Methods for Estimating Emissions Avoided by Renewable Energy and Energy Efficiency

Prepared by:

Geoff Keith and Bruce Biewald
Synapse Energy Economics

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US Environmental Protection Agency

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Executive Summary

Over the past decade there has been increasing interest in understanding the net emissions impacts of resources that could be added (or have been added) to regional power systems. This interest has come from environmental regulators focused on estimating the emission reductions attributable to energy projects and from energy market participants interested in quantifying reductions for emissions trading or to support marketing claims.

However, the operation of regional power systems is complex, so predicting how these systems will react to new resources is also complex. Simulation models have been developed to analyze power system operation, but these models are expensive to license, are not transparent and are labor intensive to use. This paper evaluates several methods of estimating displaced emissions without using a dispatch model.

We examine three different methods:

- Matching regional generating capacity to loads,
- Allocating reduced generation to plants based on capacity factors, and
- Estimating displacement based on hourly operation and emissions data from fossil-fueled plants.

One challenging task in estimating displaced emissions is accounting for major energy transfers between control areas. The first two methods do this with a review of available information about regional transfers. The third method does not account for energy transfers.

We conclude that matching capacity to loads and allocating reduced generation based on capacity factors are reasonable methods for making rough estimates of displaced emissions. However, both of these methods make simplifying assumptions about plant dispatch, a critical dynamic in displaced emissions. Work to refine these methods would be useful, but at this point we do not recommend them for situations in which a high level of accuracy is needed.

The method based on hourly operation and emissions data from fossil-fueled generators is extremely credible in that it captures the actual dispatch of these generators in the control area being analyzed. This gives the method an empirical basis, which the other methods do not have. However, this method does not account for potential impacts of the new resource on hydro units or imported energy. Thus, in regions where hydro units and imported energy are rarely used to follow load, this method would generate highly accurate estimates of displacement. In regions where hydro units and imported energy are used to follow load, the method would be less accurate.

The paper concludes with a discussion of how hourly data from fossil-fueled generators could be adjusted to account for impacts on hydro units and imported energy. More work is needed to develop this method, but we believe it has the potential to be highly accurate across a variety of different control areas.

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1. Introduction

Over the past decade there has been increasing interest in understanding the net emissions impacts of resources that could be added (or have been added) to regional power systems. This interest has come from environmental regulators focused on estimating the emission reductions attributable to energy projects and from energy market participants interested in quantifying reductions for emissions trading or to support marketing claims.

However, the operation of regional power systems is complex, so predicting how these systems will react to new resources is also complex. The main challenge stems from the fact that electric power systems are dynamic – system operators keep power systems balanced in the face of constantly changing constraints. Simulation models have been developed to analyze power system operation because these systems are very difficult to analyze with static methods.

There are drawbacks, however, to the use of dynamic simulation models. Most of these models are proprietary and expensive to license. Operating them is complex, requiring a significant learning period, and those who do not understand the model in detail must rely on assurances from experts that its assumptions and algorithms simulate system operation appropriately. Because of these drawbacks, there is considerable interest in methods of assessing displaced emissions that do not require a dispatch model. This report evaluates several such methods. We evaluate these methods using three main criteria: **accuracy** (ability to reflect typical power system operation), **transparency** (clarity of methodology and assumptions) and **labor demands**.

Section 2 of this report briefly discusses these criteria and several important issues in displacement analyses. Section 3 provides background on power system dispatch and the task of estimating displaced emissions from a new resource. Sections 4 and 5 evaluate methods of performing the two main steps in a displaced emissions analysis. Section 4 reviews methods of determining the relevant set of generating units, and Section 5 assesses methods of estimating displaced emissions within a given set of generating units. Section 6 presents a quantitative comparison of several methods, using actual data from a regional power system. Finally, Section 7 summarizes our conclusions and identifies issues for future work. An Appendix presents reference data on recent electricity transfers between regions of the U.S.

2. Objectives and Considerations

2.1 Evaluation Criteria

In this report, we evaluate methods of estimating emissions displacement using three main criteria: accuracy, transparency and labor intensiveness.

The accuracy of a method is ultimately the extent to which it predicts displaced emissions accurately. However, it is difficult to measure accuracy retrospectively in this case. To do so, one would have to operate the same power system under the same conditions twice – once with the new resource and once without it. For the purposes of assessing the accuracy of spreadsheet-based displacement estimates, we believe that careful modeling with an hourly dispatch model is the appropriate standard. Because comparisons to dispatch modeling were beyond the scope of this work, we measure a method’s probable accuracy by the extent to which it reflects and accounts for actual power system operation.

The transparency of the method is also important. A method in which each step of the calculation (and each step’s results) can be evaluated will often be more readily embraced by multiple parties than one in which a single set of outputs are produced from a number of complex inputs. Peer review of both the method and calculations performed with the method is easier with a transparent method.

Finally, a less resource intensive method will always be preferable to a more resource intensive method, other things being equal. The resources involved can include the cost of proprietary data and analytic tools as well as the cost of labor. Cost minimization is important for small energy projects estimating their own displacement impacts as well as for agencies considering funding the development of displaced emissions data for a number of regions.

2.2 Short-Term versus Long-Term Analyses

An important distinction for a displaced emissions analysis is that between the short term and the long term. The important issue is whether a significant amount of new capacity can be added to, or retired from, the system during the study period. The short term can be defined as the period during which few generating assets will be added or retired. Because the process of building or retiring capacity requires considerable lead time, the short term effectively extends for four to five years from the present. Over this time horizon, the analytic task is to predict how the *existing* regional electricity system will react to a new resource or resources. It is a question of how a fixed set of capacity resources will operate differently in the presence of a new resource.

The long term is the period during which a significant number of older generating units can be retired and new ones added. Over the long term, decisions made by power plant owners and new plant developers will take into account the changes in the regional system that take place today. The increase in supply provided by a new resource will decrease the demand for new plants slightly and it will decrease market prices slightly, putting economic pressure on the least competitive plants in the region. A long-term displacement analysis seeks to determine not just how a new resource will affect the existing system, but also how it will affect plant additions and retirements over time.

This report focuses on developing a method for short-term displacement analyses. Given the increased uncertainty associated with longer-term analyses, these are likely to be used less often for policy making and to support energy market transactions.

2.3 Emission Caps

When predicting emission reductions from energy efficiency and clean generation, it is important to consider the role of allowance, or “cap-and-trade” programs. Under these 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. There are currently two major allowance programs in the U.S., the Title IV Acid Rain program and the NO_x SIP Call Program, as well as several regional emission trading programs.

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), then 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 is likely to 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 than a similar unit with a higher emission rate, because it will have lower emissions costs factored into its operating costs. Some models redistribute allowances internally when plant operation is changed, such that total NO_x and SO_2 emissions are always at the capped level. In practice, however, generating companies’ decisions regarding their extra allowances are not so predictable. Under current 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.[1]

[1] Also, over the long term, the political and regulatory process of setting caps on system emissions can be influenced by the cost of achieving the capped levels, so investments in energy efficiency and renewable energy that lower the cost of meeting a cap can result in lower cap levels. This is, of course,

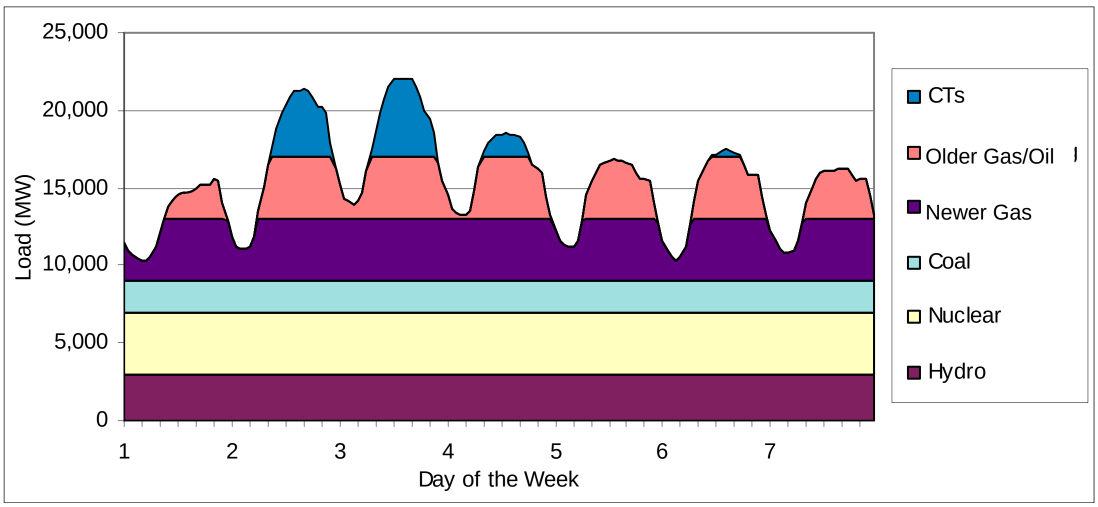
Thus, in order to realize emission reductions in the context of capped pollutants, mechanisms must be established to ensure that the reductions are not lost through emissions trading. One mechanism designed to do this is an allowance “set aside.” With this mechanism, a portion of the allowances under the cap are set aside for new renewable generation and energy efficiency. These allowances are allocated retrospectively, based on actual electricity generation 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 Acid Rain Program and the NO_x SIP Call Program.

a complex interaction between technology, economics and regulation that does not lend itself to analysis in quantitative models.

