neighboring regions when new renewable resources are developed in New England. La Capra also defined another metric, called the “incremental emission rate,” which describes the emissions reductions occurring just in New England per unit of renewable generation added in New England. The figure below shows some of the results from the La Capra analysis (see the Appendix for more results of this method).

Figure 3-4. La Capra Marginal and Incremental Emission Rates for New England (Lbs/MWh) and Change from 2006 to 2009 (%)

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2009</th>
<th>2006-2009</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Marginal Emission Rate</td>
<td>Incremental Emission Rate</td>
<td>Marginal Emission Rate</td>
</tr>
<tr>
<td>SO2</td>
<td>3.6</td>
<td>2.5</td>
<td>1.7</td>
</tr>
<tr>
<td>NOx</td>
<td>1.3</td>
<td>0.9</td>
<td>0.7</td>
</tr>
<tr>
<td>CO2</td>
<td>1,088</td>
<td>748</td>
<td>982</td>
</tr>
</tbody>
</table>


La Capra’s 2006 emissions rates were based on the most recent publicly available information at the time of the analysis (EPA data from 2000-2001), as they assumed that there would be no major changes in emission rates from the early 2000s through 2006 (even though they determined that the addition of 7,000 MW of natural gas-fired generation in New England (through 2003) decreased total and marginal emissions). Their 2009 emission rates are based on EPA expectations, assuming compliance with future state and national emission regulations, as modeled in the 2010 “Renewables Scenario-Base Case” developed by the EPA using their electric system model IPM (described in the next section). La Capra’s SO2 and NOx rates are
projected to be about 50% lower in 2009 than in 2006 while CO2 rates are expected to be about 12% lower.

In doing this analysis, they found that added generation in New England increases exports to other regions and displaces units outside of New England. This is evidenced by the incremental emission rates being lower than the marginal emission rates. Their model showed that transmission constraints in New England matter when determining avoided emissions, and that fuel prices affect total emissions but not marginal emissions.

This method is likely complete because it uses a detailed dispatch model covering New England, New York, Quebec, and New Brunswick and accounts for transfers these regions. It also takes into account both existing unit operation and future unit additions and retirements. The documentation in the report provides sufficient transparency. The method is very relevant to an analysis of potential avoided emissions in New England, and it is particularly interesting as it analyzed the potential impact of offshore wind power. As such, it will be analyzed further in the next chapter.

2. Forecasting/Optimization Models

The next most common method of estimating avoided emissions involves forecasting / optimization models (see previous chapter for features of these models). Examples of forecasting models include the Integrated Planning Model (IPM), the National Energy Modeling System (NEMS), MARKAL-MACRO, ENERGY 2020, and AMIGA.

IPM is a linear programming model that simulates the integrated fuel, emissions, capacity and generation markets of the electricity sector of the U.S. (Kerr et al., 2002). It performs both dispatch and forecasting functions on a load duration rather than chronological time frame for user-specified regions. EPA and ICF Consulting have been using IPM extensively to analyze emissions impacts, and have developed a tool using a hybrid method of combining modeling with IPM and non-modeling techniques, which will be described below.
NEMS is a forecasting model developed by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) (Keith and Biewald, 2002). NEMS models energy markets by simulating the economic activity involved in producing and consuming energy products in regions of the U.S. over a time horizon of 20 years. The NEMS electricity module uses 11 load segments (instead of a chronological time frame) and includes both an electricity dispatch submodule and a capacity planning module.

The State and Territorial Air Pollution Program Administrators (STAPPA) and the International Council of Local Environmental Initiatives (ICLEI) commissioned work to develop a software planning tool for local communities to use in assessing different emission reduction strategies (Keith and Biewald, 2002). STAPPA and ICLEI hired Tellus Institute to develop these displaced emission factors using the NEMS model. Tellus derived annual marginal emissions factors for SO2, NOx, CO2 and PM10 for 2003 to 2020 for each of the 13 North American Electric Reliability Council (NERC) regions (including separate rates for New England and New York). Tellus performed a model run for a base-case (based on the EIA’s Annual Energy Outlook 2002) and a series of runs with a set of annual demand decrements, with the decrement model run reducing load by one percent in each year.

Tellus’ method is likely complete because it uses the powerful NEMS model, which can simulate unit dispatch for New England for a number of future years. On the down side, only one rate was calculated per year. While this method seems to be relevant to studying renewable energy emission impacts in New England, marginal emissions values have not been published and so it cannot be assessed further in this report.

MARKAL-MACRO was originally developed by Brookhaven National Laboratory and combines MARKAL, an energy engineering model, with MACRO, a macroeconomic model (GETF, 2005). It is a multi-sector model using linear algebra to solve many simultaneous equations, usually for national assessments for long time frames (20-50 years). The Northeast States for Coordinated Air Use Management (NESCAUM) have been developing a Northeast model (NE-MARKAL) with state-level data. Once that model is developed, it will be relevant to
analyzing avoided emissions in New England and should be assessed for completeness and accuracy. Until then, it will not be discussed further in this report.

ENERGY 2020 is based on the FOSSIL2/IDEAS model developed for the DOE and is maintained and operated by the Systematic Solutions, Inc., an energy consulting group (Keith and Biewald, 2002). ENERGY 2020 is a forward-looking policy assessment model designed for scenario analysis that simulates energy production, consumption and emissions levels while monitoring electricity capacity expansion, regulated rates and market prices, and changes in regulation. The model accounts for NOx, SO2, CO2 and PM10 for each plant type and uses load duration curves for NERC regions. The model can be joined with an AC load flow model (PowerWorld), which includes detailed information on transmission systems. The model is different from optimization models like IPM and NEMS in that it is not designed to converge on an optimal solution but instead simulates the way that energy markets actually work by focusing on market imperfections such as the exercise of market power. While the detail provided by the power flow model is useful, publicly available information is insufficient to determine whether this method is complete and relevant for use in evaluation of avoided emissions. As marginal emission rates have not been published, this method cannot be assessed further in this report.

AMIGA was developed by Argonne National Laboratory and is a multi-sector, economic model similar to MARKAL-MACRO (GETF, 2005). AMIGA is used to simulate the national economy on an annual basis out to 2050. AMIGA employs plant-level resolution (as opposed to unit-level) for the electricity sector, as do IPM and NEMS, but pollution control technology assumptions are less detailed than in IPM. As marginal emission rates have not been published, this method cannot be assessed further in this report.

Because of their potential, EPA has recommended studying the comparability of results across IPM, NEMS, and AMIGA (GETF, 2005). While such tools are powerful, there are limits to model capability and investigative resources like time and budget. For those reasons, many non-modeling or "accounting" techniques have been developed. Some prominent examples of these methods are described below.
B. Non-Modeling / Accounting

Most non-modeling methods attempt to identify the marginal units in a system using one of several accounting techniques, and then use the emission rates of these units to calculate avoided emissions. While many of these methods achieve sufficient completeness and transparency and often require fewer resources than running computer models, there are several drawbacks (Kerr et al., 2002). First, identifying the marginal unit is difficult, especially for all time periods and for each region of interest. Also, the marginal unit might not be economically dispatched or might be one of several units dispatched to meet marginal load. Accounting methods are usually based purely on historic data and so are often not appropriate for making long-term forecasts of avoided emissions. Finally, access to sufficient data is often limited and the computation required for detailed analysis is often complicated and arduous. In spite of these challenges, many research and consulting organizations have published avoided emission analyses using non-modeling methods.

Synapse (see Keith and Biewald, 2005 and Keith et al., 2004) has described five non-modeling methods of estimating avoided emissions that identify the marginal generating units using different criteria. They are listed below in order of increasing completeness:

1. Geography
2. Unit type
3. Load curve
4. Capacity factor
5. Dispatch data

In all of these methods, after the marginal units are identified, marginal emission rates are calculated and then multiplied by clean generation (or energy savings) to estimate emissions reductions. These methods differ most in terms of completeness and labor-intensiveness and are described below.
1. Geography

To identify marginal units by geography, one would simply choose a certain geographic area and then use emission rates averaged from the selected plants or units. One example of a method that identifies marginal units by geography has been developed by NREL (Chambers et al., 2005). NREL created a method (called the Plant Average Method) that estimates emissions displaced by specific energy efficiency programs by using EPA eGRID data from 2000 to calculate emission rates from generating units defined by geography and, in some cases, by ownership. Emission rates were calculated for geographic scales ranging from national to city-wide for annual and seasonal time frames.

This represents the simplest method as it does not attempt to distinguish which generating units are on the margin during the hours that the project or program operates and ignores imports and exports. While this method is very transparent, and may be relevant, it is likely the least accurate of all methods described here and will not be assessed further.

2. Unit Type

To identify the marginal units by unit type, one would choose certain types of generating units, usually classified by the fuel they use, and then use emission rates averaged from the selected units (Keith, et al., 2004). The simplest technique is to use all types of fossil-fueled generators and calculate the average system emission rates, which is a similar method to identifying marginal units by geography. An example of this technique can be found on the Cape Wind website where the “offset[s] from Cape Wind in one year of operation” of SO2, NOx, CO2 and other pollutants are presented (Cape Wind, 2006a). These “offsets” are the amounts of each pollutant emitted by coal, oil, natural gas if each fuel were solely used to generate as much electricity as the Cape Wind project is expected to in one year. While this method is very transparent may be relevant, it is among the least accurate of the methods described here because the marginal units offset by the Cape Wind project over the course of a year will be a mix of fuel types, and it will not be assessed further.
Operating Characteristics

Methods that identify the marginal units by operating characteristics are more complete and are often more accurate than techniques relying on simple geographic or fuel distinctions. The main ways to identify the marginal units by operating characteristics are a) to match generation to loads using supply and demand curves, b) to use historical capacity factors, and c) to use historical dispatch data. All of these methods attempt to determine which units are “load following”.

