Synapse
Energy Economics, Inc.

Modeling Demand Response and Air Emissions in New England

Prepared by:
Geoff Keith, Bruce Biewald, David White and Mike Drunsic
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

Prepared for:
U.S. Environmental Protection Agency

August, 2003

Revised: September 4, 2003

Table of Contents

Executive Summary

In January 2003 Synapse began work to assess the potential emissions impacts of demand response (DR) and energy efficiency programs in New England. Synapse performed this work under subcontract to Eastern Research Group, funded by the U.S. EPA. EPA funded this project largely to inform the work of the New England Demand Response Initiative (NEDRI), a collaborative process designed to develop recommendations for expanding DR programs in New England. The key goals of the analysis were to:

- Estimate the net emissions impacts of mature DR programs in New England under different assumptions,
- Explore the impact of DR generating technology and fuel mix on net emissions,
- Explore the extent to which additional DR capacity in New England could result in reduced air emissions from more efficient unit commitment,
- Explore the impact of load shifting on net emissions, and
- Compare the emissions impact of DR programs to those of energy efficiency programs.

In addition to this work, EPA also requested that Synapse develop a methodology for estimating the emissions impacts of actual DR events retrospectively.

The dispatch modeling portion of this analysis was performed with the PROSYM/MULTISYM production costing model. A hypothetical near-term year in New England was modeled, using projected 2006 fuel prices and loads. In order to model a relatively capacity-constrained year (i.e., a year in which there was likely to be robust DR operation), a 20-percent system reserve margin was created by making minor adjustments to NEPOOL's projected plant in service in 2006.

An economic DR program was modeled. This is a program in which DR resources bid into the day-ahead energy market along with other supply-side resources and are dispatched based on their bids, like supply-side resources. The DR program modeled included 500 MW of DR capability, with 60 percent assumed to be load response and 40 percent, generation. This ratio is based on data provided by ISO New England regarding recent (February 2003) enrollment in the New England economic DR program, (known then as the "Class 2" program). Scenarios were explored involving several different mixes of diesel- and gas-fired engines providing the generation portion of the DR.

DR capacity was allocated to locational marginal pricing (LMP) zones based primarily on industrial electricity sales, with some capacity shifted from capacity-surplus zones to southwestern Connecticut, to reflect the tight capacity situation there. DR resources were modeled as bidding at five bid points: \$100, \$200, \$300, \$400 and \$500 per MWh. This assumption is based on research performed in New York State on the cost of providing DR. Within a zone, equal amounts of DR were bid at each bid point, and generators bid a four-hour minimum up time. Sensitivity analyses were performed to determine the impact that load shifting has on total net emissions from DR.

In addition to DR, the air impacts of two different energy efficiency programs were explored: an energy-targeted program and a peak-targeted program. The energy-targeted program reduced peak demand by one percent and annual energy use by 0.75 percent. The peak-targeted program reduced peak demand by 1.2 percent and annual energy use by 0.50 percent. These numbers were developed based on a review of current efficiency program impacts in New England.

Results

- In the economic DR program modeled, the DR resources provided 3,361 MWhs of load relief during the summer: 1,451 MWhs of onsite generation and 1,910 MWhs of load response. This is over three times the amount of load relief provided by ISO New England's 2002 economic DR program (1,011 MWh). This level of DR activity is consistent with our goal of modeling a mature DR program in a moderately capacity constrained year. DR resources would operate more in an extremely constrained period, such as the California crisis of 2000-2001.
- Over 90 percent of the DR load relief occurs in southwestern Connecticut. Much of the 500-MW DR resource is never dispatched (including all of the capacity in Maine, New Hampshire and Rhode Island); however all of the DR capacity is used to meet operating reserve requirements during the summer if allowed to do so.
- When the DR resource is used to meet reserve requirements, the result is more efficient unit commitment, reduced operation of oil- and gas-fired steam units and increased operation of combined-cycle units in New England. New England also imports more energy from neighboring control areas with the DR resource. The net impact of these dynamics is a potential reduction in criteria pollutant emissions. However, in order to realize the NO_x and SO_2 reductions, mechanisms would have to be established to ensure that they were not lost through emissions trading.
- Potential emission reductions in this scenario are largest in the summer months. Assuming no diesel generation in the DR program, summer NO_x reductions could be as large as 41 tons (0.18 percent); SO_2 reductions could be 218 tons (0.3 percent), and CO_2 reductions could be 31,800 tons (0.13 percent). The impact of DR on mercury emissions is negligible; however there are small increases in several air toxics associated with internal combustion (IC) engine generators.[1]
- This finding (potential emission reductions come from additional DR capacity used to meet reserve requirements) is specific to New England and should not be extrapolated to other control areas. Further, this finding is based on clearly identified assumptions about how the ISO currently commits generating units and meets reserve requirements. To the extent that these assumptions do not capture the full complexity of this process, this finding may need to be reevaluated.
- Different assumptions about the mix of diesel- and gas-fired generation in the DR program lead to small but significant impacts on the emissions numbers listed above.

[1] These toxics are: 1,3 Butadiene, Acetaldehyde, Acrolein, Benzene, Formaldehyde and PAHs.

If we assume that 50 percent of the generation portion of the load relief is diesel fueled (rather than zero percent), the potential NO_x benefits of the DR program are reduced by about 9 tons (22 percent). This level of diesel generation would reduce potential SO_2 benefits by about one ton (0.5 percent), and potential CO_2 benefits by about 200 tons (0.6 percent). It would reduce emissions of several air toxics associated with natural gas-fired ICs, but it would increase slightly emissions of PAHs and diesel fine particulates – the toxics that pose the greatest health threats.

- When the DR resource is *not* used to meet reserve requirements, the impact on emissions is much smaller. Emissions of NO_x could either fall by about 4 tons or rise by about 15 tons, depending on the fuel mix of the DR generation. Emissions of CO_2 would fall, and emissions of the "IC toxics" would increase by small amounts. Because generators operating in DR programs are not subject to the NO_x and SO_2 caps, and the units that they displace generally are subject to these caps, there is a potential source of "leakage" that should be of concern to air regulators.
- While the net emissions impacts of DR operation (assuming it is not used to meet reserves) are small compared to total system emissions, in specific locations these impacts could exacerbate non-attainment problems and pose significant health risks. More work needs to be done to understand the health risks of operating IC generators in New England.
- Comparing the impacts of the DR program to the single-year impacts of efficiency programs, we find that both efficiency programs could provide significantly greater emission reductions than the DR program.[2] The peak-targeted efficiency program could reduce annual emissions of NO_x and SO_2 more than the energy-targeted program, but the energy-targeted program could reduce CO_2 the most. We use the term "could reduce," because efficiency programs (like DR programs) would have to ensure that NO_x and SO_2 reductions were not lost through emissions trading in order to capture those reductions.
- In the interest of estimating the emissions impacts of actual DR events retrospectively, we recommend that environmental regulators seek to obtain information on actual DR generation by plant type (e.g., diesel- versus gas-fired engine). Having this information would significantly reduce the uncertainty of these estimates, especially in a scenario in which DR is not used to meet reserve requirements.

[2] We compare the effects of the efficiency programs to the effects of the DR program in which DR resources are used to meet reserve requirements.

1. Introduction

There has been increasing interest in recent years in demand response (DR), programs that incentivize electricity customers to reduce demand or operate on-site generators during periods of high loads and/or high prices. The benefits that DR could provide include lower market prices during certain hours, increased system reliability and mitigation of market power. However, along with these benefits, some types of DR programs could bring environmental costs in the form of increased air emissions from small, on-site generators that have been subject to little regulation in the past.