3. Plant Dispatch and Displacement Analyses

Regional power systems are generally dispatched based on economics, with the lowest cost resources dispatched first and the highest cost, last.[2] Thus economic theory tells us that a new resource will reduce the operation of the "marginal" unit in the system, the most expensive unit needed to meet demand. To see this, consider Figure 1, a simplified representation of plant dispatch in a hypothetical system during a typical summer week. The lowest cost generating units – baseload units – operate at full load around the clock. In this system these are hydro, nuclear and coal units. Higher cost units operate in a more cyclic manner, increasing their output during the day and decreasing it during the night. In Figure 1 these are newer, efficient gas-fired units. Less efficient gas- and oil-fired units are brought on line during the daytime when loads are highest, and combustion turbines are dispatched in the peak afternoon hours.

Figure 1. Unit Dispatch in a Simplified Power System



Economic theory tells us that any new resource will shift upward all resources above it in the dispatch order, reducing demand on the marginal unit or units. For example, consider a new generating unit that operates in a baseload manner. Regardless of exactly where in the baseload dispatch order this resource falls, it will effectively shift all resources above it upward in the dispatch order, reducing demand for the marginal unit in every hour. Combustion turbines would be displaced in the peak hours, older gas and oil units would be displaced during intermediate hours and new gas units, during the lowest load hours. An energy efficiency program targeting baseload appliances would have the same effect.

Actual plant dispatch, however, is far more complicated than the representation in Figure 1. First, system operators do not treat generating units as single entities in the dispatch

[2] Under certain circumstances units are dispatched out of merit order due to transmission constraints or other factors, and though these units may be the most expensive ones operating, they are not affected by reductions in load outside of the constrained area.

process. In competitive markets, plant owners typically bid generating units in several blocks (at different prices) rather than as a single block of capacity. These bids reflect the unit's efficiency at different output levels, the unit's low operating limit (below which the owner will not run the plant and the owner's bidding strategy. The supply curve, then, consists of many blocks of generating capacity, not entire generating units, and the blocks from a given unit can be at different places in the curve. Second, it is time consuming to start and stop large generating units, and limitations on unit ramp rates force system operators to keep some units running during periods when they are not needed, in order to have the units available when they are needed. In such cases, units are said to be running "out of merit order." Finally, transmission constraints also require operators to dispatch certain units out of merit order. That is, a more expensive unit must be dispatched when less expensive units are available, because transmission constraints prevent the cheaper units from serving the load.

These three factors make actual unit dispatch look very different from the ideal shown in Figure 1. Rather than ramping up one unit and then the next through the dispatch order, system operators increase the output of a number of units as loads grow. The units ramping in any given hour are said to be "following load." The units following load represent the most efficient way (as determined by the dispatch software) for system operators to increase system output. Of course, due to the realities of fuel costs, load following units at lower load levels are more likely to be coal-fired and more efficient gas units, and at higher load levels there is likely to be less coal following load and more gas. But the simplicity of Figure 1 is not likely to describe actual system dispatch adequately in any U.S. region.

Given the complexities of unit dispatch, the most credible way to estimate the impact of a new resource on a power system is with a dispatch model. Through an hourly simulation of system dispatch with and without the new resource, a dispatch model captures the impact of the new resource during each hour that the new resource operates. Dispatch models are designed to simulate energy transfers among different regions, optimized system dispatch given complex bids from generating units (multiple blocks from a single unit), transmission constraints, forced outages and limitations on specific power plants (e.g., ramp rates, start-up constraints minimum down time).

The goal of this report, however, is to evaluate methods of estimating displaced emissions that do not use a dispatch model. In a spreadsheet-based displacement analysis, simplifying assumptions must replace the model's dynamic analysis of plant dispatch and electricity transmission. The hope is that these assumptions approximate system operation in a manner robust enough to provide reasonably accurate results. The following two sections focus on the two major steps in a spreadsheet-based displacement analysis.

- First, one must determine the relevant set of generating units for the analysis. This involves identifying the "primary area" in which the new resource will be located and accounting for major energy transfers between the primary area and other areas.
- Second, one must estimate the displaced emissions from those units.

4. Determining the Relevant Set of Generating Units

In both of the methods we examine for determining the relevant set of generating units one must first identify the "primary area" of the analysis. The first step here is to identify the power control area in which the new resource is (or will be) located and the operator of that area. In some areas of the country, the local system operator will be a recently formed Independent System Operator (ISO). ISOs are independent entities that dispatch a group of generating units that formerly were owned and dispatched by the various utilities in the region.[3] In areas of the country where the electric industry has not been restructured, many utilities still operates the generating units in their service territory. Utility control areas are typically smaller than ISOs, although several utility areas are quite large.

While a control area will be the "primary area" for a displacement analysis in many cases, it will not be so in all cases. Transmission constraints within control areas can divide them into several distinct dispatch zones. For example, the PJM control area has long consisted of two dispatch zones, "PJM East" and "PJM West," and as PJM expands into the Midwest it will likely include additional distinct zones. In cases such as this, the primary area for the displacement analysis should be the dispatch zone, not the entire control area. Similarly, there are regions in which formerly distinct utility control areas have moved to centralized dispatch. For example, the companies in the ERCOT region of Texas have implemented an ERCOT-wide market. In cases like this, formerly separate utility areas should be treated as one dispatch area. Thus, the appropriate primary area for a displacement analysis is defined by centralized dispatch and transmission constraints on its borders, and this area may consist of a portion of a control area or a group of former control areas.

Once the primary area has been identified, one must determine whether the new resource is or will be located in a "load pocket" within that area. Major transmission constraints within a control area create "load pockets." In these areas, during constrained hours, higher-cost generating units within the load pocket must be operated rather than lower-cost units outside the pocket. A new resource located within the load pocket would displace the higher-cost units operating out of merit order. Thus, the load pocket would be the primary area for a displacement analysis during the constrained hours, while the entire control area might be the primary area during other hours. It is particularly important to check for transmission constraints in a displaced emissions analysis, because many new resources are likely to be located in load pockets in response to reliability policies and market signals (high energy and capacity prices in the load pocket).[4]

[3] Examples of ISOs are the New York, New England and California ISOs, the Pennsylvania/New Jersey/Maryland Interconnection (PJM) and the emerging Midwest ISO.

[4] The process of checking for important transmission constraints involves reviewing ISO data and communicating with system operators or other parties familiar with the control area in question. Important transmission constraints are usually well known, and in many cases ISO rules or policies exist that address them directly. Examples of such policies are ISO New England's RFP for demand response and generating capacity in SW CT and the 80% installed capacity requirement in New York City.

Identifying the primary area and checking for load pockets is not difficult. The more difficult part of determining the relevant set of generating units comes in accounting for major energy transfers between control areas. In Sections 4.1 and 4.2 we look at two methods of doing this.

4.1 Adjusting Bid Stacks Based on Transfer Data

In this method, one takes the generating units within the primary area and places them in an order representing typical dispatch. Currently the best source of data for this type of analysis is EPA's EGRID database. This database includes historical generation and emissions data for most power plants in the U.S. The generation data can be used to calculate capacity factors and order the units into a bid stack. However, there are two drawbacks to using EGRID data. First, there is a considerable time lag in the release of EGRID data. Currently, the most recent data available are for the year 2000. Second, the database includes only annual generation data. Thus, one cannot calculate seasonal capacity factors to develop seasonal bid stacks. The power plant database for the Department of Energy's National Energy Modeling System (NEMS) also includes most large generating units in the country, and it is available on a shorter time lag than EGRID data. However, the NEMS data does not include actual emissions; emissions must be approximated from information on fuel type and emission controls. The information in the NEMS database is also much less clearly labeled than the EGRID data.

When ordering generating units into a bid stack based on historical capacity factors, it is important to adjust the data to reflect unit outages. Generating units are taken off line periodically for planned and unplanned maintenance work, and these outages reduce a unit's capacity factor, because no energy is generated during the outage. Thus, a nuclear unit that was off-line for much of a year would have a relatively low capacity factor, which could place it rather high in the dispatch order. This would be wrong, as nuclear units are typically operated as baseload resources during all hours that they are available.

During many hours of the year, the primary area may import or export significant amounts of energy. Electricity loads and transmission constraints affect the availability of energy from other areas, and because loads and available transmission are constantly changing, the set of generating units available to system operators is always changing. The first step in addressing transfers is to determine whether there have been significant energy transfers in recent years between the primary area and other areas. If transfers have been small relative to generation in the primary area, they can be ignored, but one must account for large transfers. The following three data sources are available on electricity transfers.