Some problems with calculating marginal emission rates using load following units are that generating units follow load for different reasons (some are system operator controlled and some may be Automatic Generation Control (AGC) units) and that the set of units that follows a system’s load changes over time (Keith et al., 2004). Despite these limitations, methods using emission rates of load following units are superior in accuracy to other accounting methods.

3. Load Curve

To match generating capacity to loads, using a so-called “load curve analysis,” one first determines the relevant set of generating units (derating unit capacity when appropriate), and then gets load data for the area of interest (Keith, et al., 2004). One then matches the supply curve of the system’s generators to its load duration curve (LDC) for a given time period, identifies the generating units on the margin in each time period or estimates the number hours each unit type is on the margin, and finally calculates the average emission rate of these marginal units. While this method is transparent, it uses an over-simplified representation of unit-dispatch, does not account for outages, energy imports, exports and transmission constraints, and is labor-intensive, as there may be difficulty in stacking (ordering) the units.

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17 The term “load following” usually refers to units that vary their output over short time intervals (on the order of hours) to match frequent changes in system demand.

18 AGC is a feedback control system that regulates the power output of generators to maintain a certain system frequency and/or power flow.
One example of a method that identifies marginal units by load curve analysis is the work of PA Government Services for the Wisconsin Division of Energy to estimate the impact of the state's energy programs (Erickson et al., 2004). A load duration curve analysis was used to calculate avoided emissions of SO2, NOx, CO2 and Hg. The supply curve of the upper Midwest region's generators was matched to the region’s load duration curve for four different time periods (two times of day and two seasons) to identify the units on the margin. The marginal units’ total emissions, calculated from EPA’s historical hourly database for 2000, were divided by total energy to get marginal emission rates for each time period. While the method is reasonably complete and transparent, it is not relevant to an analysis of New England without further work and will not be assessed further.

Another example of a method that identifies marginal units by load curve analysis is Lawrence Berkeley National Laboratory’s (LBNL) Marginal Avoided GHG – Power (MAGPWR) (Meyers et al., 2000). The LBNL MAGPWR method is designed to provide a multi-project baseline for a power system that is both simple and accurate and that could be used by a national energy agency or other entity in granting carbon credits. The LDC is defined for each region and time period (e.g. season or year), the generation is filled in to meet the load, and then the marginal unit type is found. One may use known or estimated emissions factors for the marginal unit type, or, if several unit types are on the margin, one may use an average of multiple emissions sources, weighted by the number of hours each source is marginal. While the method is also reasonably complete and transparent, it is most applicable for simple systems and is not relevant to an analysis of New England without further work and will not be assessed further.

4. Capacity Factor

To use historical capacity factors to identify marginal units, one determines the set of generating units, gets or calculates their historical capacity factors, and then creates a rule for allocating reduced generation to units based on their historical capacity factors (Keith and Biewald, 2005). This method is potentially more accurate at identifying load following units than a load curve analysis, as it gets closer to specifying individual unit operation.
One example of using historical capacity factors is work involving EPA, the Electric Reliability Council of Texas (ERCOT), Texas A&M University’s Energy Systems Laboratory (ESL), and the Texas Commission on Environmental Quality (TCEQ) for a State Implementation Plan (SIP) for eastern Texas (EPA, 2006c). This project assessed county-specific emission reductions of SO2, NOx, and CO2 using EPA eGRID data on plant emissions and capacity factors and ERCOT data on power control area interchanges (GETF, 2005). Fossil fuel-fired plants with a capacity factor of 80% or greater (and hydro and nuclear plant types) are assumed to be baseload and unaffected by energy efficiency; while those with a capacity factor of 20% or less are assumed to be peaking units for which all generation is potentially displaced by energy efficiency. In between 20% and 80% a linear rule was used where plants are assumed to be load-following with some generation possibly displaced.

The geographic specificity (at the county level) and the low labor-intensiveness (a spreadsheet does the math) make this prospective method, based on historic trends, transparent and accurate for some units and locations. While it accounts for transmission constraints within ERCOT to some degree, imports and exports are ignored. The use of capacity factor as a proxy for dispatch status will tend to over-estimate a facility’s role in load following, as outages make a baseload unit have a capacity factor that resembles that of a load-following unit. While this method is reasonably complete and transparent, it is not relevant to an analysis of New England without further work and will not be assessed further.

Building on the ERCOT method, Texas A&M’s ESL developed an Emission Reduction Calculator (eCalc), which is a web based calculator allowing users to design and evaluate a range of projects in energy savings and emissions reduction (GETF, 2005). Energy savings are identified by county and then associated with specific energy suppliers and then associated with generation reductions at specific power plants to provide emission reductions by county. To get projections, future emission reductions are discounted from historical values. While this calculator seems to be complete in identifying the marginal unit and is detailed in geography, its main limitation is age of data (from eGRID) and it is not relevant to an analysis of New England without further work and will not be assessed further.
5. Dispatch Data

Another method that identifies marginal units by operating characteristics is to use historical dispatch data. One may use or develop a database of historical generation, emissions, and loads, identify “load-following” units in each hour, and then calculate an average emission rate for each hour (Keith and Biewald, 2005). This method is complete if hydroelectric power and imports are not big factors in the region and it is transparent, though very labor-intensive.

One example of a method that identifies marginal units by historical dispatch data is one developed by Environmental Resources Trust (ERT) and the Resource Systems Group (RSG) for analysis of a wind project in Maryland (GETF, 2005). To identify the “load following” units in the area, whose output would be displaced by the wind project, RSG got a list of plants in dispatch ranking from the load serving entity in the region and identified the load-following units. RSG used emission rates for units obtained from EPA. Avoided emissions were discounted by 50% to reflect uncertainty in the new method and in uncertainty over transport of pollutants. While this method is superior in completeness to those that simply using geography or fuel used, it is lacking in transparency because the term “load following” was not defined. Also, such dispatch information is proprietary and often hard to come by, making this technique not easily replicable. As such, it will not be assessed further.

Another method that identifies marginal units by historical dispatch data was developed by researchers at the Massachusetts Institute of Technology (MIT) for an analysis of emissions reductions from photovoltaic (PV) systems for EPA (Connors et al., 2004a). The MIT “Load Shape Following” (LSF) method identifies marginal units by looking at which generating units were responding to changes in load on an hour-to-hour basis using EPA hourly generation and emissions data. The MIT researchers calculated marginal emissions rates for SO2, NOx and CO2 for the period of 1998-2002 for each NERC region by averaging the marginal units’ emission rates, weighted by how much each LSF unit was responding to changes in load.

The researchers also calculated “Slice of System” (SOS) marginal emission rates using average system-wide fossil unit emission rates, representing a method based simply on geography.
Hourly avoided fossil power plant emissions were calculated by multiplying hourly renewable generation with the corresponding hourly LSF or SOS emissions rate. The figure below shows the LSF and SOS marginal emission rates for New England for 2002 (see the Appendix for more results from this analysis).

![Figure 3-5: MIT Marginal Emission Rates for New England for 2002 (Lbs/MWh) and Difference in LSF and SOS Rates (%)](image.png)

<table>
<thead>
<tr>
<th>Lbs/MWh</th>
<th>Load Shape Following</th>
<th>Slice Of System</th>
<th>LSF - SOS</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>4.7</td>
<td>4.0</td>
<td>-15%</td>
</tr>
<tr>
<td>NOx</td>
<td>1.7</td>
<td>1.5</td>
<td>-7%</td>
</tr>
<tr>
<td>CO2</td>
<td>1,682</td>
<td>1,676</td>
<td>-0.3%</td>
</tr>
</tbody>
</table>


Annual averages of hourly data.

Through their analysis, the MIT researchers showed that the emission rates of load shape following units differ from those of all fossil units in a region. For New England, 2002 annual average LSF rates differ from SOS rates by up to 15%. They also showed that emission rates improve over time (though this trend has likely slowed since, due to increases in natural gas prices). Results illustrated how evening hours tend to be dirtier than mid-day hours.

The LSF method is more complete than the SOS method (and the other accounting methods described above), as it takes into account AGC and different operating characteristics of units. While both methods are data- and calculation-intensive, and retrospective, they provide the greatest level of temporal specificity practical and sufficient geographic resolution. Both methods are sufficiently transparent and relevant to assessing avoided emissions from offshore wind in New England and will be analyzed further in the next chapter.\(^1\)

Synapsee describes another method using historical dispatch data. It suggests plotting total emissions as a function of total fossil generation for a certain time period, using EPA hourly data (Keith and Biewald, 2005). The linear regression line of the plot gives a slope that approximates the marginal fossil emission rate for that time period. The figure below shows such a plot and

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\(^1\) Because of the accuracy of the LSF method, Berlinski and Connors used the MIT database of hourly LSF emissions rates to look at avoided emissions from wind in New England (Berlinski and Connors, 2006), which will be discussed more in the next chapter.
line for New England for 2000. This method could provide a very simple yet complete and transparent way to estimate marginal emissions and should be investigated in greater detail. However, as it involves gathering a good amount of data, it is not applicable without further effort and so it will not be assessed further.

