Estimating the Emission Reduction Benefits of Renewable Electricity and Energy Efficiency in North America:
Experience and Methods

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1. Introduction

When a new power plant operates in a regional electric system, the plant affects the system in a number of ways. Assuming that regional loads remain the same, the new plant will probably reduce the operation of another generating unit (or units) in the same system. Alternatively, all plants in the system might continue to operate at the same level, causing increased exports to (or decreased imports from) neighboring systems. New energy efficiency equipment has a similar effect: as demand is reduced, either generating units within the local system operate less or transactions with neighboring systems change. The result of either a new generating unit or reduced demand is likely to be a net change in air emissions across the interconnected systems.

Over the past decade there has been increasing interest across North America in understanding the net emissions impacts of specific resources that could be added (or have been added) to regional electric systems. However, estimating these emissions impacts in a comprehensive and accurate way is a complex process. The Commission for Environmental Cooperation (CEC) is interested in promoting a comparable methodology for estimating displaced emissions from renewable energy and energy efficiency across North America, in order to facilitate both trade and the development of these technologies. While many different policies and market-based mechanisms exist that have the potential to support these technologies, their potential is limited to some extent by the challenge of quantifying environmental benefits. Thus, credible and comparable methods to quantify these benefits can help to ensure that the policies and mechanisms, as well as the technologies they are designed to support, can reach their potential. In addition, comparable methods of measuring and displaying these benefits facilitate public awareness by showing, in a consistent way, the contribution these technologies can make to quality of life.

This paper explores the important methodological issues related to estimating the net air impacts of specific resources, or groups of resources, in electric systems.[1] In addition, we describe a number of studies undertaken across North America in which the emissions benefits of new resources—both renewable projects and efficiency programs—have been estimated. Finally, we briefly explore different views of the principles that should underlie this kind of work and several important policy issues that this work raises.

2. Estimating Avoided Emissions

Governments, companies and other interested parties have a variety of reasons for wanting to quantify avoided emissions from renewable electricity generation or energy efficiency programs. These reasons range from assessing the probable air impacts of environmental regulations and energy policies to quantifying emission reductions for the establishment of tradable emissions credits or the sale of "green power." Some assessments of emission reductions, such as energy

[1] Note that this paper focuses on analyzing the emissions impacts of specific projects or groups of projects. It does not address the issues important in assessing the impacts of programs, such as subsidies for renewable energy or energy efficiency. These issues relate to the market response to the program and include dynamics, like free ridership, spillover effects and other market responses.

policy analysis, are prospective, while others, such as quantification of reductions for crediting, are often retrospective.

Regardless of the purpose of the assessment or whether it is foreward or backward looking, there are two tasks involved in estimating the emissions impacts of renewable electricity generation and energy efficiency programs. These tasks are:

- Quantifying the electrical energy generated or saved, and
- Predicting how the regional electricity system will react (or did react) to the energy saved or generated.

A variety of methods and analytic tools can be used for each of these tasks. The specific methods and tools selected for a given study are primarily dependent upon the resources available and the purpose for which the avoided emissions are calculated. For example, simulating the operation of a system with a dispatch model is more resource intensive than estimating a system marginal emission rate and applying this rate to the energy generated or saved. However, the latter approach may be sufficient for rough estimates of displaced emissions. Other important considerations in choosing a method and tools include the time frame and geographic scope over which the estimate is being made.

In addition to assessing the emissions benefits of specific energy resources, one can also assess the marginal emission rate in a give region during different time periods to develop emission factors that can be used to assess multiple resources. As discussed in Section 2.2, the marginal unit is usually the unit affected most by new generation or reduced loads. Assessing a regional marginal emission rate is similar to assessing the impact of a specific resource in that one must review the power plants dispatched in the region in detail, either with a model or with data on actual unit dispatch. However, the first of the two steps listed above—quantifying the energy generated or saved—is unnecessary when developing system marginal emission factors.

The subsections below describe the methods and tools commonly applied to these two tasks. Section 3 discusses a number of studies in which various organizations in North America have applied these methods and tools. Section 4 examines some principles that have been outlined to govern emission reduction estimates.

2.1 Quantifying Clean Energy Generated or Energy Saved

The first step in a prospective assessment of avoided emissions is to estimate how much energy the resource in question will produce or save, when and where the energy will be produced or saved, and whether there will be air emissions associated with the energy. To do this, one must predict how the generator or efficiency equipment will operate within the regional electric system. Similarly, in a retrospective analysis one must know something about the operational profile of the resource—when where and how it generated or saved energy. Often, assessing the historical impacts of an existing resource is easier than predicting the impacts of a new resource, because the historical operation of the existing resource is known and does not have to be estimated.

The simplest way to predict the performance of a new asset is to estimate operation of the asset based on information about the typical operation of that resource type. More complex approaches include (a) using actual data from an existing plant similar to potential new resource and (b) modeling the operation of the asset within the regional power system. The latter two approaches are more resource-intensive, but they often lead to a more credible analysis. As noted, when assessing the historical impacts of an existing resource, data on operation of that resource are often available, and this is the best information to use.

Task 1: Quantifying the Resource's Operation

- *How much energy is generated?*
- *Where is it generated?*
- *When is it generated?*
- *Does it produce air emissions?*

To aid in estimating the output of a new plant, information is available on the amount of energy likely to be produced by different resource types. For example, data are available on the production of a wind turbine operating in a given wind regime and the temporal distribution of that production. This information is often called the "load profile" of the resource. Similarly, data are available on the amount and timing of the energy savings likely to accrue from a given efficiency program. When estimating the performance of a potential resource, the analyst should document the basis of the estimation and attempt to quantify the range of uncertainty associated with it.

Detailed data sets, based on the operation of actual equipment, are also available for different types of resources, but many of the best data sets are proprietary and must be purchased if they can be obtained at all. In the US, the National Renewable Energy Laboratory (NREL) is a good place to find data on the performance of renewable technologies. Other good places to seek such data sets are federal energy offices and renewable energy trade associations.[2] Detailed data sets describing the load profiles of energy end uses and efficiency equipment can be more difficult to find than data on renewables. Two organizations in the US that generate this type if information are the American Council for an Energy Efficient Economy (ACEEE) and Regional Economic Research (RER). RER sells hourly load profile data on residential, commercial and industrial equipment for each US state. The company develops these data using SitePro, a model based on analysis of many hourly load profile data sets. Other good places to look for this information are state and federal energy efficiency agencies and advocacy groups.

Places to look for information on the histrocial operation of existing plants or plant types in Canada include: the Energy Sector of Natural Resources Canada, the Office of Energy Efficiency and CANMET Energy Technology Centre. Organizations that house this type of information in Mexico include: the *Secretaría de Energía*,[3] *Comisión Nacional para el Ahorro de Energía*, *Comisión Reguladora de Energía*, and the *Comisión Federal de Electricidad* (CFE), *Subdirección de Programación*. Good places to look in the US are the US Department of Energy (DOE), the Environmental Protection Agency (EPA) and the Electric Power Research Institute (EPRI).

[2] The Canadian federal energy office is the Energy Sector of Natural Resources Canada <www2.nrcan.gc.ca/es>, the Mexican counterpart is the National Energy Efficiency Agency or Conae in Spanish <www.conae.gob.mx>, and the US office is the Department of Energy <www.eia.doe.gov>.

[3] For more information see: <www.sener.gob.mx> and <www.cfe.gob.mx>.

The most credible method of estimating the performance of a new electric asset is to simulate its operation within the appropriate regional electric system. This is done with an electric system dispatch model, sometimes called a production costing model. A number of consulting firms in North America have experience applying these models, and most electric utilities use them for planning studies and other purposes. These models simulate plant dispatch based on input data defining load levels, transmission constraints and other factors. Importantly, dispatch modeling is often used in the second task in estimating displaced emissions (predicting how the regional electricity system will react to the energy saved or generated). Thus, these models allow the user to predict *both* how the new asset will operate *and* how the regional system will react in one step. Dispatch models are discussed further in Section 2.2 below.

The final step in characterizing the operation of the asset in question is to estimate the air emissions associated with it. Some renewable generating technologies (e.g., biomass and landfill gas) have pollutant emissions, and these emissions must be taken into account when assessing net emissions impacts. Emission factors for these generating technologies are available from federal and state environmental regulators and from the various renewable technology trade associations.[4]

After the operating data on the resource(s) in question have been obtained, estimated or modeled, these data must be used to determine how the resources will affect (or did affect) the regional electric system. This entails developing a "reference case," an assumption about how the system would have operated without the resource(s) in question.

2.2 Estimating the Net Air Impacts of Electricity Resources

Three methods are commonly used to estimate the net air impacts of generating plants and efficiency equipment. These methods are:

1. **Displaced emissions analysis and time-specific marginal emission rates**. This approach is based on an hour-by-hour analysis of plant dispatch—either analysis of utilities' actual dispatch records or analysis using a system dispatch model. Electric system dispatch models, which provide a dynamic representation of the regional electric system, can be used to assess net emissions impacts by simulating the operation of the new resource within the regional system. (As noted, dispatch models predict the operation of the resource in question and its affect on the regional system in a single step.) These models can also be used to derive marginal emission rates for different time periods, which can then be used to estimate displaced emissions from a variety of policies and specific resources.

2. **Plant addition/retirement emission factors**. Displaced emission rates can be developed based on the emission rates of the new plants projected to be added to the

Over the short term, new resources displace generation from existing units. Over the long term, new resources displace other new resources competing for market entry.

[4] In particular, see: US EPA, *Compilation of Air Pollutant Emission Factors, AP-42*, Fifth Edition, at: <www.epa.gov/ttn/chief/ap42>.

system over the long term (from five to twenty-five years out) and the old plants projected to be retired. This approach is most appropriate for the assessment of emission impacts in medium- to long-term future years.

3. **System average emission factors**. These rates are calculated by dividing total system emissions by total system generation, yielding a system average emission rate in terms of pollution mass per unit of energy generated. This emission factor is then applied to the output of specific resources to estimate net changes in emissions.