- First, data on total generation and energy use in the primary area will indicate whether it was a net energy importer or exporter and the size of the transfers relative to total generation. Data on generation and loads are available from EIA on about a two-year time lag.
- Second, most system operators typically release information annually about generation, loads and interchange on their system. Most ISOs release comprehensive annual reports, and many of them publish hourly data on energy

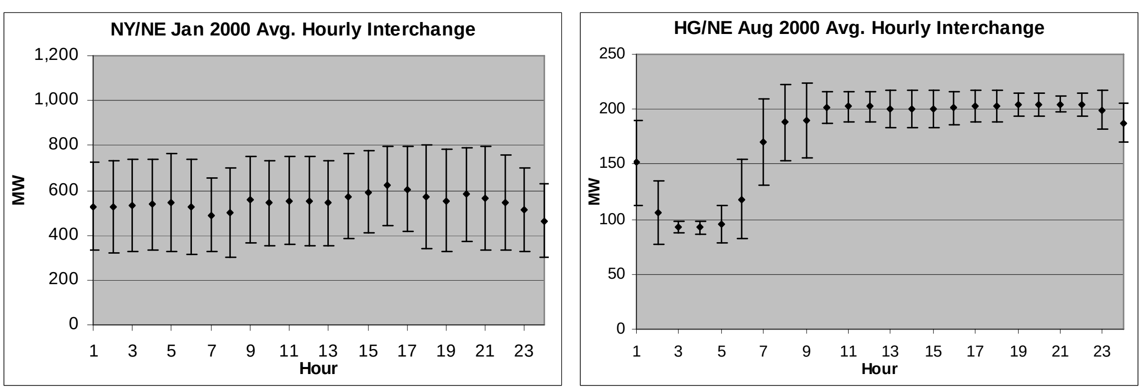
transfers across internal and external interfaces. Utilities tend to release less information formally, although they often release additional data when asked. The websites established for scheduling transmission usage ("OASIS" sites) may also have useful information.

- Third, data on electricity transfers between control areas are available via FERC Form 714. These data, however, can be internally inconsistent (for example, the same two control areas often report conflicting information about their exchanges). Thus, these data should be used with other information rather than used alone.

By comparing data from these three sources, one can usually determine the typical pattern of energy transfers in the region in recent years. In regions where hourly transfer data are released, this information provides a very detailed picture of historical transfer patterns. Figure 2 shows data on average hourly energy transfer between New York and New England and Quebec and New England in one month of 2000. Each point shows the average import level for than hour, with error bars showing one standard deviation around the average. Note the different patterns of transfer. The New York interface data for January (on the left) show a very stable pattern of imports from New York to New England during this month. That is, the transfer level does not follow a daily load pattern. This energy would be added to the New England bid stack as a baseload resource in a displacement analysis, and the same amount of capacity would be added to the peak and off-peak bid stacks, reflecting the stability of these imports throughout the day.

Imports from Quebec in August (on the right) are quite different during peak and off-peak hours, and the off-peak imports appear to follow off-peak load fairly closely. As a load-following resource, these imports could potentially be displaced by a new resource. To summarize the Quebec imports with two bid stacks, one might add 200 MW of baseload capacity during summer peak hours and 100 MW of capacity higher in the dispatch order during summer off-peak hours.

Figure 2. Examples of Hourly Transfer Data

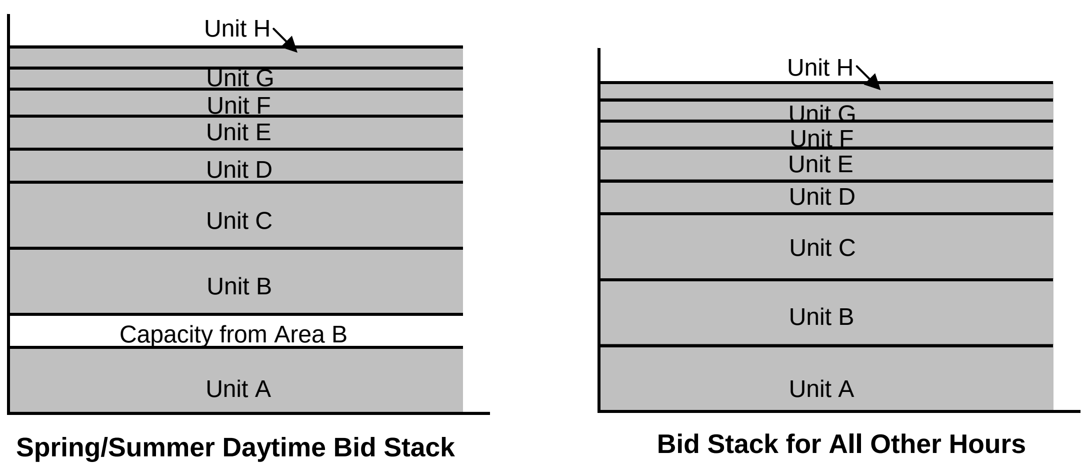


In many cases, patterns of major energy transfer are common knowledge among system operators and market participants, and sometimes the generating units involved are known as well. (Consider hydropower exports from the Northwest or Eastern Canada.)

In some cases data may be available on long-term power purchase agreements that underlie these transfers. This kind of information provides a strong basis for near-term projections. In a few cases, recent energy transfers may be so complex that they do not support a credible prediction. In these cases a dispatch model may be necessary for an assessment of displaced emissions. However, credible projections are likely to be possible for most areas of the country at any given time. This is because regional patterns of energy generation and transfer are largely determined by the relative economics of generating energy at different unit types during different seasons. These economics are driven by factors that follow annual patterns – mainly weather and relative fuel prices. Thus, regional energy generation and transfer also tend to fall into annual patterns. Things become less predictable in response to major infrastructure changes, such as the addition or retirement of large plants or transmission lines, but with time new patterns usually emerge.

Once typical energy transfers have been characterized, the bid stack in the primary area is adjusted to account for these transfers. The task here is to represent common system conditions with a few different bid stacks – to summarize the dynamic system with several representative snapshots. To see how this is done, consider a region that imports baseload hydropower from a neighboring region during the spring and summer daytime hours. For a displacement analysis one would develop two bid stacks: one representing summer peak hours and another representing all other hours. As shown in Figure 3, the summer daytime bid stack would include the amount of hydropower capacity typically imported. The bid stack for all other hours would not include this capacity.

Figure 3. Multiple Bid Stacks to Account for Different System Conditions



Though not addressed in this example, if there are periods when significant energy is being exported from the primary area, the capacity likely to be generating the excess energy should be removed from the bid stack.

Baseload energy transfers, such as those shown in Figure 3, would not need to be characterized in terms of their emissions, because they would not be displaced by a new resource. However, for energy transfers that are highly correlated to loads, one must characterize the emissions associated with the energy. This characterization should be based on transfer data and information on the generating supply in the various control areas of the region. Again, the type of generation typically imported or exported is often well known based on the economics of generation in the exporting region and transfer patterns.

Table 1. Summary of Adjusting Bid Stacks Based on Transfer Data

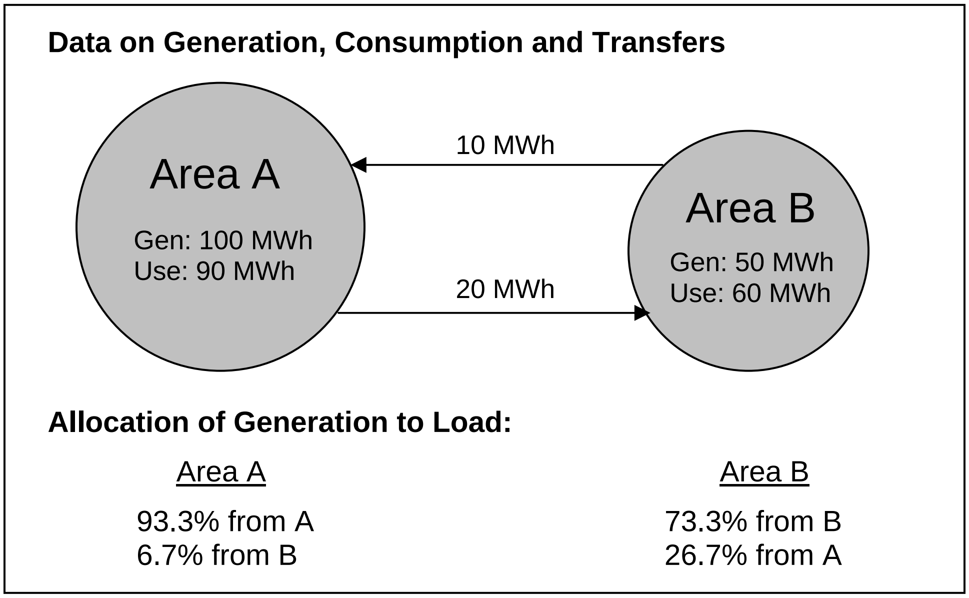
Step 1:	Identify the primary area for the analysis.
Step 2:	Determine whether the new resource will be located in a load pocket within the primary area.
Step 3:	Research recent energy transfers in the region and discern the seasonal patterns of energy transfer.
Step 4:	Develop multiple bid stacks for the primary control area, representing typical seasonal conditions.
Accuracy:	Where hourly transfer data are available this method is likely to generate accurate estimates of the bid stacks available to system operators during different time periods. Where little information is available on transfers, the method could be less reliable.
Transparency:	The method is very transparent. The characterization of energy transfers can be stated simply and the data underlying it can be summarized.
Labor Demands:	Characterizing energy transfers is moderately labor intensive, requiring one to two days of work (assuming data are readily available).

4.2 Allocating Transfers with Simultaneous Equations

The second method of accounting for energy transfers between dispatch areas allocates historical generation to areas by entering historical data into a system of simultaneous equations. These equations allocate energy transfers to dispatch areas on a pro rata basis as if all transfers had occurred simultaneously.

Figure 4 shows an example of this method. Assume that 100 MWhs were generated in control Area A, and 50 MWhs were generated in Area B. Further assume that 20 MWhs were delivered from A to B, and 10 MWhs were delivered from B to A. Thus, 90 MWhs were consumed in Area A (100 minus 20 plus 10), and 60 MWhs were consumed in Area B (50 minus 10 plus 20). All of this information would be entered into simultaneous equations to distribute the energy transfers evenly across both control areas. Figure 4 shows the results: 93.3 percent of the energy consumed in A is assumed to be generated in A, and 6.7 percent generated in Area B. Because the system is solved as if the transfers occurred simultaneously, Area A effectively gets back some of the energy it delivered to area B.

Figure 4. Solving Simultaneous Equations to Allocate Energy Transfers to Control Areas



After allocating energy transfers among the various areas in the region, one would estimate emission reductions by allocating reduced generation to units based on historical capacity factors, as described in Section 5.2.

There are two important aspects of this method. First, the method assumes that all transactions in the historical year occurred simultaneously. As discussed in Section 4.1, there is usually a seasonal pattern to regional energy transfers, based on the economics of different types of generation in different seasons. If one assumed that all energy transfers within an entire year occurred simultaneously, this pattern would be lost. For example, the 20 MWhs delivered from A to B might be excess hydropower delivered in the spring, while the energy delivered from B to A might be excess gas-fired generation delivered during the summer, when gas prices are low. The assumption that all of this energy transfer took place simultaneously would not be a credible representation of this pattern, and it could lead to an inaccurate estimate of displaced emissions.

Thus, to use this method one must divide the historical data into relatively stable time periods before performing the algebra to allocate energy. Dividing the historical transfer data into summer and winter peak and off-peak periods would probably be sufficient to capture the major patterns of energy transfer.

The second important aspect of this method is more problematic. The method provides no way to determine whether imported energy is subject to displacement or not. Rather, all imported energy is assumed to be affected by the new resource being assessed. For example, in Figure 4 the method estimates that 6.7 percent of the energy used in Area A came from Area B. However, it does not tell us whether the imported energy was low-cost baseload energy, which would not be displaced, or higher cost energy, which could potentially be displaced. In order to make an informed assumption about whether imported energy is subject to displacement, one must go back to the available data on historical energy transfers in the region and discern the typical patterns of energy generation and transfer. Again, the best way to do this is by reviewing hourly transfer data, but a reasonable characterization of imported energy could also be developed from less detailed data.

Thus, we do not believe that allocating historical energy transfers mathematically captures enough information on regional energy transfers to generate accurate estimates of displacement across a variety of regional power systems. For systems that import and export very small amounts of energy, this method would be accurate. However we do not recommend it for systems that import and export large amounts of energy.

Table 2. Summary of Allocating Transfers with Simultaneous Equations

Step 1:	Identify the primary area for the analysis.
Step 2:	Determine whether the new resource will be located in a load pocket within the primary area.
Step 3:	Enter historical data on energy generation and transfer into a system of simultaneous equations to allocate generation to control areas.
Accuracy:	We do not recommend this method for use in regions where large amounts of energy are transferred between control areas, because the method does not discern whether imported energy is subject to displacement or not.
Transparency:	This method of allocating energy transfers is less transparent than a method based on historical transfer data that can be summarized graphically, as in Figure 2.
Labor Demands:	This method requires roughly the same amount of work as adjusting bid stacks based on historical transfer data.

5. Estimating Displaced Emissions

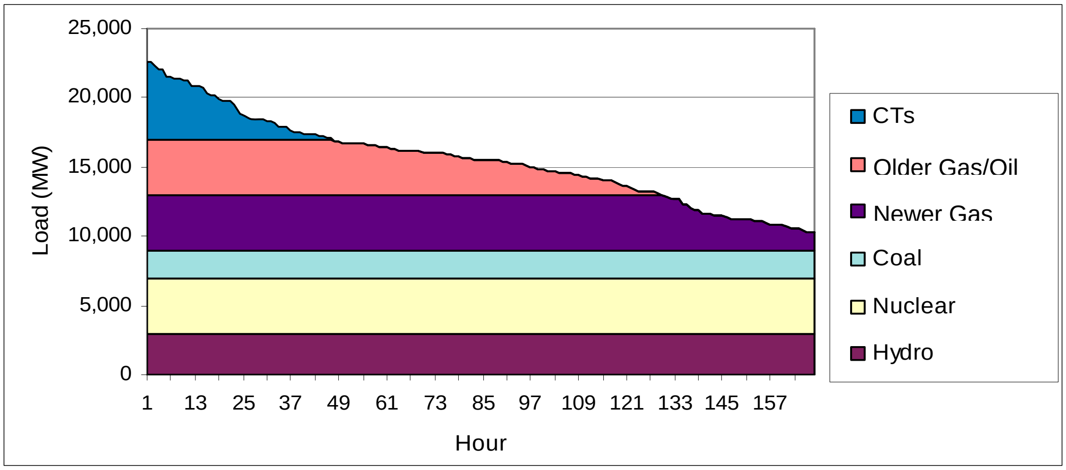
The second step in a displacement analysis is to determine the impact of the new resource on the generating units identified in the first step. We examine three methods of doing this:

- matching generating capacity to loads,
- allocating reduced generation based on historical capacity factors, and
- using data from Continuous Emissions Monitors (CEMS).

5.1 Matching Generating Capacity to Load

The first approach is to use load data from the primary area to identify marginal generating units during different time periods. There are two ways to depict this process visually. First, Figure 5 shows the generating unit types and loads from Figure 1 stacked under a load duration curve. In this graph, hourly system loads for a summer week have been ordered from highest to lowest. The generating units immediately under the curve at a given hour are on the margin during that hour. Compare this graph to Figure 1. Unit types are on the margin for the same number of hours in both graphs, the hours are simply ordered differently. To estimate displaced emissions for this week, one would calculate the weighted average emission rates of the units on the margin (weighted by the number of hours each unit was on the margin).

Figure 5. Stacking Generating Units under a Load Duration Curve



The second way to visualize this method is with the generating units ordered across the horizontal axis in the order of dispatch. Figure 6 shows the 2000 New England bid stack in this way. These data were developed for our quantitative comparison, discussed in Section 6. The grey line plots the NOx emission rate of each generating unit. Roughly the first 7,000 MW in this supply curve is hydro and nuclear baseload capacity, units with NOx rates of zero. From 7,000 to about 13,000 MW, the region's fossil-fueled baseload plants dominate – units with much higher NO_x rates. The area between about 14,000 and 22,000 MW is dominated by combined-cycle combustion turbines (with very low NO_x rates) with oil- and gas-fired steam units interspersed. Above about 22,000 MW are the region's peaking turbines and diesel engines with extremely high NO_x rates.

Figure 6. Comparing Loads to NO_x Rates along a Regional Supply Curve

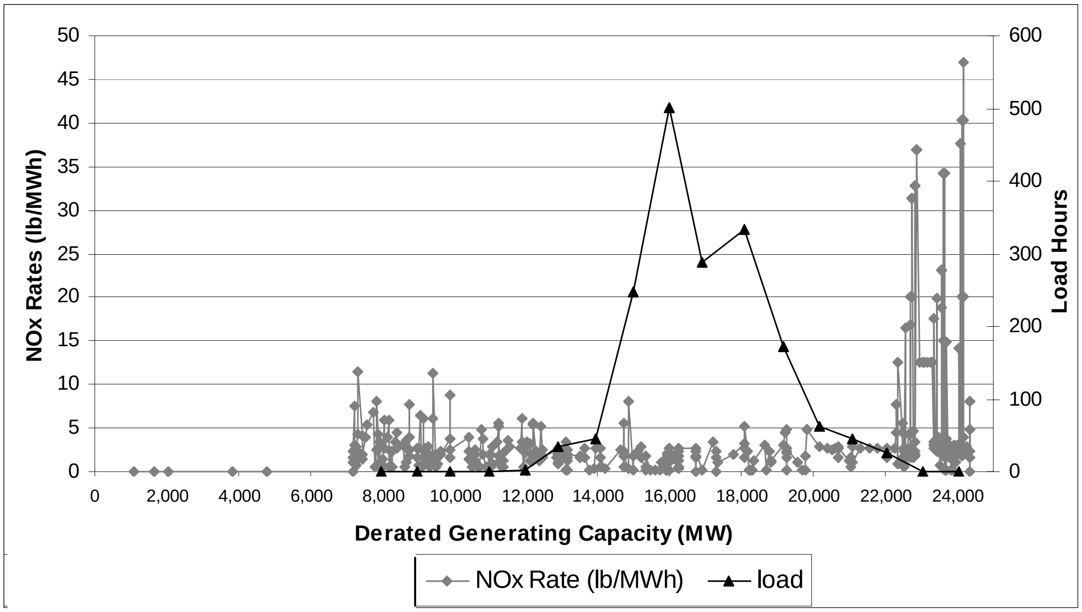


Figure 6 also includes a histogram (marked with triangles) showing the distribution of 2000 hourly load levels in New England during the summer daytime hours. The higher this curve is above the horizontal axis, the more hours the regional load was at that level. This image illustrates well how displacement is assessed using this method. To estimate displaced emissions for a resource operating during summer daytime hours, one would calculate the weighted average NO_x rate under the load histogram, using the load data to weight the emission rates.

One important step in this method is to derate generating unit capacities in the bid stack to reflect plant outages. Because generators are routinely taken off line for planned and unplanned maintenance, system operators never have all generators available to them at their nameplate capacities. Thus, unit capacities must be derated to provide a bid stack that represents the typical amount of capacity available. Information on typical outage rates for different types of generating units is available from the North American Electricity Reliability Council (NERC) in its Generator Availability Database (GADS).