Figure 3-6. New England Emissions as a Function of Fossil Generation for 2000


C. Hybrid

In addition to the modeling and non-modeling methods described above, one may imagine a hybrid method combining both approaches. EPA has been developing the Average Displaced Emission Rate (ADER) tool to draw on the power of a model and the user-friendliness of a simple spreadsheet calculator (Kerr et al., 2002). EPA plans to create an on-line “Emissions Profile Tool” to make the ADER methodology available to the public:

Recognizing the analytical limitations of existing methodologies in estimating displaced emission from energy efficiency measures and clean energy technologies, U.S. EPA and ICF Consulting have developed a new approach to estimating the potential for displaced emission – the “Average Displaced Emissions Rate” (ADER) methodology. (Kerr et al., 2002)

For ADER, the IPM model is used to define avoided emission parameters for SO2, NOx, CO2 and Hg in lbs/kWh for 11 hour blocks for five U.S. regions (the Northeast region includes New England, NY, and PA-NJ-MD-DE (PJM)) for four years (2005, 2010, 2015, and 2020). The parameters are calculated as the ratio of displaced emissions projected from IPM from a
reference case (currently EPA Base Case 2000) to displaced generation input into the model in a decrement case (currently using U.S. Climate Change Action Plan programs). Users can then take the ADER parameters and apply them to the energy their projects generate (or save) and calculate total displaced emissions.

The advantages of the ADER approach center on its use of a sophisticated model in IPM, which takes into account regional transmission constraints. Providing the power of IPM and its forecast ability to users through a simple online tool enhances completeness and transparency. The main drawbacks are that IPM aggregates regions, groups units by unit type, and runs selected future years. Further, the ADER parameters are sensitive to what programs are modeled in the decrement case, and so are applicable only to projects that match the amount of change in the decrement run. Despite these limits, ADER should be a relevant and useful tool once it is released.

Review of Methods

This chapter has described the main methods for calculating avoided emissions, which are summarized in the table below. While there exist other examples of these method types, a review of the methods discussed here is sufficient to highlight important characteristics to consider when selecting a method. First, one should decide how relevant the geographic focus (e.g. county vs. regional) and the time horizon (historical vs. prospective) are to the case at hand. Also, it is important to know how completely the method addresses the major complexities of the electricity system. One should question whether the time scale of the results (annual vs. seasonal and time of day) is sufficient. Finally, it is important to remember that the more complete methods often require more analytical resources (time and money).
<table>
<thead>
<tr>
<th>Method Type</th>
<th>User, Method Name</th>
<th>Identifying Marginal Units</th>
<th>Geographic Scale</th>
<th>Effort Required</th>
<th>Retro-/Prospective</th>
<th>Results Time Scale</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Modeling</strong></td>
<td>ISO-NE MEA</td>
<td>Chronological; hourly</td>
<td>New England</td>
<td>Intense: Calibrating model</td>
<td>Retro: one year</td>
<td>Annual, seasonal, time of day</td>
</tr>
<tr>
<td><strong>Forecasting / Optimization Models</strong></td>
<td>IPM</td>
<td>LDC; load blocks (~10-40 / year)</td>
<td>U.S. – NERC regions</td>
<td>&quot; &quot;</td>
<td>Pro: 5-30 years</td>
<td>&quot; &quot;</td>
</tr>
<tr>
<td></td>
<td>STAPPA / ICLEI NEMS</td>
<td>LDC; load blocks (11 / year)</td>
<td>&quot; &quot;</td>
<td>&quot; &quot;</td>
<td>Pro: 2003-2020</td>
<td>&quot; &quot;</td>
</tr>
<tr>
<td></td>
<td>NESCAUM NE-MARKAL</td>
<td>LDC; load blocks</td>
<td>New England states</td>
<td>&quot; &quot;</td>
<td>Pro: 20-50 years</td>
<td>&quot; &quot;</td>
</tr>
<tr>
<td></td>
<td>ENERGY 2020</td>
<td>LDC</td>
<td>From company to national</td>
<td>&quot; &quot;</td>
<td>Pro</td>
<td>?</td>
</tr>
<tr>
<td></td>
<td>AMIGA</td>
<td>&quot; &quot;</td>
<td>U.S.</td>
<td>&quot; &quot;</td>
<td>Pro: 20-50 years</td>
<td>Annual</td>
</tr>
<tr>
<td><strong>Accounting</strong></td>
<td>NREL Plant Average Method</td>
<td>From city to national</td>
<td>Minimal: identify plants in area</td>
<td>Retro: 2000</td>
<td>Annual, seasonal</td>
<td></td>
</tr>
<tr>
<td>Unit Type</td>
<td>Cape Wind Associates</td>
<td>Unit type: fuel</td>
<td>&quot; &quot;</td>
<td>Small: identify marginal plant types</td>
<td>Retro</td>
<td>?</td>
</tr>
<tr>
<td>Load Curve</td>
<td>PA Government Services – WI Load duration curve</td>
<td>MAIN and MAPP regions</td>
<td>Moderate: organize hourly data, identify marginal units</td>
<td>Retro: 2000</td>
<td>Annual, seasonal, time of day</td>
<td></td>
</tr>
<tr>
<td></td>
<td>LBNL MAGPWR</td>
<td>Any; user defined</td>
<td>&quot; &quot;</td>
<td>&quot; &quot;</td>
<td>Retro</td>
<td>Any; user defined</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>EPA ERCOT</td>
<td>Capacity factor</td>
<td>ERCOT counties</td>
<td>&quot; &quot;</td>
<td>Pro: based on historical data</td>
<td>Annual</td>
</tr>
<tr>
<td></td>
<td>ESL eCalc</td>
<td>&quot; &quot;</td>
<td>&quot; &quot;</td>
<td>Small: get program performance by county</td>
<td>&quot; &quot;</td>
<td>&quot; &quot;</td>
</tr>
<tr>
<td><strong>Dispatch Data</strong></td>
<td>ERT / RSG – MD Dispatch data from LSE</td>
<td>PA-NJ-MD-DE</td>
<td>Small: get emission rates of marginal plants in area</td>
<td>Pro: based on historical data</td>
<td>Annual</td>
<td></td>
</tr>
<tr>
<td></td>
<td>MIT LSF Dispatch data on LSF units</td>
<td>U.S. – NERC regions</td>
<td>Intense: organize hourly data, identify marginal units</td>
<td>Retro</td>
<td>Any; user defined</td>
<td></td>
</tr>
<tr>
<td></td>
<td>MIT SOS Dispatch data on all units</td>
<td>&quot; &quot;</td>
<td>Moderate: organize hourly data, get emission rates</td>
<td>Retro</td>
<td>Any; user defined</td>
<td></td>
</tr>
</tbody>
</table>

Note: Bullets indicate method selected for application to New England offshore wind resources in this paper.
Because many organizations attempting to quantify avoided emissions have limited analytical resources, I have illustrated my ratings of methods by price and completeness in the figure below. The price listed is in relative terms; it is difficult to assign a cost in dollars to any method depends on the particular system and time horizon of interest and on factors such as data availability. The preparation time is a rough estimate of effort required to complete an analysis of a system using a certain method, assuming data is available and is, again, more of a relative value.

<table>
<thead>
<tr>
<th>Method du Jour</th>
<th>Price</th>
<th>Prep Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Historical / Current Mode</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Geography or Unit Type</td>
<td>$</td>
<td>One day</td>
</tr>
<tr>
<td>Least complete. Right order of magnitude.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Load Curve</td>
<td>$$</td>
<td>One week</td>
</tr>
<tr>
<td>Data- and labor-intensive to get complete. Good value in simple systems.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>$$$</td>
<td>One month</td>
</tr>
<tr>
<td>Data- and labor-intensive. Amply complete. Good value.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dispatch Data</td>
<td>$$$</td>
<td>One month</td>
</tr>
<tr>
<td>Data- and labor-intensive. Most detail and most complete.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Prospective Process</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dispatch Model</td>
<td>$$$$</td>
<td>Six months</td>
</tr>
<tr>
<td>Data- and labor-intensive. Most accurate for short-term (&lt;5 yr)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Forecasting Model</td>
<td>$$$$</td>
<td>Six months</td>
</tr>
<tr>
<td>Data- and labor-intensive. Most accurate for long-term (&gt;5 yr)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hybrid</td>
<td>$$</td>
<td>One week</td>
</tr>
<tr>
<td>Combines power of models with simple interface. Best value.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

While the Geography and Unit Type methods are the least complete, they will likely yield results on the same order of magnitude as more sophisticated methods. In some cases this may be acceptable. The Capacity Factor method probably provides the best value for a historical analysis because a simple rule identifying the marginal units may be developed. A Hybrid approach represents the best value for a prospective analysis because it is based on a model but requires
only simple inputs from the end user. Of course, the relevance of the model assumptions plays a role in the method’s accuracy. In the next chapter a Hybrid approach of sorts is used to quantitatively compare the previously selected methods by applying their results to offshore wind power in New England.
CHAPTER 4: Application of Selected Methods to Offshore Wind Resources

In the previous chapter, existing methods for calculating avoided emissions from renewable energy resources were described and five were selected for further review based on their relevance (mostly a function of geographic focus) and on availability of data. (Because of limited time and budget resources, I only selected methods with published marginal emission rates.) This chapter first compares the marginal emission rates from those methods, then describes the offshore wind resource in New England, and finally assesses the resulting estimations of avoided emissions when those rates are applied to potential New England offshore wind projects. Marginal emission rate patterns from different methods and even from different sources using similar methods are surprisingly different.