In January 2003 Synapse began work to assess the potential emissions impacts of DR and energy efficiency programs in New England. Synapse performed this work under subcontract to Eastern Research Group, funded by the U.S. EPA.[3] EPA funded this project largely to inform the work of the New England Demand Response Initiative (NEDRI), a collaborative process designed to develop recommendations for expanding DR programs in New England. The key goals of the analysis were to:

- Estimate the net emissions impacts of mature DR programs in New England under different assumptions,
- Explore the impact of DR generating technology and fuel mix on net emissions,
- Explore the extent to which additional DR capacity in New England could result in reduced air emissions from more efficient unit commitment,
- Explore the impact of load shifting on net emissions, and
- Compare the emissions impact of DR programs to those of energy efficiency programs.

The desire to explore how DR could affect unit commitment grew out of a longer term discussion about the need for more quick-start capacity in New England. New England has a small amount of quick-start capacity relative to the regional peak load compared to most other control areas. Many analysts have noted that this requires large power plants to operate more than they would otherwise have to in order to maintain sufficient operating reserves – capacity that can be provided quickly in response to unplanned losses of capacity. A key goal of this work for EPA was to verify that large units were indeed being operated more than necessary in New England to meet reserve requirements, to gauge the probable emissions impacts of this dynamic, and to estimate the potential emission reductions that additional DR could provide if it were used to meet operating reserve requirements. (This dynamic is discussed in more detail in Section 2.5).

Finally, in addition to the work discussed above, EPA also requested that Synapse develop a methodology for estimating the emissions impacts of actual DR events retrospectively. This methodology is intended to complement the more predictive analysis discussed above by providing a way to estimate the impacts of actual DR activity after the fact. Together, the modeling work presented here and this methodology provide

[3] This work was performed under Contract 68-W-02-055, Task Order 007.

a roadmap, identifying the dynamics that can be expected from increased DR activity in New England, and a way to assess actual experience to determine if the intended results of new DR programs are indeed being realized.

Section 2 of this report lays out the assumptions underlying the DR modeling work, and Section 3 presents the results of this work. Section 4 presents the methodology developed for assessing the emissions impacts of DR events retrospectively.

2. Inputs and Assumptions

The dispatch modeling portion of this analysis was performed with the PROSYM/MULTISYM production costing model.[4] Synapse licenses PROSYM from Henwood Energy Services, Inc., the company that developed the system and continuously updates it. The PROSYM system is used throughout the U.S. by well over 100 energy organizations, including generation companies, transmission companies and a wide variety of consultants. PROSYM is described in more detail in the Appendix.

The input assumptions for this modeling work were developed with input from EPA and consultants to the NEDRI group with specific attention to the project goals. We modeled a hypothetical near-term year in New England, using projected 2006 fuel prices and loads. Region-specific prices for natural gas and oil (i.e., different prices for each control area) were developed from NYMEX futures prices as of January 2003. Plant-specific coal prices were developed from data reported by generating companies. For all fuels, PROSYM uses different prices for each month of the year. While fuel prices always represent an uncertainty in dispatch modeling, they do not represent an important uncertainty in this analysis, because the same fuel prices were used in both the reference case and the DR cases.

It was agreed that a near-term year was preferable as the modeling year, as this would minimize the effects of assumptions about future plant additions and retirements. In any simulation of future system operation one must make an assumption about what kind of plants will be added to and retired from the system, and this assumption usually has a significant impact on the results of long-term studies. By choosing a near-term year as the study year, we were able to reduce the effect that this assumption had on the results.

It was also agreed that we should model a relatively capacity-constrained year (i.e., a year in which there was likely to be robust DR operation) but not an extreme kind of capacity deficiency. We created a 20-percent system reserve margin by making minor adjustments to NEPOOL's projected plant in service in 2006. The plant in service for the study year is based on NEPOOL's 2002 *Report on Capacity Energy Loads and Transmission* (CELT). We adjusted this plant in service by "taking out" several proposed power plants, which the 2002 CELT assumed would be constructed by 2006.

[4] We use the term PROSYM to refer to the PROSYM/MULTISYM system, because PROSYM is the more commonly known name of the system.

2.1 The DR Program Modeled

We modeled a Day Ahead Demand Response Program (DADRP). This is an *economic* DR program, one in which DR resources bid into the day-ahead energy market along with other supply-side resources and are dispatched based on their bids, just like supply-side resources. Importantly, the economic DR programs under development today are different from the more common reliability-based DR programs. Under a reliability-based DR program, DR resources are dispatched based on a measure of system reliability or available reserves (such as OP 4, Step 12 status in New England). That is, DR resources are only dispatched when they are needed for system reliability. In contrast, DR resources are dispatched based entirely on their bids in an economic DR program, regardless of the load level or the status of reserves. We chose to investigate the environmental impacts of economic DR rather than emergency DR, because the impacts of economic DR are much more controversial and potentially much larger than those of emergency DR. There is more concern over the impacts of economic DR programs because these programs could potentially dispatch DR resources in far more hours of the year than emergency programs (which would dispatch DR only during emergencies).

The DADRP program we modeled included 500 MW of DR capability. It was agreed that 500 MW is a reasonably good representation of a mature DR program in New England, based on currently available data. We modeled 60 percent of the DR capability as load response and 40 percent as generation. This ratio is based on data provided by ISO New England regarding recent (February 2003) enrollment in the New England economic DR program, (known then as the “Class 2” program). These data show a DR capability of roughly 75 MW, including 44 MW of load response (58 percent), 31 MW of generation (41 percent), and one MW of a combination of the two (one percent).

The vast majority of the generators operated by electricity consumers in New England are either diesel- or natural gas-fueled internal combustion (IC) engines. While customers may begin to use combustion turbines for peak shaving and other purposes over the long-term, we assume that IC engines will be the dominant generators used for DR for the foreseeable future. We explored DR scenarios involving several different mixes of diesel- and gas-fired engines. Exploring different assumptions about the kind of engines providing DR generation was an important goal of both EPA and some NEDRI participants. Because economic DR programs will dispatch DR resources during non-emergency periods, generators whose air permits define them exclusively as emergency generators would presumably be precluded from participating in economic DR programs. However, there is currently very little information available on the status of onsite generators in New England, and many smaller ones have not been required to obtain an operating permit to date. Some customers with generators may not know if they could legally operate their unit for peak shaving rather than emergency purposes, because they have never had the opportunity to do so. Thus, it is important to explore scenarios in which confusion and other non-compliance problems lead to significant participation in economic DR programs by high-emitting emergency generators.

2.2 Geographic Distribution of DR Capacity

We allocated the DR resource to locational marginal pricing (LMP) zones based primarily on industrial electricity sales, reflecting the assumption that DR capacity will be provided primarily by industrial customers. Having allocated the DR resource based on industrial sales, however, we shifted DR capacity from capacity-surplus zones to southwestern Connecticut, to reflect the tight capacity situation there. This reallocation is consistent with the assumption that more DR capacity will enroll in LMP zones with small reserve margins (i.e., zones likely to need DR) than in zones with large reserve margins. Table 1 shows the regional allocation of DR resources modeled.

Table 1. Allocation of DR Resources for Modeling (MW)

LMP Zone	Allocation Based on Industrial Sales	Allocation Used: Targeted to SW Connecticut
CT	126	66
CTSW		100
ME	103	93
WEMA	100	90
NEMA	60	60
SEMA	16	16
NH	42	32
RI	31	21
VT	22	22
Total	*500*	*500*

Source: Sales data are from EIA, Electric Power Annual, 2002.

We modeled the DR resources at five bid points: \$100, \$200, \$300, \$400 and \$500 per MWh. This assumption is based on research performed in New York State on the cost of providing DR. Within a zone, equal amounts of DR bid at each bid point, and generators bid a four-hour minimum up time. Because little information is available on the amount of DR load reductions that are shifted to other periods, we performed sensitivity analyses to determine the impact that load shifting has on total net emissions from DR.