The major strength of this method is its transparency. The major drivers of a displacement analysis can easily be examined by looking at the spreadsheet in which loads are matched to capacity or at a chart like Figure 6. The major weakness of this method is that it is based on a simplified conception of unit dispatch in which only one unit is subject to displacement in any given hour. As discussed in Section 3, system operators follow load with a number of units. Under certain circumstances, this simplifying assumption is likely to reduce the accuracy of this method. This issue is discussed further in Section 6.

Table 3. Summary of Matching Generating Capacity to Load

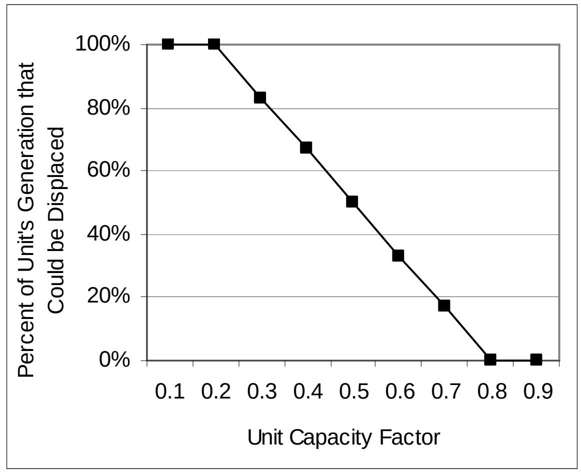
Step 1:	Determine the relevant set of generating units and develop seasonal bid stacks as described in Section 4.1.

Step 2:	Derate the generating units to fit the load data appropriately.
Step 3:	Obtain data on historical or projected hourly loads in the region.
Step 4:	Identify the marginal generating units during the hours that the new resource will operate.
Step 5:	Calculate the weighted average emission rates of the units on the margin when the new resource will operate.
Accuracy:	The method is based on a simplification of the dispatch process in which only one generating unit is considered to be marginal in any given hour. This is likely to reduce the method's accuracy when applied to some control areas.
Transparency:	This method is extremely transparent – the key drivers of a displacement estimate can be clearly seen in the spreadsheet or a chart.
Labor Requirement:	The method is labor intensive. One displacement analysis can take a week to ten days to complete.

5.2 Allocating Displacement to Generating Units based on Historical Capacity Factor

The second method of approximating unit dispatch does not seek to estimate which generating unit(s) will be on the margin at different load levels. Rather, it takes the total energy generated or saved by the new resource and allocates it to the plants in the region based on each unit's capacity factor. The method was developed by staff at the U.S. EPA for analysis of energy efficiency programs in the ERCOT region.

Figure 7. EPA/ERCOT Rule Applying Reduced Generation



In EPA's analysis of ERCOT, a simple rule was developed to allocate the savings projected from selected efficiency projects to generating units in the ERCOT region. The rule, summarized in Figure 7, causes units with lower historical capacity factors to be displaced at a greater rate than units with higher capacity factors. Units with capacity factors 20 percent and below can be completely displaced, and units with capacity factors 80 percent and above cannot be displaced at all. Between these extremes, "displacebility" falls in a linear way as capacity factor rises.

Using this rule, one calculates the amount of each unit's generation (MWhs) that could be displaced by the new resource. Next, one takes the total energy produced or saved by the new resource and allocates reduced generation to units. Table 4 illustrates this process, evaluating an efficiency program projected to save 1,000 MWhs pear year. There are seven generating units in this hypothetical power system, labeled A through G. Column [2] shows the percentage of each unit's production that could be displaced by the efficiency program, based on the rule from Figure 7. Column [3] shows each unit's actual generation in the historical year being used. Column [4] shows the amount of energy that could be displaced at each unit – column [2] times column [3]. Column [5] shows the percentage of the energy saved by the efficiency program (1,000 MWs) allocated to each unit, and column [6] shows the MWhs displaced at each generating unit.

Table 4. Allocating Saved Energy to Generating Units

[1] Unit	[2] % Displaceable	[3] Historical Gen. (MWh)	[4] MWhs Displaceable	[5] % of Energy Saved Allocated to Unit	[6] MWhs Displaced
A	100%	50,000	50,000	7%	65
B	82%	65,000	53,300	7%	69
C	79%	120,000	94,800	12%	123
D	48%	500,000	240,000	31%	312
E	22%	1,500,000	330,000	43%	430
F	0%	1,800,000	0	0%	0
G	0%	2,000,000	0	0%	0
Totals		6,035,000	768,100	100%	1,000

The use of a rule to allocate displacement based on historical plant utilization is attractive in that it is simpler than matching generation to load. Load data does not need to be obtained and analyzed, and generating unit capacities do not need to be derated to fit the load data. This method applies displacement directly to generating units based on their historical position in the dispatch order. Note that this method does not avoid the task of developing a database of generating units in the region with data on historical generation and emission rates. This work would be necessary in order to calculate each unit's historical capacity factor. However, one may be able to ignore nuclear and hydro units using this method, based on the assumption that these units are never displaced. This would allow one to work with a smaller power plant data set.

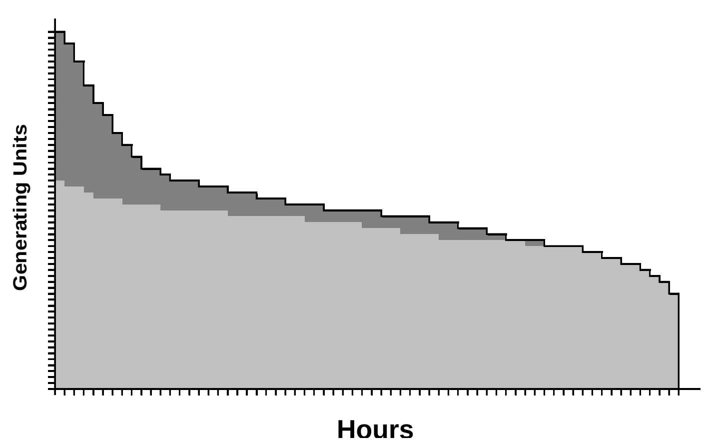
Two aspects of carrying out this method are important. First, seasonal capacity factors should be used, rather than annual, in allocating reduced generation. If annual capacity factors were used, any seasonal patterns in plant utilization would be lost. For example, many combustion turbines operate only during summer daytime hours during a typical year. The use of annual capacity factors would allocate displaced emissions to these units during other seasons of the year.

The second important issue is to ensure that the allocation rule used accurately reflects the new resource being assessed. For example, the linear allocation rule in Figure 7 includes an assumption about when the efficiency project will reduce energy – it assumes that the efficiency project effects peaking units most, other units with low capacity factors slightly less, and so on down the bid stack. This assumes that the efficiency program displaces far more MWhs during peak hours than during other hours of the year.

Figure 8 illustrates the application of this rule with a typical load duration curve. The descending step function plots hourly load levels throughout the year, with loads ordered from highest to lowest. (In this simplified example, there are only 65 hours in the year.) Sixty hypothetical generating units (equally sized) are stacked on the Y axis in order of descending capacity factor. The units near the bottom of the Y axis are baseloaded units, with capacity factors in the range of 80 to 100 percent. The units at the top of the Y axis are peaking units, with capacity factors in the range of 0 to 20 percent. As the curve indicates, these peaking units operate only a few hours per year.

The dark grey area under the curve shows the application of the displacement rule from Figure 7. The dark areas indicate the portion of a unit's generation that can be displaced. Note that any unit with a capacity factor below 20 percent can be fully displaced, and the extent to which units can be displaced falls as you travel down the dispatch order. The effect of this rule is that the energy removed from the load duration curve is heavily weighted toward the peak hours. This pattern

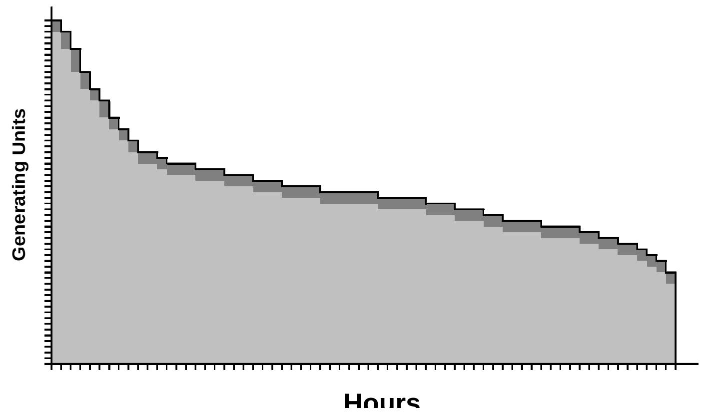
Figure 8. Application of a Linear Displacement Rule to a Load Duration Curve



of energy savings is consistent with an efficiency program targeted toward peak-hour energy use. Thus, this rule would be appropriate for evaluating this type of program, but it would not be appropriate for evaluating an efficiency program that affected "baseload" energy uses. The savings from a baseload efficiency program are typically represented on a load duration curve as a consistent decrement in energy use across all hours of the year, as seen in Figure 9. Note that in this case, a different mix of generating units would be displaced than in Figure 8.

Thus, one can apply load reductions to generating units with a capacity-factor based rule as long as the rule is appropriate to the technology being assessed. For example, one might start each displacement analysis by evaluating the projected operation of the new resource and developing an appropriate rule for allocating displaced emissions. Alternatively, one might develop a number of allocation rules applicable to different resources, which could be applied as needed.