The five methods selected for comparison were:

1. ISO-NE Marginal Emissions Analysis (MEA)
2. Synapse OTC Workbook
3. La Capra Emission Model
   (which all involve the PROSYM dispatch model)
4. MIT Load Shape Following (LSF)
5. MIT Slice of System (SOS)
   (which both rely on historical dispatch data)

To evaluate both retrospective and prospective analyses, I compare these methods for both a historic (2002) and a future year (2009). Four of the methods – ISO-NE MEA, Synapse OTC Workbook, MIT LSF, and MIT SOS – are compared based on their marginal emission rates for 2002, the only year in common to them. The data available from these four methods allows them to be compared for two seasons (ozone and non-ozone) and two times of day (on-peak and off-peak) as well as for seasonal and annual averages. For an analysis of prospective methods, the

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20 Ozone season is defined as May 1 to September 30. Non-ozone season consists of all other days.
21 The ISO-NE and MIT methods define on-peak as 8AM - 10PM weekdays, while the Synapse OTC Workbook defines on-peak as 7 AM - 11 PM weekdays. Off-peak consists of all other hours.
Synapse OTC Workbook and *La Capra* Emission Model are compared based on their average annual marginal emission rates for 2009. The table below lists the methods assessed, the years of the data available, and the time periods compared.

### Figure 4-1. Methods Compared in Application to New England Offshore Wind Resources

<table>
<thead>
<tr>
<th>Year of Comparison</th>
<th>Methods Compared</th>
<th>Times of Year</th>
<th>Times of Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>ISO-NE MEA</td>
<td>Annual</td>
<td>Average</td>
</tr>
<tr>
<td></td>
<td>MIT LSF</td>
<td>Ozone Season</td>
<td>On-peak</td>
</tr>
<tr>
<td></td>
<td>MIT SOS</td>
<td>Non-Ozone Season</td>
<td>Off-peak</td>
</tr>
<tr>
<td></td>
<td>Synapse OTC Workbook</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>La Capra Emission Model</td>
<td>Annual Average</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Synapse OTC Workbook</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Marginal Emission Rates

The following table shows the marginal emission rates of each selected method for 2002. The ISO-NE MEA and Synapse OTC Workbook reports provide annual average and seasonal on- and off-peak values only.\(^2\) Because I have access to the MIT hourly emissions database, I was able to calculate rates for all times of year and times of day for the MIT LSF and MIT SOS methods. Although the SO\(_2\) and NO\(_x\) rates are displayed to the single decimal place and the CO\(_2\) rates are shown in whole numbers, greater precision is maintained in the comparisons and calculations of avoided emissions.

First, one should notice the spread of emission rates for each pollutant across seasons. It should not be surprising that all methods (except the MIT-SOS method for CO\(_2\)) yield higher rates for the non-ozone season than the ozone season. Because of seasonal fuel price swings and the strict emissions limits during the ozone season, many fossil plants use cleaner fuel and/or emissions control technologies. Also, because of the higher electricity demand in the summer in New England, cleaner, natural gas-fired plants are operating on the margin more often.

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\(^2\) Synapse cautions that the "Annual Average" rate should only be used by itself to assess Emission Performance Standards, and not for programs that displace generation from the grid such as renewables (Keith et al., 2002). While I use both the Annual Average and the seasonal and time of day rates, I focus on the latter in this analysis.
Figure 4-2. New England Marginal Emission Rates for 2002 (Lbs/MWh)

<table>
<thead>
<tr>
<th></th>
<th>Annual Average</th>
<th>Ozone Season Average</th>
<th>Non-Ozone Season Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On-Peak</td>
</tr>
<tr>
<td>SO2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MIT LSF</td>
<td>4.7</td>
<td>4.6</td>
<td>4.8</td>
</tr>
<tr>
<td>MIT SOS</td>
<td>4.0</td>
<td>3.8</td>
<td>4.1</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>3.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synapse</td>
<td>3.3</td>
<td>0.5</td>
<td>3.8</td>
</tr>
<tr>
<td>NOx</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MIT LSF</td>
<td>1.6</td>
<td>1.6</td>
<td>1.7</td>
</tr>
<tr>
<td>MIT SOS</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>1.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synapse</td>
<td>1.1</td>
<td>0.4</td>
<td>1.2</td>
</tr>
<tr>
<td>CO2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MIT LSF</td>
<td>1,683</td>
<td>1,642</td>
<td>1,711</td>
</tr>
<tr>
<td>MIT SOS</td>
<td>1,676</td>
<td>1,631</td>
<td>1,703</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>1,338</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synapse</td>
<td>1,000</td>
<td>900</td>
<td>1,240</td>
</tr>
</tbody>
</table>

Sources: Connors et al., 2004; ISO-NE, 2004; Keith et al., 2002.

Note: MIT seasonal and time of day values calculated from MIT hourly emissions database.

What is interesting is that the differences in seasonal rates (the amount by which non-ozone season rates are greater than ozone season rates) range from only about 5-10% in the MIT methods to about 40% in the ISO-NE method to about 60% in the Synapse method. This is a very wide range of differences for a phenomenon that should be better measured by now. Because the MIT LSF method relies on historical hourly dispatch data, it likely best represents the true relative values for seasonal marginal emission rates.

Figure 4-3. New England SO2 Marginal Emission Rates for 2002 (Lbs/MWh)

Sources: Connors et al., 2004; ISO-NE, 2004; Keith et al., 2002.
Next, one should notice the spread of emission rates across times of day. Off-peak rates are higher than on-peak rates by about 5% in the MIT methods (except that SO2 and NOx off-peak rates are 5% lower than on-peak rates in the MIT LSF method) and by anywhere from 30% to several hundred percent in the Synapse method, while in the ISO-NE method, off-peak rates are actually about 30% lower than on-peak rates.

Referring back to the New England supply curve illustrated by Figures 2-2a and 2-2b, one will notice the wide range of emission rates for the units located between the average and maximum demand levels (which were likely the marginal units in many on-peak hours). Also, there is a wide range of emission rates for the units located between the average and minimum demand levels (which were likely the marginal units in many off-peak hours). The disparities in relative values between on-peak and off-peak times from the methods is likely a consequence of differences in accounting for or simulation of unit operation during different times of day (and less likely a function of differences in on-peak and off-peak definitions).

The spread of rates for each pollutant across methods is also notable. Taking the ISO-NE MEA marginal emission rates as a reference, the Synapse OTC Workbook has similar annual rates for
SO2 and NOx but 30% lower rates for CO2, while the MIT SOS annual rates are 20-40% higher and the MIT LSF rates are 30-50% higher. On-peak rates for both ozone and non-ozone seasons are more similar across methods, with the MIT methods giving rates up to 20% different than the ISO-NE MEA, while the Synapse OTC Workbook has 30-90% lower on-peak rates. Off-peak rates are least similar across methods, with the MIT methods giving rates 30-120% higher than the ISO-NE MEA, while the Synapse OTC Workbook has off-peak rates up to 90% higher. The figures below show the marginal emission rates for each method for each pollutant.

![Figure 4-5. New England CO2 Marginal Emission Rates for 2002 (Lbs/MWh)](image)

Sources: Connors et al., 2004; ISO-NE, 2004; Keith et al., 2002.

The MIT methods give higher emission rates than the other methods for all time periods except non-ozone on-peak (for SO2). One explanation for this is the different weight put on hydroelectric units and imports in each method, which play a non-trivial role in load following in New England. The MIT methods only partially take hydro units and imports into account, as these methods rely on historical fossil generator operations given historical loads, which account for the offsets of hydro units and imports. However, when the MIT methods calculate the marginal emission rate, these resources are left out, potentially resulting in a high rate. The ISO-NE MEA and the Synapse OTC Workbook methods rely on their dispatch models to capture the roles of hydroelectric units and imports, which seem sufficient from method documentation. The Synapse method takes into account interactions with other control areas for the six seasonal and
time of day rates but not for the annual average, which represents marginal emissions in the
target area only. It is unclear why the Synapse on-peak rates are so low compared to the other
methods, but it is likely due to model assumptions placing natural gas on the margin in many of
those hours.

One reason why the ISO-NE MEA rates are lower than the MIT rates is that in the ISO-NE
modeling imports were netted out from the historical hourly New England loads, leaving only
domestic supply and demand. Because New York marginal generation is dirtier than New
England, imports from NY would raise New England marginal emission rates. Moderating this
effect is the fact that the ISO-NE MEA method adds 500 MW of load in each hour to calculate
the marginal emissions, pushing demand up the supply curve and forcing more inefficient and
often dirtier units to operate, increasing marginal emission rates.

The wide range of marginal emission rates for 2002, given that it is a historical year, raises
several questions. Why are there large differences in rates for each time period when many data
on the actual electricity system operation exist? Has access to this historical data been limited, or
have the data been misinterpreted? Do different retrospective methods really produce
incompatible results? Given these differences, which method should an analyst choose to provide
a best guess or a conservative estimate? While these questions cannot be answered with one
simple comparison, they should be kept in mind when reviewing or using methods to calculate
avoided emissions.