2.3 Emission Rates

For large power plants, emissions of NO_x, SO_2 and CO_2 were determined within the model, based on unit-specific emission rates. Emissions of $PM_{2.5}$, PM and seven air toxics were calculated by applying emission factors to the output of plant types. Emission factors are from EPA's *Compilation of Air Pollutant Emission Factors, AP-42.* Emission factors for eight different plant types were used: gas-fired combined cycle, oil-fired combined cycle, gas-fired combustion turbine, oil-fired combustion turbine, and coal-, gas-, oil- and wood-fired steam plants. As noted, we modeled two types of generators operating in DR programs: diesel-fueled and natural gas-fueled IC engines. We applied the emission factors shown in Table 2 to these two unit types.[5]

[5] The NO_x, SO_2 and CO_2 emission rates in Table 2 are based on research performed by Synapse staff and on work performed in the development of the *Model Regulations for the Output of Specified Emissions from Smaller Scale Electric Generation Sources*, published by the Regulatory Assistance Project. Note

Table 2. Emission Rates Applied to DR Generators (lb/MWh)

Pollutant	Diesel IC	Gas IC
NOx	30	5.0
SO_2	3.0	0
CO_2	1,600	1,100
PM	0.7	0.10
$PM_{2.5}$	0.5	0.10
Mercury	0	0
Formaldehyde	7.9E-04	0.5
Acetaldehyde	2.5E-04	7.9E-02
Acrolein	7.9E-05	4.9E-02
Benzene	7.8E-03	4.2E-03
1,3-Butadiene	0	2.5E-03
PAH	2.1E-03	2.6E-04

Source: see footnote 3.

2.4 Energy Efficiency Programs

In addition to DR, we explored two different energy efficiency programs: an energy-targeted program and a peak-targeted program. The energy-targeted program reduced peak demand by one percent and annual energy use by 0.75 percent. The peak-targeted program reduced peak demand by 1.2 percent and annual energy use by 0.50 percent. These numbers were developed based on a review of current efficiency program impacts in New England. We also explored a scenario in which a DR program is implemented with the energy-targeted efficiency program.

2.5 Operating Reserves Under Standard Market Design

An important goal of this work was to investigate the effect that additional DR would have on unit commitment in New England, and specifically on the way in which operating reserve requirements would be met. As noted, New England has a small amount of quick-start capacity relative to the regional peak load. Because quick-start units can be brought on line quickly, they can provide reserve capacity in a non-operating mode. In contrast, large generating units must be operating to provide reserve capacity. ISO New England has noted that the lack of quick-start capacity in New England requires system operators to run large power plants more than they would otherwise have to in order to maintain sufficient operating reserves. A key goal of this work for EPA was to gauge the probable emissions impacts of this dynamic and to estimate the potential emission reductions that additional DR could provide if it were used to meet operating reserve requirements. As background for the results presented in Section 3, we provide here a brief discussion of how operating reserves requirements are currently met in New England.

that these emission factors reflect the emissions of *existing* onsite generators in New England. Most new diesel- and gas-fired gensets emit less pollution than this. The factors for PM and air toxics are from: *U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42.*

On any given day, ISO New England must meet minute-to-minute demand for energy and maintain sufficient reserves to deal with contingencies – unplanned outages of plants or transmission lines. Capacity maintained to deal with contingencies is called "operating reserves," and there are several different kinds. "Spinning reserves" are provided by generating units that are operating (synchronized to the grid) and can increase their output immediately upon being notified of a contingency. "Supplemental reserves" must be able to come online within 10 minutes of notification, and "replacement reserves" must be able to come online within 30 minutes. Importantly, supplemental and replacement reserves need not be provided by operating units; many combustion turbines and other units able to start quickly can provide these reserves. Further, these reserves could be provided by DR resources able to respond quickly and reliably.[6]

When considering the impact of DR on the way that reserve requirements are met in New England, it is important to note two changes that have taken place over the past year at ISO New England. First, ISO New England and the New York ISO have entered into a reserve sharing agreement, and second, ISO New England has implemented the Standard Market Design (SMD).

The reserve sharing agreement with the New York ISO has reduced the amount of operating reserves that ISO New England must maintain in many hours of the year. The amount of reserve capacity available to New England via the agreement fluctuates based on load and transmission conditions in the respective control areas, but in many hours of the year it is in the range of 200 to 300 MW.

The implementation of SMD is important vis-à-vis reserves, because prior to SMD there were separate markets for energy and operating reserves in New England. Generating units could bid into either market, and if they were selected in one of the markets, they were paid the market-clearing price in that market. However, under the ISO's current implementation of SMD, there are no longer separate markets for energy and reserves.[7] The ISO clears the energy market and ensures adequate operating reserves in a two-step process.

The first step of the process takes place in the Day-Ahead Market when the ISO takes the offers of all generating units (submitted on a day-ahead basis) and clears the energy market from primarily an economic perspective. In this stage, the ISO's dispatch software designates units based on the participants' demand bids and each unit's energy offer. The software does consider the reserve requirement, but it does not *ensure* that the reserve requirement is met. If the total load bid into the financial Day-Ahead Market is substantially less than the ISO forecast of load, then the physical supply of reserve in real

[6] In New England, the amount of necessary operating reserves is calculated based on a scenario, in which the largest asset in the system and half of the second largest asset are assumed to fail simultaneously. During most hours of the year, the operating reserve requirement is in the range of 1,500 to 2,200 MW.

[7] A number of parties, including FERC, have recommended that reserve markets that are co-optimized with the energy market be established. ISO New England is in the process of developing and implementing such markets.

time would fall short of requirements. This situation is prevented in the next step of the process, the reserve adequacy analysis (RAA).

In the RAA, the ISO determines whether the units committed in clearing the day-ahead energy market provide sufficient reserve capacity to meet the following day's reserve requirements. If there is insufficient reserve capacity, additional units are selected in the RAA to meet the reserve requirements. Importantly, additional units are selected based on their startup and no-load costs, and the costs to operate those units at their respective economic minimum output. Therefore, a unit with a very high energy bid, but low startup and no-load costs, might well be selected to meet the reserve requirement. (In the real-time operation of the system, each unit's energy bid determines where it is dispatched. Thus, in the event of a contingency, reserve capacity is dispatched based on its energy bid.) By relying more on quick-start resources to meet reserve requirements, costs are reduced and emissions are avoided, because these units can provide reserve capacity in a non-operating mode.[8]

When additional capacity must be added in the RAA, DR capacity would be likely to be selected, because it would likely have very low startup and noload costs. Thus, under the ISO's current implementation of SMD, if new DR resources were allowed to meet reserves, they would probably be used to do so often. However, once the region has sufficient quick-start capacity to meet reserve requirements efficiently, adding additional DR capacity would not provide additional emissions benefits in this way.

3. Results

The modeling work performed here indicates that additional DR capacity can have significant emissions impacts in New England and that the most important variable affecting those impacts is whether or not the DR is used to meet reserve requirements or not. Other important variables include the fuel mix (diesel versus natural gas) of the engines providing the generation component of the DR and the extent to which loads reduced during DR events are shifted to other periods. The subsections below present the emissions impacts of the economic DR program modeled here under a number of different assumptions about program implementation and market responses.