Figure 9. Load Reductions from a Baseload Efficiency Program



This method is attractive in that it is less labor intensive than matching capacity to loads and it requires less power system expertise. However, this method too is based on a simplifying assumption about the relationship between generating unit dispatch and displacement. The method assumes that a unit's capacity factor is a good measure of the extent to which the unit is subject to displacement. In very general terms this assumption is appropriate – for example, baseload units are rarely subject to displacement and they have very high capacity factors. However, capacity factor is not likely to be a good measure of displacement for all units. There are undoubtedly units with low capacity factors (say 10 to 30 percent) that are not used to follow load. They either operate at full capacity or not at all. While these units would rarely be subject to displacement, this method would allocate reduced generation to them. More work is needed to determine how accurately this method estimates displaced emissions when applied to large numbers of generating units.

Table 5. Summary of Allocating Displacement Based on Historical Capacity Factors

Step 1:	Determine the relevant set of generating units as discussed in Section 4.1, and obtain or calculate seasonal capacity factors for each unit.
Step 2:	Develop a rule to allocate reduced generation to units based on their historical capacity factors. Ensure that this rule appropriately reflects the expected operation of the new resource in question.
Step 3:	Allocate reduced generation (equal to generation or savings from the new resource) to existing units using the rule.
Accuracy:	The method assumes that capacity factor is a good measure of "displaceability." This is likely to be a reasonable assumption of many units, but not all units. More work is needed to understand the range of error associated with this method.
Transparency:	The method is quite transparent. The amount of energy displaced at each generating unit can be easily discerned and summarized.
Labor Demands:	This method is considerably less labor intensive than matching capacity to load.

5.3 Estimating Displacement Using CEMS Data

The third method we examine, developed by researchers at MIT, uses hourly data from power plants to identify the load following units in each hour of the year. The US EPA collects data in five-minute intervals from Continuous Emissions Monitors (CEMS) at all large power plants in the country. These data allow one to see how the production of each generating unit changed throughout the day as loads changed. The MIT researchers used this information to identify the units that were following load – increasing and decreasing their production in response to changes in load. This allowed them to calculate weighted average marginal emission rates (the average of the load following units) for any group of hours.[5]

The development of the database on which this method is based was extremely labor intensive. Researchers had to review five-minute CEMS data from all generating units in the country, filling in missing data and adjusting information that was clearly wrong. The five-minute data were ultimately summed to the hourly level and merged with hourly generation data (unit-specific) and hourly load data in each US control area. Developing this database for even one control area would require considerable labor.

Once the database is developed, one identifies load following units in each hour of the year. Load following units are defined as units that increased output during an hour in which system load increased or decreased output during an hour in which system load

[5] Connors, Stephen, et. al., *National Assessment of Emissions Reduction of Photovoltaic (PV) Power Systems*, Massachusetts Institute of Technology, prepared for the US EPA, Air Pollution Prevention and Control Division. See: http://web.mit.edu/newsoffice/2004/renewables.html.

decreased. Using these hourly load-following emission rates, one can assess displacement from any type of resource based on the hours during which the resource operates.

These weighted average emission rates of load following units reflect the group of units that system operators actually used to meet marginal demand in that hour. This is a more accurate representation of the marginal emission rate than a one based on the idea that a single generating unit is marginal in any given hour (such as matching generating capacity to load, described in Section 5.1). Thus, the strength of this method is that it is based on actual data from fossil-fired generators. A weakness of this method is that it does not account for generation from hydro units or units located outside of the local control area (because it is based on CEMS data from units within the control area). The method was developed to assess emission reductions from very small resources (PV arrays), and ignoring hydro generation and transfers may be appropriate when assessing displacement from units this small. However, impacts on hydro units and transfers should be captured when assessing displacement from larger resources.

In most regions, load following is done largely with fossil units, so errors stemming from ignoring hydro and energy transfers are likely to be small. We suspect that in some regions there is substantial load following from hydro units, although we have not researched this question. This method would be less accurate in regions where a large number of hydro generators commonly follow load. Also, in some regions certain energy imports appear to follow load fairly closely, and this could result in errors from this method too, although this is probably less of a concern than hydro load following. More research is needed to determine the extent to which hydro units and energy imports follow load in the various US control areas. (In addition, as discussed in Section 7.2 it may be possible to develop a method based on CEMS data that does account for hydro generation and transfers.)

Table 6. Summary of Using Hourly Emissions (CEMS) Data

Step 1:	Develop or obtain a database of CEMS and load data for the control area in question, including hourly emissions and generation for each generating unit and hourly loads for the control area.
Step 2:	Identify load following units in each hour and calculate hourly average load following emission rates.
Step 3:	Determine the hours that the new resource will operate and calculate the average of the load following rates for those hours (weighted by the amount the new resource operates in each hour).
Accuracy:	In regions where most load-following is done with in-region fossil units, this method is likely to be very accurate. In regions where hydro resources and/or imported energy follow load, the method would be less accurate.
Transparency:	The method is transparent in that the units typically following load in a region can be summarized, and detailed data on load following could be provided along with an estimate of displaced emissions.
Labor Demands:	Developing the database necessary to use this method is by far the most labor-intensive task evaluated in this paper. However, if such a database has been developed, implementing this method requires significantly less work than the other two methods evaluated.

6. Quantitative Comparison of Methods

To complement our qualitative evaluation of these methods, we applied each method to a historical data set. (Due to the weaknesses we found in the method using simultaneous equations, we did not include this method.) The data set was from ISO New England for the year 2000. We compared these methods to a Marginal Emissions Analysis (MEA) done by the New England Power Pool in the year 2000. This analysis used the PROSYM dispatch model, with fixed transfer levels. (That is, they did not allow the model to select the optimal level of energy transfer in each hour.) Table 7 shows the three methods we compared, including the two steps employed in each method.

Table 7. Methods Compared

Method	Task 1: Determining Relevant Generating Units	Task 2: Estimating Marginal Emissions
Matching Capacity to Load	Bid stacks adjusted based on transfer data	Seasonal bid stacks matched to loads
Capacity Factor Rule	Bid stacks adjusted based on transfer data	Linear CF rule applied to reduced energy
CEMS Load-Following	Single control area – no transfers	Calculated hourly “load-following” emission rates
NEPOOL MEA	Multiple control areas (but transfers fixed)	Dispatch modeling

We compiled data for the comparison from three sources:

- EPA's EGRID database (generating unit names, capacities, emissions and annual capacity factors),
- ISO New England (generating unit names and capacities and hourly load and transfer data), and
- CEMS data from EPA (hourly data on emissions and production).

We began by ordering the generating units in ISO New England (from the EGRID database) into a supply curve, with highest capacity factors on the bottom and lowest on top. Next we used ISO New England data to create two bid stacks, one with summer capacity ratings and one with winter ratings. In this process, we cross-checked the capacities of all units over 100 MW, and replaced EGRID capacity figures with ISO New England ones where they were significantly different.

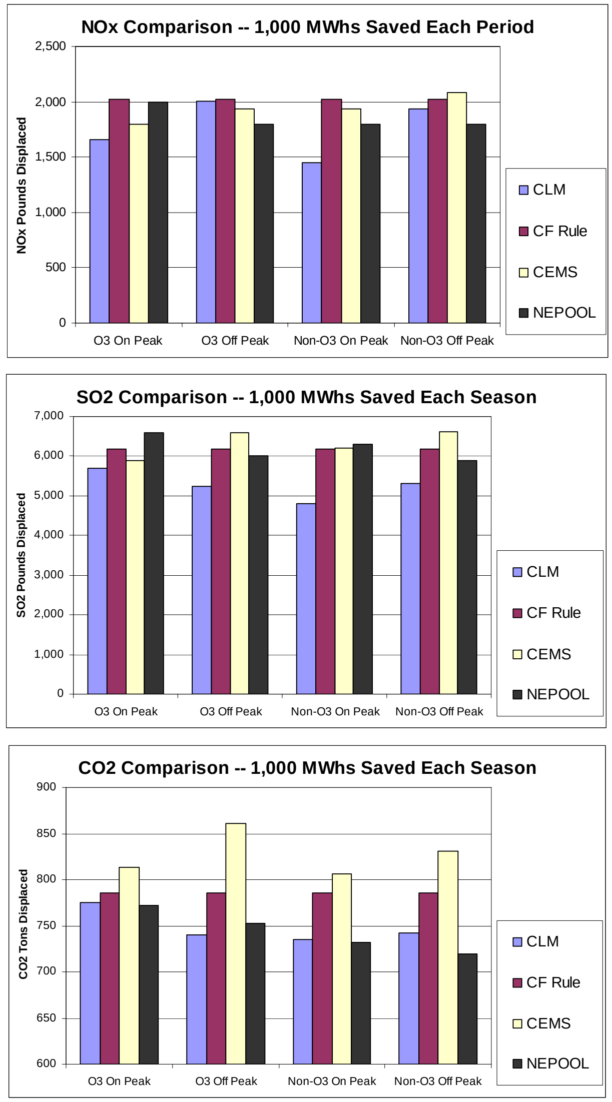
Next, we reviewed hourly transfer data to determine seasonal patterns of energy transfer. From the summer and winter bid stacks, we developed bid stacks for four time periods: ozone season (summer) on peak and off peak and non-ozone season (winter) on peak and off peak. We adjusted each bid stack to reflect average interchange levels in each season.