For a comparison of 2009 marginal emission rates, the La Capra Emission Model and the
Synapse OTC Workbook are useful. The most relevant results from the La Capra analysis are
their annual average “Marginal Emission Rates” and “Incremental Emission Rates” from their
“Renewables - Base” and “More Wind” scenarios. The calculation of the Marginal Emission
Rates includes interaction with other control areas (NY, PJM, and Canada) while calculation of
the Incremental Emission Rates only takes into account New England supply and demand,
though both rates are considered “marginal emission rates” as defined for this thesis. The
Renewables - Base scenario has more renewable generation than the benchmark case (including
162 MW of offshore wind), while the More Wind scenario has the same amount of that
renewable generation, but with more of it coming from wind (including 367 MW of offshore wind). From the Synapse OTC Workbook, annual average default marginal emission rates for New England for 2009 were used.\textsuperscript{23}

The differences across published rates for 2009 are less than for 2002, as both La Capra and Synapse used the PROSYM dispatch model to simulate the northeastern U.S. electricity system and as marginal unit emission rates converge around expected long-term levels. However, differences in assumptions about plant additions and other factors such as fuel prices cause differences in emission rates, as shown in the table below. Recall that the Synapse default rates for the medium-term (2006 through 2010) are a blend of the near-term factors and new/retired plant emission rates. Also recall that La Capra’s 2009 rates are based on EPA expectations and reflect compliance with future state and national emission regulations. More details about their modeling assumptions may be found in the published reports of their analyses (see La Capra Associates, 2003 and Keith et al., 2002).

<table>
<thead>
<tr>
<th></th>
<th>La Capra Emission Model</th>
<th>Synapse OTC Workbook</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Marginal</td>
<td>Incremental</td>
</tr>
<tr>
<td>SO\textsubscript{2}</td>
<td>1.7</td>
<td>1.1</td>
</tr>
<tr>
<td>NO\textsubscript{x}</td>
<td>0.7</td>
<td>0.5</td>
</tr>
<tr>
<td>CO\textsubscript{2}</td>
<td>982</td>
<td>644</td>
</tr>
<tr>
<td></td>
<td>955</td>
<td>692</td>
</tr>
<tr>
<td></td>
<td></td>
<td>950</td>
</tr>
</tbody>
</table>

Sources: La Capra Associates, 2003; Keith et al., 2002.

One should first notice that the 2009 marginal emission rates are 20-50\% lower than the 2002 rates. As mentioned before, marginal generation is becoming cleaner over time as cleaner plants are built. Also, as New England has become a net exporter of power, it no longer imports as much dirtier marginal generation from New York. The figure below displays the marginal emission rates for New England for 2009.

\textsuperscript{23} Although Synapse recommends using the default seasonal and time of day rates instead of its default annual average values for calculations of avoided emissions from projects, comparable seasonal and time of day rates were not available from the La Capra report and so annual values were compared.
The spread of rates across methods is notable. Taking the La Capra Marginal Emission Rates for the Renewables - Base case as a reference, the More Wind case Marginal Emission Rates are pretty similar, while the Incremental Emission Rates from the Base and More Wind cases are about 30% lower. As for the Synapse OTC Workbook, the rates for NOx and CO2 are similar to the Base case Marginal Emission Rates, while the SO2 rate is about 70% higher. The Incremental Emission Rates are lower than the Marginal rates primarily because they do not take into account reductions in generation outside of New England as a result of increased clean generation in New England. While the Synapse method also excludes interactions with other control areas for the annual average, its rates are higher than the most of the La Capra rates.

Considering the ISO-NE MEA annual average rates for 2002 and 2003 (as shown in Figure 2-3), the Synapse SO2 rate for 2009 seems a bit high, but the rates for the other pollutants seem reasonable. The La Capra rates for 2009 are consistent with each other, and seem reasonable given the recent historical rates estimated by ISO-NE. The range of 2009 marginal emission rates across methods raises many of the questions posed after review of the 2002 values. To understand these prospective analyses, one needs to review the methods’ modeling assumptions especially fuel prices.
Offshore Wind Data Set

Now that marginal emission rates for New England have been chosen, the next step is to select offshore wind generation data to apply to the 2002 and 2009 rates. As the 2002 rates are retrospective and are given by season and time of day, it would be best to use offshore wind data from 2002 for similar time periods. The MIT offshore wind database satisfies these criteria and is used for 2002. Similarly, the 2009 rates are prospective, annual values so a projection of annual offshore wind generation would be best. I use the expected annual generation from the Cape Wind project for 2009.

The MIT offshore wind database is the most appropriate data set for a historical avoided emissions analysis of New England offshore wind resources because it is the most complete historical hourly offshore wind data set available. The database contains hourly wind speeds from the last 20 years for 16 offshore data sites in the northeastern U.S. (see map in the Appendix), compiled from the National Oceanic and Atmospheric Administration (NOAA) National Data Buoy Center (NDBC), with the gaps in the raw data filled in (Berlinski and Connors, 2006). The MIT database also contains hourly estimated generation and capacity factor data for a GE 3.6sl wind turbine hypothetically located at each data site. This database is useful because the hourly data may be averaged or summed to match any time periods (such as seasons and times of day).

For the present analysis, I use data from 2002 for the Buzzards Bay station, a near shore data site located in an environment similar to that where the Cape Wind project is to be located (see map in the Appendix). The Buzzards Bay station is located on a small rock outcrop about 35 miles southwest of Buzzards Bay, MA (about five miles west of Cuttyhunk, MA and about five miles south of Westport Point, MA), in Buzzards Bay. The tables below list reference information about the Buzzards Bay data site and the MIT estimates for its resource parameters for 2002.

---

24 The hourly wind speed data is available by request from the researchers.
25 It is important to note that the wind profile at the Buzzards Bay data site is not necessarily representative of the resource at all offshore sites. See Berlinski and Connors (2006) for a discussion of the variety of offshore wind resources in the northeastern U.S.
Figure 4-8. Reference Information on Buzzards Bay Data Site

<table>
<thead>
<tr>
<th>Station Name</th>
<th>Station ID</th>
<th>Location, Latitude Longitude</th>
<th>Distance From Shore, nautical miles (miles)</th>
<th>Location, Direction from Shore Point</th>
<th>Anemometer Height, m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buzzards Bay</td>
<td>BUZM3</td>
<td>41.40 N 71.03 W</td>
<td>30 nm (35 mi)</td>
<td>SW of Buzzards Bay, MA</td>
<td>25</td>
</tr>
</tbody>
</table>

Source: Economic and Environmental Performance of Potential Northeast Offshore Wind Energy Resources (Berlinski and Connors, 2006)

Figure 4-9. Wind Resource at Buzzards Bay Data Site in 2002

<table>
<thead>
<tr>
<th>NOAA Data Site</th>
<th>Average Wind Speed @ 75m (m/s)</th>
<th>Average Wind Speed @ 75m (mph)</th>
<th>Wind Power Class</th>
<th>Annual Generation (GWh/MWi)</th>
<th>Capacity Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buzzards Bay</td>
<td>8.8</td>
<td>19.8</td>
<td>6</td>
<td>4.28</td>
<td>48.8</td>
</tr>
</tbody>
</table>

Source: Economic and Environmental Performance of Potential Northeast Offshore Wind Energy Resources (Berlinski and Connors, 2006)

Note: Generation is given in gigawatt hours per installed MW (GWh/MWi) of wind turbine capacity, which can be scaled to reflect the capacity of a wind farm of any size.

As previously discussed, the set of marginal generating units changes over the course of a year, and so does the offshore wind speed. Just as capturing the intra-annual supply and demand dynamics is important to estimating marginal emission rates, accurately accounting for the variable offshore wind resource is important when calculating the avoided emissions from offshore wind generation. The figure below shows estimated hourly generation of a (1 MW) wind turbine at Buzzards Bay, summed by month of year and hour of day. As one can see, there is more generation in the winter than in the summer as it is windier in the winter.

Figure 4-10. Generation at Buzzards Bay Data Site by Month and Hour for 2002 (MWh/MWi)

Source: MIT offshore wind database
To use the 2002 offshore wind data for Buzzards Bay in my calculation of avoided emissions, I summed the generation by season and time of day (see table below). I applied these values to the marginal emission rates listed in Figure 4-2 above to calculate avoided emissions from offshore wind in 2002, which are reported in the next section.

<table>
<thead>
<tr>
<th>Annual</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
<th>MWh/MWi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>Total</td>
</tr>
<tr>
<td>4,276</td>
<td>1,709</td>
<td>2,566</td>
<td>1,375</td>
</tr>
<tr>
<td>40%</td>
<td>32%</td>
<td>68%</td>
<td>38%</td>
</tr>
</tbody>
</table>

Source: MIT offshore wind database

Because the MIT offshore wind database only has historical data, an alternate data set for 2009 was needed. While the Cape Wind project's expected generation is an obvious choice, expected hourly generation or wind speed data of the Cape Wind project are not publicly available. I instead used expected annual output to calculate avoided emissions from offshore wind power for 2009 (Clean Power Now used annual output in its estimate of the Cape Wind project's avoided emissions (see Kleekamp, 2006a and 2006b)). Expected output is cited as 170 MW on average on the Cape Wind website (Cape Wind, 2006b). I applied the estimated 1.5 million MWh\(^6\) to the 2009 annual average marginal emission rates listed in Figure 4-6 (the only rates common to the two selected methods) to calculate avoided emissions from offshore wind in 2009.

Avoided Emissions from Offshore Wind Power

A quick look at the number of hours in each time period gives a first order approximation of magnitudes of avoided emissions, given a flat generation profile. The table below shows that, because of the definition of the ozone season, there are more hours in the non-ozone season. The proportion of ozone season to non-ozone season hours in a year is about 40 / 60. With more non-ozone season hours, the non-ozone season marginal emission rates will weigh more heavily in calculations of avoided emissions. Because of the definition of on-peak and off-peak, there are

\[^6\] 170 MW times 8,760 hours per year equals 1,489,200 MWh per year.
more off-peak hours in a year and in each season. The ratio of on-peak to off-peak hours in a year or a season is about 40 / 60. With more off-peak hours, the off-peak marginal emission rates will weigh more heavily in calculations of avoided emissions.