The most detailed approach to assessing net emissions impacts is to analyze hourly plant dispatch with and without the resource in question. A retrospective analysis of this type might use utilities' records of actual system dispatch to determine when the resource operated and what other resources would have operated without it. If utility records are unavailable, one can use an electric system dispatch model to simulate plant dispatch under the same load conditions. Either way, *the goal is to identify the generating units, or types of units, that the asset in question is likely to affect and the extent of the effects.* Often the unit affected most is the *marginal* unit—the most expensive unit operating at a given time. Because power plants in regional electric systems are dispatched in order of increasing costs (or bids in the case of competitive markets), additional energy or reduced demand usually reduces the operation of the most expensive unit that would otherwise be operating in a given hour. However, because there are a number of constraints on system operation (such as transmission constraints, limitations on plant operation and reserve requirements), units other than the marginal unit can be affected as well.

Hour-by-hour analysis using actual dispatch records or a dispatch model is the most effective way to estimate the net air impacts of a specific resource. As noted above, a dispatch model can also be used to assess a particular region rather than an asset, in order to derive system marginal emission factors for the region. In this case, the goal is to identify what type of generating units are on the margin during different periods of the day and year. Marginal emission factors reflecting the different unit types are developed for different time periods, and these factors can then be applied to the output of specific resources without rerunning the model.

The latter two approaches listed above do not investigate the hourly operation of the asset in question within the regional electric system. Rather, these approaches apply emission factors to the output of the asset. Plant addition/retirement emission factors can be used to assess the long-term air impacts of a resource added today, because over the long term, new resources displace other resources competing for market entry. When a new resource is added, it increases supply and reduces prices, making market entry less attractive to potential entrants.[5] This is a crucial distinction in assessing displaced emissions. Over the short term, new resources displace existing units—primarily the marginal unit—in the *existing* electric system. Over the long term, a resource added today will displace other new resources competing for market entry and/or cause

[5] In competitive (i.e., unregulated) electricity markets, this dynamic operates as follows. When new plant developers turn to capital markets for financing, potential lenders and investors assess projected prices in the proposed region to determine whether to finance the project or not. In regulated markets, utilities petition the local utility commission to build the new plant. The commission, based on an assessment of need, determines whether to allow the utility to build.

retirements of existing capacity.[6] When considering the effects of a specific resource over both the short and long term, one must factor in both of these dynamics. That is, the short-term effects of a new resource on the existing system give way to the long-term effects on other plants competing for market entry.

Often, system average emission factors have been used to estimate displaced emissions from specific resources, primarily because these factors are relatively easy to calculate. Many budget-constrained studies and quick estimates of displacement rely on system average rates. This method, however, can provide highly inaccurate results. As noted, additional generation or reduced load in an electric system affects the marginal generating units far more than it affects other units, and in most systems, the units that operate on the margin are quite different from the units providing baseload energy. For example, hydro and nuclear units—with very low air emissions—provide much of the baseload energy in many regions of the US. If a weighted system average is calculated, these units' extremely low emission rates have a large impact on the result. But most new assets will have virtually no affect on the operation of baseload units. Thus, this is clearly an inappropriate emission rate to use for assessing the air impacts of new assets. (As an example of how different system average emission rates can be from marginal rates, see Table 10 in Section 3.3.1.)

Despite the potential inaccuracy of this approach, the use of system average emission factors persists, largely because it is easier and less resource intensive than predicting plant additions and retirements or simulating system operation with a dispatch model. Avoided emissions can be calculated using a system average emission rate at the cost of several hours of labor if data are readily available on the generators within the system. In contrast, model licensing fees and the labor-intensive nature of modeling make it difficult to assess displaced emission with a model for less than about US$10,000, and most modeling studies cost considerably more than this.

As noted, the resources available for a study are likely to be a key factor determining the method chosen for estimating displaced emissions. The purpose for which the estimate is being developed, however, will also play a role in the decision. For some purposes, such as quantifying emission reductions for the establishment of credits, a high level of certainty may be necessary. Other purposes may require less certainty. However, even when ample resources are available and the highest degree of certainty is required, there are several key factors to consider in choosing the most appropriate model or emission factor. The two main considerations are: what is the time frame over which displaced emissions are being estimated, and what is the geographic scope over which they are being estimated?

In the context of a prospective analysis, the key distinction between the short term and the long term is whether or not a significant amount of new capacity will be added to, or retired from, the system. Thus, we define the short term as the period during which few generating assets will be added or retired. Over this time horizon, the analytic task is to predict how the *existing* regional electricity system will react to additional clean generation or reduced energy use. The long term is the period during which old generating units can be retired and new ones added. Usually, this

[6] In many cases it will still be desireable to perform dispatch modeling when assessing a long-term scenario, to capture the specific resource's impacts on system dispatch. For example, intermittent resources may have a different impact on system dispatch than dispatchable resources.

is the period starting roughly four years from the present. Over the long term, the task is to predict how the new asset will affect plant additions and retirements.[7] The major challenge in a long-term analysis is in predicting which generating units will be retired, where and when, and what kinds of new units will be built, where and when.

2.2.1 The Short Term

For assessing how a given asset affects an existing electric system, analysis with a system dispatch model provides a comprehensive and accurate approach. A dispatch model is important, because the regional electric systems in North America operate in complex, integrated ways, characterized by fluctuating demand and randomly occurring outages of equipment. A credible prediction of how a system will respond to increased generation or reduced load must be based on the ability to simulate these changes in a way that reasonably represents the manner in which the system is operated.

Dispatch models require information about the generating units within the region of interest, as well as the regional transmission system and regional electricity loads. Information about generating units includes: unit size, fuels used, emission rates, plant efficiency and operating limitations (such as start-up ramp times and minimum up and down times), operating costs and fuel costs. The user also enters detailed information on the regional transmission system, such as transmission constraints within control areas and transmission limits between control areas.

The most detailed dispatch models simulate dispatch chronologically—whereby the loads and resources are matched on a sequential hourly basis. These models require a full series of hourly loads for one, or usually more, load zones. Based on varying degrees of future knowledge, the models simulate chronological unit dispatch and commitment. Such models can represent the full implications of unit-specific operating constraints, maintenance outages and other time-sensitive events. Unplanned unit outages (also called "forced outages") are represented in chronological dispatch models probabilistically. That is, the models' algorithms recognize and reflect the randomly occurring nature of forced outages. Because dispatch models rely on such detailed information, they are rarely used to simulate dispatch across large geographic areas, such as all of Canada or the US.

The most commonly used dispatch models include PROMOD, PROSYM/MULTISYM, GE MAPPS and ELFIN. (PROSYM and GE MAPPS simulate dispatch chronologically, while ELFIN and PROMOD do not.) While these models can be used to assess long planning horizons, they are not designed to predict plant additions or retirements over time. When one of these models is used to simulate a multi-year period, the user directs the model to add specific generating units (or unit types) in specific years or to maintain a certain capacity reserve margin by adding a specific type of plant as needed. In contrast, when analysts want a model to predict the capacity mix in the future, they turn to a forecasting model. These models are discussed below.

[7] Note that in both cases we are evaluating an asset added in the near term. The long-term analysis envisioned here assumes that there is ample time for all players in wholesale power markets to factor the new asset into their planning.

Dispatch models can be used either to assess displaced emissions directly or to develop system marginal emission factors, which are then used in a displacement analysis. To assess displacement directly, the user proceeds as follows.

- Run a "Base Case," simulating plant dispatch without the asset in question.
- Run an "Alternative Scenario," simulating dispatch with the asset in question.
- Subtract total system emissions in the "Alternative Case" from system emissions in the "Base Case" to derive the estimate of emissions displaced by the asset in question.

Because the system has been dispatched to minimize costs in both runs, this approach captures all of the impacts that the new resource would have on the system, from energy impacts to capacity impacts and effects on operating reserves.[8] Most importantly, this approach captures only the emissions changes at generating units that operate less because of the new unit. As previously discussed, these are primarily the units that were on the margin when the new unit operated, but other units can be affected by the new resource as well.

To develop system marginal emission factors for a particular electricity control area, one uses a similar method. First, one performs a Base Case run, and next a "Decrement Run," in which all hourly loads are reduced slightly. These two runs are designed to isolate the emissions of the marginal plants. However, rather than assessing emissions over the entire year, it is best to develop system marginal factors for a number of specific time periods. This is important because, as demand rises and falls throughout the day and year, different generating units are on the margin. The system marginal emission rate when loads are high can be quite different from the rate when loads are low. For example, consider a region with substantial hydro and nuclear capacity with a relatively small amount of intermediate coal- and oil-fired steam units and combustion turbines (CTs) for peak periods. During peak-load hours, when the CTs are on the margin, the marginal NO_x and CO_2 rates would be extremely high. During intermediate-load hours, when the steam units were on the margin, marginal NO_x rates might be lower but SO_2 rates higher. During low-load hours, with hydro or nuclear units on the margin, the marginal rates of all pollutants would be virtually zero. Thus, it is important to develop system marginal emission factors for different time periods in order to assess new resources that will operate in different time periods.

One can develop system marginal emission factors for any number of time periods, but it is most common to use between four and fifteen. In the case of four, marginal rates could be developed for the spring, summer, winter and fall. More time periods would allow for division into daily time periods, such as night and day or peak and off peak. Again, the number of different marginal factors developed should be chosen based on the characteristics of the region under evaluation. Regions with large fluctuations in emission rates along their supply curves should be assessed in more detail than regions with more uniform supply curves.

[8] Several control areas have moved to bid based dispatching of generating resources. To the extent that the dispatch is "bid-based" rather than "cost-based" the simulation model may not strictly minimize the costs of producing electricity to meet demand, but the concepts of "least-cost central dispatch" still apply.

Having developed the system marginal emission factors, they can then be applied to the projected output of specific assets. For example, one could use generation data from an actual wind farm to allocate output of a potential wind farm to time periods for analysis with the system marginal emission rates. Or one could use the load profile data for a particular type of efficiency equipment to allocate energy savings to time periods.[9] The important thing to remember, however, is that these marginal emission factors would govern displaced emissions over the near term. To assess the long-term impacts of a new asset, one would have to predict that asset's effect on plant additions and retirements.

2.2.2 The Long Term

Over the long term, decisions made by power plant owners and new plant developers will take into account many of the changes in the regional system that took place during the near term. The increase in supply provided by the new plant will have two important effects. First, it will decrease the demand for new plants, and second, it will decrease market prices, putting economic pressure on the least competitive plants in the region. Through the latter dynamic, a new plant effectively pushes the least competitive plants toward retirement. In light of these dynamics, the question of what kind of generating units will be added and retired is extremely important to predicting displaced emissions over the long term. Unfortunately, predicting what kind of units will be added and retired is difficult.

Predicting plant additions and retirements is difficult, because it is not simply a question of costs. Many factors—regulatory, political, economic and financial—influence the decision to build a new unit or retire an existing one, and plant developers and owners do not always behave like the rational market participants assumed in textbook economics. In addition to basic economics (such as relative fuel prices and technology costs), some of the important factors affecting plant additions are: the prevailing attitudes of capital markets toward the power generation sector, environmental regulatory policy (e.g., in attainment and non-attainment areas), energy policies designed to support the addition of certain unit types and discourage the addition of others, strategic considerations and market power, and irrational behavior in the project development process.[10]

Task 2: Quantifying the New Resource's Operation

- *When assessing the short term, a marginal emissions analysis with a detailed dispatch model is best.*
- *When assessing the long term, the analyst must predict new plant additions and retirements, and an emission rate reflecting these plants is best.*
- *A system average rate should be avoided if possible, as it can result in inaccurate estimates of emissions impacts.*

[9] Projects using dispatch models to develop system marginal emission factors are discussed in section 3.3.1 and 3.3.2 below.

[10] For many of the players involved in a power project, compensation is directly linked to the project's success. If the project is scrapped, people such as project developers and lawyers make much less money than if the project succeeds. Thus, there are strong incentives for these players to push a project forward even if the economic outlook for the project becomes weaker.

Decisions regarding plant retirements are in many ways harder to predict than decisions about new units. Many different costs and benefits factor into unit retirement decisions, and these costs and benefits are very difficult to quantify. Key aspects of plant retirement decisions include: the true operating costs of the unit (usually known only to the plant operators), the hedging value of avoiding "retired" status, the extent of future costs and risks (such as exposure to compliance costs associated with new environmental regulations), and the capacity value of the unit. In addition, plant retirements often come in the context of deals made with regulators to bring new plants on line.

Thus, predicting future unit additions and retirements is an uncertain endeavor; however, it is an endeavor crucial to predicting long-term emission reductions from energy efficiency and clean generation. There are essentially two approaches to predicting unit additions and retirements. One approach is to use a forecasting model, and the other is for the policy maker or analyst to make predictions for a specific region, based on key indicators in that region.

Energy forecasting models are broader in scope than the dispatch models described above. The major forecasting models have modules that focus on each energy sector (e.g., transportation, industrial fuel use, residential fuel use, etc.). They forecast the evolution of these energy sectors by simulating the interaction of the sectors in areas such as fuel prices and supply and demand in each sector. For example, as new gas-fired power plants are added in the electric sector, the impact of these units' fuel use is factored into natural gas supply and pricing across all energy sectors. If gas prices are predicted to rise, the viability of additional new gas-fired power plants is reduced. Forecasting models generally use a mathematical optimization technique. Some operate iteratively, converging on an optimal solution (or at least a stable one) after a number of runs, while others use techniques such as linear programming to find system expansion plans that best satisfy an objective function (e.g., least total cost) subject to constraints.

Examples of forecasting models include the Canadian Power Planning Program (CANPLAN), the US DOE's National Energy Modeling System (NEMS), the Integrated Planning Model (IPM®), the MARKAL model and the Energy 2020 model. Importantly, these models are flexible in their operation, and users can input a variety of different types of data. For example, when simulating US energy markets for its Annual Energy Outlook, the DOE uses highly aggregated data in the electricity module of NEMS. Other analysts focus NEMS more specifically on the electric industry and enter more detailed data into the model than does the DOE.

A forecasting model can be used to assess long-term displacement in two ways—just as a dispatch model can be used to assess short-term displacement in two ways. First, the operation of the specific new resources in question can be simulated over the long term. As the model simulates plant addition and retirement decisions with the new asset, it captures the air impacts of that asset over time. Second, a forecasting model can be used to develop long-term marginal emission factors. By performing a Base Case run and a Decrement run, modelers can assess the type of new plant likely to be displaced over the long term and the type of old plant likely to be retired. The long-term marginal displaced rate should be a weighted average of displaced new entrants (plants that do not get built) and retired, existing plants.

Examples of the use of forecasting models to develop long-term displaced emission are discussed in sections 3.3.2 and 3.3.3 below.

2.3 Geographic Scope

In addition to the time frame of a study, its geographic scope will also affect the choice of methodology. When large areas are modeled, such as all of Canada or the US, more aggregated data on loads and generators must be used as well as simplifying assumptions for dynamics like forced outages. Models like NEMS, IPM® and Energy 2020 are well suited to these studies. When smaller areas are simulated, such as Mexico or single regions of Canada or the US, detailed input data can be accommodated, and a detailed dispatch model should be used.

However, the issue of scope affects more than the selection of a model. Because electricity grids in North America are interconnected, and energy commonly flows between them, changes in emissions in neighboring control areas must be factored into displaced emissions analyses. As discussed above, a new plant will likely affect most the operation of other units within the same control area; however it may also affect the operation of units in neighboring areas. In some cases, the largest air impact of a new asset may come in a different control area. This is especially true in Mexico and the northeastern US, where the distinct control areas are relatively small. Thus, a displaced emission study must cover a large enough geographic area to confidently capture the majority of the air impacts. The appropriate size of the study area depends on the region being assessed. When assessing a very large control area, or one that imports and exports very little energy, it may be appropriate to limit the study to that area only. When assessing a control area that imports and exports significant amounts of energy, all the control areas involved must be assessed.

One simple check to ensure that the study area is appropriately sized is the change in total generation in the Base Case versus the Alternative Case. Assuming that loads are the same in these two cases, generation in the study area should be the same in the two cases. If there is less generation in the control area in the Alternative Case, then the area is importing more energy in that case. If there is more generation in the study area in the Alternative Case, the study area is exporting more energy and displacing emissions in another area.

2.4 Avoided Emissions in the Context of Capped Pollutants

When predicting emission reductions from energy efficiency and clean generation, it is important to consider the role of allowance trading programs. Under these programs, also known as "cap-and-trade" programs, total emissions of a pollutant are capped within a specified geographic area and emission allowances are allocated to sources. Sources are typically required to hold one allowance for every ton emitted during each accounting period. The US currently has two major allowance programs, the Title IV Acid Rain program and the NO_x Budget program in the Ozone Transport Region (in the northeastern United States) as well as several programs operating in areas of Texas and California.[11] The government of Ontario implemented an allowance trading program for NO_x and SO_2 in the electric sector in 2002, and other allowance programs are under consideration in Canada.

The important issue raised by allowance programs is whether emission reductions from energy efficiency and renewable energy will be traded away by sources that are allocated emission allowances. For example, an energy efficiency program may be projected to reduce several tons of NO_x during a given year. However, if that program achieves those reductions by reducing the operation of plants that receive emission allowances, the owners of those plants can simply sell the unneeded allowances to other sources. In fact, if allowance markets are operating efficiently, (and emissions are indeed constrained) total emissions in the capped area will be at the capped level, and new zero-emission generation (or load reductions) will simply make it easier for the regulated plants to meet the cap. (That is, it will lower the market price of emission allowances.)

Most electricity dispatch and forecasting models factor allowance costs into the operating costs of generating units. The result is that a unit with a lower emission rate will operate more hours than a similar unit with a higher emission rate, because it will have lower emissions costs factored into its operating costs. Some of the larger models redistribute allowances internally when plant operation is changed, such that total NO_x and SO_2 emissions are always at the capped level.[12] In practice, however, the decisions of generators regarding their extra allowances is not so predictable. In the current US programs, generators may bank unneeded allowances for use in future years or sell them. The allowances could be used by a plant near the selling plant or at a plant a considerable distance away. The result is that, while emission reductions from clean energy and efficiency are immediate and real, over the course of an entire season or year, those reductions may be lost through emissions trading.

Thus, in order to realize emission reductions in the context of capped pollutants, mechanisms must be established to ensure that the reductions are not lost through emissions trading. One mechanism designed to do this is an allowance "set aside." With this mechanism, a portion of the allowances under the cap are set aside for new renewable generation and energy efficiency. These allowances are allocated retrospectively, based on actual electricity generaton or savings. If these allowances are not used for compliance, then the cap has effectively been lowered in proportion to the new generation or savings. If the allowances are sold to other emitting generators, then the renewable or efficiency resource receives the revenue, making the resource more economically viable. Currently, there are set asides for renewables and efficiency in the US Acid Rain Program and the OTC Budget/NO_x SIP Call, as well as in Ontario's electric sector emissions cap.

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[11] In 2004 the OTC NO_x Budget Program will be superceded by the larger NO_x SIP Call trading program, covering the 32 easternmost states in the country.

[12] Linear programming models effectively "reallocate" the allowances by simply ensuring that an overall emission constraint—that the sum of the emissions from generators within the system does not exceed the cap—is satisfied.

3 Recent Studies Including Avoided Emissions Estimates

In this section we present a number of studies carried out in Canada, Mexico and the US in which displaced emissions have been calculated for clean energy and energy efficiency resources. It is important to note that the studies discussed here represent a small portion of the work being done in North America on the issue of emissions displacement. Many other studies, many of them not publicly available, have estimated displaced emissions in one way or another. In particular, there is little information available on studies done in Canada and Mexico using system dispatch models. This is because most of this work is being done by utilities, much of it in system planning studies, and these companies have chosen not to release these studies.

In addition, there are significant efforts underway outside of North America both to assess displaced emissions from resources in the electric power sector and to develop standardized methods for doing so. One of the most important of these studies is located within the Clean Development Mechanism of the United Nations Framework Convention on Climate Change (UNFCCC). Under the provisions of the Clean Development Mechanism (part of the Kyoto Protocol), organizations may receive credit for projects that reduce GHG emissions in other countries.

For information on the methodologies under development for Clean Development Mechanism projects, see: <http://cdm.unfccc.int/EB/Panels/meth/PNM_Recommendations/index.html>.

3.1 Canada

Six Canadian studies are discussed below in which avoided emissions from clean energy are estimated in various ways. These studies are:

- The Canadian Energy Supply and Demand Outlook to 2025
- A project submitted to the Greenhouse Gas Emission Reduction Trading Pilot,
- The Canadian Government's Wind Power Production Incentive,
- Several Green Power Marketing Programs,
- BC Hydro's Green Certificates Program,
- The Canadian Government's Discussion Paper on Climate Change, and
- The Pilot Emission Removals, Reductions and Learnings Initiative.

Most of these studies use a system average emission rate to estimate emission reductions. Other studies have been done in Canada that use more rigorous methods to estimate reductions, but detailed information was not available on these studies during the writing of this paper. In particular, Canadian utilities commonly use dispatch models for planning studies, but information is not publicly available on any studies of displaced emissions done by these companies. The federal government is also working on an effort to estimate displaced emissions from a Renewable Portfolio Standard (RPS) in various provinces in Canada. This study is currently being performed for Environment Canada using the IPM® model.

3.1.1 The Canadian Energy Supply and Demand Outlook to 2025

Canada's National Energy Board Act requires that the National Energy Board (NEB) keep under review the outlook for Canadian supply of all major energy commodities including electricity, oil and natural gas and their by-products, and the demand for Canadian energy both domestically and abroad. However, it should be noted that the NEB's Energy Outlook is not the official projection of energy supply and demand in Canada. The official Government of Canada projections are prepared by Natural Resources Canada. The most recent one was published in 1999: *Canada's Emissions Outlook: an Update*. These projections were the bases for a comprehensive study by the federal, provincial and territorial analytical modeling group—the Analysis and Modeling Group.

The NEB's report, *Canadian Energy Supply and Demand to 2025*, published in June 1999, examines two possible outlooks for electricity demand and supply in Canada—Cases 1 and 2. Case 1 is based on extrapolations of current trends in both electricity supply and demand, while Case 2 assumes that accelerated investment in efficiency reduces energy use relative to Case 1. Three sensitivity analyses were also considered, including one assuming "high penetration of alternative technologies and renewable fuels" (hereafter the AR scenario). The NEB report evaluated GHG emissions resulting from the two cases and the AR scenario. (Only GHGs—carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O)—are included in the emissions outlook.)

The AR scenario is primarily an energy demand sensitivity analysis that was developed from Case 2. It is also an energy supply sensitivity analysis in that more of the electricity consumed may be produced from alternative technologies or renewable fuels. The renewable resources modeled included small hydro, wind, and biomass such as wood waste, landfill methane and urban wastes for electricity generation. The alternative technologies considered were alternative vehicles (hybrids and fuel cell vehicles), diesel automobiles and integrated coal gasification combined cycle generation. Alternative resource penetration rates were modeled as increasing over time, with these resources providing up to 20 percent of incremental demand by 2025. Generation from alternative resources in the AR scenario rises from 1.5 percent of total generation in 1997 to 4.2 percent in 2025.

With respect to the electric sector, NEB used an in-house computer model, the Canadian Power Planning Program (CANPLAN), to perform the load/resource balance, to develop and analyze generation planning, and to project energy trade. Modeling was done on a provincial and territorial basis. Key inputs to CANPLAN include projected electricity demand, current generating capacities and planned retirements and additions. Main outputs relate to projected capacity, generation, inter-provincial and international trade, and fuel use. Emissions of GHGs were estimated by applying emission factors to end-use energy demand in the various sectors (residential, commercial, industrial, transportation, fossil fuel production and electricity generation).

The 1999 NEB study finds that, across all sectors, the AR scenario reduces GHG emissions relative to Case 1 by 152 million tonnes and relative to Case 2 by 30 million tonnes, in 2025. In the electric sector, the AR scenario yields emission reductions of 42 million tonnes relative to Case 1 and 15 million tonnes relative to Case 2 in 2025. These impacts are the result of reduced energy use, and increased penetration of alternative and renewable technologies. Thus displaced emission rates for specific technologies cannot be calculated from these numbers.

3.1.2 The Greenhouse Gas Emission Reduction Trading (GERT) Pilot

The Greenhouse Gas Emission Reduction Trading Pilot (GERT Pilot) was initiated in June 1998, to learn about GHG emission reduction trading by reviewing and validating emission reduction projects. The GERT Pilot focused on the quantification of "registered emissions reductions" (RERs) and on developing and putting into practice eligibility criteria. Working on a consensus basis, federal and provincial government, industry, and environmental participants piloted rules and criteria for the quantification, validation and verification of GHG projects and emission reductions. GERT reviewed 10 projects expected to produce approximately 380,000 tonnes of GHG emission reductions per year.

Sellers offering emission reduction credits were required to prepare a "project document" that addressed all the eligibility criteria and to submit an "emission reductions report," including estimates of GHG emissions displaced by the proposed reduction project, using the calculation methodology that had been accepted for the project. Project documents were reviewed and revised with proponents until their monitoring, measuring, and quantification methodologies were acceptable. Mandatory evaluation criteria included assessing whether each projects' emissions reductions were "real," "measurable," "verifiable," and "surplus." Consideration was also given to project "additionality." Information on individual projects can be accessed through the GERT web site <http://gert.org> or via the GERT emission reduction registry hosted at Canada's Climate Change Voluntary Challenge and Registry Inc. <http://www.vcr-mvr.ca/reduction/gert_e.cfm>. Two of the projects involved renewable electricity, and for one of these projects, a green power sale by Enmax to the Government of Canada, RERs were approved.

As a pilot effort forming part of the Government of Canada's Green Power Procurement program, Natural Resources Canada and Environment Canada purchased wind and biomass generated electricity from Enmax beginning in 1997 in Alberta. A project document was developed and registered with the GERT Pilot, involving a projected total of 16 GWh of wind power for Environment Canada from 1997–2007, and 12.6 GWh of wind power for Natural Resources Canada from 1998–2008, from two new 600 kW wind turbines installed as a result of the purchase. The project document included both a prospective estimate of the total CO_2 emissions that will be displaced by the energy purchased over the ten-year period and a methodology for calculating emission reductions retrospectively to create RERs.

For the prospective estimate, CO_2 emissions from the Enmax wind purchase were estimated using a system average CO_2 rate for the Alberta Power Pool. This system average rate was developed by calculating a weighted average emission rate for all the utility-owned power plants in Alberta during 1995. The CO_2 emission factor resulting from this calculation was 908 kg per MWh, and the total CO_2 equivalent displaced by the energy purchased over the ten-year period was estimated to be 31,104 tonnes. This method was used only to estimate total emissions likely to be avoided by the energy purchase. It was not used to calculate RERs.

The methodology laid out in the project document for quantifying RERs is based on an annual, retrospective analysis, focusing on the difference in emissions from all units on the Alberta Interconnected Electricity System (IES) in a hypothetical reference case (without the wind turbines) and actual system operation (with the turbines). Hourly greenhouse gas emissions from the generating units on the Alberta IES were estimated from plant-specific emission factors combined with hourly unit electricity generation records. Hourly Alberta IES average emission factors derived from these figures were then applied to the corresponding hourly wind power generation records to produce an annual emissions reduction per unit of wind power generated. Imports and exports to the Alberta IES were assigned zero emissions for the purposes of the calculation. Information on the last-dispatched units was also sought to enable a true marginal calculation, but these data were not available due to confidentiality considerations.

The emissions reductions from this wind project are calculated retrospectively each year as actual electricity data become available, using the most recently available generation unit emissions factors. The result is then submitted to Voluntary Challenge and Registry to be accepted as RERs. Emissions reductions calculated from 1997–2001 for Environment Canada's purchase are shown in Table 1.

Table 1: Alberta System Average Emission Rates Used for Enmax Wind Power Purchase

	1997	**1998**	**1999**	**2000**	**2001**	**Total**
RERs (tonnes CO_2)	448	1707	1804	1793	1775	7527
Wind Energy (MWh)	523	2023	2184	2200	2181	9110
Annual Average IES Emission Rate (kg/MWh)	866	847	826	820	816	829

3.1.3 Wind Power Production Incentive

The Wind Power Production Incentive (WPPI) was announced in the Government of Canada's December 2001 budget and is intended to encourage electric utilities, independent power producers and other stakeholders to install wind power capacity. The WPPI, hosted by NRCan, provides financial support for the installation of 1,000 MW of new wind capacity until 2007. The incentive will cover approximately half of the current cost of the premium for wind energy in Canada compared to conventional sources. This incentive will be available to electricity producers for the first ten years of a project's life.

Displaced emissions estimated for WPPI were calculated by NRCan using a simple methodology, which has not been made public. According to a WPPI program official, emission reduction quantification used simplified assumptions about the location of the projected wind projects, average emission rates of displaced power sources in these regions, and a set capacity factor (30 percent) for wind power. Using this methodology, WPPI program officials estimated that the WPPI will reduce GHG emissions by three million tonnes CO_2 equivalent annually by 2010. This estimate is based on the assumption that the 1,000 MW of wind power capacity to be installed under this initiative will generate approximately 2,600 GWh of electricity per year.

Thus, the implicit displaced emission factor used in this estimation is 1,150 kg CO_2 equivalent per MWh.

3.1.4 Green Power Marketing Programs in Canada

Several utility programs are operating in Canada to market green power to commercial, industrial and/or residential customers. These programs include:

a) ENMax Energy (Alberta): ENMax, a City of Calgary-owned utility, offers green power through their program called Greenmax. The program provides Alberta customers with the option of paying a premium on their electricity bill for green power provided by wind farms.

b) EPCOR Energy Services (Alberta): EPCOR's green power program offers residential customers the option to purchase "eco-packs," i.e., blocks of energy coming from a small run-of-the-river hydro plant, a biomass plant, a solar power installation and a wind turbine.

c) Maritime Electric Services Company: the Maritime Electric Green Power Program is provided with wind power from a wind farm in PEI.

d) SaskPower: Saskpower Green Power is currently offered to residential, farm, business and industrial customers, and the power is provided by a wind farm in Saskatchewan. A second wind farm was added in 2002.

e) BC Hydro: BC Hydro is now selling the attributes of its green electricity ("Green Power Certificates"), generated in British Columbia, to domestic business customers on a pilot basis.

The first four programs were examined in a 2002 report by the Pembina Institute in order to estimate the displaced emissions of each from 1998 to 2001. System average emission rates were used to estimate reductions, based on the system average fuel mix at the time and place of the renewable energy addition. Life cycle emissions for the conventional and the renewable resources were included in the emissions displacement analysis.

Table 2 provides the emissions reduction rates that were estimated for these four programs' green energy sales in 2001.

Table 2. Displaced Emission Rates Green Marketing Programs in Canada (kg/MWh)

	GHGs	Acid Rain Precursors	Ozone Precursors	PM	CO
ENMax	937	4.4	1.8	0.2	0.5
EPCOR	914	3.7	0.4	0	0.4
SaskPower	775	3.8	1.5	0.1	0.4
Maritime Elec.	546	5.4	5.4	0	1.5

3.1.5 BC Hydro's Green Certificates Program

BC Hydro hosts the Green Power Certificates Program, which sells the environmental and social attributes of green electricity. Each Green Power Certificate has a face value of one MWh of electricity generated at qualifying green generation facilities.

In order to estimate the GHG emissions displaced by one MWh of green electricity in BC, the company uses a projected new plant emission rate. This rate is the CO_2 rate of a combined-cycle combustion turbine, 360 kg per MWh. In BC Hydro's most recent Integrated Energy Plan, CCCTs were identified as the technology of choice going forward for new capacity additions. Thus, for every certificate sold, 360 kg of GHG are assumed to be avoided.

3.1.6 Canada's Discussion Paper on Climate Change

In May 2002, the Government of Canada released a Discussion Paper on Canada's Contribution to Addressing Climate Change. The Discussion Paper presented four options for addressing Canada's climate change commitments and the analytical results that were available. It also sought input on a number of key issues. The Discussion Paper included a range of targeted measures (e.g., incentives and regulations) aimed at increasing the contribution of renewable energy sources and increasing energy efficiency in buildings and industrial processes. The Discussion Paper also highlighted the global environmental benefits created by exporting clean energy from Canada to the US.

The impact of the policy and program actions highlighted in the Discussion Paper were estimated using the Energy 2020 model. With respect to the renewable electricity generation measure, Energy 2020 simulates how the electrical generation system would react. The intermittency of renewable sources requires a modified dispatch of the entire system to accommodate the fluctuations in output. Base-load, intermediate, and peaking plants are affected. Thus, the emission reduction reflects a mix of coal, oil and gas-generation changes.

The Discussion Paper also discusses an approach for estimating the environmental benefits of exporting clean energy to the United States of America. To estimate displaced emissions from Canadian energy delivered to the US, NRCan estimated US GHG emissions under a reference case and under a scenario without imports of hydropower and natural gas from Canada. Emissions in the zero-import scenario are based on an estimation of the fuel mix in the new market equilibrium in the US and application of emission factors to that fuel mix. The new market equilibrium in the US resulting from the zero-import scenario is divided in two parts. On the electricity side, NRCan assumes that all "missing" hydroelectricity would be replaced by high-efficiency coal-based electricity generation. On the natural gas side, NRCan's scenario in the case of zero natural gas exports assumes a number of market reactions: 26-percent higher US natural gas production, 6-percent higher liquid natural gas imports, 30-percent higher consumption of coal and oil, and 6-percent lower energy consumption.

This study estimates that displaced GHG emissions from Canadian clean energy exports to the US in 2010 would be 20 million tonnes of CO_2 equivalent from hydro exports and 62 million tonnes from natural gas exports, for a total of 82 million tonnes of CO_2 equivalent. The study does not provide the displaced emission rates associated with these estimates.

3.1.7 The Pilot Emission Removals, Reductions and Learnings Initiative (PERRL)

PERRL is a federal initiative, which is part of the Government of Canada's Action Plan 2000 on Climate Change. It is designed to provide Canadian companies and organizations with an economic incentive to undertake new actions to reduce greenhouse gas emissions. As a pilot project, it is also meant to help both Canadian governments and private sector organizations better understand a number of important elements of emissions trading.

The federal government has allocated $15 million to fund and administer PERRL until the end of 2007. Through PERRL, the federal government plans to buy verified greenhouse gas emission reductions from eligible projects on a fixed price per tonne basis. For example, a potential bidder submits a project to reduce greenhouse gas emissions by 100,000 tonnes between 2003 and 2007 and asks PERRL to pay $1.00 per tonne. If this bid is successful, PERRL will pay the seller $100,000 over the five-year period, and the federal government will take ownership of the reductions. PERRL will purchase reductions in four project areas, one of which is renewable energy.

In order to quantify both anticipated and actual emission reductions from renewable energy projects, PERRL is developing provincial monthly marginal grid emission intensities. In an attempt to assess accurately the displacement impacts of new renewable energy sources occurring due to the PERRL program, the IMP® model has been used to forecast grid dispatch and identify resources operating on the margin in Canada over the contracting years of the initiative.

Once the marginal resources have been identified on a monthly and provincial basis, a weighted emission intensity is calculated. Renewable energy proponents will use these emission intensities as the alternative baseline for the expected generation of their project. At the end of the pilot, the forecast marginal emission intensities will be updated based on historical generation data and proponents will be required to perform “true-ups” on their calculations.

A competitive request for proposal with numeric emissions reduction information and further details of the quantification method is anticipated to be issued in late 2003.

3.1.8 Summary of Canadian Emission Reduction Estimates

Table 3 below summarizes the displaced GHG emission factors developed within several of the Canadian initiatives described above.

Table 3. Summary of Canadian Emission Reduction Estimates			
	Region	**Method**	**CO_2 equivalent (kg per MWh)**
Enmax Wind Power Sale to Environment Canada	Alberta	Retrospective Hourly Analysis of System Operation	829
Prospective Assessment of Enmax Wind Sale to Env. Can.	Alberta	System Average Rate	908
WPPI Analysis	Canada	Unknown	1,150
Pembina - ENMax	Alberta	System Average Rate	937*
Pembina - EPCOR	Alberta	System Average Rate	914*
Pembina - SaskPower	Saskatche wan	System Average Rate	775*
Pembina - Maritime Electric	Maritimes	System Average Rate	546*
Pembina - BC Hydro Green Power	BC	New Plant Rate	360

*These displaced rates are listed for "GHGs." We assume that the figures are CO_2 equivalents.

3.2 Mexico

Below we describe four methodologies utilized for calculating avoided emissions from energy projects in Mexico. These four methodologies correspond to four Mexican agencies, two of them public—National Commission for Energy Efficiency, or Conae, and CFE, the largest public power utility in the country—a private trust fund (*Fideicomiso para el Ahorro de Energía Eléctrica* Fide) and an NGO (*Asociación de Técnicos y Profesionistas en Aplicaciones Energéticas*, ATPAE)

The most recent proposed methodology (ATPAE, 2003), developed under the USAID auspices, represents a collaborative effort that incorporated an important set of stakeholders. The objective of this effort was to integrate information and develop a single methodology for estimating emission factors in the National Electric System (90 per cent of total generation in the country) that would be widely accepted by private project developers and public agencies. This integration and definition of methodology is in advanced stages of development and is being led by the Ministry of Energy, the public agency that is in charge of all technical aspects of the currently under creation: Mexican Office for Climate Change.

3.2.1 Estimates Made by Mexico's National Commission for Energy Efficiency

Conae is the Mexican federal government agency in charge of promotion, standardization and technical assistance in the areas of energy efficiency and renewable energy. Conae carries out a series of programs, including developing and supervising compliance with energy efficiency standards and implementing energy conservation programs in key economic sectors, where it works together with industry groups, businesses and consulting firms.

Conae estimates the energy savings resulting from many of its programs, based on the programs' distinct characteristics. For instance, in calculating benefits from Official Energy Efficiency Standards, information provided by manufacturers and suppliers is used. In calculating the benefits of Energy Savings Programs, information on energy use levels is supplied by energy users and project consultants. Conae then applies emission factors to the energy savings estimates to calculate the emissions benefits of its programs.

Conae uses system average emission factors for the national interconnected electric system. These factors are calculated using information on generation levels from the *National Energy Balance*, published every year by the Ministry of Energy, and information on emissions from the publication, *Emission Factors for Fuels*, approved by the Ministry of the Environment and Natural Resources (Semarnat) and utilized in official documents such as the National Inventory of Greenhouse Gases. Actual values utilized by Conae are presented in Table 4.

Table 4. System Average Emission Factors Used by Conae

Pollutant	(kg/MWh)
CO_2	625
SO_x	10
NO_x	1.9
TSP	0.73

These emission factors take into account losses in generation, transmission and distribution of energy. Thus, when multiplied by avoided end-use energy figures, they provide avoided emissions at generating plants.

Conae also estimates the emissions benefits of programs outside the electric sector, such as programs to increase the efficiency of residential water heaters burning Liquefied Petroleum Gas (LPG). LPG is the most important fuel source for the residential and commercial sectors in Mexico and is generally used for cooking and water heating in nearly every home (as well as restaurants and hotels) in the country.[13]

Recently, Conae focused on the LPG savings associated with increased market penetration of energy efficient water heaters in Mexico. Conae estimates that the adoption of these water heaters will avoid consumption of roughly 11 million barrels of LPG annually by the year 2011. The Agency commissioned a study to define emission factors for existing (i.e., less efficient) water heaters, based on fuel analysis and emissions testing. Those emission factors were applied to the projected LPG savings. Table 5 shows emission coefficients established for typical LPG water heaters in Mexico.

[13] Liquefied petroleum gas is a fuel much less commonly used in the United States and Canada than in Mexico. It can be used in cars, where it produces fewer emissions than traditional gasoline-fueled vehicles. It is also used for recreational purposes in camp stoves, etc.

Table 5. Emissions Derived from LPG burning for Water Heaters in Mexico City (1995)	
Pollutant	**Emission Factor (kg/Gigajoule)**
CO_2	63.0
NOx	0.05
CO	0.01
CH_4	0.001

Using these emission factors, estimated emissions avoided due to the adoption of efficient water heaters are shown in Table 6, based on Conae's forecast for market penetration of efficient water heaters.

Table 6. LPG Savings and Avoided Emissions from Efficient Water Heaters in Mexico

Year	**LPG (000 Barrels)**	**Displaced Emissions (tonnes)**				
		CO_2	**CO**	**NO_x**	**CH_4**	**Hydrocarbons**
2002	3,119	733,720	116	547	13	42
2003	3,868	909,916	144	679	16	52
2004	4,642	1,091,993	173	815	19	62
2005	5,440	1,279,716	203	955	22	73
2006	6,270	1,474,967	234	1,100	26	84
2007	7,126	1,676,334	266	1,251	29	96
2008	8,019	1,886,406	299	1,407	33	108
2009	8,937	2,102,358	334	1,568	37	120
2010	9,887	2,325,838	369	1,735	41	133
2011	10,874	2,558,022	406	1,908	45	146

In addition to efficient water heaters, there are approximately half a million square meters of passive solar systems installed in Mexico, that represented an avoided consumption of 580 thousand barrels of LPG in 2001, displacing approximately 140 thousand tons of CO_2. In the future, further displacement due to this form of renewable energy will be evaluated according to the evolution of the market for these systems. Some analysts have projected that aggressive policies to support solar water heating could lead to five million square meters of solar water heaters in Mexico by the year 2005.[14] However, policies of the type envisioned in this projection are not currently being implemented in Mexico.

[14] *Impacto Ambiental del Uso Masivo de Calentadores Solares de Agua para Uso Doméstico*, by Enrique Caldera M., Consejo *Consultivo para el Fomento de las Energías Renovables*, Conae, *Asociación Nacional de Energía Solar*, Mexico City, 1998. Section 6.

3.2.2 The Comisión Federal de Electricidad (CFE) Estimates

Mexico's public power utility, CFE, has utilized a detailed model for assessing the possible impacts of renewable energy projects on the Mexican electric grid.[15] The model is part of a multi-institutional research project called "Database and Methodologies for Comparative Assessment of Different Energy Sources for Electricity Generation" (DECADES).[16] Using this model, CFE has developed displaced emission factors representative of the marginal generating plants on the Mexican power grid. However, detailed information about these displaced emissions factors is not publicly available.

The DECADES project is broader than simply an effort to assess displaced emissions. It is an information system that also provides tools for energy analysts and planning officials, with the main objective of supporting power sector planners in making decisions about adding new electricity resources in Mexico.

Some of the products of the DECADES project are:

- A database that contains an inventory of generation technologies covering energy linkages based on fossil fuels, nuclear and renewable energy;
- Linkages covering primary source production, power generation, emissions and final disposal;
- A database on toxicology and air impacts of electricity production;
- A system for managing databases for deploying and processing data used in analytical models and other tools; and
- A tool package for analysis and planning of the power sector.

3.2.3 Fideicomiso para el Ahorro de Energía Eléctrica (Fide) Estimates

The *Fideicomiso para el Ahorro de Energía Eléctrica* (Fide) is a non-profit organization, closely linked to Mexico's power utilities with the mission of promoting energy efficiency in the Mexican electric industry. In 1999, Fide made its first attempt to estimate avoided emissions derived from its energy efficiency projects. To do this, Fide acquired information on the emission rates of the major Mexican power plants from Mexico's public electric utility, the Comisión Federal de Electricidad (CFE).[17] These emission rates were derived by applying emission factors from the US Environmental Protection Agency (EPA) on fuel use at CFE power plants.[18] In applying the EPA emission factors to their power plants, CFE considered factors

[15] This CFE project is discussed in the ATPAE study. See note 13.
[16] The Project was derived as a mandate of an *Expert's Symposium on Electricity and the Environment* that took place in Helsinki on May 1991. The participating agencies were: OECD Nuclear Agency, World Bank, The Commission for European Communities, the International Energy Organization, The World Health Organization, UNEP and other international institutions.
[17] CFE owns all of the transmission and distribution assets in Mexico and roughly 85 percent of the power plants there.
[18] US EPA, *Compilation of Air Pollutant Emission Factors, AP-42*, Fifth Edition <www.epa.gov/ttn/chief/ap42>.

specific to Mexico, such as characteristics of Mexican fuels (sulfur content) and the firing configuration of the large predominant boilers.

To estimate avoided emissions from efficiency programs, Fide has published system average emission rates representative of all Mexican power plants. These system average rates were derived by applying the EPA emission factors to the output of each plant to get total emissions and dividing this by total electricity sold. These displaced emission rates for the year 2000 are shown in Table 7 below.

Table 7. Fide Displaced Emission Factors

Pollutant	Emission Factor (kg per MWh)
SO_x,	17.6
NO_x	1.91
CO_2	1,510.00
CO	0.35
PM	0.58
VOC	0.013

While these system average factors are used to calculate emission reductions from most efficiency equipment, Fide also uses marginal emission rates for equipment when the specific power plants displaced can be identified with some certainty.

Table 8 below shows the estimated CO_2 savings from Fide's main programs and projects to date.

Table 8. Estimated CO_2 Savings from Fide Efficiency Programs

Sector/Program	Number of projects		Savings		Displaced CO_2 (tonnes)
			MW	GWh/ Year	
Residential	ILUMEX	2,454,923	72	137	153,250
	Pilot project Fluorescent lighting	974,651	58	44	49,219
	Pilot Project A.C. installed equipment	39,154	7	12	13,423
	Pilot project Refrigerators	1,479	0.7	0.3	290
	Isolated housing	78,676	19	80	89,489
	Energy audits	12,387	11	29	32,440
Micro and Small Enterprises	Projects	680	16	18	20,135
Commercial, Industrial and Municipal	Industrial (number of projects)	787	167	807	902,721
	Commercial	387	30	88	98,438
	Municipal services	225	31	85	95,082
Daylight Savings Program	Ongoing since 1996		900	1,118	1,250,610
Incentives and Market Development	Installed fluorescent lamps	6,615,735	169	203	227,079
	Electric motors	182,262	145	578	646,559
	Lighting units	3,970,810	68	111	124,166
	Compressors	1,109	11	34	38,033
Agricultural	Fluorescent lighting in Chicken farms	1,184,000	50	39	43,626
	Water pumping equipment	13,610	175	758	847,909

Table 8. Estimated CO_2 Savings from Fide Efficiency Programs				
Sector/Program	Number of projects	Savings		Displaced CO_2 (tonnes)
		MW	GWh/ Year	
TOTAL		1,930	4,141	4,632,469

3.2.4 The Asociación de Técnicos y Profesionistas en Aplicación Energética (ATPAE) Estimates

ATPAE or *Asociación de Técnicos y Profesionistas en Aplicación Energética* (the Association of Technicians and Professionals in Energy Application) is a Mexican NGO with a 22-year history of promoting energy efficiency and environmental protection. ATPAE recently concluded a two-year study aimed at analyzing methodologies for estimating electricity emission factors for GHGs produced by power plants and at making recommendations on how these methodologies might be implemented in Mexico.[19] This methodology is currently under discussion and final review, and ultimately it will constitute a unified method for calculating net emission reductions from all Mexican electricity projects. Information on dispatch of the plants withing the national grid was provided for this study by Mexico's two public power unilities, Luz y Fuerza del Centro and CFE. CFE provided information through its Centro Nacional de Energia (CENACE).

The ATPAE study lists three methods of developing displaced emission factors very similar to the three methods described in Section 2 above: system marginal, new plant and system average. However, the study points out that two of these types of factors—the system average and new plant factors—can be calculated for all resources or just for fossil-fueled resources.[20]

The APTAE report evaluated each of these methods both quantitatively and qualitatively. The quantitative analysis compared the estimated coefficients to determine how close these were to the characteristics of current and future operation of the National Electric System (NES). NES includes all facilities of the public sector in Mexico, which currently provide 85 percent of Mexico's total generation. This analysis utilized elements, such as dispatch model runs with ten-year forecasts, variations of the four different regional systems that encompass the NES, and the impact of transmission and distribution losses. The qualitative analysis includes the assessment of the five coefficients according to the following criteria: available data, exactness, cost, transparency and international congruency.

After reviewing the analysis of these methods within the study, ATPAE developed a set of hybrid displaced emission rates, which they believed to be the most accurate rates with which to

[19] The information contained here is based on "Metodologías para Calcular el Coeficiente de Emisión Adecuado para Determinar las Reducciones de GEI Atribuibles a Proyectos de EE/ER. Justificación para la Selección de la Metodología (Resumen Ejecutivo)," Borrador Final para Distribución Limitada, under the Auspices of USAID/Mexico. Consulting Team: PA Government Services, Inc., Consultoría y Servicios en Tecnologías Eficientes S.A. de C.V., Tellus Institute, Science Applications International Corporation. Mexico City, May 2003. 19 pages.

[20] Presumably, by ignoring non-fossil resources, which tend to be used as baseload resources, the fossil emission factors better reflect the plants that will be affected by a new resource.

assess new electricity projects in Mexico. These hybrid rates consist of a 50/50 blend of system average thermal rates and rates of the plants most recently added to the system. ATPAE developed displaced rates for each of the four electricity control areas in Mexico. These displaced emission rates are shown in Table 9. In considering these emission factors, note that the Interconnected control area covers approximately 80 percent of Mexico.