After developing these bid stacks we used them to match capacity to loads (see Section 5.1) and to allocate reduced energy based on capacity factors (see Section 5.2). We assessed a hypothetical program that saved 1,000 MWhs in of four time periods. We then calculated weighted average load-following emission rates for the same periods using CEMS data and applied these emission rates to 1,000 MWhs per period (see Section 5.3). The results of this comparison are shown in Figure 10.

First, note that the CF Rule method estimates the same amount of emission reductions in each of the four time periods. This is because we used annual capacity factor data, so the output of each generating unit is reduced by the same amount in each time period. Because New England has a fleet of peaking units with very high NOx emission rates, the use of annual capacity factors has probably led to overestimates of displaced NOx emissions in all but the ozone season peak period, when these peaking units tend to operate. (That is, the use of annual capacity factors simulates displacement at these units during seasons in which they are not typically used.)

In addition, two patterns emerged in the results of the quantitative comparison. First, the capacity/load matching method tends to estimate lower emission reductions (fewer tons reduced) than the other methods. It provides the lowest estimate in two periods for NO_x, in all four periods for SO_2 and in one period for CO_2. In four of the five other periods it provides the second lowest estimate. This is probably due to two facts. First, the New England supply curve has a large section of relatively clean generation in its middle, much of which is newer combined cycle units. (This section can be seen between roughly 14,000 and 22,000 MWs in Figure 6 above). Second, this method assumes that only one generating unit is displaced in each hour. During some time periods, the generating unit displaced often falls in this section of low-emission units, resulting in a relatively low estimate of displaced emissions. In reality, system operators are likely to be following load with a number of generating units in any given hour, some of which are probably not in this low-emission section of the supply curve. Thus, in this particular power system, this method appears to understate displaced emissions. In a system with more homogeneous emission rates along the supply curve, this underestimation would probably not occur.

Figure 10. Results of Quantitative Comparison



The second pattern we found is that the CEMS-Based method estimates the highest displaced CO_2 emissions in all four periods, and they are considerably higher in several periods. One possible explanation for this is that New England system operators often follow load with relatively inefficient units (i.e., units with high CO_2 rates). If this were true, the CEMS-based marginal emission rates would capture this dynamic, while the spreadsheet-based methods would not. The NEPOOL modeling *could* capture this dynamic, but we suspect that the NEPOOL modelers have not calibrated PROSYM to match actual system dispatch in areas like load following.[6]

The fact that the CEMS-Based method does not factor in potential load following from hydro units or imports may also be contributing to the high CO_2 estimates from this method. However, the CEMS method does not consistently yield the highest estimates for NO_x and SO_2 emissions, as it does for CO_2. If this aspect of the method were wholly responsible for the high CO_2 estimates, one would expect the NO_x and SO_2 estimates to be similarly high. This issue warrants further investigation.

[6] NEPOOL performed its modeling in 2000 with PROSYM. ISO New England dispatches the system with its own security-constrained dispatch software.

7. Conclusions and Further Work

7.1 Conclusions

We assessed two methods of accounting for energy transfers between control areas, the major task in the first step in a displacement analysis. Our assessment of these two methods is as follows.

- **Allocating Energy Transfers Using Simultaneous Equations.** We do not recommend using this method to determine the relevant set of generating units, because it does not capture seasonal patterns in energy transfer and it assumes that all energy imported into a region is subject to displacement.
- **Adjusting Bid Stacks Based on Historical Transfer Data** is a credible way to determine the relevant set of generating units, however it is a somewhat subjective process requiring informed judgment.

We assessed three methods of estimating displaced emissions. Two of these adjust bid stacks based on historical transfer data as part of the first step in the analysis. The third, the CEMS-Based approach, does not account for energy transfers between control areas.

- **Matching Generating Capacity to Load** is based on the assumption that only one generating unit is subject to displacement in any given hour and that this unit is the most expensive unit operating. This does not reflect the reality of system dispatch, in which a number of units are used to follow load in a given hour. Because of this assumption, this method is sensitive to a region's particular mix of emission rates and the location of those emission rates on the supply curve. Thus, this method would be appropriate for making rough estimates of displaced emissions, but we do not recommend it for purposes that demand a high level of accuracy.
- **Allocating Reduced Generation Based on Historical Capacity Factors** is an attractive method of estimating displacement because it is simpler and more objective than matching capacity to load. Our quantitative comparison underscored the idea that seasonal capacity factors should be used to implement this method, rather than annual ones. However, this method too is based on a simplifying assumption – that a unit's capacity factor is an effective measure of the extent to which it is subject to displacement. This assumption is likely to be reasonable for many, but not all, generating units. At this point, we would only recommend this method for making rough estimates of displaced emissions. More work should be done to determine whether this method produces accurate results consistently.
- The **CEMS-Based** method examined here is extremely credible in that it captures the actual dispatch of the fossil-fired generators in the primary area of analysis. This gives the method an empirical basis, which the other methods do not have. However, this method does not account for potential impacts on hydro units or energy transfers. Thus, in regions where hydro units and imported energy are rarely used to follow load, this method would generate highly accurate estimates

of displacement. In regions where hydro units and imported energy are used to follow load, the method would be less accurate. In Section 7.2 we outline a way that one might incorporate hydro operation and energy transfers into a CEMS-based method.

- In all three methods (matching capacity to load, using a capacity factor rule and using hourly CEMS data) historical data could be adjusted for a prospective analysis in a region experiencing plant turnover. For the first two methods, one would adjust bid stacks to reflect expected plant additions and retirements. For the CEMS-Based method, one would adjust the weighted average marginal emission rate based on expected additions and retirements. None of the three methods is clearly better for a prospective analysis than the others.
- If an hourly CEMS database has already been compiled, the CEMS-Based Load Following method is the least labor intensive method. If such a database has not been compiled it is the most labor intensive method. The CF Rule method is less labor intensive than the Capacity/Load Matching method.
- A method based on CEMS data, but also accounting for potential impacts on hydro units and energy transfers, could be more accurate and credible than any of the methods discussed above. We present some ideas for such a method in Section 7.2.

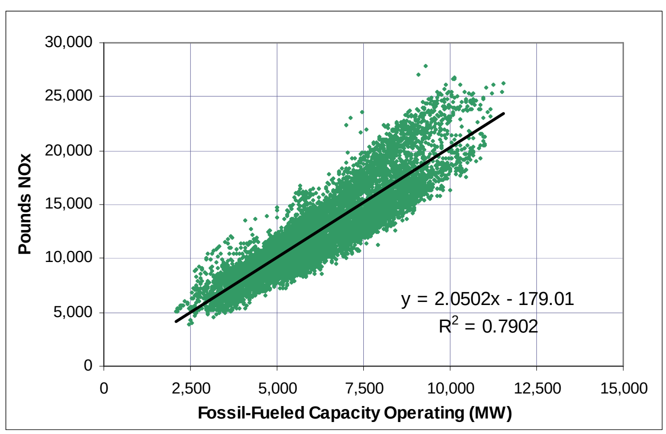
7.2 Further Work

As noted in our conclusions above, a method based on CEMS data, but also factoring in hydro generation and interchange between control areas, might be more credible and accurate than any of the methods assessed here. Using CEMS data is attractive because it captures the actual mix of fossil units being used to follow load. The non-CEMS methods assessed here make simplifying assumptions about plant dispatch.

There are two challenges to factoring hydro generation and interchange into a CEMS-based analysis. First, one must determine the extent to which hydro units and imported energy are following load. Second, if either hydro or imported generation are following load to a significant degree, one must factor this into the displacement analysis.

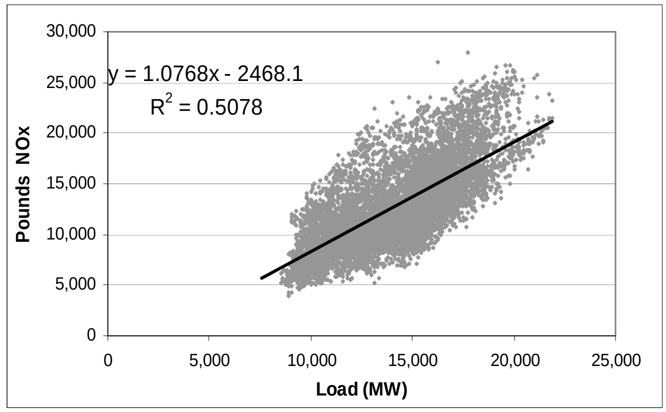
One way to determine whether hydro and imported energy are following load is to look at the CEMS data. By plotting total system emissions as a function of in-region fossil generation one can see how fossil generation is dispatched on a typical day. Figure 11 shows this plot for New England in the year 2000. The slope of the linear regression line at any point is the marginal fossil NO_x rate at that

Figure 11. System NO_x Emissions as a Function of Fossil Generation



point. Note that the data fit a linear regression line fairly closely ($R^2 = 0.8$). This reflects the fact that system operators follow load with multiple generating units rather than with a single marginal unit.

Figure 12. System NO_x Emissions as a Function of System Load



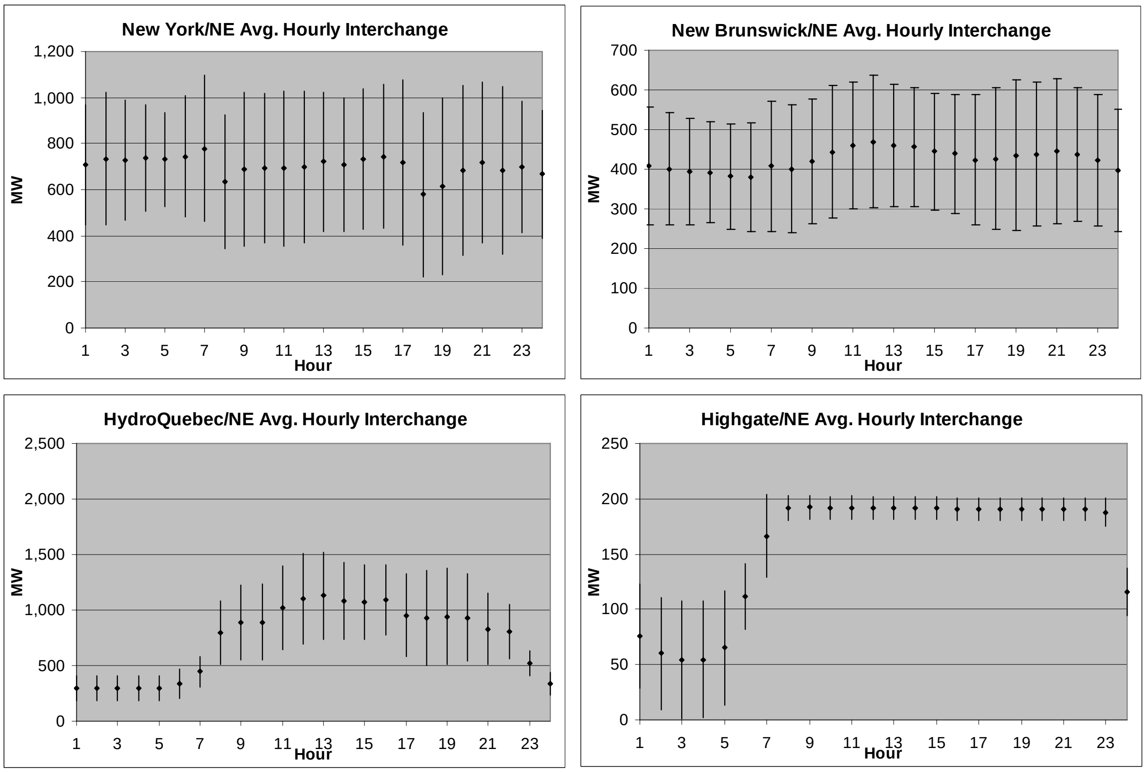
To assess whether hydro and/or imports are being used to follow load, one could compare this graph to a plot of total system emissions as a function of load. Figure 12 shows this plot for the same power system (same CEMS data). Note that the slope of the linear regression line on this chart is roughly half (1.08) of the slope in Figure 11 (2.05). More work is needed to understand these data better, but these two plots suggest that system operators were using some zero-emission units and/or imports to follow load during the day. If they had been using only fossil-fueled units to follow load, the slopes in the two charts would be roughly the same.[7]

One could examine other data to fill out this picture of system operation. In some regions, system operators may be willing to discuss how they use hydro resources and imported energy. In some regions hourly data on hydro generation and energy interchange may be available. Figure 13 shows plots of hourly interchange data at New England's four major interties in December of 2000. Note that imports from New York and New Brunswick were used generally in a baseload fashion. Imports from Hydro Quebec appear to have followed load during many daytime hours, and imports on the Highgate interface (also hydropower from Quebec) followed load during the off-peak hours.

In addition to these imports, we suspect from anecdotal evidence that some in-region hydro units are also typically used to follow load in New England.

[7] In a power system that typically exports a large amount of fossil generation (such as ECAR), one might see the opposite pattern. That is, a plot of emissions as a function of load might have a steeper slope than one of emissions and fossil generation, because much of the in-region fossil generation is going to serve out of region load.

Figure 13. Imports into New England in December 2000



Now, how could one adjust the CEMS data to account for load following from hydro and imports. First, consider that the slopes in Figures 11 and 12 essentially bound the marginal NO_x rates in this system. If all of the generation not captured in the CEMS data were imported fossil generation, the true marginal NO_x rate would be close to the slope in Figure 11, the plot of emissions against fossil generation.[8] In contrast, if all of the generation not captured in the CEMS data were hydro generation (in region or imported) then the true marginal NO_x rate would be very close to the slope in Figure 12, in which all load not met with fossil generation has no emissions. If system operators were using a mix of hydro and imported fossil, the true marginal NO_x rate would fall somewhere between these two slopes. In many cases, available data on hydro generation and interchange may provide sufficient basis to estimate where the marginal NO_x rate lies relative to plots like these.

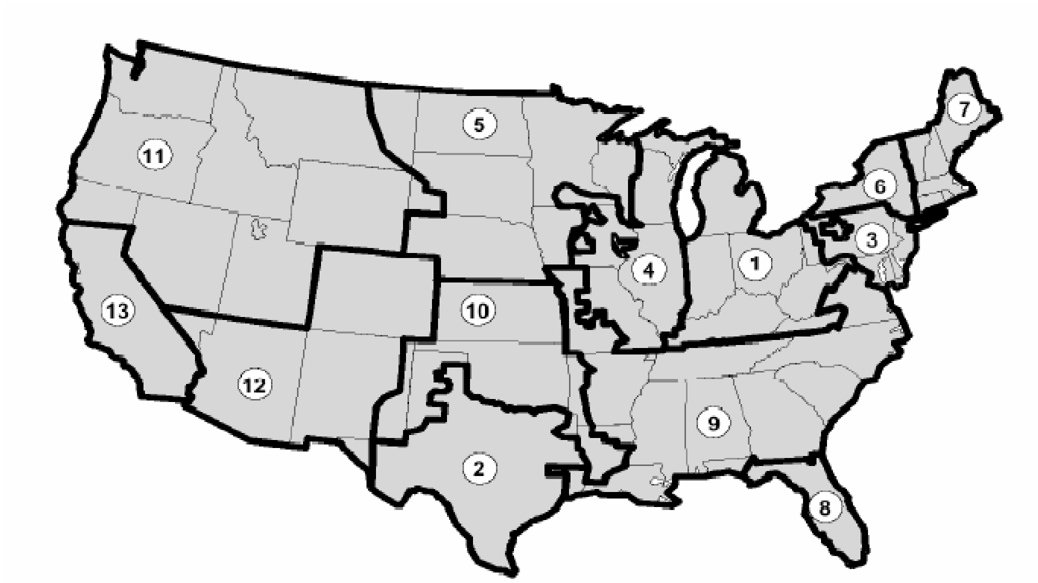
There would be uncertainty in this adjustment, but the method would start with empirical data on a critical driver of displaced emissions – the load following patterns of the region's fossil-fired units. Ultimately this may be more accurate than a method based on a simplifying assumption about how fossil plant dispatch, such as those examined in this paper. More work is needed to investigate and test this method.

[8] If the imported generation were higher NOx on average than the in-region fossil, the true marginal rate would be slightly higher than in Figure 11. If the imported fossil generation were cleaner than the in-region fossil, the true NOx rate would be lower than in Figure 11.

Appendix: Typical U.S. Electricity Transfers

In some spreadsheet-based displacement analyses a significant amount of work will be required to account for energy transfers between control areas. To inform this issue, we present large scale data on recent U.S. energy transfers. These data are from the US Department of Energy's (DOE) annual electricity modeling work (Annual Energy Outlook). Each year, DOE releases historical data on actual electricity generation and use across the U.S.[9] The DOE releases data for 13 regions of the country, with each region consisting of one or more power control areas. The 13 regions are shown in Figure A1 and Table A1 below. Some of these regions consist of one control area, while others consist of multiple control areas – as shown in Table A1.

Figure A1. The NERC Subregions



1. ECAR (EI)	6. New York (EI)	11. NWPP (WI)
2. ERCOT	7. New England (EI)	12. RM-AZNM-SNV (WI)
3. MAAC (EI)	8. FRCC (EI)	13. California (WI)
4. MAIN (EI)	9. SERC (EI)	
5. MAPP (EI)	10. SPP (EI)	

These regions are divided into three main U.S. interconnections: the Eastern and Western Interconnections and ERCOT. Very little energy flows between these interconnections, so they provide useful boundaries in assessing interregional energy flows. The key in Figure A1 indicates which interconnection each control area lies in.

Table A1 shows the net import data averaged for the years 2001 and 2002. Note that four regions, New York, New England, FPCC and California, were net importers of electricity in these two years, and two regions (MAIN and RM-ANM-SN) were significant net exporters, although ECAR and NWPP were moderate net exporters.

[9] DOE releases these data on about a two year time lag.

Table X. Regional Electricity Imports, Average of 2001 and 2002

Region	Number of Control Areas	Imports	Exports	Net Imports	% Net Imports
ECAR	13	8	-53	-45	-8%
ERCOT	1	5	-2	-3	1%
MAAC	1	23	-17	6	2%
MAIN	13	8	-54	-46	-16%
MAPP	14	15	-18	-3	-2%
New York	1	28	-12	16	12%
New England	1	15	-1	13	12%
FPCC	11	43	0	43	24%
SERC	23	75	-60	15	2%
SPP	18	23	-19	3	2%
NWPP	16	33	-46	-13	-6%
RM-ANM-SN	14	20	-58	-38	-19%
California	4	76	-12	64	32%

Numbers don't equal due to rounding.

Because many of the NERC subregions regions include many control areas, this analysis cannot tell us exactly where (in which control areas) energy transfers are likely to be significant. However, these data do provide a general sense of the location and direction of regional electricity flows in the US.