<table>
<thead>
<tr>
<th></th>
<th>Annual</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average</td>
<td>8,760</td>
<td>3,672</td>
<td>5,088</td>
</tr>
<tr>
<td>On-Peak</td>
<td>3,654</td>
<td>1,526</td>
<td>2,128</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>5,106</td>
<td>2,146</td>
<td>2,960</td>
</tr>
<tr>
<td>Hours</td>
<td>42%</td>
<td>42%</td>
<td>42%</td>
</tr>
<tr>
<td>% of season</td>
<td>58%</td>
<td>58%</td>
<td>58%</td>
</tr>
<tr>
<td>% of year</td>
<td>100%</td>
<td>42%</td>
<td>58%</td>
</tr>
</tbody>
</table>

As Figure 4-2 above shows, the selected methods differ as to whether on-peak or off-peak rates are higher. The MIT and Synapse OTC Workbook methods have higher rates in the off-peak than in the on-peak for all pollutants, while the ISO-NE MEA method has higher on-peak rates.

Of course, in addition to the magnitude of the marginal emission rates and the number of hours in each time period, the renewable energy generation profile is important to the calculation of avoided emissions. Looking at Figure 4-10 above, we see that the strong winter winds produce more energy in the winter (non-ozone season) than in the summer (ozone season). The ratio of ozone season to non-ozone season generation in a year for offshore wind in the northeastern U.S. is about 30 / 70. It is important to note that, while the generation profile of the Buzzards Bay data site is typical of northeastern U.S. near shore sites, sites further from shore generally have a less flat profile over the year, shifting generation towards the non-ozone season.

To calculate avoided emissions from offshore wind for 2002, I applied the Buzzards Bay generation profile from the MIT wind resource database to the marginal emission rates of each selected method. I applied hourly generation data to the hourly MIT rates (using seasonal and time of day instead of hourly values changes the results by up to a few percent). I applied hourly generation data summed by season and time of day to the rates of the other methods. The table below shows the calculated avoided emissions for 2002 from a hypothetical (1 MW) wind turbine located in an environment similar to that at the Buzzards Bay data site.
Figure 4-13. Avoided Emissions from the Offshore Wind Resource at the Buzzards Bay Data Site for 2002 (Tons/MWt)

<table>
<thead>
<tr>
<th></th>
<th>Annual Total</th>
<th>On-Peak</th>
<th>Off-Peak</th>
<th>Ozone Season Total</th>
<th>On-Peak</th>
<th>Off-Peak</th>
<th>Non-Ozone Season Total</th>
<th>On-Peak</th>
<th>Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>MIT LSF</td>
<td>10.2</td>
<td>4.0</td>
<td>6.2</td>
<td>3.0</td>
<td>1.3</td>
<td>1.7</td>
<td>7.2</td>
<td>2.7</td>
</tr>
<tr>
<td></td>
<td>MIT SOS</td>
<td>8.6</td>
<td>3.3</td>
<td>5.3</td>
<td>2.7</td>
<td>1.1</td>
<td>1.6</td>
<td>5.9</td>
<td>2.2</td>
</tr>
<tr>
<td></td>
<td>ISO-NE</td>
<td>7.0</td>
<td>3.8</td>
<td>3.4</td>
<td>1.9</td>
<td>1.1</td>
<td>0.8</td>
<td>5.4</td>
<td>2.7</td>
</tr>
<tr>
<td></td>
<td>Synapse</td>
<td>6.0</td>
<td>0.9</td>
<td>5.1</td>
<td>1.6</td>
<td>0.1</td>
<td>1.5</td>
<td>4.4</td>
<td>0.8</td>
</tr>
<tr>
<td>NOx</td>
<td>MIT LSF</td>
<td>3.6</td>
<td>1.4</td>
<td>2.2</td>
<td>1.0</td>
<td>0.6</td>
<td>0.5</td>
<td>2.6</td>
<td>1.0</td>
</tr>
<tr>
<td></td>
<td>MIT SOS</td>
<td>3.3</td>
<td>1.3</td>
<td>2.0</td>
<td>0.9</td>
<td>0.4</td>
<td>0.5</td>
<td>2.4</td>
<td>0.9</td>
</tr>
<tr>
<td></td>
<td>ISO-NE</td>
<td>2.4</td>
<td>1.2</td>
<td>1.2</td>
<td>0.7</td>
<td>0.4</td>
<td>0.3</td>
<td>1.7</td>
<td>0.8</td>
</tr>
<tr>
<td></td>
<td>Synapse</td>
<td>2.7</td>
<td>0.7</td>
<td>2.0</td>
<td>0.6</td>
<td>0.1</td>
<td>0.5</td>
<td>2.1</td>
<td>0.6</td>
</tr>
<tr>
<td>CO2</td>
<td>MIT LSF</td>
<td>3,617</td>
<td>1,408</td>
<td>2,209</td>
<td>1,150</td>
<td>490</td>
<td>660</td>
<td>2,467</td>
<td>917</td>
</tr>
<tr>
<td></td>
<td>MIT SOS</td>
<td>3,590</td>
<td>1,402</td>
<td>2,188</td>
<td>1,148</td>
<td>484</td>
<td>664</td>
<td>2,442</td>
<td>918</td>
</tr>
<tr>
<td></td>
<td>ISO-NE</td>
<td>2,860</td>
<td>1,276</td>
<td>1,617</td>
<td>877</td>
<td>419</td>
<td>457</td>
<td>2,016</td>
<td>857</td>
</tr>
<tr>
<td></td>
<td>Synapse</td>
<td>2,537</td>
<td>892</td>
<td>1,645</td>
<td>752</td>
<td>267</td>
<td>485</td>
<td>1,785</td>
<td>625</td>
</tr>
</tbody>
</table>

Notes: ISO-NE total annual avoided emissions based on annual average marginal emission rates and not summed from seasonal values. Synapse total annual avoided emissions summed from seasonal values and not based on annual average marginal emission rates, as recommended by Keith et al. (2002).

One should first notice that many more emissions are avoided in the non-ozone season than in the ozone season, even though the marginal emission rates are roughly equivalent. This is mainly due to more wind generation in the non-ozone season (about twice as much as in the ozone season) and higher marginal emission rates (10-30% higher in the non-ozone season). The MIT methods produce 130% more avoided emissions in the non-ozone season than in the ozone season, the ISO-NE MEA method 150% more, and the Synapse OTC Workbook 190% more. The ratio of ozone to non-ozone emissions from all four methods is about 30 / 70. The figures below show the avoided emission results across seasons and methods for each pollutant.
Figure 4-14. Avoided SO2 Emissions from Offshore Wind Power in 2002 (Tons/MWi)

Figure 4-15. Avoided NOx Emissions from Offshore Wind Power in 2002 (Tons/MWi)
The second noticeable result is that more emissions are avoided during off-peak hours than during the on-peak. The MIT methods yield results where off-peak avoided emissions are 30% greater than on-peak during the ozone season and 70% greater during the non-ozone season. The ISO-NE MEA method yields results where off-peak avoided emissions are 0-30% higher than on-peak during the non-ozone season, while off-peak avoided emissions are 30% lower than on-peak during the ozone season for SO2 and NOx (due to lower marginal emission rates) and 10% higher for CO2.

Looking more closely at the avoided emissions throughout the year, the figure below shows the potential hourly avoided emissions from the wind resource at the Buzzards Bay data site for 2002 using the MIT LSF method. Recall from Figure 4-2 that the marginal emissions rates from load shape following fossil generators are highest during off-peak hours (nights and weekends) and in the non-ozone season (winter). The avoided emissions results for Buzzards Bay show that the correlation is high between strong winter offshore winds and load shape following operation of dirtier power plants. The figure below and the ones above show that the amount of emissions avoided from wind or other renewable plants depends not only on the average marginal emissions rate and the total renewable generation, but also on the hourly and seasonal profile of that generation.
Using the MIT LSF Method, Berlinski and Connors showed that offshore wind resources with significant generation potential (both those very far offshore and in outstanding near-shore wind regimes) may offer up to twice as much in terms of avoided emissions from onshore sites (Berlinski and Connors, 2006). Near shore sites that provide 50-60% more annual generation than onshore sites may produce up to 60-70% more avoided emissions. These changes must be tempered with whatever power transmission losses might occur while getting power ashore, but relative differences remain fairly large. These insights are useful when considering the potential emissions impact of future offshore wind projects.

For a prospective analysis of avoided emissions, I applied the expected average annual output of 1.5 million MWh from the Cape Wind project to the marginal emission rates for 2009 from the selected methods (shown in Figure 4-6 above). (Coincidentally, 2009 is the earliest that the Cape Wind project could come online.) It should be noted that applying annual generation to annual average marginal emission rates is not as rigorous as using hourly or even seasonal and time of day values. However, given the availability of data, this is a calculation that is done often and
provides a good first order approximation of avoided emissions. As shown in the table below, the potential avoided emissions from the Cape Wind project are significant, though lower than the amounts stated by Cape Wind consultants and supporters.