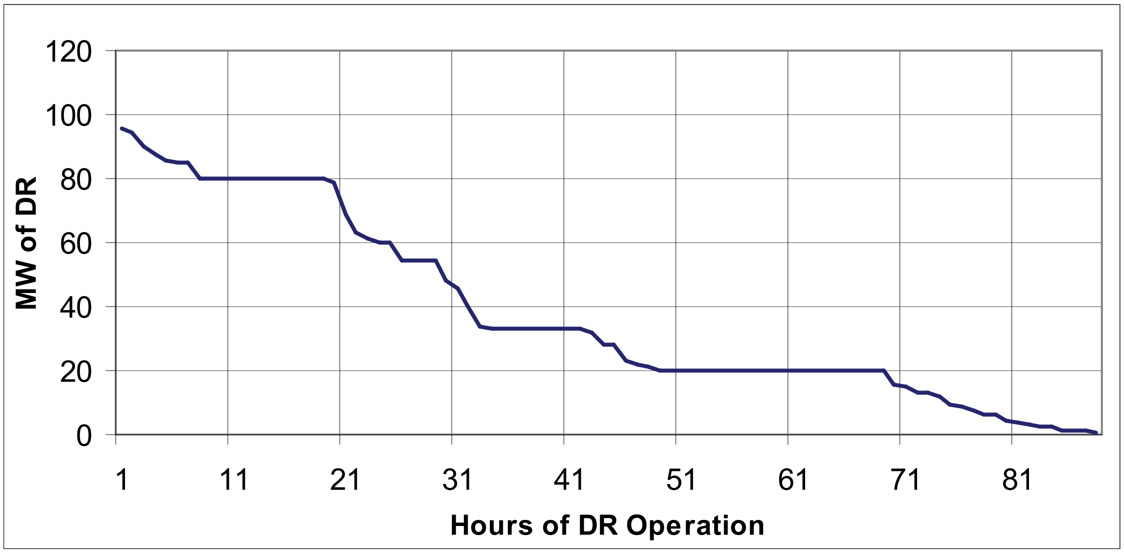
3.1 DR and Power Plant Operation

During the summer modeled, DR resources provided 3,361 MWhs of load relief. Upon iterative analysis, we found total load relief (MWhs) to be stable within about ±10

[8] Quick-start units that are designated to meet the reserve requirement but are not dispatched when providing reserves do not receive an energy payment. They do receive a monthly ICAP payment. In contrast, any units that are providing on-line reserves (i.e., operating) are eligible for "make-whole" payments if their actual costs exceed their startup and no-load costs.

percent.[9] Below is a duration curve illustrating DR resource operation. In the hour with the most DR operating, slightly over 95 MW of DR capacity was "online," or about one fifth of the 500-MW regional DR resource. The peak DR output is a relatively small fraction of the total DR resource because under New England's LMP system, prices tend to spike only in certain zones, not across the entire region. When zonal prices rise, only DR that can be delivered to the high-priced zone(s) is dispatched.

Figure 1. Summary of DR Operation



DR resources were dispatched in six of the nine zones in which we analyzed DR operation. These zones are consistent with the eight LMP zones in New England, except that we divide the Connecticut LMP zone into "CT" and "CTSW" for better analysis of the capacity-constrained southwest Connecticut area. As shown in Table 3, the vast majority of DR operation occurred in southwest Connecticut. The majority of the DR operation occurred in July and August, with smaller amounts in May, June and September.

Table 3. Geographic Distribution of DR Operation

Zone	MWh	Percent Of Total
CT	106	3.2%
CTSW	3,125	93.0%
NEMA	60	1.8%
SEMA	3	0.1%
VT	13	0.4%
WCMA	54	1.6%
Total	*3,361*	

[9] The variable we altered in these iterations is the pattern of forced outages at power plants across the Northeast. Obviously, DR operation is very sensitive to forced outages at other plants, because it is primarily such outages that create capacity deficiencies. To assess the range of uncertainty, we ran the same DR scenario with different patterns of forced outages, which were developed by the model using average availability rates for plant types.

A key finding of this work is that, in the near term in New England, emission reductions in criteria pollutants could result from new DR resources that are used to meet reserve requirements. This finding is discussed further in Sections 3.2 and 3.3. Here, we discuss the changes in plant operation that lead to this result. The potential emission reductions when DR is used for reserves are the result of more efficient unit commitment in New England, which is characterized by three main dynamics:

- Oil- and gas-fired steam units in New England operate less,
- Combined-cycle units in New England operate more, and
- New England imports slightly more energy.

As shown in Table 4, the decrease in oil and gas-fired steam generation is roughly 100 GWh; the increase in CCCT generation is roughly 34 GWh; and the increase in net imports is approximately 62 GWh. The vast majority of the increased generation outside New England occurs in the Pennsylvania/New Jersey/Maryland Interconnection (PJM), New York and Ontario. Emission reductions in all criteria pollutants are the net result of these changes.

Table 4. Changes in Summer Plant Utilization in New England When DR is Used for Reserves

Plant Type	Fuel Type	Base Case (GWh)	DADRP (GWh)	Change (GWh)	Change by Plant Type (GWh)
Combined Cycle	Gas	19,197	19,226	29.4	34.3
	Gas/Oil	298	303	4.8	
Combustion Turbine	Gas	75	74	-0.8	-0.9
	Gas/Oil	0	1	0.2	
	Oil	5	5	-0.3	
Various	Landfill Gas	81	81	0.0	0.0
Cogeneration	Gas	1,492	1,492	0.4	0.4
Hydro	Water	1,870	1,870	0.0	0.0
DR	Various	0	3	3.4	3.4
Nuclear	Uranium	13,842	13,842	0.0	0.0
Steam	Gas	241	231	-10.5	-99.9
	Gas/Oil	343	284	-59.5	
	Oil	4,294	4,264	-30.0	
Steam	Coal	7,706	7,707	1.3	1.3
	Other	255	255	0.0	
	Renewable	3,232	3,232	0.0	
Storage	Various	1,348	1,348	0.0	0.0
WT	Renew	15	15	0.0	0.0
Total		54,295	54,233	-61.6	-61.6

We refer to the emission reductions achieved in this scenario as "potential reductions," because many of the oil- and gas-fired steam units that operate less with DR currently receive NO_x allowances, and some of them receive SO_2 allowances as well. The extra allowances created by this reduced generation could be traded to other sources, resulting in no reduction in overall system emissions. In fact, if allowance markets are working efficiently, one would expect allowances to be reallocated, reducing the total cost of meeting the emissions cap. In order for these emission reductions to be captured and preserved, regulators would have to establish mechanisms to prevent the sale of excess allowances from units that operate less as a result of the additional DR.

3.2 Air Emissions When DR is Used for Reserves

Table 5 below shows the potential summer emissions impacts of the DR resources when they are used to meet reserve requirements. These figures include the emissions associated with: (a) DR operation, (b) the use of DR to meet reserve requirements and (c) load shifting. Here we assume that 60 percent of loads curtailed are shifted to the soonest off-peak period. In Section 3.5 we investigate alternative load-shifting scenarios. We also account for emission increases in neighboring control areas, associated with the increased imports into New England.

Table 5 shows the results of three different assumptions about the fuel mix of the engines providing the generation portion of the load relief. These assumptions range from all gas-fueled engines to all diesel-fueled engines. Note that changing this assumption has a significant impact on some pollutants, and a small impact on others. Of the criteria pollutants, this variable affects NO_x emissions most. Moving from a DR program with no diesel generation to one with half diesel generation reduces NO_x benefits by 9 tons, or 22 percent, while it reduces SO_2 benefits by only 0.5 percent and CO_2 benefits by only 0.6 percent.

Table 5. Summer Air Impacts When DR Is Used for Reserves

	NO_x (tons)	SO_2 (tons)	CO_2 (tons)	$PM_{2.5}$ (tons)	PM (tons)	Mercury (lbs)
All Gas	-41	-218	-31,800	-12.8	-21.6	-0.30
50% Diesel	-32	-217	-31,600	-12.6	-21.4	-0.29
All Diesel	-23	-216	-31,400	-12.5	-21.2	-0.29
	1,3 Butadiene (lbs)	Acetaldehyde (lbs)	Acrolein (lbs)	Benzene (lbs)	Formaldehyde (lbs)	PAHs (lbs)
All Gas	4.3	124	73	10	683	2.2
50% Diesel	2.5	67	38	13	320	3.6
All Diesel	0.6	9	2	15	-44	4.9

Range of Uncertainty: *±10%*

The fuel mix assumption affects the changes in toxic emissions much more (in percentage terms) than the criteria pollutants, because these toxics tend to be associated with either diesel or gas-fired IC generation. Natural gas combustion in an IC engine produces more acetaldehyde, acrolein, and formaldehyde emissions than diesel combustion, because these chemicals are a product of incomplete methane oxidation. Diesel engines emit more of the heavier toxics that come from incomplete oil oxidation (PAHs) than gas engines. Diesels also emit slightly more fine particulates, but more importantly, they emit more carcinogenic fine particulates than gas-fired engines. Of the air toxics assessed here, PAHs and fine particulates from diesel engines probably pose the greatest health threats. To understand the risks posed by the increases in toxic emissions shown in Table 5, one would need to study the locations of the IC generators relative to populated areas.

Transmission line losses factor into the numbers in Table 5 in two ways. First, when DR operates it reduces system line losses relative to reference case system operation. This is because when energy is provided to customers from the grid it often comes from power plants a considerable distance from the point of end use, and energy is lost in transmission. Usually line losses are in the range of 5 to 10 percent, but they can be higher during periods when transmission lines are heavily loaded. In contrast, the DR resource – be it a load reduction or a generator – is located at the site of energy use, so no energy is lost in transmission. Emission reductions associated with line losses are not included in the figures in Table 5, because these reductions are likely to be very small – well within the range of error of these figures.[10]

The second issue regarding line losses is a DR policy implementation issue. Because DR avoids line losses, a DR resource of five MW is comparable to a grid-connected asset slightly larger than five MW. This is because when a DR resource provides five MWhs at a customer site, it avoids the generation of more than five MWhs at a grid-connected plant. It may be appropriate for system operators to factor these avoided line losses in when determining the amount of reserve capacity with which DR resources should be credited. For example, a five-MW DR resource might be credited as providing 5.5 MW of reserve capacity if average system line losses during DR events were determined to be roughly 10 percent. However, this is just one factor system operators will need to consider in determining whether and how a given DR resource should be allowed to provide reserve capacity.

To put in perspective the numbers shown above, Table 6 shows the percentage changes in summer New England emissions that each number in Table 5 represents.

Table 6. Percentage Summer Air Impacts When DR Is Used for Reserves

	NO_x	SO_2	CO_2	$PM_{2.5}$	PM	Mercury
All Gas	-0.18%	-0.30%	-0.13%	-0.37%	-0.32%	-0.07%
50% Diesel	-0.14%	-0.30%	-0.12%	-0.37%	-0.32%	-0.07%
All Diesel	-0.10%	-0.30%	-0.12%	-0.36%	-0.31%	-0.07%
	1,3 Butadiene	Acetaldehyde	Acrolein	Benzene	Formaldehyde	PAHs
All Gas	4.33%	0.29%	0.04%	0.01%	0.23%	0.54%
50% Diesel	2.49%	0.16%	0.02%	0.01%	0.11%	0.86%
All Diesel	0.64%	0.02%	0.00%	0.01%	-0.01%	1.19%

It is important to note several things about these findings. First, they are specific to New England, resulting from the particular capacity mix here and the large size of the contingencies (relative to total capacity) for which ISO New England must maintain operating reserves.[11] Second, the figures in Table 5 represent the maximum potential

[10] We estimate the emission benefits of reduced line losses by applying the loss factor – say 10 percent – to the total MWhs provided by DR, 3,361. This yields roughly 336 MWhs of line losses avoided by the DR operation. Even assuming that the plants displaced have very high emission rates, the emissions savings are small percentages of the numbers in Table 5. For example, assuming a displaced NO_x rate of 4 lb per MWh yields a NO_x savings of a little over half a ton.

[11] In many summer hours, the operating reserve requirement in New England is over 2,000 MW, roughly eight percent of the peak load. This is a larger reserve requirement, in percentage terms, than most control areas must maintain.

benefits that DR would provide under the modeled scenario. Currently, ISO New England selects units for reserves based on the "no-load and startup" costs included with their bids. We believe that most DR resources will bid zero no-load and startup costs, and we have modeled all DR as bidding in that way. If some DR resources included these costs in their bids, they would be less likely to be used for reserves.

In addition to exploring different assumptions about the fuel mix of DR generators, we explored varying levels of load shifting. Table 7 shows the results of this sensitivity analysis. Here, we assume that 25 percent of the DR generation is diesel fueled and 75 percent gas fueled, and we explore three different levels of load shifting. In one scenario none of the curtailed energy use is shifted to off-peak periods; in the second, half is shifted and in the third all of it is shifted. To derive emission rates for shifted loads, we recorded the range of nighttime load levels (hourly loads from 8:00 pm to 12:00 am) on each day in which DR resources were dispatched and then examined this load range in the ISO NE supply curve. The emission rates applied to shifted loads are a weighted average of the generating units in this load range.

Table 7. Load Shifting Analysis at 25 Percent Diesel Generation

	NO_x (tons)	SO_2 (tons)	CO_2 (tons)	$PM_{2.5}$ (tons)	PM (tons)	Mercury (lbs)
None Shifted	-37	-221	-32,600	-12.9	-21.8	-0.30
50% Shifted	-36	-218	-31,800	-12.7	-21.5	-0.30
All Shifted	-36	-215	-31,100	-12.6	-21.2	-0.29
	1,3 Butadiene (lbs)	Acetaldehyde (lbs)	Acrolein (lbs)	Benzene (lbs)	Formaldehyde (lbs)	PAHs (lbs)
None Shifted	3.4	95.4	55.4	11.5	497	2.9
50% Shifted	3.4	95.5	55.4	11.5	501	2.9
All Shifted	3.4	95.6	55.4	11.6	504	2.9

The load-shifting variable affects emissions of criteria pollutants a small amount, because the primary emission reductions from the DR program come from changes in unit commitment, as DR capacity is used to meet reserve requirements in virtually all summer hours. Adding in emissions associated with a portion of the actual loads curtailed makes a very small difference. The load-shifting variable has virtually no effect on emissions of the IC toxics, because there are no IC units among the generators that meet the shifted loads.

3.3 Emissions When DR is Not Used for Reserves

When we modeled a DADRP in which the DR resources are not used to meet reserve requirements, the resulting emissions impacts were so small compared to total system emissions that they fell within the model's range of uncertainty (±0.05 percent change in total summer emissions). This is not surprising, given that the DR resources replaced only 3,361 MWhs of the roughly 125,014,000 MWhs the system produced. To estimate the net impacts of DR operation only, we performed a net emissions analysis on the DR operation predicted in the model. This analysis consists of the following four steps:

1. Calculate gross emissions from DR generation,

2. Estimate emissions displaced by all DR activity, including both generation and load response,
3. Subtract displaced emissions from gross DR emissions to get the net emissions impact of DR generation and load response,
4. Estimate and add in emissions resulting from shifting 60 percent of the loads curtailed to off-peak hours.

Gross emissions from DR generation were calculated by multiplying projected generation by AP-42 emission factors. As above, we explored a range of assumptions about the fuel mix of DR generation. We estimate displaced emissions by analyzing (a) the ISO NE supply curve in the area where the DR resources bid, (b) model outputs in hours when DR operated and (c) actual bid data published by ISO NE. This analysis reveals that oil- and gas-fired combustion turbines (CTs) dominate this area of the supply curve, with blocks of oil- and gas-fired steam capacity interspersed.[12] Based on this analysis we estimate that roughly 70 percent of the energy displaced by DR resources would have come from gas-fired CTs, 10 percent from oil-fired CTs, 12 percent from gas-fired steam units, and three percent from oil-fired steam units. We calculate displaced emissions by multiplying the appropriate percentage of DR MWhs by the emission factors for each of these unit types.

To estimate emissions from load shifting, we assume that 60 percent of the energy use curtailed during DR events is shifted to the nighttime hours immediately following the event. (We derive emission rates for shifted loads as described on page 15.)

Table 8 shows the estimated net emissions from the dispatch of DR resources during the modeled summer, based on the methodology described above. Note that net emissions of NO_x depend on the fuel mix of the DR generation, with the "all gas" scenario resulting in a net reduction and significant diesel-fired generation resulting in a net increase. Net CO_2 emissions fall across all fuel mix assumptions, primarily because the IC engines providing the DR energy are more efficient (and thus have lower CO_2 emission rates) than the peaking turbines and steam units they displace. Emissions of SO_2 increase with the DR program. Emissions of both fine and coarse particulates increase small amounts with increased diesel generation, as do emissions of benzene and PAHs. Emissions of the air toxics associated with natural gas-fired ICs decrease with more diesel generation.

[12] ISO bid data reveal that few large generating units bid all of their capacity at one price, and many large steam units bid their last blocks of capacity at very high prices.

Table 8. Estimated Net Summer Air Impacts from All DR [13]

	NO_x (tons)	SO_2 (tons)	CO_2 (tons)	$PM_{2.5}$ (tons)	PM (tons)	Mercury (lbs)
All Gas	-3.7	2.3	-703	0.1	0.3	0.00
50% Diesel	5.7	3.4	-521	0.2	0.5	0.01
All Diesel	14.7	4.5	-338	0.4	0.7	0.02
	1,3 Butadiene (lbs)	Acetaldehyde (lbs)	Acrolein (lbs)	Benzene (lbs)	Formaldehyde (lbs)	PAHs (lbs)
All Gas	3.6	114	71	5.6	708	0.2
50% Diesel	1.7	57	35	8.2	345	1.5
All Diesel	-0.1	0	0	10.5	-19	2.9

Range of uncertainty: ±10 percent.

Importantly, the emissions changes shown in Table 8 (increases or decreases, depending on the fuel mix assumption) would likely occur outside of the NO_x and SO_2 caps, because the IC engines likely to participate in DR programs are not subject to these cap-and-trade programs. Thus, any NO_x and SO_2 increases projected would come in addition to the capped level of emissions.

The changes in criteria pollutant emissions shown in Table 8 represent very small percentage changes in total system emissions. (Refer to the percentage changes shown in Table 6, and consider that the tonnage figures here are an order of magnitude or more below those in that scenario.) The environmental effects of the net SO_2 and CO_2 emissions from DR are likely to be quite small. The effects of the NO_x emissions, however, could be significant, given that these emissions are likely to come on summer afternoons with high ozone levels. A health risk analysis would need to be performed to gauge the risks of the net toxic emissions shown in Table 8. An effective study of this type would consider not only changes in the mass of pollutants emitted but also changes in the type and location of emissions. (For example, fine particulates from diesel engines are more carcinogenic than fine particulates from most other power plants.)

Table 9 explores the effect of load shifting on the net impacts of DR operation (shown in Table 8). For criteria pollutants, different assumptions about load shifting have large percentage impacts but small impacts in terms of mass. The load-shifting variable has virtually no effect on emissions of the IC toxics, because there are no IC units among the generators that meet the shifted loads.

[13] These figures are based on the assumption that 60 percent of the load curtailed in the DR program (excluding DR generation) is shifted to off-peak hours.

Table 9. Load Shifting Analysis at 25 Percent Diesel Generation [14]

	NO_x (tons)	SO_2 (tons)	CO_2 (tons)	$PM_{2.5}$ (tons)	PM (tons)	Mercury (lbs)
None Shifted	-0.1	-0.5	-1,490	-0.1	0.0	0.00
Half Shifted	0.8	2.3	-758	0.1	0.3	0.00
All Shifted	1.7	5.0	-27	0.3	0.6	0.01
	1,3 Butadiene (lbs)	Acetaldehyde (lbs)	Acrolein (lbs)	Benzene (lbs)	Formaldehyde (lbs)	PAHs (lbs)
None Shifted	2.7	86	53	6.8	522	0.78
Half Shifted	2.7	86	53	6.9	525	0.79
All Shifted	2.7	86	53	6.9	529	0.79

Range of uncertainty: ±10 percent.

3.4 Largest Single-Day Impacts of DR

To gauge a worst-case scenario in terms of emissions from DR, we also assessed the single day from the modeled summer with the most DR activity within a zone – July 13 in southwest Connecticut. On this day, DR resources in that zone produced 922 MWhs of load relief: 390 MWhs of onsite generation and 523 MWhs of load reduction. Table 10 shows the gross emissions in southwest Connecticut from DR generation across the same range of assumptions about fuel mix. These emissions would be accompanied by (a) emission reductions at other power plants due to the curtailed loads and (b) emissions shifted from peak to off-peak hours due to the shifted loads.

Table 10. July 13 Emissions from DR Generators in CTSW

	NO_x (tons)	SO_2 (tons)	CO_2 (tons)	$PM_{2.5}$ (tons)	PM (tons)	Mercury (lbs)
All Gas	1.0	0.0	221	0.02	0.02	0.00
50% Diesel	3.5	0.3	271	0.06	0.08	0.00
All Diesel	6.0	0.6	321	0.10	0.14	0.00
	1,3 Butadiene (lbs)	Acetaldehyde (lbs)	Acrolein (lbs)	Benzene (lbs)	Formaldehyde (lbs)	PAHs (lbs)
All Gas	1.0	31	19.5	1.7	200	0.1
50% Diesel	0.5	16	9.8	2.4	100	0.5
All Diesel	0.0	0	0.0	3.1	0	0.9

Range of uncertainty: ±10%

Note that NO_x emissions on this simulated day range from one to nearly six tons, depending on diesel participation. Under current state regulations, owners of the IC generators participating in the DR program would not have to acquire NO_x or SO_2 allowances for these emissions. At 50-percent diesel generation, fine particulate emissions would be about 0.06 tons (120 pounds) and PAH emissions roughly 0.47 pounds. Again, an analysis of the likely emission locations would be necessary for a clear understanding of the health threat these numbers represent.

[14] These figures are based on the assumption that 25 percent of the DR generation is diesel fired and 75 percent is natural gas-fired.

3.5 The Impacts of DR versus Energy Efficiency

In addition to estimating the net air impacts of DR programs, EPA and NEDRI were interested in comparing these impacts to those of common energy efficiency programs. To make this comparison, we modeled the following two energy efficiency programs:

- An energy-targeted program providing a peak load reduction of one percent and an annual energy reduction of 0.75 percent
- A peak-targeted program providing a peak load reduction of 1.2 percent and an annual energy reduction of 0.50 percent

We examined the net air impacts of both of these program types in New England as well as a scenario in which the economic DR program was implemented along with the energy-targeted DR program.

Before examining the results it is important to note several key differences between DR programs and efficiency programs. First, efficiency investments are by nature long-term investments, because the equipment installed continues to save energy for many years. In contrast, an investment in DR might not reduce demand for multiple years. If the DR funds were spent on program design or the systems necessary to communicate with DR providers, they might provide multiple-year reductions. However, if the funds took the form of payments to DR providers, they would only provide one-time demand reductions. It is important to keep in mind this multiplier effect regarding the benefits of efficiency when comparing efficiency programs to DR programs.

Second, it is difficult to compare an efficiency program and a DR program on a consistent basis. Efficiency equipment operates far more hours per year than DR is likely to be dispatched, and this includes more peak-oriented efficiency equipment, such as air conditioners. In order to make a "fair" comparison between efficiency and DR programs, we considered two normalizing approaches: peak load reduction and program costs. Neither of these proved to be an acceptable normalizing characteristic. An efficiency program that reduced peak loads by 500 MW (the amount of DR capacity modeled) would provide vastly greater emission reductions than the DR program. Thus, this did not seem like a fair comparison. In terms of program costs, we did not have enough information about the costs of implementing a DR program to normalize the two program types in this way. Thus, we have compared the DR program to a typical efficiency program, modeled on the kind of programs currently operating in New England. The peak load and energy reductions provided by the modeled efficiency programs (stated in the bullets above) are based on the kind of reductions being achieved by the efficiency programs underway in Connecticut, Massachusetts and Vermont. Hence, while we model what we believe to be typical DR and efficiency programs, the comparison is something of an "apples to oranges" comparison, and it is important to keep the differences in the two program types in mind.

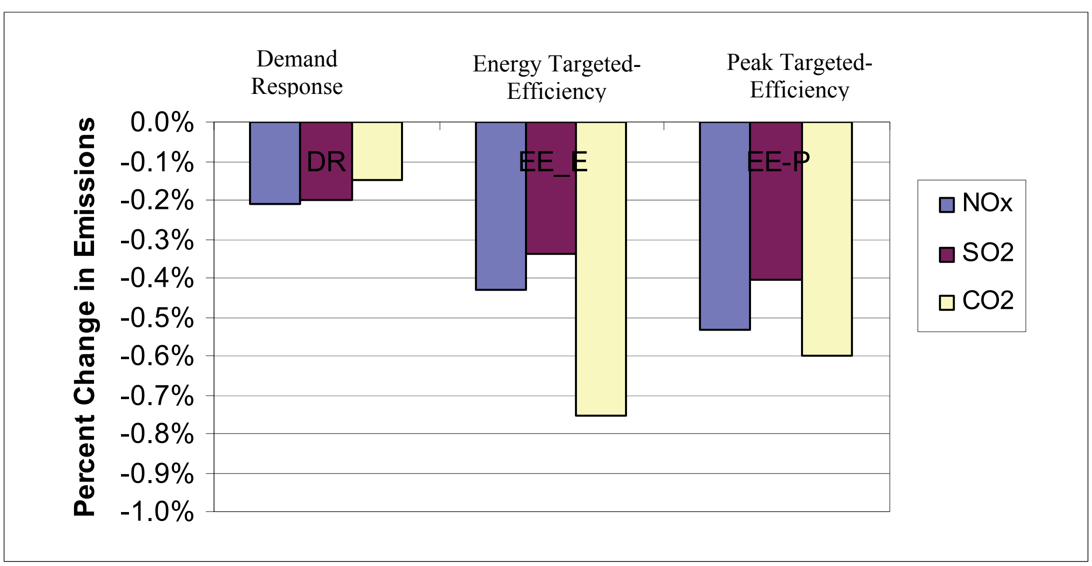
Finally, note that energy efficiency programs face the same challenge that DR programs face regarding capped pollutants. If a generator receiving emission allowances operates less due to an efficiency program, the extra allowances can be sold to other generators, with the net effect being a reduction in the cost of meeting the cap rather than emission reductions. Therefore, we characterize the emission reductions that could be achieved by both DR and efficiency programs as "potential" reductions.

Below, we compare the projected single-year impacts of the DADRP program to those of the efficiency programs. We compare the efficiency programs to the DR program in which the DR resources are used to meet reserve requirements. We present this DR program because the potential emissions impacts when DR is not used for reserves are so small that there would be essentially no comparison to the efficiency programs.

Figure 2 shows the annual emissions results of the two efficiency programs compared to the DR program. The data shown for the DR program are from the scenario in which 25 percent of the DR generation is diesel fueled and 60 percent of curtailed loads are shifted. Note that both efficiency programs offer greater potential emission reductions than the DR program. There are two reasons for this. First, the year-round demand reductions achieved by the efficiency programs produce significant energy savings – 0.75 percent annual savings for the energy-targeted program and 0.50 percent savings for the peak-targeted program. While the DR program results in more efficient unit commitment, it does not achieve energy savings. The reduced generation achieved by the efficiency programs has a more potent effect on emissions than the DR program's changes in unit commitment.

Second, recall that the DR program reduces generation and emissions in New England but increases generation and emissions outside of New England. In contrast, the efficiency programs reduce generation and emissions both within and outside of New England. Thus, while the in-region emission reductions achieved by the DR program are compromised somewhat by increases outside the region, the in-region reductions of the efficiency programs are enhanced by additional reductions outside the region.

Figure 2. Annual Air Impacts from Efficiency versus Demand Response

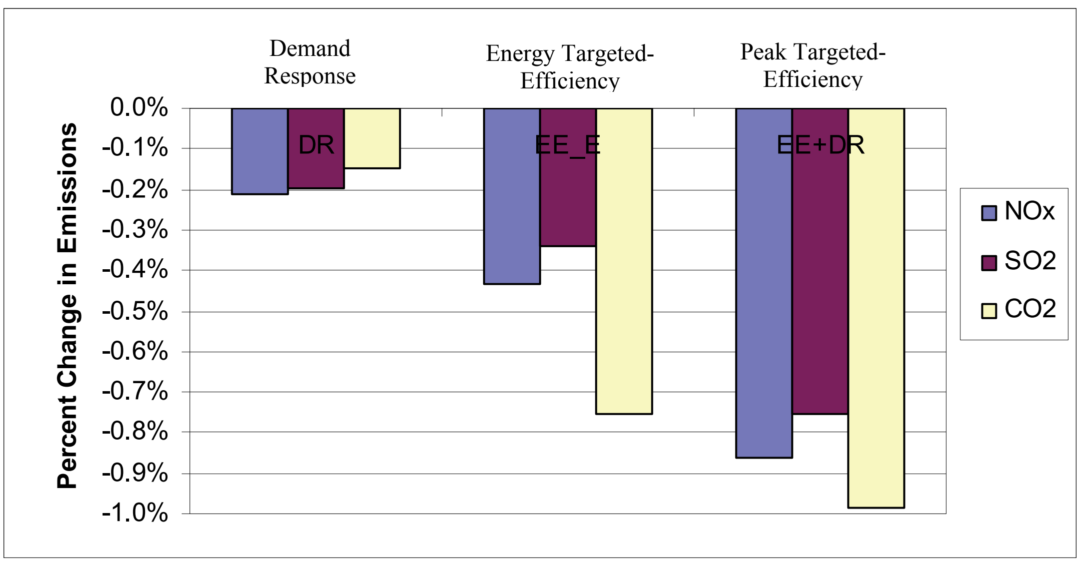


Also note in Figure 2 that the peak-targeted efficiency program offers larger potential reductions in NO_x and SO_2 than the energy-targeted program. This is because the peak-targeted program affects the high emitting peaking units more than the energy-targeted program. The energy-targeted efficiency program, however, could reduce CO_2 emissions more than the peak-targeted program, because it reduces total annual generation more (and because the differential in CO_2 emission rates between peaking and other units is not as large as the differential in NO_x and SO_2 rates).

Again, note that only the one-year impacts of these programs are shown here. One-year's investment in efficiency equipment would provide these kind of reductions for ten to fifteen years, while a one-year investment in DR might not.

Figure 3 compares the effects of the DR program and energy-targeted efficiency program implemented in isolation to a scenario in which the two programs are implemented together. Note that the programs appear to complement one another considerably. That is, the emission reductions from the two programs together are greater than the sum of the reductions from the single programs. Moreover, this result is driven by emission reductions achieved in New England, not by changes in emissions in other regions. (In other words, the emission reductions *in New England* under both programs are greater than the sum of the reductions from the isolated programs.) Exploring this finding in detail was beyond the scope of this project, and more research is needed to understand exactly how these programs would interact and how robust this finding is.

Figure 3. Annual Air Impacts of Energy-Targeted Efficiency Implemented with Demand Response Compared to Separate Program Impacts



4. A Methodology for Assessing DR Events Retrospectively

In developing a method for assessing the net emissions impacts of actual DR events, one distinction is critical: whether or not DR resources are used to meet reserve requirements. If DR resources are used to meet reserve requirements, two dynamics must be assessed: (1) the emissions impacts of using DR for reserves and (2) the net emissions impacts of DR operation. If DR resources are not used to meet reserves, only the latter dynamic needs to be assessed. We outline methods for both scenarios.

The method for assessing a summer in which DR resources are used to meet reserve requirements follows closely the method used in Task 1 of this project. First, emission reductions from the use of DR to meet reserves would be estimated by simulating plant commitment and dispatch in the region as closely as possible with an hourly dispatch model. Data on actual hourly loads, plant in service and plant outages could be obtained from ISO New England within six months to a year after the fact. It is possible that a confidentiality agreement would need to be signed with the ISO in order to obtain some of this information. The actual data on hourly loads plant in service and plant outages would be input into the model in order to simulate the historical year as accurately as possible. A Base Case year would be simulated, without the DR resources, and a "DR Case" would be run, which included all the DR resources that were enrolled in the program. If only a subset of the total DR resources were allowed to provide operating reserves, it would be important to make this distinction within the model.

Second, emissions from DR operation would be estimated. If information on energy produced by different types of DR generator is available from the ISO, it should be used to assess emissions. However, this information is unlikely to be available from the ISO or other sources during 2003 and perhaps 2004. In this case, emission factors would be applied to DR generation (MWhs) based on an assumption informed by any available data. These emission factors would be a significant source of uncertainty in the calculation, and we recommend that environmental regulators seek to obtain information on DR generation by plant type within a reasonable time frame.

Next the analysts would factor in emissions associated with shifted loads. Ideally, customers providing demand reductions would be interviewed to determine the amount of load shifting and the common times to which loads were shifted. Absent this kind of research, the analysts would have to make assumptions in these areas. In the work described above, we assume that 60 percent of the energy use curtailed during DR events is shifted to the nighttime hours immediately following the event. To derive emission rates for shifted loads, we recorded the range of nighttime load levels (hourly loads from 8:00 pm to 12:00 am) on each day in which DR resources were dispatched and then examined this load range in the ISO NE supply curve. The emission rates applied to shifted loads are a weighted average of the generating units in this load range.

If DR resources were not used to meet reserves during the summer in question, then only the net effect of DR operation would need to be assessed. The method we propose for this scenario, laid out on pages 15 and 16 above, involves four steps.

1. Calculate gross emissions from DR generation.
2. Estimate emissions displaced by all DR activity, including both generation and load response.
3. Subtract displaced emissions from gross DR emissions to get the net emissions impact of DR generation and load response.
4. Estimate and add in emissions resulting from shifting 60 percent of the loads curtailed to off-peak hours.

As discussed on pages 15 and 16, the analyst would develop an assumption about the resources displaced (step 2) based on a detailed analysis of the regional supply curve and actual bid data from the ISO. (The ISO currently releases bid data periodically.) This step is necessary because dispatch modeling would probably not provide reliable information on the net impacts of DR operation.[15] After estimating displaced emissions, the consultant would factor in emissions from DR generation and from shifted loads as described on pages 15 and 16. Importantly, the consultant should also perform the sensitivity analyses necessary to describe the range of uncertainty around the results.

[15] The emission impacts of DR operation are likely to be small relative to total system emissions in most years, as the DR resource is likely to operate during a small portion of total summer hours. In an extreme case, where DR resources operated a large portion of the summer, these impacts could be assessed with a dispatch model. As discussed above, with the DR resource providing roughly 3,400 MWhs, we found that the emission impacts fell within the model's range of uncertainty (±0.05% change in total summer emissions).

Appendix: The PROSYM/MULTISYM Model

Synapse licenses PROSYM from Henwood Energy Services, Inc., the company that developed the system and continuously updates input data for it.[16] The modeling system is used throughout the United Stats by well over 100 energy organizations, including generation companies, transmission companies, and a wide variety of consultants. Thus, work performed with PROSYM is readily transferable to other regions, and additional analyses can be performed in the future by a wide variety of industry analysts.

The basic geographic unit in PROSYM is a subregion of a control area, called a "transmission area." Transmission areas are defined in practice by actual transmission constraints within a control area. That is, power flows from one area to another in a control area are governed by the operational characteristics of the actual transmission lines involved. ISO New England, for example, consists of ten transmission areas. Hourly load data are entered into PROSYM by distribution utility area, meaning that policy implementation can be simulated at the utility level.

PROSYM can also simulate operation in any number of control areas. Synapse models groups of contiguous control areas in order to capture all regional impacts of the dynamics under scrutiny. When assessing New England, Synapse usually simulates operation in New England, New York, PJM, and the three control areas in Southeast Canada. Model outputs can be sorted in a variety of ways. Results can be assessed by control area to discern the larger geographic distribution of impacts or by state or transmission area for higher resolution analysis. Similarly, changes in unit operation by fuel type can be explored to assess impacts on different classes of generator.

PROSYM operates using hourly load data and simulates unit dispatch in chronological order. In other words, 8,760 distinct load levels are entered for each transmission area for each study year. The model begins on January 1st and dispatches generating units to meet load in each hour of the year. Using this chronological approach, PROSYM takes into account time-sensitive dynamics such as transmission constraints and the operating characteristics of specific generating units. For example, one power plant might not be available at a given time due to its minimum down time (i.e., the period it must remain off line once it is taken off). Another unit might not be available to a given transmission area because of transmission constraints created by current operating conditions. These are dynamics that system operators wrestle with daily, and they often cause generating units to be dispatched out of merit order. Few other electric system models simulate dispatch in this kind of detail. Many models use as load data step functions or load duration curves for representative time periods. Rather than simulating unit dispatch on each day of a future summer, for example, these models dispatch units to meet several types of summer days and then extrapolate predicted unit operation for those hours to the entire summer. This type of model does not allow the user to explore the operation of DR programs, which are implemented for several hours on a handful of days each year.

---

[16] This model is technically called MULTISYM when more than one control area is being modeled, as in this project. However, we use the term PROSYM throughout this description because it is the model's more commonly known name.

PROSYM also uses highly detailed information on generating units. For larger units, emission rates and operating characteristics are based on unit-specific data reported to EPA and EIA rather than on data based on unit type. Operating costs for each unit are based on plant-level operating costs reported to FERC and assessment of unit type and age. In some cases, plant owners have been contacted to verify input data. For smaller units (e.g., combustion turbines), most input data are based on unit type. All generating units in PROSYM operate at different heat rates (efficiencies) at different loading levels. In contrast, many models simply apply one heat rate to each unit at all load levels. This distinction is especially important in the case of combined-cycle units, which often operate in a simple-cycle mode at low loadings. PROSYM determines the fuel a unit burns by placing a generating unit into a "fuel group." PROSYM does not limit the number of fuel groups used, and creating new fuel groups to simulate a few unusual units is a simple matter. Over the course of past projects focused on the Northeast, Synapse has often adjusted unit fuel groupings to better simulate the operation of dual-fueled units.

PROSYM calculates emissions of NO_X, SO_2, and CO_2 based on unit-specific emission rates. Emissions of other pollutants (e.g., particulates and air toxics) are calculated from emissions factors applied to fuel groups. Synapse also commonly includes in base-case assumptions the effects of all existing air regulations. Allowance costs associated with the Ozone Transport Commission (OTC) NO_X Budget Program and the Acid Rain Program are included in unit operating costs, and results are checked to ensure that the NO_X cap is not exceeded.

PROSYM simulates the effects of forced (i.e., random) outages probabilistically, using one of several Monte Carlo simulation modes. These simulation modes initiate forced outage events (full or partial) based on unit-specific outage probabilities and a Monte Carlo-type number draw. Many other models simulate the effect of forced outages by derating the capacity of all generators within the system. That is, the capacities of all units are reduced at all times to simulate the outage of several units at any given time. While derating usually results in a reasonable estimate of the amount of annual generation from baseload plants, the result for intermediate and peaking units can be inaccurate, and very inaccurate over short periods. This issue is very important when modeling DR programs, which operate mostly, or even exclusively, during system peak hours.