Table 9. Recommended CEE by ATPAE for Small and Large Projects (Year 2001)	
System	**Emission Factor (kg CO_2 per MWh)**
Interconnected	652
Northwest	615
Baja California	603
Baja California Sur	809
National Average	654

Source: ATPAE, "Metodologías para Calcular el Coeficiente de Emisión Adecuado para Determinar las Reducciones de GEI Atribuibles a Proyectos de EE/ER. Justificación para la Selección de la Metodología (Resumen Ejecutivo)" Borrador Final para Distribución Limitada, page RE- 5. May 2003.

3.2.5 Summary of Mexican GHG Emission Reduction Estimates

Table 10 summarizes the displaced GHG emission factors generated by the Mexican projects described above.

Table 10. Summary of GHG Displaced Emission Factors Developed in Mexico (kg per MWh)			
	Region	**Method**	**CO_2 equivalent**
Conae	Interconnected	System Average Rate	625
Fide	Mexico	System Average Rate	1,510
ATPAE	Interconnected	Thermal Avg/New Plant	652
ATPAE	Northwest	Thermal Avg/New Plant	615
ATPAE	Baja California	Thermal Avg/New Plant	603
ATPAE	Baja California Sur	Thermal Avg/New Plant	809
ATPAE	National Average	Thermal Avg/New Plant	654

3.3 The United States

Below we examine five projects by US organizations in which displaced emissions have been estimated. These five projects are:

- The development of system marginal emission rates for the Ozone Transport Commission (OTC);
- The development of system marginal emission rates for the US EPA;
- The development of system marginal emission rates for the State and Territorial Air Pollution Prevention Agencies (STAPPA) and International Council of Local Environmental Initiatives (ICLEI);

- A GHG-reduction project submitted to the Northeast States for Coordinated Air Use Management (NESCAUM) GHG Demonstration Project; and
- The development of retrospective system marginal emission rates by the New England Independent System Operator.

3.3.1 The Ozone Transport Commission (OTC) Estimates

In 2002 the Ozone Transport Commission (OTC) sponsored work to develop a tool with which users can assess the emissions impacts of clean energy and energy efficiency projects in the northeastern US. The OTC retained Synapse Energy Economics to develop the tool. Synapse performed hourly dispatch modeling for the three control areas in the Northeast to develop displaced emission factors for each of these areas. (These three control areas are: New York, New England and the Pennsylvania/New Jersey/Maryland Interconnection.) Synapse used PROSYM, an hourly dispatch model, to develop system marginal emission rates for six different time periods.

Displaced emission factors were developed for the years 2002 through 2020, for NO_x, SO_2, CO_2 and mercury. The factors for the near-term years (2002 through 2005) are based on dispatch modeling of the existing electricity systems, including any new plants under construction in 2002. The factors for the medium-term years (2006 through 2010) are a blend of the near-term factors and new/retired plant emission rates. The factors for the long-term (2011 through 2020) are based purely on new/retired plant emission rates.

The emission factors developed for this project were embedded in a spreadsheet-based workbook, which allows the user to apply them to the projected energy impacts of clean energy technologies or efficiency equipment. Load profiles are provided in the workbook for common renewable and efficiency technologies, allowing the user to allocate projected energy production or savings to six different time periods.[21]

Table 11 below shows the displaced emission factors Synapse developed for the state of New York. To see the other displaced emission factors developed in this work, download the workbook from the OTC at <www.sso.org/otc>.

Table 11. 2003 OTC Displaced Emission Factors for New York State (kg/MWh)

Pollutant	Summer Peak	Summer Off-Peak	Non-Summer Peak	Non-Summer Off-Peak	Annual Average
SO_2	0.9	1.1	0.8	1.2	0.5
NO_x	2.1	3.7	1.4	3.6	1.3
CO_2	620	706	624	710	376
Mercury	0.00001	0.00004	0.00001	0.00003	0.00001

[21] This spreadsheet tool is available for download free of charge from the OTC web site at: <www.sso.org/otc>.

3.3.2 The Environmental Protection Agency (EPA) Estimates

Staff at the EPA are currently working with consultants at ICF Consulting to develop a tool that will allow people to estimate CO_2 reductions from a wide range of efficiency and renewable energy technologies. This project is called the "ADER" project, reflecting the fact that it will use Average Displaced Emission Rates to estimate emission reductions. The tool will include displaced emission rates developed using the IPM® model. Displaced CO_2 rates are being developed for five different regions of the country and for the nation as a whole, for the years 2005, 2010, 2015 and 2020.

The displaced emission factors under development, called "ADER parameters," correspond to a particular time of day, year and region. For example, one parameter might be for (a) weekday mornings, (b) in the year 2005, (c) in the southeastern United States. The parameter would represent the rate at which CO_2 emissions would be reduced in 2005 during this time of day in the Southeast when load is reduced or new generation added. A user of this ADER parameter would apply it, for example, to kWhs saved by an efficiency program on weekday mornings in the Southeast. The parameters are being developed through region-specific dispatch modeling, thus they will take into account the specific mix of existing plant types within each region, transmission constraints and other region-specific factors.

As part of this project, displaced emission rates are being developed for 11 different hour types. That is, each year is broken into 11 different time blocks. Users of the tool will be able to select a load shape for the equipment or project of interest, from 15 common load shapes contained within the ADER tool. These load shapes will automatically allocate the energy produced or saved by the project to the appropriate time blocks and apply the appropriate ADER parameters to calculated emission reductions.

The EPA is currently in the final stages of reviewing the ADER rates. The Agency had plans to make the planning tool public during the summer of 2003.

3.3.3 The STAPPA/ICLEI Planning Tool

During 2000 and 2001 the State and Territorial Air Pollution Program Administrators (STAPPA) and 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. One aspect of this work was the development of avoided emissions factors for different regions of the country, which the software will use to calculate emission reductions from strategies under consideration. STAPPA and ICLEI hired consultants at Tellus Institute to develop displaced emission rates for electric power generation in different regions of the United States. Tellus used the National Energy Modeling System (NEMS) to develop these avoided emission factors model.

For this project, Tellus derived annual avoided emissions factors for NOx, SO_2, CO_2 and particulate matter (PM) for each of the 13 electricity regions in the US. Tellus' analysis produced avoided emission factors for each year 2005 through 2020, however the STAPPA/ICLEI software will only use the factors for 2005, 2010, 2015 and 2020. One avoided emission factor was developed for each pollutant for each year. That is, Tellus did not develop separate emission factors for assessing different seasons or times of day.

To develop displaced emission rates, Tellus performed a Base Case model run and a series of decrement runs, with the decrement runs reducing load by one percent in each year. For NO_x, SO_2 and CO_2, NEMS provided emissions for both runs, taking account of emission control technology in electricity plants and types of coal. Tellus calculated PM_{10} emissions based on fuel consumption provided by NEMS and emission factors by fuel. Dispatch also accounted for all applicable environmental regulations, such as the Title IV SO_2 program and the NO_x SIP Call allowance program. Decrement-run emissions were subtracted from base-case emissions to get incremental emission reductions per MWh.

3.3.4 ISO New England's Annual Marginal Emission Rates Analysis

The operator of the New England electricity grid (ISO New England) uses a system dispatch model to calculate retrospective marginal and average emission rates each year. This practice began in 1994, when regulators began an effort to analyze the impact that energy efficiency programs had on NO_x emissions in the power pool. Later in 1994, NEPOOL released an analysis of marginal NO_x, SO_2 and CO_2 emission rates to complement the initial NO_x effort. Since 1994, ISO New England has published a marginal emissions analysis every year.[22]

The ISO publishes retrospective system marginal emission rates for each of four distinct time periods. These periods are: summer on-peak hours, summer off-peak hours, non-summer on-peak hours and non-summer off-peak hours. The summer is defined as the period between May 1 and September 30, and the peak period is 8:00 am through 8:59 pm.

ISO New England derives these system emission rates by evaluating two consecutive dispatch simulation runs. First, the New England system is dispatched to meet the actual loads recorded on each day of the year being assessed. The results of this run become the Base Case. Next, an increment run is performed. That is, the system is dispatched in a scenario in which all hourly loads are increased by 500 MW. To calculate marginal emission rates, total NO_x emissions from the Base Case run are subtracted from emissions in the increment run for each time period. The incremental emissions in each time period are then divided by the incremental generation in the corresponding period to derive a marginal emission rate in terms of pounds per MWh.

The 2001 system marginal emission rates for these four time periods, as well as the annual average rate, are shown in table 12 below.

[22] These marginal emission rate analyses can be downloaded from the ISO NE web site at: <www.iso-ne.com>.

Table 12. 2001 System Emission Rates for ISO New England (kg/MWh)				
Pollutant	Summer Peak	Summer Off-Peak	Non-Summer Peak	Non-Summer Off-Peak
SO_2	2.4	2.0	2.3	2.3
NO_x	0.9	0.7	0.8	0.7
CO_2	650	606	636	630

3.3.5 Greenpoint PV Project Submitted in NESCAUM Demo Project

Northeast States for Coordinated Air Use Management (NESCAUM) sponsored a "Demonstration Project" (Demo Project) designed to gain experience with quantifying GHG reductions in the context of actual projects. The Demo Project brought together a variety of companies and organizations in the northeastern US to review proposed GHG reduction projects and work toward a standard methodology for quantifying emission reductions. As part of this project, Greenpoint Manufacturing and Design Center Local Development Corporation (GMDC) submitted a report summarizing emission reductions from two photovoltaic (PV) installations in Brooklyn, New York. These projects include a 59-kW system with a 50-kW storage battery and a 76-kW system. The use of a new zinc-bromine battery technology at one of the sites will allow that building to utilize all of the solar power generated on site, without having to sell or lose energy when production exceeds on-site demand.

In estimating displaced emissions, the 1999 system average emission rates of the New York Power Pool were multiplied by the expected output of the two systems. The case study report on the project notes that because use of "the marginal rate is preferable, the emission rate used here has a low degree of certainty" and may not accurately reflect the benefits of the project. One goal of the NESCAUM Demo Project was to work toward the use of system marginal emission factors whenever possible in estimating GHG reductions.

Table 13 shows the emission factors used in this project and the resulting estimates of displaced emissions.

Table 13. Displaced Emission Factors and Tonnes from Greenpoint PV Projects					
Displaced Emission Factors (kg/MWh)			**Displaced Emissions (tonnes)**		
NO_x	SO_2	CO_2	NO_x	SO_2	CO_2
0.7	2.0	428	1.1	3.2	706

During the first three years of operation, GMDC will monitor the output of the two PV systems. NESCAUM plans to use actual output data from the projects, along with marginal emission factors of the New York Power Pool, to obtain better estimates of the systems' displaced emissions.

3.3.6 Summary of US GHG Displaced Emissions Estimates

Table 14 summarizes the displaced GHG emission factors generated by the US projects described above.

Table 14. Summary of Mexican GHG Emission Reduction Estimates (kg/MWh)

Project	Region	Period	Method	CO_2
OTC 2002	New York	Summer Peak	Dispatch Modeling	620
OTC 2002	New York	Summer Off-Peak	Dispatch Modeling	706
OTC 2002	New York	2002 Annual	Annual Average Rate	376
ISO NE 2001	New England	Summer Peak	Dispatch Modeling	650
ISO NE 2001	New England	Summer Off-Peak	Dispatch Modeling	606
PV Demo Project	New York	1999 Annual	Annual Average Rate	428

4 Principles to Guide Emission Reduction Estimates

In addition to the work underway to estimate emission reductions from specific policies and projects (discussed in Section 3), significant work has been done to develop principles to guide this process. As noted, estimating emission reductions from changes to electric power systems is a complex process, and as we move toward a widely accepted methodology, it is important to articulate the key attributes that such a methodology should have.

National agencies in all three North American countries have established offices to work with organizations to quantify GHG reductions, and these agencies are also involved in efforts to develop guiding principles. For example, in Canada the Canadian Greenhouse Gas Verification Centre has been established to assist Canadian GHG-reduction initiatives in developing protocols for calculating, measuring or verifying their GHG emissions. In the US such outreach efforts are housed in the EPA's Climate Protection Partnerships Division and its Climate Leaders Partnership program. In Mexico, the first steps for establishing a methodology and quantifying GHG reductions are being taken jointly by the Undersecretary of Energy Policy and Technological Development at the Ministry of Energy (Sener) and various branches of the Ministry of the Environment and Natural Resources (Semarnat).

One leader in developing protocols and principles for assessing GHG reductions is a joint project underway at the World Resources Institute/World Business Council on Sustainable Development (WRI/WBCSD). This project has developed a corporate GHG accounting framework called the GHG Protocol. Many corporations in Canada, Mexico and the US are involved with the GHG Protocol, as is the Canadian Greenhouse Gas Verification Centre and the US EPA.

The first version of the GHG Protocol document, released in 2001, identifies, among other things, a set of five guiding principles for emission accounting systems. These principles are as follows:

- **Relevance**: Define boundaries that appropriately reflect the greenhouse gas emissions of the organization and the decision-making needs of users.
- **Completeness**: Account for all greenhouse gas emission sources and activities within the chosen organization and operational boundaries. Any specific exclusions should be stated and justified.
- **Consistency**: Allow meaningful comparison of emissions performance over time. Any changes to the basis of reporting should be clearly stated to facilitate continued valid comparison.
- **Transparency**: Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Important assumptions should be disclosed and appropriate references made to the calculation methodologies used.
- **Accuracy**: Exercise due diligence to ensure that greenhouse gas calculations have the precision needed for their intended use and provide reasonable assurance on the integrity of the reported greenhouse gas information.

For more information on the WRI/WBCSD GHG Protocol see: <www.ghgprotocol.org>.

A second document in which principles have been articulated was produced by the government of Alberta as part of its effort to implement a provincial greenhouse gas-reporting program for companies in Alberta. In December 2002, the Ministry of Environment released a report to provide information to stakeholders, which includes guiding principles for a provincial reporting program. The report states five key principles:

- Comprehensiveness
  - Participation of all major emitters
  - Coverage of all significant emission sources
  - Enable identification of emissions of key GHGs
  - Inclusion of indirect emissions due to energy imports
- Consistency
  - Use of standardized emissions methodologies
  - Reporting amenable to harmonization with provincial and national reporting requirements
- Transparency
  - Easily verifiable emissions estimations
- Accuracy
  - Reports signed by an executive, professional or third party
  - Legal provisions for failure to report or for reporting false or misleading information

  - Record-keeping to facilitate report verification

- Timeliness
  - Emission data submitted and released on a regular basis

A third project in which principles for estimating emission reductions have been articulated is the GHG Demonstration Project organized by NESCAUM. This project brought together organizations in the northeastern US to review proposed GHG reduction projects and work toward a standard methodology for quantifying emission reductions. As part of this project, participating organizations submitted GHG reduction projects for review and discussion by the group. The method of quantifying emission reductions was a key area of discussion. To guide participants in submitting projects, the NESCAUM Demonstration Project developed a "Check List," which provided guidelines in important aspects of quantification. The main aspects of quantification covered are listed below, as laid out in the Check List.

- **Baseline Emissions Determination/Base Period Used**. Describe the baseline activity level and associated emissions during the baseline period for the applicable equipment/process as a rate per: hour of operation, capacity factor, production output, fuel consumption (type, amount), etc. Use the lower of the historical or allowable emission rate for a time period that corresponds to the generating period for the baseline emissions. Include a quantitative analysis of the uncertainty of the baseline where possible or at least a qualitative discussion of the baseline uncertainty.
- **Demonstration of Surplus**. Describe all applicable state and federal regulations as well as voluntary commitments relating to the pollutant. Demonstrate that the ERCs created are surplus to those regulations. Include notification whether the case study is or will be reported to any voluntary reporting program (i.e., Voluntary Challenge Registry or the Voluntary Reporting Program for GHG Emissions Reductions as established under section 1605 (b) of the Energy Policy Act of 1992). Describe any uncertainty regarding the claim that this activity is surplus.
- **Demonstration of Real.** An emission reduction is real if it is a reduction in actual emissions, resulting from a specific and identifiable action or undertaking, net leakage of emissions. Explain how a real reduction in actual emissions has occurred due to a change in process, technology and or operation. This section should include a statement declaring the availability of documents which provide insight into the claimed emissions reductions for any future verification of the case study.
- **Quantification of Emission Reductions**. This section should include a detailed quantification of emission reductions resulting from the project. Document the actual reduction beyond the baseline emission level. Describe the actual activity level and associated emissions during the period for the applicable equipment/process as a rate consistent with that used for the baseline. Describe the technology and equipment changes, operational changes, the extent that the reduction is dependent upon any change in operating methods and the expected duration of the emission reduction strategy. Uncertainties should be noted quantitatively when possible in each step of the equation (i.e., emission factors, monitoring equipment, etc.). A qualitative discussion must at least

be provided. Point out the assumptions inherent in the calculation and an overall degree of certainty of the calculation (low, medium or high).

- **Data Integrity and Uncertainty**. Provide a detailed sample of the ERC calculation showing units and conversions. Describe the sources of any factors or conversions included in calculations. Describe the type of measurement or calculation used to determine the baseline and actual emissions. Where measured data is used provide statistical support for the level of certainty/significance, e.g., the accuracy, range and repeatability of the instrumentation used to gather data. Describe the procedures followed to ensure the integrity and accuracy of the data. Where the data has been obtained through any mathematical model, show all assumptions and formula applied.

  Consolidate all the areas of uncertainty here. In addition, after quantitatively and qualitatively explaining the areas of uncertainty in the case study, conclude with a statement as to the overall certainty that the emission reductions attributed to the case study actually occurred (low, medium or high).

- **Emission Reduction Credits Created**. Show total actual emissions during the credit generating period, the calculated baseline emissions and the net ERCs created annually and over the lifetime of the project. Note any significant intervals during the generating/creation period when the strategy was not in place or credits were not generated. Give reasons for such intervals.

- **Ownership.** Any issues regarding ownership of the emission reduction credits are to be addressed in this section. Identify the owner(s) of the facility, the entities paying the operational costs of the facility, and the entities that paid for or subsidized the initial and the ongoing costs of the emission reduction action. Include a clear statement of what fraction of the title to the credits reported in this case study are claimed by each of the credit owners.

- **Other Environmental Impacts** (e.g., other air pollutants, nuclear). Identify any positive or negative environmental impacts that may result from the strategy and quantify these impacts as much as possible. Stationary source strategies may need to evaluate the potential for load shifting. Mobile source strategies should evaluate the geographic range of vehicle operation.

For more information on the NESCAUM demonstration project see: <www.nescaum.org/Greenhouse/index.html>.

As efforts to quantify emission reductions from electricity grids progress, it will be important to continue honing the principles underlying these calculations. Moreover, a key step in moving toward a consistent method for estimating reductions for North America is harmonization of the principles being developed in the three countries.

5 Conclusions

Currently, a variety of methods are in use across North America to estimate air emissions reduced by new renewable and energy efficiency projects. The three most commonly used methods are:

- Displaced emissions analysis and time-specific marginal emission factors,
- Plant addition/retirement emission factors, and
- System average emission factors.

Of these, marginal emission factors are most appropriate for analysis of the near-term impacts of new resources (up to roughly five years into the future). Emission factors reflecting projected plant additions and retirements are most appropriate for analysis of the long-term impacts. The use of system average emission factors can provide highly misleading results, as these factors include the emissions of many plants (such as baseload resources) that are rarely affected by new generation or load reductions. However, because system average emission factors are more readily calculated than marginal factors, they continue to be widely used to estimate emission reductions. Avoided emissions can be calculated using a system average emission rate at the cost of several hours of labor if data are readily available on the generators within the system. In contrast, it would be difficult to assess displaced emission with a model for less than about US$10,000, and most modeling studies cost considerably more than this.

A wide range of work is underway, both in North America and outside of it, which will likely increase the accuracy and credibility of emission reduction estimates over the coming years. Within this work are several projects focused on developing principles to guide emission reduction estimates and on producing standardized methods for making these estimates. Such efforts are crucial to developing the kind of emissions accounting procedures—both national and international—that will be needed to reduce global GHG emissions significantly.