**Figure 4-18. Estimated Avoided Emissions from the Cape Wind Project in 2009 (Tons) and Differences in Estimations from La Capra Marginal More Wind Case (%)**

<table>
<thead>
<tr>
<th>Emission</th>
<th>SO2</th>
<th>NOx</th>
<th>CO2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>1,236</td>
<td>521</td>
<td>731,071</td>
</tr>
<tr>
<td>More Wind</td>
<td>1,199</td>
<td>678</td>
<td>711,324</td>
</tr>
<tr>
<td>Incremental</td>
<td>812</td>
<td>343</td>
<td>479,887</td>
</tr>
<tr>
<td>Synapse OTC Workbook</td>
<td>871</td>
<td>491</td>
<td>515,099</td>
</tr>
<tr>
<td>La Capra - Cape Wind DEIS</td>
<td>2,009</td>
<td>667</td>
<td>707,370</td>
</tr>
<tr>
<td>Clean Power Now</td>
<td>4,000</td>
<td>1,180</td>
<td>949,000</td>
</tr>
<tr>
<td>% change</td>
<td>SO2</td>
<td>NOx</td>
<td>CO2</td>
</tr>
<tr>
<td>----------</td>
<td>-----</td>
<td>-----</td>
<td>-----</td>
</tr>
<tr>
<td>Base</td>
<td>3%</td>
<td>-23%</td>
<td>3%</td>
</tr>
<tr>
<td>More Wind</td>
<td>-32%</td>
<td>-49%</td>
<td>-33%</td>
</tr>
<tr>
<td>Incremental</td>
<td>-27%</td>
<td>-27%</td>
<td>-28%</td>
</tr>
<tr>
<td>Synapse OTC Workbook</td>
<td>-33%</td>
<td>-2%</td>
<td>-1%</td>
</tr>
<tr>
<td>La Capra - Cape Wind DEIS</td>
<td>68%</td>
<td>-2%</td>
<td>3%</td>
</tr>
<tr>
<td>Clean Power Now</td>
<td>234%</td>
<td>74%</td>
<td>33%</td>
</tr>
</tbody>
</table>

Notes: Synapse total annual avoided emissions based on annual average marginal emission rates and not summed from seasonal values. La Capra used marginal emission rates from the ISO-NE MEA report for 2000 in their analysis for the Cape Wind DEIS. Clean Power Now used rates from the 2002 ISO-NE MEA.

The relative differences in avoided emissions across methods are the same as in the marginal emission rates (see Figure 4-6 above). Using the results of the La Capra Marginal Base case as a reference, the Marginal More Wind case avoided emissions are similar, while the Incremental Base and More Wind cases are about 30% lower. As for the Synapse OTC Workbook avoided emissions, the NOx and CO2 results are similar to the Marginal Base case results, while the avoided SO2 emissions are about 70% higher. Again, these differences across results are partly a function of differences in the treatment of interactions between New England and neighboring regions across methods. The figures below illustrate the potential avoided emissions from the Cape Wind project.
Figure 4-19. Estimated Avoided SO2 Emissions from the Cape Wind project in 2009 (Tons)

Figure 4-20. Estimated Avoided NOx Emissions from the Cape Wind project in 2009 (Tons)
Assuming that the La Capra More Wind scenario provides the closest simulation of the northeastern U.S. electricity system with the Cape Wind project in place, the Marginal case is most appropriate to compare to the published statements about the Cape Wind project’s expected avoided emissions, as it reflects avoided emissions from generation outside New England as well as inside. The claimed reductions for the Cape Wind project in the DEIS are over twice as much as the La Capra Marginal More Wind results for SO2, 75% more for NOx, and 33% more for CO2. The Clean Power Now estimates are also higher than the La Capra Marginal More Wind results: by twice as much for SO2, 20% more for NOx, and 40% more for CO2.

While the Cape Wind project’s environmental performance may not be as great as previously estimated, several items are important to consider when reviewing this result. First, the La Capra analysis for the Cape Wind DEIS was conducted in 2002 (using the 2000 ISO-NE MEA marginal emission rates) and the Clean Power Now estimates were based on the 2002 ISO-NE MEA report. The marginal emissions data used in these analyses, while current in the year of analysis, have been shown to be higher than later marginal emission rates. It is therefore expected that marginal emissions calculations using more recent data will provide lower avoided emissions. Second, using a dispatch model such as PROSYM (which La Capra used for the Cape Wind DEIS analysis) is more likely to provide an accurate estimate of a project’s potential...
avoided emissions than simply taking the marginal emission results of such an analysis and applying a project’s generation (which I have done here).

Considering these issues, current values of expected marginal emission rates for 2009 should be representative of future rates and sufficient for projections of avoided emissions from offshore wind projects such as Cape Wind. Although marginal emission rates have been coming down over time (refer to Figure 2-3), they will likely level off as cleaner generating technologies penetrate the system. Therefore, the La Capra DEIS and Clean Power Now avoided emissions estimates are significantly higher than more likely values, though they are on the same order of magnitude.

Despite the likely lower avoided emissions from the Cape Wind project, the values are still noteworthy. Offsets of about one thousand tons of SO2 and NOx and seven hundred-thousand tons of CO2 each year deserve credit. It is also important to keep in mind that this shows the results of only one project. The combined effect of many wind or other large renewable energy projects will likely have a greater and substantial impact on emissions.

This quantitative analysis of historical (2002) and prospective (2009) avoided emissions from offshore wind in New England has shown that emission reductions, like marginal emission rates, vary across methods and over time. Calculations of avoided emissions are sensitive to choice of method, its completeness, and its relevance to the system under analysis. While simple methods may not be as complete as sophisticated models, they may provide a sufficient first-order approximation of likely avoided emissions. The next chapter draws out some implications of this analysis for the various electricity system stakeholders and makes recommendations for future work.
CHAPTER 5: Implications for Stakeholders and Recommendations

Quantifying avoided emissions from renewable generation is important in calculating the benefits, and therefore the value, of resources such as offshore wind power. Such calculations also inform policymakers when designing energy policies. In this chapter, I describe the implications of this analysis for the various electricity system stakeholders and make recommendations for future work in quantifying avoided emissions from renewable energy resources.

Implications of this Analysis for Stakeholders

Citizens
The analysis in the previous chapter showed that projected emissions reductions due to the Cape Wind and similar projects are likely to be significant (even though they may be smaller than previously estimated). Such quantification of avoided emissions can be used to estimate expected health and environmental benefits (like lower health care costs) of this and other renewable energy development, which can then be considered by citizens when debating the merits of the projects.

Developers
The clean attribute of renewable energy projects, in terms of their zero emissions and potential to offset emissions from fossil fuel generators, is important in winning approval for development and in securing revenue. The analysis in the previous chapter showed that offshore wind project developers can claim substantial expected avoided emissions, and they may claim significant environmental benefits as a result. These claims, if transparent and consistent, may help garner support for a project and facilitate permitting.

The potential to offset emissions is also a possible source of revenue for clean energy generators. In addition to traditional energy markets, renewable energy plant owners may seek revenue from emission markets, though access to these markets has been low in the past (see discussion in Chapter 1). Using data from 2004 for emission prices and marginal emission rates, the potential
revenue from emissions offsets is about 3$/MWh (or about .1¢/kWh per pollutant), as shown in the table below.

### Figure 5-1. Value of Avoided Emissions in Current U.S. Emission Markets

<table>
<thead>
<tr>
<th></th>
<th>$/ton</th>
<th>ton/MWh</th>
<th>$/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>700</td>
<td>0.0015</td>
<td>1.0</td>
</tr>
<tr>
<td>NOx</td>
<td>3,000</td>
<td>0.0005</td>
<td>1.5</td>
</tr>
<tr>
<td>CO2</td>
<td>1.45</td>
<td>0.4800</td>
<td>0.7</td>
</tr>
<tr>
<td>Total</td>
<td>3.2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


Three-tenths of a ¢/kWh is quite small in comparison to the potential revenue from energy markets (up to 5.5¢/kWh in New England), the federal Production Tax Credit (PTC) (currently at 1.9¢/kWh), and Renewable Energy Certificates (RECs) (expected to settle around 2.5 ¢/kWh in New England) (Berlinski and Connors, 2006) (see figure below). While the magnitude of potential emissions revenue may be small currently, there is the likelihood that emission prices will increase as environmental regulations become more stringent, especially for CO2.

### Figure 5-2. Potential Revenue Sources for Offshore Wind in New England

Source: Adapted from “Economic and Environmental Performance of Potential Northeast Offshore Wind Energy Resources” (Berlinski and Connors, 2006).
Despite the small current dollar value per unit energy of avoided emissions, it is important to keep in mind the volume of electricity produced by large wind farms. If the Cape Wind project’s expected annual output of 1.5 billion kWh received credit for .3¢/kWh from offsetting emissions, it would generate $4.5 million per year, certainly not an insignificant amount.

It is also important to note that these emission prices do not include putting an economic value on the avoided health impacts of the reduced emissions. The total avoided external cost from wind energy is huge. Using European data from 2000, the European Wind Energy Association (EWEA) has estimated that if all of the externalities of fossil fuel electricity generation in terms of impact on human health and the environment were monetized, they would be worth about ten cents per kWh (10¢/kWh) (EWEA, 2005). This reveals a huge potential societal value of clean energy generators like wind power.

Policymakers
State and local governments will be happy to know that offshore wind energy will help them meet environmental regulations by offsetting emissions. As the analysis in the previous chapter showed, significant potential generation from offshore winds makes for serious cuts in emissions of all pollutants over a year. This is especially important for reductions of precursors to fine particulates, for which the health effects are still being learned. It is important to realize that offshore wind power is better suited to addressing certain issues over others. For example, because it is windier in the winter than in the summer, offshore wind is only slightly beneficial in reducing ozone season NOx emissions.

In addition to meeting current regulations, quantifying avoided emissions aids in designing smart new energy and environmental policies. Understanding that marginal emission rates and renewable energy generation profiles change over different times of day (on-peak vs. off-peak) and times of year (ozone vs. non-ozone) allows policymakers to create the right incentives for maximizing benefits. For example, a program of peak energy reduction may have less of an impact on reducing emissions from power plants than a program of overall energy reduction. This is because generation on the margin at the peak is likely to be cleaner than marginal generation over all hours of a given time period.
Recommendations

This analysis has introduced some of the major issues in calculating avoided emissions and in quantifying the environmental benefits of renewable energy resources. After describing various methods for estimating avoided emissions, I applied selected techniques to some New England offshore wind data and compared the results. Now that the implications of those results have been discussed, I put forward the following recommendations for future work:

1. Share Information and Update Guidance
2. Data, Data, Data
3a. Choose Method Wisely
3b. Compare Solutions to Achieve Goals at Least Cost
5. Give More Weight to Environmental Benefits in Environmental Impact Assessments
6. Document Claims of Environmental Benefits

1. Share Information and Update Guidance
The EPA, UN, and other government bodies involved in monitoring emissions should continue to analyze methods for calculating emission reductions and share information on the various techniques and their challenges. As central authorities in environmental protection, these institutions are best situated to collecting examples of methods for calculating emission reductions and assessing them based on established guiding principles. Assessments of new methods should be published every year.

As the current guidance is relatively new (released in 2004), it should be reviewed and commented on by regulated entities and other interested parties. These organizations should work with regulators to make the guidelines as specific as possible and to update the guidance documents as necessary.
2. Data, Data, Data
To inform smart energy and environmental decision making, analysts and decision makers need a better understanding of the dynamics of the electric power system and its environmental impacts, on both short (hourly) and long (decadal) time scales. To achieve this, more information on unit-specific performance over a year and on plant additions and retirements over many years is required. Enabling access to the data essential in identifying marginal generating units and their emission rates is the responsibility of all electricity industry stakeholders. Government organizations should be provided the necessary funding and authority to ensure sufficient data collection and dissemination. EPA, EIA, and state energy offices should gather more emission and generation data. DOE and NOAA should expand their energy resource assessment data sets.

3a. Choose Method Wisely
There exist many methods of calculating avoided emissions, varying in sophistication and cost. The need for accuracy and precision must be tempered by the budget available for the analysis. Decision makers must learn enough about the electric power system to make an informed choice of which method to use and how to use it constructively. Analysts should keep in mind the GHG Protocol guiding principles when assessing methods (Accuracy, Relevance, Completeness, Transparency, and Consistency). New methods of calculating avoided emissions should be developed, documented, and shared.

3b. Compare Solutions to Achieve Goals at Least Cost
Entities subject to environmental regulation should use an appropriate method to evaluate different energy programs to help them meet environmental goals at least cost. Comparing the environmental performance of both supply side and the demand side energy technologies (suitable for the local region) will inform decisions on designing energy programs and making sound investments for a clean energy future.

Because energy efficiency and renewable energy (EE/RE) projects may reduce emissions from power plants, they should be allowed to participate fully in emission markets. Federal and state governments should establish clear rules for participation that take into account the dynamic
nature of the electricity systems and that address issues such as location of emission reductions and ownership of allowances. The market rules should be slowly changed over time to allow the various market participants time to adapt.

One way to improve participation is expanding the allocation of emission set-asides for EE/RE projects, or establishing new types of allowances for EE/RE resources. Quantification of avoided emissions facilitates the analysis needed to establish optimum amounts of allowances for EE/RE resources. Retiring allowances should be kept as an option for reducing air emissions.

Enhancing emission markets will help internalize the high external costs of fossil fuel generation and will help EE/RE projects secure additional revenue. Internalizing these costs and providing another source of revenue for EE/RE projects may reduce the need for direct subsidies to EE/RE projects.

5. Give More Weight to Environmental Benefits in Environmental Impact Assessments
When one is weighing the pros and cons of a project or program, such as in an environmental impact assessment, one should take into account the likely emissions and related health and environmental impacts of the alternatives. Similarly, the potential to improve human health and the environment should be taken into account when assessing the impact of offshore wind farms and other large renewable energy power plants and when comparing the alternatives.

6. Document Claims of Environmental Benefits
EE/RE project owners and program administrators should document their claims of the environmental benefits of their projects and programs, especially avoided emissions. Greater transparency will allow independent review of claims and will inform others of the potential environmental performance of certain technologies. Clean Power Now, for example, provided sufficient documentation in their estimate of the Cape Wind project’s avoided emissions to allow for comparison in this paper. Consistency of results will also enhance credibility of developers and administrators. Such documentation will prepare project owners for participation in emissions markets, as certification will be required.
References


Cape Wind. (c) “Frequently asked questions: Cape Wind and the Environment.”


Appendix

1. Map of New England Offshore Wind Resource

![Map of New England Offshore Wind Resource](image1)


2. Map of Offshore Wind Data Sites for Analysis

![Map of Offshore Wind Data Sites for Analysis](image2)

Source: Adapted from Economic and Environmental Performance of Potential Northeast Offshore Wind Energy Resources (Berlinski and Connors, 2006)
3a. MIT Load Shape Following (LSF) Marginal Emission Rates for 2002

Source: National Assessment of Emissions Reduction of Photovoltaic (PV) Power Systems (Connors et al., 2004)

MIT Annual Marginal Emission Rates

<table>
<thead>
<tr>
<th>Lbs/MWh</th>
<th>Load Shape Following</th>
<th>Slice Of System</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2</td>
<td>4.7</td>
<td>4.0</td>
</tr>
<tr>
<td>NOx</td>
<td>1.7</td>
<td>1.5</td>
</tr>
<tr>
<td>CO2</td>
<td>1,682</td>
<td>1,676</td>
</tr>
</tbody>
</table>

3b. MIT Slice of System (SOS) Marginal Emission rates for 2002

Source: National Assessment of Emissions Reduction of Photovoltaic (PV) Power Systems (Connors et al., 2004)
### 4a. ISO-NE Marginal Emission Rates for 2000

<table>
<thead>
<tr>
<th>Emission</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
<th>Annual Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On-Peak</td>
</tr>
<tr>
<td>SO2</td>
<td>6.6</td>
<td>6.0</td>
<td>6.3</td>
</tr>
<tr>
<td>NOx</td>
<td>2.0</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>CO2</td>
<td>1,545</td>
<td>1,505</td>
<td>1,463</td>
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</table>

Source: 2000 NEPOOL Marginal Emission Rate Analysis (ISO-NE, 2002)

### 4b. ISO-NE Marginal Emission Rates for 2002

<table>
<thead>
<tr>
<th>Emission</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
<th>Annual Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On-Peak</td>
</tr>
<tr>
<td>SO2</td>
<td>3.7</td>
<td>2.0</td>
<td>4.9</td>
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<tr>
<td>NOx</td>
<td>1.4</td>
<td>0.8</td>
<td>1.5</td>
</tr>
<tr>
<td>CO2</td>
<td>1,412</td>
<td>1,171</td>
<td>1,536</td>
</tr>
</tbody>
</table>

Source: 2002 NEPOOL Marginal Emission Rate Analysis (ISO-NE, 2003)

### 5. Synapse OTC Workbook Marginal Emission Rates

**Figure 3.3: The Default Displaced Emission Rates for ISO New England (lb/MWh)**

<table>
<thead>
<tr>
<th>Emission</th>
<th>Ozone Season</th>
<th>Non-Ozone Season</th>
<th>Annual Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>On-Peak</td>
<td>Off-Peak</td>
<td>On-Peak</td>
</tr>
<tr>
<td>SO2</td>
<td>2.9</td>
<td>2.5</td>
<td>2.3</td>
</tr>
<tr>
<td>NOx</td>
<td>3.5</td>
<td>4.5</td>
<td>4.1</td>
</tr>
<tr>
<td>CO2</td>
<td>1,600</td>
<td>1,780</td>
<td>1,820</td>
</tr>
</tbody>
</table>

### 6. La Capra Marginal Emission Rates

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2006 Marginal Emission Rates</th>
<th>2009 Marginal Emission Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SO2 (lbs/MWh)</td>
<td>NOx (lbs/MWh)</td>
</tr>
<tr>
<td>Renewables - Base</td>
<td>(3.57)</td>
<td>(1.34)</td>
</tr>
<tr>
<td>No CT RPS</td>
<td>(2.52)</td>
<td>(0.98)</td>
</tr>
<tr>
<td>More Wind</td>
<td>(2.59)</td>
<td>(1.12)</td>
</tr>
<tr>
<td>More Biomass</td>
<td>(3.23)</td>
<td>(1.13)</td>
</tr>
<tr>
<td>Fuel Price*</td>
<td>(3.20)</td>
<td>(1.60)</td>
</tr>
<tr>
<td>Transmission**</td>
<td>(3.39)</td>
<td>(1.27)</td>
</tr>
</tbody>
</table>

* The shift in fuel prices would last no more than a few months; fuel price scenario was compared to a Benchmark - Fuel Price Case. See report for details.
** Transmission Congestion Scenario was compared to the Benchmark - Transmission Case. See report for details.

### Source: