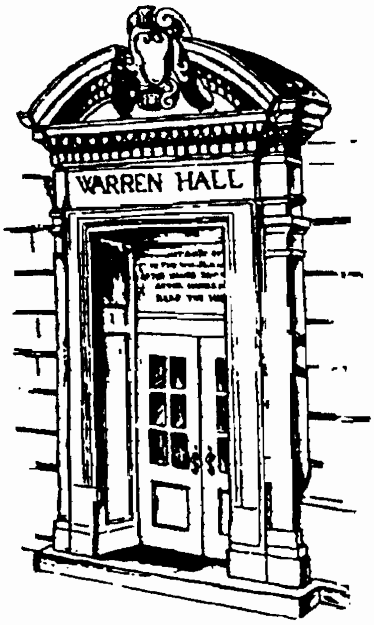
file copy

WP 94-2
February 1994



Working Paper

Department of Agricultural, Resource, and Managerial Economics
Cornell University, Ithaca, New York 14853-7801 USA

MEETING CLEAN AIR STANDARDS FOR ACID RAIN AND URBAN OZONE: IMPLICATIONS FOR ELECTRIC UTILITIES IN NEW YORK STATE

Martha Czerwinski
Brian Minsker
Timothy D. Mount

MEETING CLEAN AIR STANDARDS FOR ACID RAIN AND URBAN OZONE: IMPLICATIONS FOR ELECTRIC UTILITIES IN NEW YORK STATE

By

Martha Czerwinski
Systems Analyst

Brian Minsker
Research Support Specialist

Timothy Mount
Professor

Cornell University

Abstract:

The new regulations for controlling acid rain and the first phase for controlling urban ozone in New York State are shown to be effective, in terms of reducing emissions of sulfur dioxide and nitrogen oxides, and relatively inexpensive. In contrast, the total cost and the marginal cost per ton of reduced emissions of nitrogen oxides in the second phase for controlling urban ozone are relatively high. Consequently, questions are raised about the efficiency of these proposals for controlling emissions from electric utilities versus controlling emissions from other sectors, such as transportation, which may play an even greater role in the formation of urban ozone.

I. INTRODUCTION

The primary objective of this paper is to evaluate the economic implications of the 1990 Amendments to the Clean Air Act (CAA90) on the cost of producing electricity in New York State. The two main sections of the CAA90 that affect electric utilities relate to emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) and their contribution to acid rain and urban smog, particularly the formation of ozone. In the CAA90, emissions of NO_x are controlled through the conventional regulatory practice of setting maximum rates of emissions for individual power plants. (In practice, state regulatory agencies set these standards for NO_x in states like New York State that violate ambient air standards because the federal standards are set for ozone rather than the precursors of ozone such as NO_x.) However, the proposed procedure for controlling emissions of SO_2 introduces a new national market for emission allowances. Consequently, although total emissions of SO_2 are limited by the total number of allowances issued, the actual rate of emissions of SO_2 and the type of control strategy used at any particular power plant are not specified in the CAA90. The expectation is that this market mechanism for SO_2 allowances will lead to lower costs for the nation compared to setting standards for individual power plants, and it will still meet the mandated reduction in national emissions of SO_2. Additional information about the regulations in the CAA90 that affect electric utilities is given in the following section.

The analysis of the CAA90 is conducted using the CCMU Model of power production in New York State. This model simulates the market for power production in the state on an annual basis and is a screening model for long-run planning. It can be used to determine economically efficient ways to meet environmental objectives, such as the regulations in the CAA90, and to predict the effects of these regulations on the average cost of service for customers. A brief description of the CCMU Model is given in Section 3.

The results of the analysis are summarized and discussed in Sections 4 and 5. Different scenarios are run for the period 1991 to 2010 to determine the incremental effects of individual components of the CAA90. The overall conclusions suggest that the requirements for SO_2 can be met at a relatively low cost in the state. Some of the requirements for NO_x, however, are expensive because of the difficulty in meeting ozone standards in urban areas along the eastern seaboard, especially in New York City. Since there is still considerable doubt about the effectiveness of proposed strategies for meeting ozone standards, and the costs of the proposed controls are so high, a number of issues should be clarified before current plans for controlling emissions are accepted. The most important of these is to assign the correct balance of responsibility for meeting ozone standards among electric utilities, transportation, and other industrial sources.

2. THE CLEAN AIR ACT AMENDMENTS OF 1990

The Clean Air Act Amendments of 1990 (CAA90) include two significant sections related to electric utility boiler emissions: Title IV dealing with acid deposition and Title I dealing with ambient air quality. The focus of Title IV is sulfur dioxide (SO_2) emissions from utility boilers, with a few provisions related to nitrogen oxides (NO_x) emissions. The provisions of Title I are an attempt to bring nonattainment areas into compliance with ambient air quality standards for ozone, carbon monoxide, and small particulate matter. The requirements for ozone nonattainment areas affect electric utilities most directly due to the role of NO_x emissions in the formation of ozone. (Hydrocarbons, primarily non-methane Volatile Organic Compounds, react with NO_x to form ozone in the presence of sunlight.)

Title IV

The acid deposition provisions of Title IV of the CAA90 create a nationwide emissions trading market for SO_2 allowances. Each allowance entitles the owner to emit one ton of SO_2.

Allowances may be bought from other allowance holders, sold to other affected facilities, or banked for future use. The provisions of Title IV are implemented in two phases beginning in 1995.

Electric utilities are issued allowances based on their average actual energy consumption for 1985, 1986, and 1987, known as a unit's baseline. In Phase I of the program, approximately 265 units at 110 plants (listed in the CAA90) will be issued allowances calculated from their baseline using an emissions rate of 2.5 lb/MMBtu. Selection criterion for the Phase I units were the capacity (100 MW or more) and high SO_2 emissions rates (2.5 lb/MMBtu or more). Phase I takes effect on January 1, 1995, but units that install flue gas desulfurization units or other high-efficiency emissions control devices are eligible for a two-year extension of the compliance date and additional bonus allowances. Phase II of Title IV affects all electric utility boilers larger than 25 MW on January 1, 2000. Allowances are issued according to a unit's baseline using an emissions rate of 1.2 lb/MMBtu. The total number of allowances nationwide is capped at 8.9 million tons per year.

Emissions of NO_x are also addressed in Title IV, although they are not included in the emissions trading system of SO_2 allowances. A unit must meet the applicable NO_x standard, if any, when the unit becomes an affected source for SO_2. To date, the Environmental Protection Agency has proposed NO_x limits of 0.50 lb/MMBtu for dry-bottom wall-fired coal boilers and 0.45 lb/MMBtu for dry-bottom tangentially-fired coal boilers. It is unclear at this date whether limits will be imposed on other types of boilers.

Title I

Title I of the CAA90 affects electric utilities primarily through the requirements for ozone nonattainment areas. Ozone, the primary component of urban smog, is formed through a complex series of reactions involving hydrocarbons, nitrogen oxides, and sunlight. Consequently, the provisions of Title I attempt to reduce ozone through controls on hydrocarbon and NO_x emissions.

Title I classifies the approximately 100 ozone nonattainment areas based on the severity of the ozone concentration. These classifications are marginal, moderate, serious, severe, and extreme ozone nonattainment areas. All of the nonattainment areas in upstate New York are classified as marginal and must be in compliance by November 1993. The downstate region is classified as severe and must comply with the ambient air quality standard by 2007. Areas that are not in compliance by the required date are moved to the next higher classification and must implement more stringent requirements. In addition, the entire state is included in the Northeast Ozone Transport Region. The entire transport region must implement the requirements of moderate nonattainment areas.

For electric utilities, the Title I requirements restrict NO_X emissions. Existing units will be required to install Reasonably Available Control Technology (RACT), while new units will be required to meet the Lowest Achievable Emissions Rate (LAER) and obtain offsets for their actual emissions. The proposal by the New York State Department of Environmental Conservation (DEC) for RACT in New York State implements standards that may be met through the use of combustion modifications to control NO_X from electric utilities in 1995. The draft proposal also considers standards in 2000 that would require the use of post-combustion control technologies such as selective catalytic reduction. These proposed standards are summarized in Table 1, and the control technologies for NO_X are described in an appendix.

TABLE 1

PROPOSED NEW YORK STATE RACT STANDARDS FOR NO_X (lb/MMBtu)

FUEL	BOTTOM	FIRING	1995	2000
Coal	Dry	Wall	0.43	0.20
		Tangential	0.38	0.20
		Stoker	0.30	0.20
	Wet	Wall	1.00	0.20
		Tangential	1.00	0.20
		Cyclone	0.55	0.20
Gas/Oil	---	Wall	0.25	0.10
		Tangential	0.25	0.10
		Cyclone	0.43	0.10
Gas	---	Wall	0.20	0.10
		Tangential	0.20	0.10

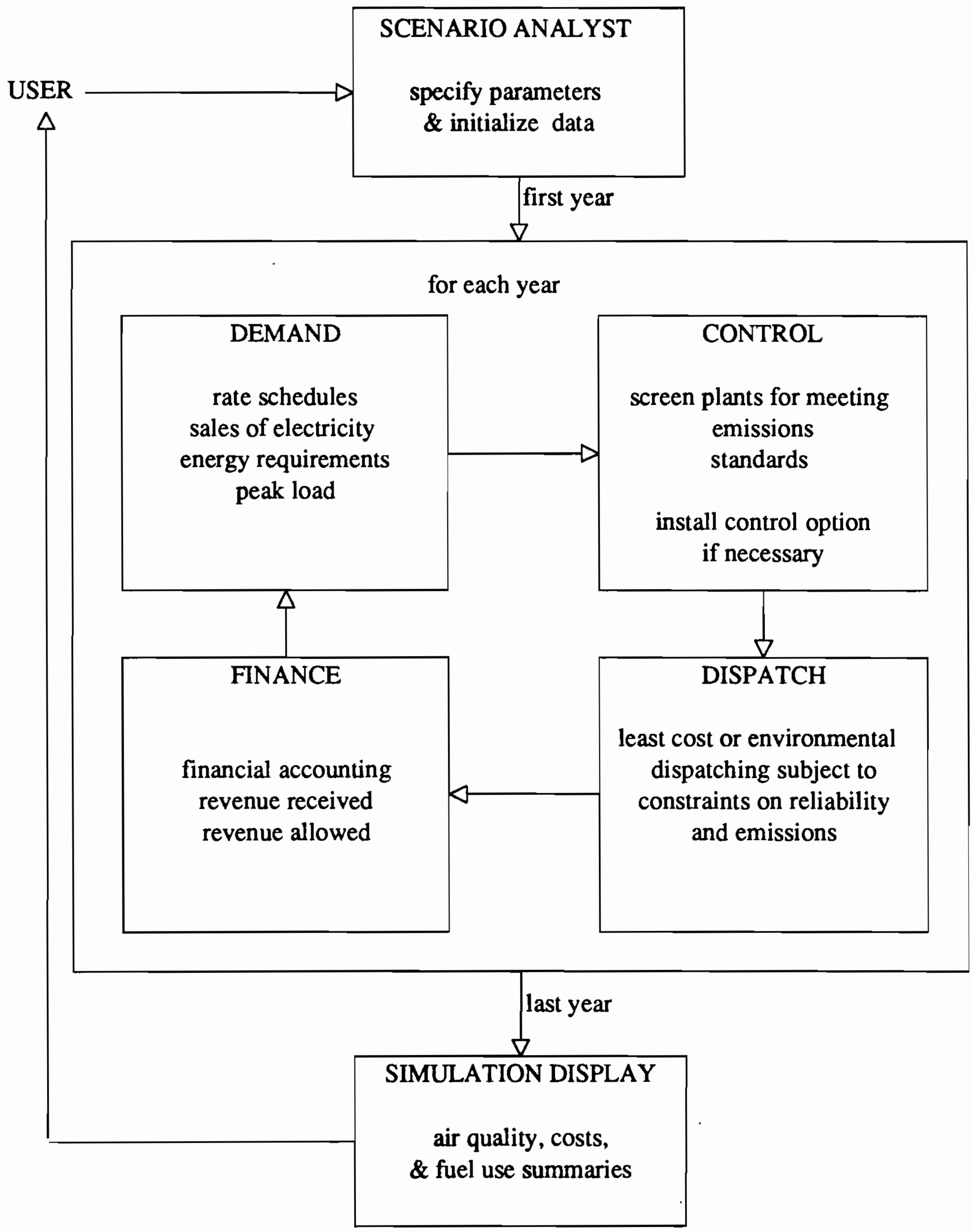
3. STRUCTURE OF THE CCMU MODEL

The CCMU Model of power generation in New York State operates on an annual basis at the state level. In a typical scenario, individual plants are dispatched to minimize costs subject to meeting load and constraints on system reliability and emissions. In addition, generation from non-utility sources (NUG) and demand-side management (DSM) are included. The model has a fully integrated financial structure in the sense that higher production costs are passed on to customers as higher rates, and these higher rates lower levels of demand and revenues received by utilities. Consequently, the market for power is modeled in an internally consistent manner. There are four main analytical components of the model that have undergone extensive modifications to incorporate specific capabilities relating to the New York Power Pool (NYPP).

The operating sequence of the four components of the model is illustrated in Figure 1 and is initiated by setting the rates charged for electricity in the Demand Module (DEMAND) for three classes of customer. This determines revenues received, annual energy requirements and load for the coming year. The next component is the Pollution Control Module (CONTROL) which screens plants to ensure that they meet SIP (State Implementation Plan) standards for emissions of SO_2, NO_x and particulates. If a plant does not meet standards, an appropriate new control option is selected which might involve switching to a cleaner fuel or installing control equipment. This is the standard way of dealing with emissions of NO_x and total suspended particulates.

Prior to dispatching the plants operated by the NYPP, energy requirements and peak load are modified to account for firm or prescheduled imports, exports and net losses from pumped storage. Generation from NUG sources, DSM, potential new sources of power, fuel switching and retrofitting scrubbers on NYPP plants are all incorporated into the Dispatch Module (DISPATCH). The inclusion of this range of options in the Dispatch Module is a feature that distinguishes the CCMU Model from standard production models of generation. The implication

FIGURE 1
STRUCTURE of the CCMU MODEL
New York State Electric Utility Simulation Model



is that the timing of installing new generating capacity or new technologies (e.g. scrubbers) can be determined by the model as well as specified by users.

The Dispatch Module is based on the XMP linear programming algorithm, and it determines the optimum pattern of generation to meet a five step load duration curve subject to specified environmental and reliability constraints. A typical activity (column) in the linear programming model (LP) represents a plant in one of the five load segments. Each activity can be constrained by a maximum (representing availability) and minimum (representing "must-run" requirements). The maximum capacity factor for a plant is represented by a row constraint across all five load segments. The Dispatch Module determines the pattern of generation and provides the data used to calculate emissions and production costs. Production costs and the net cost of purchases of power are then passed on to the Finance Module (FINANCE). All costs, including capital charges, are accounted for in this module to determine allowed revenues for the year. This information is passed on to the Demand Module to determine rates for the following year. Hence, it is assumed that the regulatory process operates with a one year lag. If actual revenues are lower (higher) than allowed revenues, electric rates are adjusted upwards (downwards) in the following year. In addition, the new rates reflect changes in the projected cost of fuels used for generation.

The levels of emissions from each plant are determined in the model on the basis of boiler characteristics, the level of generation, the quality of fuel used and the type of control equipment installed. This information is aggregated to give emissions at the utility and state level each year for carbon, SO_2, NO_x and total suspended particulates (TSP). The total level of any or all of these pollutants can be constrained in the Dispatch Module to a maximum level. Constraints can also be imposed on SO_2 or NO_x emissions in sub-state regions such as the New York City region or for plants affected by Phase I of Title IV in the CAA90. In addition, any given weighting scheme for production costs and emissions at the plant level can be used to simulate environmental dispatching as an alternative to the standard criterion that considers only production costs.

Another feature of the CCMU Model is that emissions of SO_2 and NO_x from each plant can be related to the corresponding deposition rates of wet and dry sulfates and nitrates at environmentally sensitive sites in the state. Transportation factors for each site are specified for each power plant to convert the amount of SO_2 and NO_x emitted to the annual average deposition of sulfates and nitrates per hectare. Consequently, annual levels of deposition attributable to NYPP and NUG sources can be determined in the model at the selected sites, and constraints on the maximum levels of deposition can be imposed within the Dispatch Module.

The overall implication of the structure of the CCMU Model is that economically efficient patterns of generation can be determined subject to multiple constraints on levels of emissions. Other options, such as the trading of allowances for SO_2 or offsets for carbon sequestration through reforestation, can be incorporated. Since it is also possible to modify standards for emissions at the plant level (e.g. SIP standards), sub-state levels and the state level, the framework can be used to evaluate simultaneously a wide range of policies affecting emissions. If stricter emission standards are specified at the plant level, a screening process identifies plants which do not meet the new standards, and a new fuel and/or a control device is selected in the Control Module to minimize expected production costs at the plant. The overall effect is to revise the data characteristics of a plant and the associated fuel prior to entering the Dispatch Module.

If reserve margins are high, it is possible to meet restrictions on emissions by generating more power from expensive oil plants and less from cheaper coal plants. However, getting substantial reductions of emissions this way becomes more limited and expensive when reserve margins decline. Consequently, capabilities have been added that allow for fuel switching, retrofitting control devices at existing plants and a range of potential new supply options, (including DSM) in the Dispatch Module. In general, optimum solutions for scenarios when constraints on emissions are imposed involve earlier retirement of old, dirty plants compared to scenarios with no constraints on emissions. These old plants would be replaced by new, cleaner sources of generation, such as combined cycle turbines, or reductions in demand through DSM.

4. AN INCREMENTAL ANALYSIS OF THE CAA90

The purpose of this section is to present the results from a series of scenarios using the CCMU Model. The scenarios are specified in such a way that the incremental effects of individual components of the CAA90 can be evaluated in terms of changes in emissions and costs. The scenarios are:

1. Base (no CAA90 controls)
2. Add Title IV (Acid Rain)
3. Add Title I, Phase I (Urban ozone)
4. Add Title I, Phase II downstate
5. Add Title I, Phase II upstate

The sequence of scenarios implies that the last one, Scenario 5, corresponds to implementing controls for both acid rain (Title IV) and urban ozone (Title I) throughout the state.

The characteristics of the Base are summarized in Table 2 for the forecast period 1991-2010. Most of the assumptions correspond to those used by the New York State Department of Public Service for setting Long-Run Avoided Costs in 1992 (LRAC). Levels of demand (energy requirements) are set exogenously in all scenarios. Consequently, higher costs do not have a dampening effect on sales, and the levels of energy requirements are identical in all five scenarios.

TABLE 2

SUMMARY OF INPUT ASSUMPTIONS

SCENARIO 1: BASE

Financial	**Annual Rate (1991-2010)**
General Inflation Rate	4.0%
Real O&M Escalation Rate	2.0%
Nominal Return to Deb	9.5%
Nominal Return to Pref. Equity	9.0%
Federal Tax Rate	34.0%
State Tax Rate	9.0%
Investment Tax Credit	0.0%

Economic/Demographic	**Annual Growth (percent)***
	1991-2010
Real Total Personal Income	1.4
Population	0.5
Employment - Industrial	0.7
Employment - Total	0.7

*These inputs do not affect sales because demand is determined exogenously.

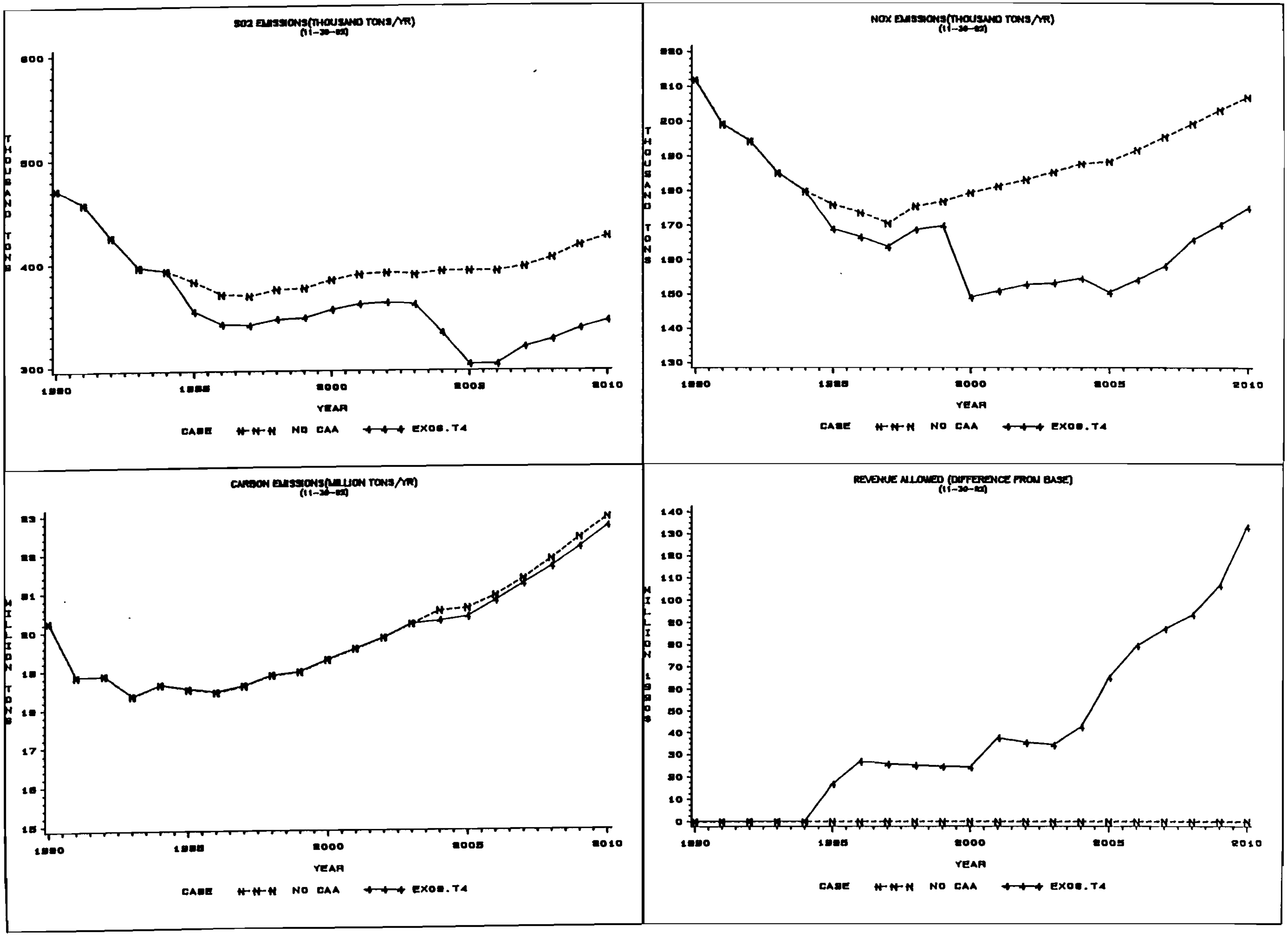
Fuel Prices (real)		**Annual Growth (percent)**				
		1991-1992	1992-1994	1994-2002	2002-2005	2005-2010
Coal	Low sulfur	-7.2	-1.6	1.1	1.3	1.2
	High sulfur	-2.1	-1.8	0.8	0.9	1.1
		4.4	-1.0	2.0	5.6	2.4
		4.4	-0.9	2.6	5.5	2.5
Oil	Low sulfur					
	High sulfur					
Natural gas		2.1	2.5	2.7	5.6	2.5
Nuclear		0.0	0.0	0.0	0.0	0.0

Energy Requirements	Exogenous at LRAC levels
Imports and Exports	Exogenous at LRAC levels
Non-Utility Generation	Exogenous at LRAC levels
Demand-side Management	Exogenous at LRAC levels
Natural Gas Availability	Unconstrained (1992-2010)
Utility Owned Additions/Retirements	Exogenous at NYPP 1992 schedule
1990 Amendments to the Clean Air Act	Not implemented in the Base

Results of the Base and Title IV of the CAA90 (Scenarios 1 and 2) are summarized in Figure 2 in terms of emission of SO_2, NO_x and carbon and the additional revenue requirements of implementing Title IV of the CAA90. In the Base (identified by N) with no CAA90 controls, emissions of SO_2 (these include emissions from NUG sources and the NYPP share of a plant at Homer City in Pennsylvania) drop from 470 Ktons per year in 1990 to about 380 Ktons by 1995 due to increased generation from NUG sources and growth of DSM. Emissions of SO_2 increase only slightly after 1995 in the Base. Patterns of emissions of NO_x and carbon in the Base are similar to the pattern for SO_2, but the rates of increase after 1995 are higher in both cases. These increases reflect increasing demand for electricity over the forecast period (sales of electricity increase by 1.4 percent per year from 1990 to 2010).

In Scenario 2 (identified by 4 in Figure 2), the acid rain controls in Title IV of the CAA90 are implemented in two phases (see Section 2 for additional discussion). It is assumed that allowances for emissions can be traded within the NYPP at no cost to the state, and that buying allowances from other states is expensive ($1253 per ton in 1990$). In Phase I, the 2 oil plants downstate (Northport 1-3 and Port Jefferson 3-4) already meet the new standard for 1995 because of the State Acid Deposition Control Act that limited the sulfur content of fuels in 1988. The 3 coal plants upstate (Greenidge 4, Milliken 1-2, and Dunkirk 3-4) do not meet the new standards, but a scrubber (Clean Coal Technology) is planned for Milliken in 1995. This scrubber is eligible for bonus allowances. The overall implications for Phase I of Title IV is that the constraint on emissions of SO_2 for affected plants in the state is not binding, and unused allowances are accumulated until Phase II is implemented in 2000. Under Phase II of Title IV, all plants are affected and a new annual level of allowances (305 Kton per year) is issued. Unused allowances from Phase I are used over the period 2000-2004 to provide an easier transition into Phase II (the constraint on total emissions of SO_2 is reduced linearly to reach the level of 305 Kton in 2005). Scrubbing was not allowed as an option in Phase II, and consequently, the constraint on emissions of SO_2 was met by switching to fuels with lower sulfur contents or by purchasing allowances

FIGURE 2
COMPARISON OF TITLE IV WITH THE BASE

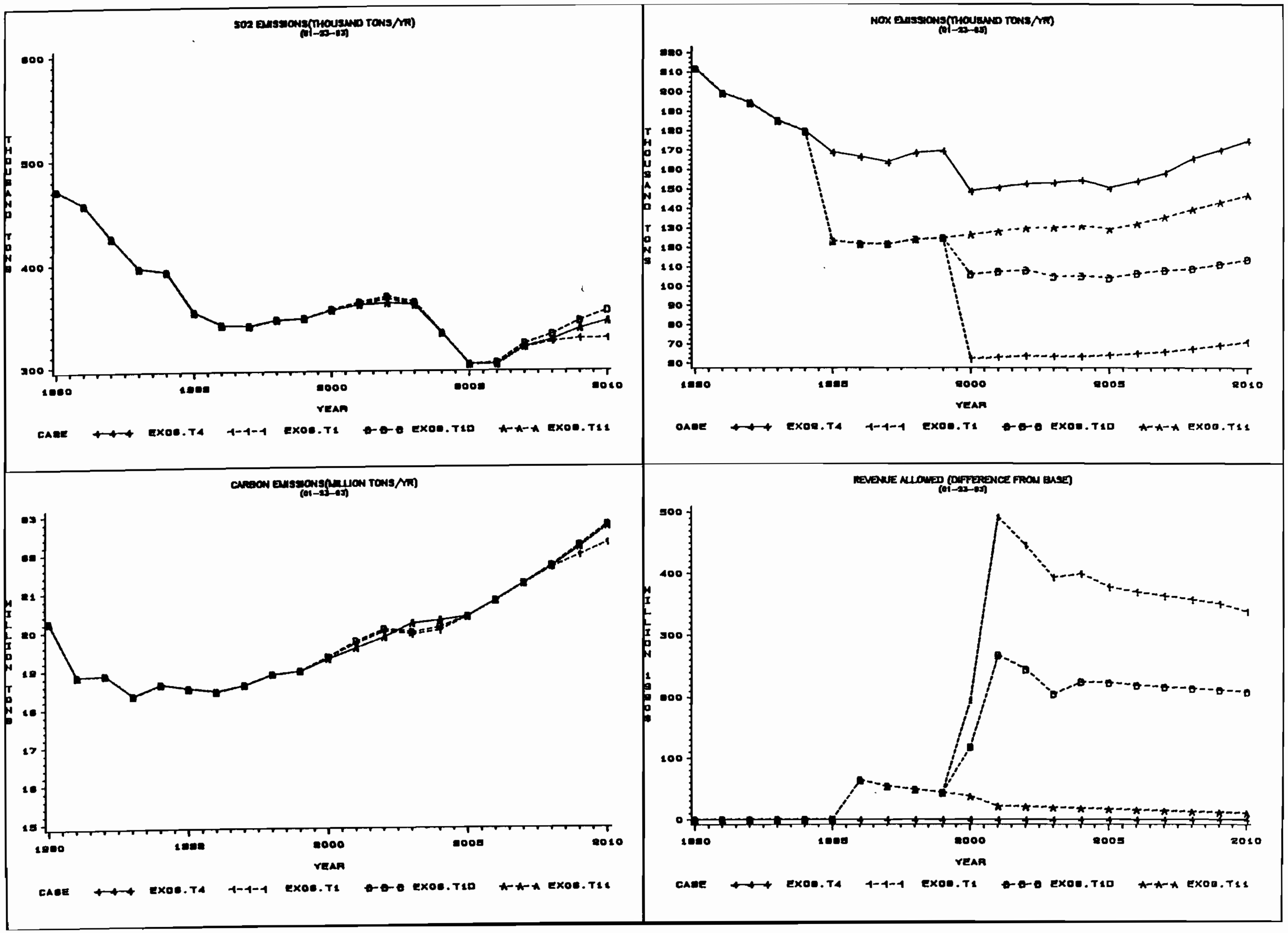


from other states. For both Phase I and Phase II of Title IV, the relatively modest standards for emissions of NO_x are imposed, and the selection of control devices is specified exogenously for any plant that does not meet the standards.

The results summarized in Figure 2 for Title IV show the expected reductions in emissions of SO_2 and NO_x in 1995 compared to the Base that result from installing a scrubber at Milliken and NO_x controls at the three coal plants affected by Phase I. Additional reductions of SO_2 and NO_x occur in 2000 when all plants are affected by Phase II. (The implications of Title IV on emissions of carbon are very small since the CAA90 does not deal explicitly with emissions that contribute to global warming.) After 2000, emissions of SO_2 are above the annual level of allowances issued to the NYPP until 2005 because unused allowances from Phase I are available. In 2005 and 2006, the annual constraint of 305 Ktons per year is binding. After 2006, emissions of SO_2 increase because allowances are purchased from other states (installing additional scrubbers in Phase II was not an option in these scenarios). The cost of meeting Title IV increases after 1995 to reach about \$130M per year in 1990\$ by 2010. This cost reflects the increasing cost differential for low sulfur coal (see Table 2) and the cost of purchasing allowances after 2006, but it corresponds to only a 0.7 percent increase of the average cost of service above the Base by 2010. In other words, the cost of meeting Title IV in the CAA90 is relatively small.

The results in Figure 3 summarize the implications of trying to meet ambient air standards for ozone in Title I of the CAA90. In this figure, Title IV is treated as the initial scenario. Phase I of Title I (Scenario 3) limits emissions of NO_x in 1995 (see Table 1) and is identified by A in Figure 3. Phase II of Title I downstate (Scenario 4) and Phase II of Title I upstate (Scenario 5), restrict emissions of NO_x in 2000 and are identified by D and 1, respectively. For all three scenarios relating to Title I (3-5), the effects on emissions of SO_2 and carbon are very small, but the effects on emissions of NO_x are, as expected, substantial. Phase I reduces emissions of NO_x in 1995 by almost one third from the level in Scenario 2. Phase II reduces emissions of

FIGURE 3
COMPARISON OF COMPONENTS OF TITLE I WITH TITLE IV



NO_x by roughly the same amount in 2000 to give total emissions of about 70Kton per year from 2000 on in Scenario 5. The decrease of emissions upstate in Phase II is about double the corresponding decrease downstate.

The cost of Phase I of Title I is modest starting at about $70M per year in 1990$ in 1995 and falling to $20M per year in 1990$ by 2010. This behavior differs from the cost pattern for Title IV because the costs in Title I are associated with capital investments rather than switching to cleaner fuels and purchasing allowances. The costs of Phase II of Title I are relatively high, however, reflecting the high capital and operating costs of post-combustion modifications (selective catalytic reduction). The full cost of implementing Title I amounts to about $400M per year in 1990$, almost three times as much as the cost of implementing Title IV at its highest level in 2010. The cost of Title I corresponds to approximately an additional 3 percent increase in the average cost of service above the cost with Title IV implemented. The overall effect of the CAA90 is to increase the average cost of service by almost 4 percent above the Base.

The costs of control devices for emissions of NO_x are specified exogenously in Scenarios 2-5, and are based on engineering estimates for individual plants. These estimates were obtained from Joe DeAngelo (New York State Electric and Gas) and were used instead of the generic cost equations that are part of the CCMU Model. A comparison of the cost estimates with the corresponding costs derived from the equations is given in an appendix. These equations were taken from the Integrated Air Pollution Control System Model (Version 4.0) developed for the US Environmental Protection Agency. In general, the equations give lower costs for Phase I (combustion modifications) and higher costs for Phase II (post-combustion modifications) than the engineering estimates. The implication is that the contrast in costs between Phases I and II would be greater using the cost equations in the CCMU Model. Phase I would be even less expensive and Phase II even more expensive than the results presented in Figure 3.

5. CONCLUSIONS

The first conclusion from the results presented in Section 4 is that the costs of meeting the requirements for controlling acid rain (Title IV of the CAA90) are relatively low (less than a 1% increase in the average cost of service by 2010). In fact, costs would have been even lower if installing additional scrubbers in Phase II had been an option or the specified price of purchasing an allowance for SO_2 had not been as high (sales of allowances have been made for $250-400 per ton compared to over $1200 per ton used in the scenarios). These results illustrate the difference between New York State and many mid-western states where controlling emissions of SO_2 will be a major undertaking. In New York State, reductions in emissions of SO_2 have already occurred because of the State Acid Deposition Control Act. Additional reductions will come from increases in generation from gas-fired NUG sources and from DSM. However, if emissions of SO_2 in the state are limited to the level of allowances issued in Phase II (by preventing purchases of allowances from other states), installing additional scrubbers on coal plants should be considered as an option (installing scrubbers in New York State would cost roughly $800 per ton of SO_2 removed which is about two thirds of the specified cost of purchasing allowances).

The incremental costs of implementing Phase I of Title I (reducing emissions of NO_x in 1995 as a step towards meeting standards for urban ozone) are lower than the costs of implementing Title IV. However, the costs of Phase II of Title I are relatively high because the controls involve installing post-combustion modifications (see the Appendix). By 2010, the cost of both Phases of Title I is roughly three times as high as the cost of Title IV. A large part of these costs are associated with the capital cost of devices for controlling emissions of NO_x. These capital costs are summarized in Table 3. The cost of the combustion modifications for NO_x installed to meet Title IV and Phase I of Title I are relatively low ($91M and $343M, respectively). Installing selective catalytic reduction at most plants to meet proposed standards for NO_x in

Phase II of Title I is much more expensive ($1561M). In addition, the operating costs are also higher than they are for combustion devices alone (see the Appendix).

TABLE 3
CAPITAL COSTS FOR NO_X CONTROLS
(MILLION 1994$)

	1995	2000	Total
Title IV	23	68	91
Title I, Phase I	343	0	343
Title I, Phase II	0	1561	1561

The overall implications of the results in Section 4 can be summarized in terms of the incremental effects on emissions and costs of the different components of the CAA90. To simplify the discussion, it is convenient to consider a single measure of emissions because emissions of SO_2 and NO_X change simultaneously in the different scenarios. A measure called "NO_X Equivalent" is defined for this purpose as the sum of emissions of NO_X plus emissions of SO_2 divided by two. This implies that one ton of NO_X causes twice as much "damage" as one ton of SO_2. (This ratio is approximately the same as the ratio of costs used by the New York State Department of Public Service to measure the non-market costs of emissions from potential new sources of generation.) The results in Figure 4 show the cumulative effects on NO_X Equivalents of the controls implemented in the four scenarios described in Section 4. In terms of emissions, the effects of Title IV (mainly on emissions of SO_2) and Phase II of Title I (mainly on emissions of NO_X) are both substantial, but the effects of Phase I of Title I from 1995 on are partly superseded from 2000 on by the effects of Title IV. The additional reductions after 2000 associated with Phase II of Title I are roughly two-thirds as big as the combined reductions for Title IV and Phase I of Title I in terms of NO_X Equivalents.

FIGURE 4
CUMULATIVE REDUCTIONS OF EMISSIONS

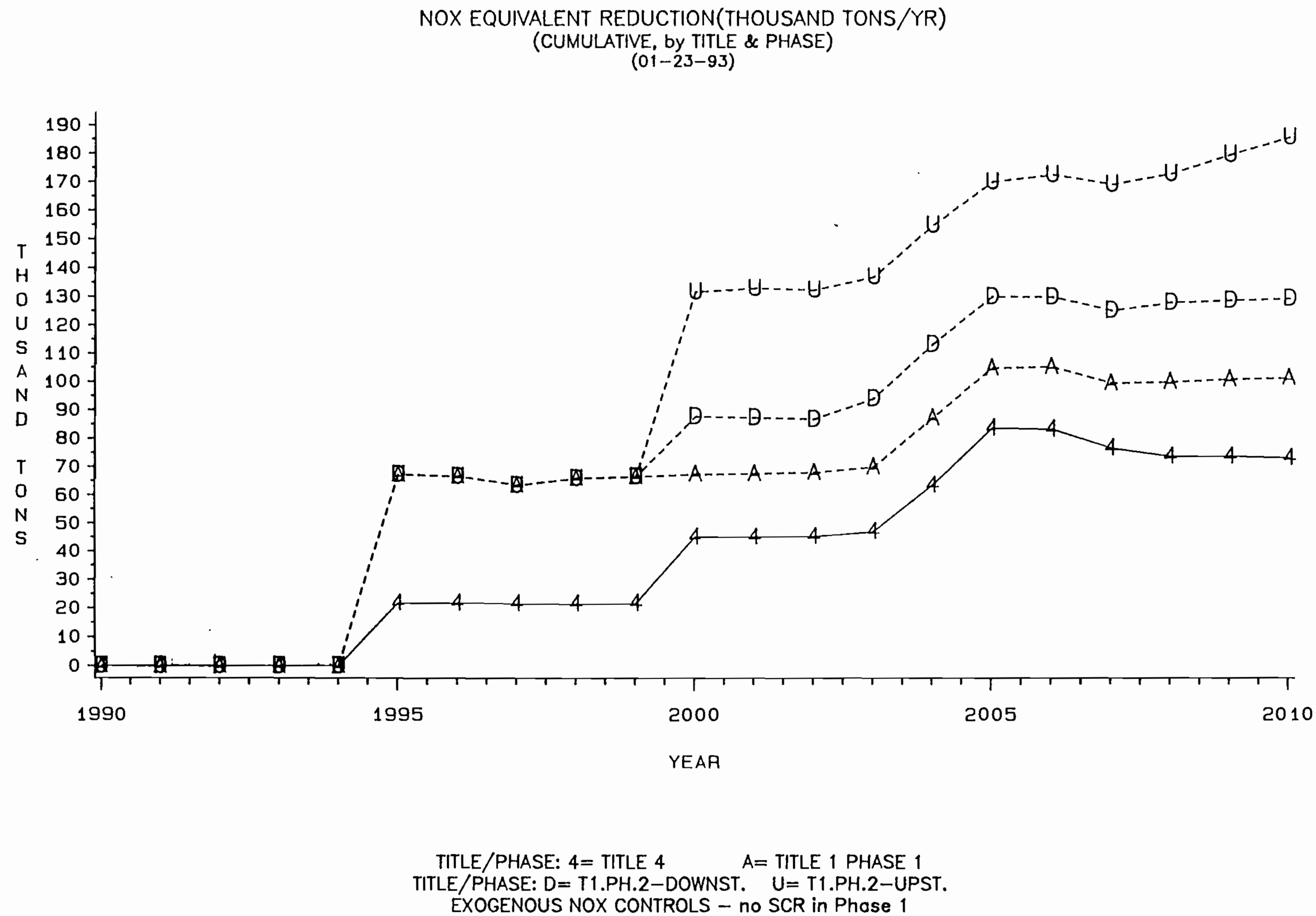


Figure 5 summarizes the corresponding incremental costs (per ton of NO_x Equivalent) of reducing emissions as the scenarios are implemented in sequence. The costs per ton for Title IV and Phase I of Title I are generally less than $2000 per ton, although the cost per ton of Title IV increases above this value by the end of the forecast period (because the price of purchasing allowances for SO_2 is high: about $2500 per ton in terms of NO_x Equivalents). The costs for Phase II of Title I are much higher than the costs for Title IV or Phase I of Title I both upstate (about $5000 per ton) and downstate (about $8000 per ton). Consequently, the logical question to ask is whether the controls in Phase II of Title I are economically efficient in the sense of 1) leading to benefits that outweigh the costs, and 2) there being no options in other sectors of the economy for reducing emissions at a lower cost (in terms of meeting standards for urban ozone).

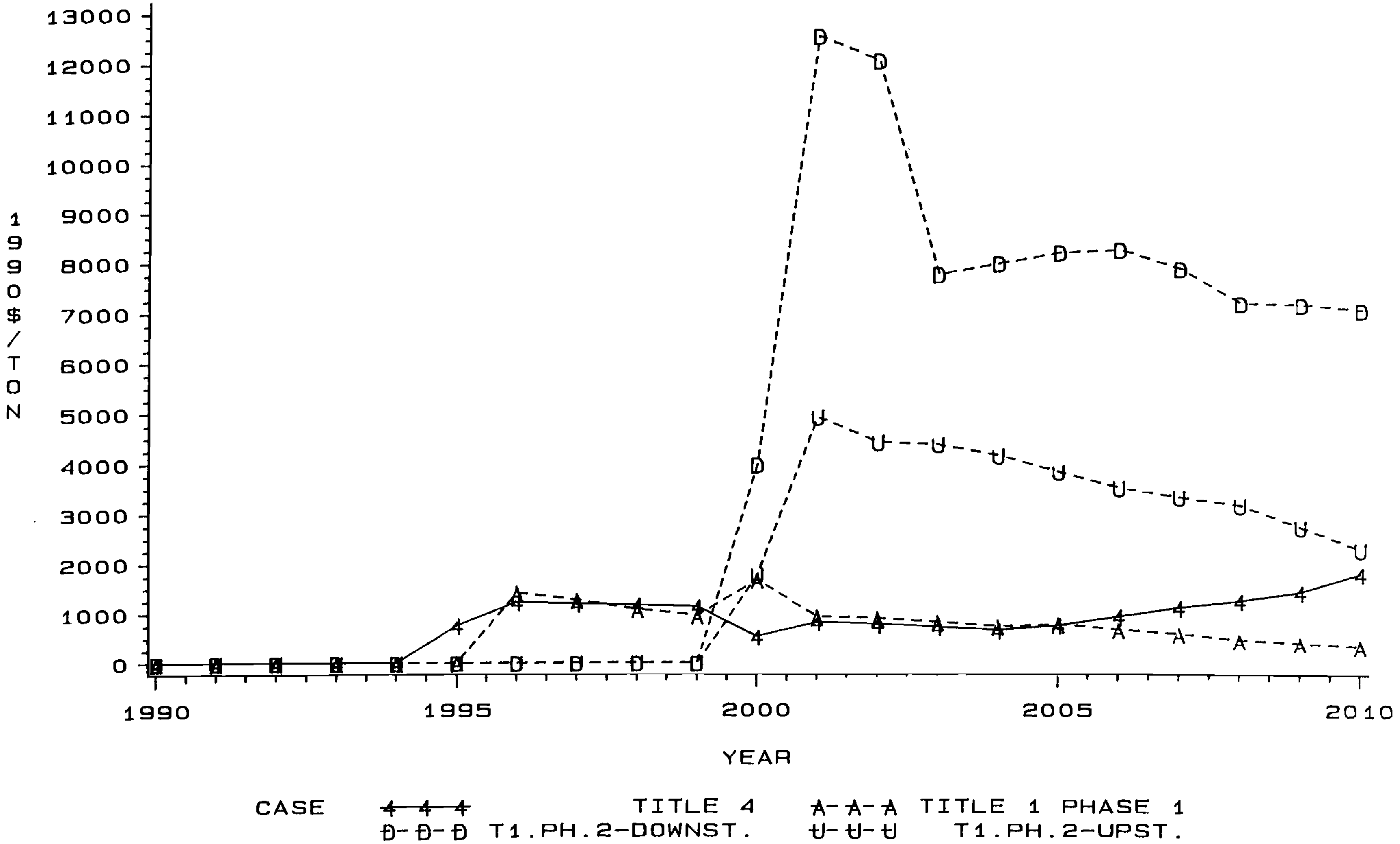
There are no simple answers to the questions raised in the previous paragraph. The violation of standards for urban ozone is episodic and requires the right mix of ingredients (NO_x and hydrocarbons: see the Appendix) and sufficient sunlight. These conditions tend to occur during the summer if air masses are relatively static for a series of days. For most of the year, levels of urban ozone meet the required standards, and emissions of NO_x pose more of a problem for acid rain than for urban ozone. In contrast, other environmental concerns like acid rain and global warming are more directly related to total levels of emissions (particularly global warming). With acid rain, an additional issue is that some regions are more sensitive to deposition than others. Total annual levels are the typical values of variables predicted by the CCMU Model. Since weather patterns where levels of urban ozone are high may be very different from average weather patterns for a year, it is difficult to use results from the CCMU Model to address the episodic nature of the ozone problem. Nevertheless, there are issues that can be illustrated by the model.

First, the location of emissions matters. For example, it is reasonable to expect that emissions of SO_2 and NO_x from plants upstate contribute more to the problem of acid rain than equivalent levels of emissions from plants downstate. The opposite argument could be made for

FIGURE 5
INCREMENTAL COSTS PER TON OF REDUCING EMISSIONS

REVENUE ALLOWED (PER TON NOX EQUIVALENT REDUCTION)

(01–23–93)



EXOGENOUS NOX CONTROLS – no SCR in Phase 1 the contribution of emissions of NO_X to the formation of urban ozone. This point is illustrated by the results in Table 4 which shows the relative effects of five utilities operating plants downstate compared to three utilities with plants upstate. The average annual rates of deposition of wet and dry nitrates from one ton of NO_X emitted each company are predicted for each of the five scenarios discussed earlier in this section. These deposition rates for three sites in the year 2005, are normalized in Table 4, so that the average rate of deposition per ton from the NYPP is 100. The first two sites (Western Adirondacks and Catskills) have been identified by the New York State Department of Environmental Conservation as being sensitive to acid rain. The third site (Brookhaven) is close to New York City, and it was chosen to represent the region affected by high concentrations of urban ozone. The year 2005 was selected to represent a year when all components of the CAA90 are enforced and no allowances for SO_2 are purchased from other states.

The greatest contrasts between the five utilities downstate and the three utilities upstate occur for Western Adirondacks and Brookhaven (Central Hudson is on the border between upstate and downstate and could be classified in either group). The upstate utilities have deposition rates per ton emitted that are above average for Western Adirondacks and well below average for Brookhaven. The opposite holds for the downstate utilities. The question that needs to be answered is what effect will reductions of NO_X from upstate plants have on concentrations of ozone in the downstate region?

Another issue for consideration is how do emissions from utilities compare to emissions from transportation and other industries in their effects on the formation of ozone? Since most of the emissions of hydrocarbons and a large part of the emissions of NO_X (larger than the share from utilities) come from transportation, the effectiveness of controls on NO_X emissions from utilities cannot be judged without considering the emissions from other sources. The analysis in Section 4 implied that the incremental costs for reducing emissions of NO_X from utilities would

TABLE 4

NORMALIZED ANNUAL RATES OF DEPOSITION OF NITRATES AT THREE SITES PER TON OF NO_X EMITTED BY COMPANY IN 2005

	W. ADIRONDACKS					CATSKILLS					BROOKHAVEN				
	SCENARIO					SCENARIO					SCENARIO				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
Central Hudson Gas & Electric	39	48	47	33	47	219	236	238	229	235	53	44	46	91	48
Consolidated Edison Company	19	24	23	16	23	69	72	68	68	69	213	189	203	372	199
Long Island Lighting Company	13	17	17	12	17	22	26	26	27	27	329	286	299	549	285
Orange & Rockland Utilities	21	26	25	18	25	43	46	47	45	46	380	318	331	656	342
New York Power Authority	25	31	30	22	30	76	82	82	79	81	200	166	173	346	180
New York State Electric & Gas	144	182	174	125	177	152	132	142	137	124	19	14	15	31	15
Niagara Mohawk Power	147	144	136	111	137	83	92	87	78	87	17	15	14	25	15
Rochester Gas & Electric	209	256	249	178	249	91	98	99	95	97	15	12	13	25	13
New York Power Pool	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
State Average*	3.6	2.9	3.0	4.2	3.0	2.9	2.7	2.7	2.8	2.7	7.4	8.9	8.5	4.3	8.2

* Average annual deposition of nitrates (grams per hectare) per ton of NO_X emitted by electric utilities.

be approximately $8000 per ton to meet the standards in Phase II of Title I of the CAA90. Since this cost is expensive and the controls only affect utilities and other point sources, the question that needs to be answered is whether there are more efficient ways to meet standards for urban ozone by reducing emissions from non-utility sectors such as transportation.

Answering these questions about the effectiveness of proposed regulations for reducing emissions of NO_X from utilities will require research by atmospheric scientists, engineers and economists. Efforts made now to provide answers have the potential for saving substantial expenditures in the future because the projected cost of investment for implementing NO_X controls in New York State is so high (over $1.9 billion (see Table 3).

NO_x APPENDIX: Control Technologies in the CCMU Model

Low Excess Air

Low Excess Air (LEA) firing controls NO_x formation by reducing the amount of atmospheric NO_x available in the furnace to form NO_x. LEA firing has the side benefit of improving boiler efficiency, resulting in lower heat rates, reduced fuel consumption, and lower production costs. Consequently, most utility boilers have already implemented LEA firing in order to reduce costs rather than to reduce NO_x emissions. LEA provides a NO_x reduction of approximately 15 percent. Control costs for LEA are on the order of $200/ton NO_x without including fuel savings. These fuel savings can result in a control cost of -$775/ton NO_x or more depending on the fuel price.

Overfire Air

Overfire Air (OFA) reduces NO_x emissions by staging the combustion inside the entire boiler. Fuel is burned in the existing burners with less than the required amount of combustion air. Combustion is completed in the region above the burners where the overfire air is injected. This combustion staging reduces NO_x emissions by reducing the peak flame temperature of the combustion process, the key variable in the formation of thermal NO_x. OFA provides a NO_x reduction of approximately 25 percent. Control costs for OFA are on the order of $125/ton NO_x.

Low-NO_x Burners

Low-NO_x burners (LNB) control NO_x emissions by staging the combustion within the burner flame itself. Like OFA, LNB reduces NO_x emissions by reducing the peak flame temperature. Because the fuel or air staging lengthens the combustion process, the use of LNB can often result in longer flames that may impinge on boiler walls in some boilers. NO_x reductions for LNB are approximately 35 percent. Control costs for LNB are on the order of $300/ton NO_x.

Low-NO_x Concentric Firing System

The Low-NO_x Concentric Firing System (LNCFS) was developed specifically for tangentially-fired boilers. NO_x reductions are achieved through fuel staging in the burners themselves and through the use of separated overfire air. LNCFS provides a NO_x reduction of approximately 40 percent. Control costs for the LNCFS system are on the order of $125/ton NO_x.

Low-NO_x Burners + Overfire Air

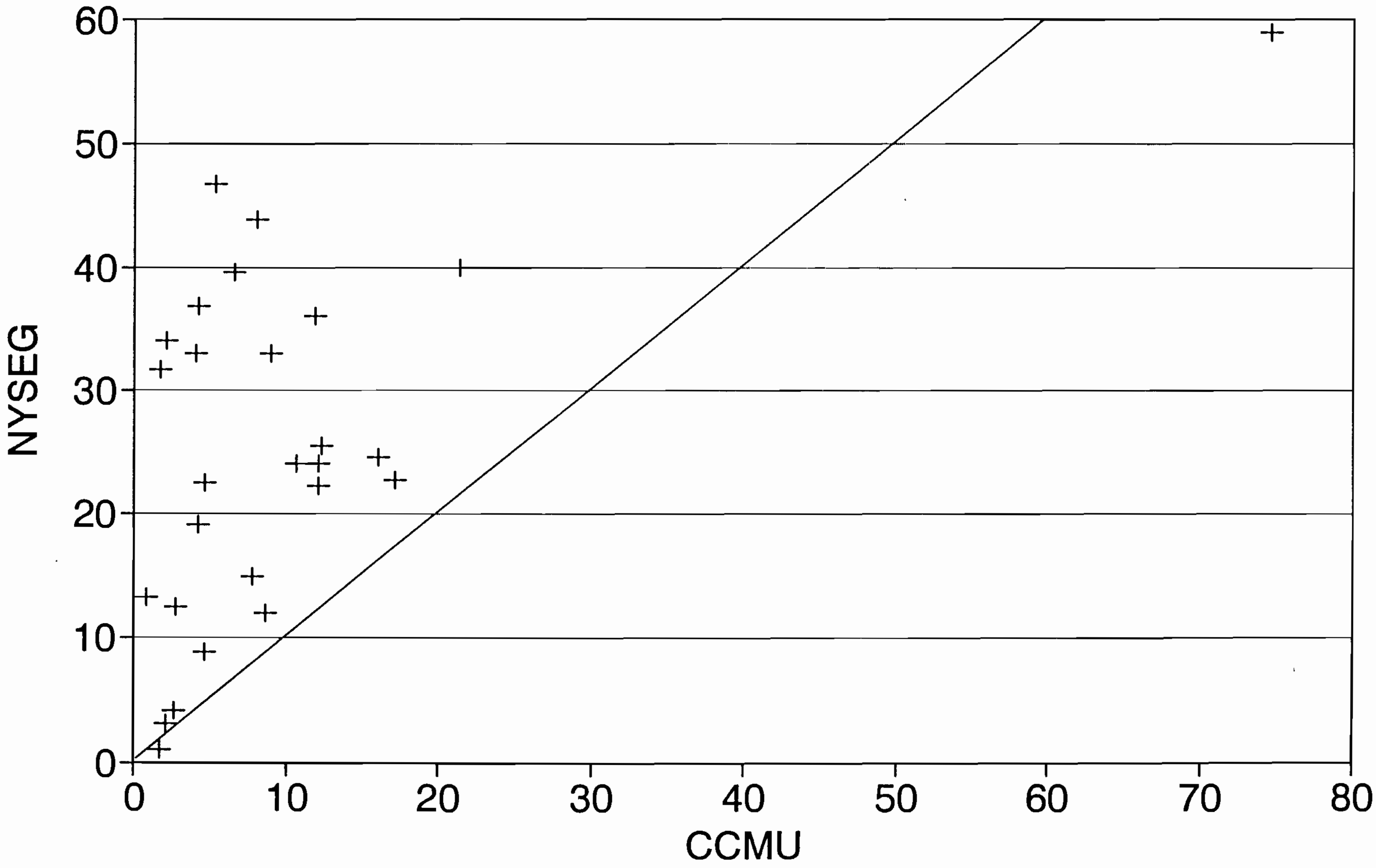
The combination of LNB and OFA results in a higher NO_x removal rate than either of the two technologies can achieve separately. The combination provides the functional equivalent of the LNCFS for wall-fired boilers. The combination of technologies can provide a NO_x reduction of approximately 50 percent. Control costs for LNB+OFA are on the order of $500/ton NO_x.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion treatment technology. Ammonia is injected into the flue gas stream where it thermally dissociates into nitrogen and hydrogen ions. These ions react with the NO_x in the flue gas over a catalyst bed to form molecular nitrogen and water. Due to the use of a precious metal catalyst bed that must be periodically replaced, both the capital and operating costs of SCR are high compared to combustion modification technologies. The ammonia is also capable of reacting with SO_2 in the flue gas to form ammonium bisulfate, a sticky compound which can foul surfaces in the catalyst bed or air heater. In addition, most of the SCR boiler installations worldwide have been on gas- or oil-fired boilers or boilers burning low-sulfur coal. To date, there has been very limited experience with the use of SCR on high-sulfur coal boilers similar to those used by U.S. electric utilities. SCR can provide a NO_x reduction of 80 percent to 90 percent from inlet NO_x concentrations. Control costs for SCR are on the order of $2,000/ton NO_x to $3,000/ton NO_x.

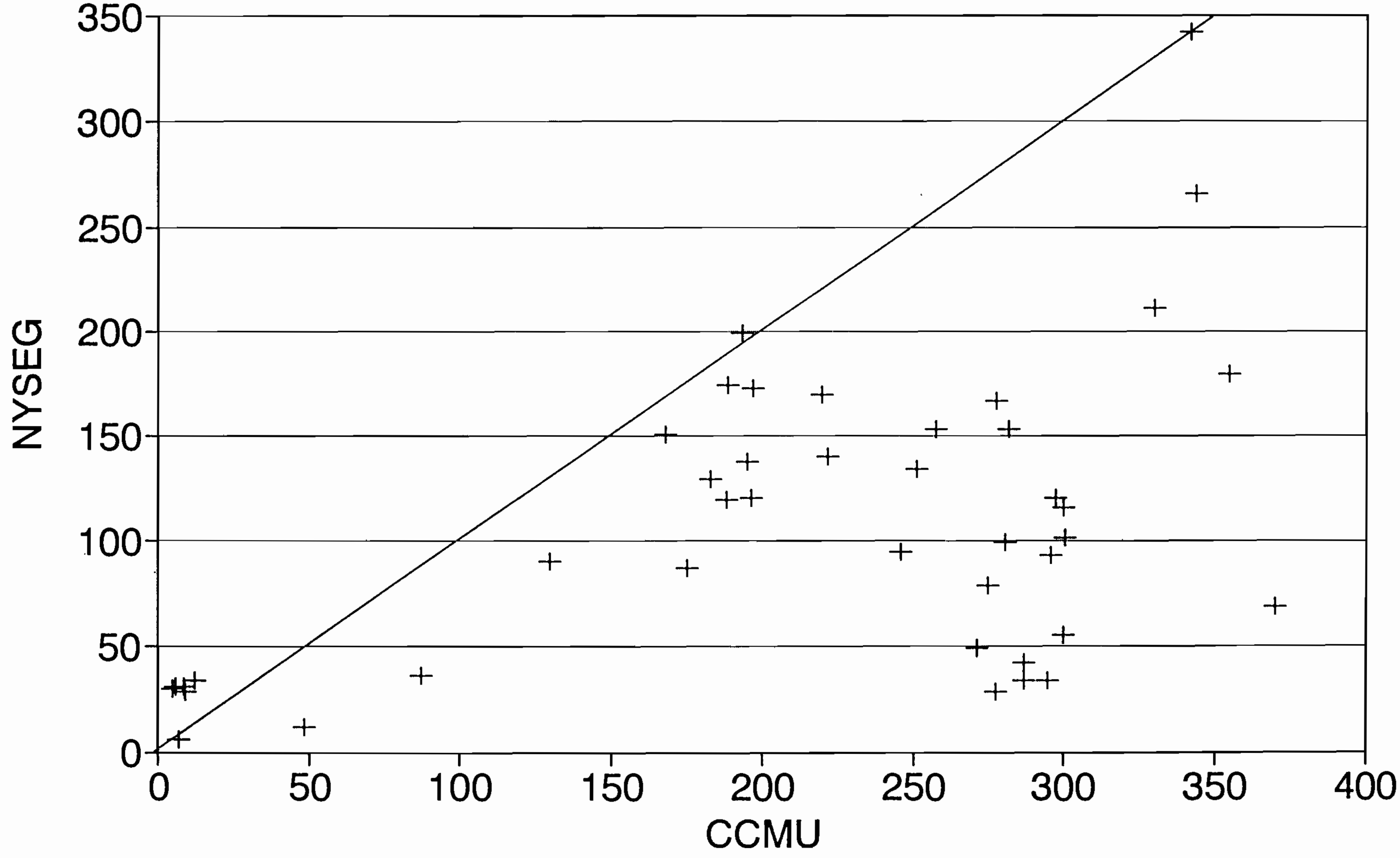
NOx Control Cost Comparison

Phase I Capital Cost (1994$/kW)



NOx Control Cost Comparison

Phase II Capital Cost (1994$/kW)



NOx Control Cost Comparison - Phase I

	CCMU						NYSEG							$/kW	
Plant Name	NOx Control	Capital (1994$)	O&M (1994$)	Old Emissions	New Emissions	% Removal	NOx Control	Capital (1994$)	O&M (1994$)	Old Emissions	New Emissions	% Removal	MW	CCMU	NYSEG
Goudey	LNCFS	$1,032,849	$22,530	0.756	0.454	40.0%	LNCFS	$5,618,000	$45,784	0.756	0.454	40.0%	128.0	$8.1	$43.9
Greenidge 4	LNCFS	$964,989	$21,050	0.520	0.312	40.0%	LNCFS	$3,559,000	$21,050	0.520	0.312	40.0%	108.0	$8.9	$33.0
Hickling	None	$0	$0	0.350	0.350	0.0%	None	$0	$0	0.350	0.350	0.0%	88.0	$0.0	$0.0
Jennison	None	$0	$0	0.350	0.350	0.0%	None	$0	$0	0.350	0.350	0.0%	71.0	$0.0	$0.0
Milliken	LNCFS	$1,484,488	$32,383	0.690	0.414	40.0%	LNCFS	$7,118,000	$32,383	0.690	0.414	40.0%	317.0	$4.7	$22.5
Homer City	LNB+OFA	$11,596,629	$252,968	0.875	0.394	55.0%	LNB+OFA	$23,925,000	$93,016	0.875	0.394	55.0%	942.0	$12.3	$25.4
Huntley 63-66	None	$0	$0	1.100	1.100	0.0%	None	$0	$0	1.100	1.100	0.0%	340.0	$0.0	$0.0
Huntley 67-68	LNCFS	$1,587,689	$34,634	0.700	0.420	40.0%	LNCFS	$7,118,000	$34,634	0.700	0.420	40.0%	375.0	$4.2	$19.0
Dunkirk 3,4	LNCFS	$1,596,123	$34,818	0.700	0.420	40.0%	LNCFS	$14,000,000	$34,818	0.700	0.420	40.0%	380.0	$4.2	$36.8
Russell	LNCFS	$1,364,979	$29,776	0.466	0.280	40.0%	LNCFS	$12,000,000	$29,776	0.466	0.280	40.0%	257.0	$5.3	$46.7
Beebee 12	None	$0	$0	0.600	0.600	0.0%	None	$0	$0	0.600	0.600	0.0%	80.0	$0.0	$0.0
Jamestown	LNB+OFA	$1,066,027	$23,254	0.597	0.448	25.0%	LNB+OFA	$2,000,000	$23,254	0.597	0.507	15.0%	50.0	$21.3	$40.0
Roseton	LNCFS	$2,528,281	$55,152	0.400	0.240	40.0%	LNCFS	$40,800,000	$55,152	0.400	0.240	40.0%	1,200.0	$2.1	$34.0
Danskammer A/B	LEA	$263,256	$5,743	0.290	0.247	15.0%	BOOS	$366,000	$5,743	0.290	0.247	15.0%	122.0	$2.2	$3.0
Arthur Kill	None	$0	$0	0.220	0.220	0.0%	None	$0	$0	0.220	0.220	0.0%	826.0	$0.0	$0.0
Astoria A/B	LEA	$2,422,061	$52,835	0.290	0.247	15.0%	BOOS	$1,291,000	$52,835	0.290	0.247	15.0%	1,417.0	$1.7	$0.9
Bowline A/B	LNB	$10,461,522	$228,207	0.340	0.153	55.0%	LNB	$14,400,000	$46,508	0.340	0.204	40.0%	1,210.0	$8.6	$11.9
East River A/B	LNB	$6,916,209	$150,870	0.370	0.222	40.0%	LNB	$10,512,000	$46,508	0.370	0.222	40.0%	430.0	$16.1	$24.4
Hudson Ave.	None	$0	$0	0.190	0.190	0.0%	None	$0	$0	0.190	0.190	0.0%	44.0	$0.0	$0.0
Ravenswood A/B	LNCFS	$2,934,757	$64,019	0.340	0.204	40.0%	LNCFS	$55,148,000	$64,019	0.340	0.204	40.0%	1,742.0	$1.7	$31.7
Waterside A/B	None	$0	$0	0.130	0.130	0.0%	None	$0	$0	0.130	0.130	0.0%	299.0	$0.0	$0.0
59th Street	None	$0	$0	0.230	0.230	0.0%	None	$0	$0	0.230	0.230	0.0%	102.0	$0.0	$0.0
74th Street	None	$0	$0	0.210	0.210	0.0%	None	$0	$0	0.210	0.210	0.0%	166.0	$0.0	$0.0
Northport 1,2,3	OFA	$1,066,027	$23,254	0.280	0.210	25.0%	OFA	$14,966,000	$23,254	0.280	0.238	15.0%	1,137.0	$0.9	$13.2
Port Jeff. 3-4	OFA	$1,066,027	$23,254	0.280	0.210	25.0%	OFA	$4,788,000	$23,254	0.280	0.238	15.0%	388.0	$2.7	$12.3
Glenwood A/B	None	$0	$0	0.200	0.200	0.0%	None	$0	$0	0.200	0.200	0.0%	220.0	$0.0	$0.0
Barrett A/B	None	$0	$0	0.240	0.240	0.0%	None	$0	$0	0.240	0.240	0.0%	385.0	$0.0	$0.0
Far Rockaway A/B	None	$0	$0	0.240	0.240	0.0%	None	$0	$0	0.240	0.240	0.0%	115.0	$0.0	$0.0
Oswego 5	LNB+OFA	$10,149,425	$221,399	1.160	0.392	66.3%	LNB+OFA	$30,600,000	$46,508	1.160	0.522	55.0%	850.0	$11.9	$36.0
Oswego 6	LNB	$9,083,397	$198,145	0.300	0.135	55.0%	LNB	$20,400,000	$23,254	0.300	0.180	40.0%	850.0	$10.7	$24.0
Albany A/B	LNCFS	$1,629,209	$35,539	0.350	0.210	40.0%	LNCFS	$13,192,000	$35,539	0.350	0.210	40.0%	400.0	$4.1	$33.0
Lovett 1-3	LNB	$3,954,522	$86,264	0.320	0.192	40.0%	LNCFS	$2,346,000	$23,254	0.320	0.192	40.0%	106.3	ERR	$22.1
Lovett 4,5	LNB	$6,632,158	$144,673	0.664	0.398	40.0%	LNB	$8,800,000	$23,254	0.664	0.398	40.0%	387.2	$17.1	$22.7
Poletti A/B	LNB+OFA	$10,041,603	$219,047	0.330	0.111	66.3%	LNB+OFA	$19,800,000	$23,254	0.330	0.198	40.0%	825.0	$12.2	$24.0
Port Jeff. 1-2	LEA	$249,058	$5,433	0.280	0.238	15.0%	BOOS	$390,000	$5,433	0.280	0.238	15.0%	94.0	$2.6	$4.1
Northport 4	None	$0	$0	0.200	0.200	0.0%	None	$0	$0	0.200	0.200	0.0%	370.0	$0.0	$0.0
Danskammer 3	OFA	$1,066,027	$23,254	0.590	0.443	25.0%	OFA	$2,028,000	$23,804	0.590	0.384	35.0%	136.0	$7.8	$14.9
Danskammer 4	OFA	$1,066,027	$23,254	0.580	0.435	25.0%	OFA	$2,028,000	$23,804	0.580	0.377	35.0%	230.0	$4.6	$8.8
Kintigh	LNB	$8,327,280	$181,651	0.550	0.248	55.0%	LNB	$15,114,000	$46,508	0.550	0.413	25.0%	684.0	$12.2	$22.1
Oswego 3,4 A/B	None	$0	$0	0.507	0.507	0.0%	None	$0	$0	0.507	0.507	0.0%	165.0	$0.0	$0.0
Greenidge 3	LNB+OFA	$4,104,293	$89,531	0.820	0.369	55.0%	LNB+OFA	$3,238,000	$89,531	0.820	0.369	55.0%	55.0	$74.6	$58.9
Dunkirk 1,2	LNCFS	$1,183,755	$25,822	0.700	0.420	40.0%	LNCFS	$7,118,000	$25,822	0.700	0.420	40.0%	180.0	$6.6	$39.5

NOx Control Cost Comparison - Phase II

Plant Name	CCMU NOx Control	CCMU Capital (1994$)	CCMU O&M (1994$)	CCMU Old Emissions	CCMU New Emissions	CCMU % Removal	NYSEG NOx Control	NYSEG Capital (1994$)	NYSEG O&M (1994$)	NYSEG Old Emissions	NYSEG New Emissions	NYSEG % Removal	MW	$/kW CCMU	$/kW NYSEG
Goudey	SCR	$31,459,366	$2,305,213	0.756	0.151	80.0%	SCR	$12,096,000	$2,305,213	0.756	0.151	80.0%	128.0	$245.8	$94.5
Greenidge 4	SCR	$27,124,618	$1,906,954	0.520	0.104	80.0%	SCR	$14,472,000	$1,906,954	0.520	0.104	80.0%	108.0	$251.2	$134.0
Hickling	SCR	$22,662,196	$1,546,965	0.350	0.070	80.0%	SCR	$13,464,000	$1,546,965	0.350	0.070	80.0%	88.0	$257.5	$153.0
Jennison	SCR	$19,984,662	$1,327,009	0.350	0.070	80.0%	SCR	$10,863,000	$1,327,009	0.350	0.070	80.0%	71.0	$281.5	$153.0
Milliken	SCR	$62,451,452	$4,889,745	0.690	0.136	80.0%	SCR	$54,696,000	$9,779,490	0.690	0.138	80.0%	317.0	$197.0	$172.5
Homer City	SCR	$157,943,437	$13,068,133	0.875	0.175	80.0%	SCR	$141,525,006	$13,068,133	0.875	0.175	80.0%	942.0	$167.7	$150.2
Huntley 63-66	SCR	$65,814,236	$5,220,450	1.100	0.220	80.0%	SCR	$67,660,000	$5,220,450	1.100	0.220	80.0%	340.0	$193.6	$199.0
Huntley 67-68	SCR	$70,812,222	$5,601,324	0.700	0.140	80.0%	SCR	$65,250,000	$5,601,324	0.700	0.140	80.0%	375.0	$188.8	$174.0
Dunkirk 3,4	SCR	$71,574,510	$5,627,521	0.700	0.140	80.0%	SCR	$45,240,000	$5,627,521	0.700	0.140	80.0%	380.0	$188.4	$119.1
Russell	SCR	$50,112,687	$3,756,275	0.466	0.093	80.0%	SCR	$35,356,000	$3,758,275	0.466	0.093	80.0%	257.0	$195.0	$137.6
Beebee 12	SCR	$22,204,545	$1,513,442	0.600	0.120	80.0%	SCR	$13,280,000	$1,513,442	0.600	0.120	80.0%	80.0	$277.6	$166.0
Jamestown	SCR	$17,182,142	$1,103,867	0.597	0.119	80.0%	SCR	$13,280,000	$1,103,867	0.597	0.119	80.0%	50.0	$343.6	$265.6
Roseton	SCR	$155,332,287	$11,704,340	0.400	0.080	80.0%	SCR	$108,000,000	$29,133,435	0.400	0.080	80.0%	1,200.0	$129.4	$90.0
Danskammer A/B	SCR	$43,279,724	$3,319,089	0.290	0.058	80.0%	SCR	$21,838,000	$3,319,089	0.290	0.058	80.0%	122.0	$354.8	$179.0
Arthur Kill	LNB+OFA	$10,045,953	$219,142	0.220	0.099	55.0%	LNB+OFA	$28,074,000	$46,509	0.220	0.099	55.0%	826.0	$12.2	$34.0
Astoria A/B	SCR	$389,125,724	$33,994,729	0.290	0.058	80.0%	SCR	$111,454,000	$33,994,729	0.290	0.058	80.0%	1,417.0	$274.6	$78.7
Bowline A/B	SCR	$335,635,140	$28,750,638	0.340	0.068	80.0%	SCR	$34,800,000	$28,750,638	0.340	0.068	80.0%	1,210.0	$277.4	$28.8
East River A/B	SCR	$127,901,812	$10,920,725	0.370	0.074	80.0%	SCR	$51,554,000	$10,920,725	0.370	0.074	80.0%	430.0	$297.4	$119.9
Hudson Ave.	LNB+OFA	$3,844,856	$83,871	0.190	0.086	55.0%	LNB+OFA	$1,584,000	$48,508	0.190	0.086	55.0%	44.0	$87.4	$36.0
Ravenswood A/B	SCR	$472,373,930	$41,190,397	0.340	0.068	80.0%	SCR	$85,130,000	$41,190,397	0.340	0.068	80.0%	1,742.0	$271.2	$48.9
Waterside A/B	LNCFS	$1,450,178	$31,634	0.130	0.076	40.0%	LNCFS	$8,908,000	$31,634	0.130	0.078	40.0%	299.0	$4.9	$29.8
59th Street	LNB+OFA	$4,955,769	$108,105	0.230	0.104	55.0%	LNB+OFA	$1,225,000	$4,608	0.230	0.104	55.0%	102.0	$48.6	$12.0
74th Street	LNCFS	$1,146,030	$24,999	0.210	0.126	40.0%	LNCFS	$952,000	$24,999	0.210	0.126	40.0%	166.0	$6.9	$5.7
Northport 1,2,3	SCR	$318,779,338	$27,321,334	0.280	0.058	80.0%	SCR	$112,245,000	$27,321,334	0.280	0.056	80.0%	1,137.0	$280.4	$98.7
Port Jeff. 3-4	SCR	$116,498,776	$9,701,145	0.280	0.056	80.0%	SCR	$44,802,000	$9,701,145	0.280	0.056	80.0%	388.0	$300.3	$115.5
Glenwood A/B	LNCFS	$1,282,691	$27,981	0.200	0.120	40.0%	LNCFS	$6,732,000	$27,981	0.200	0.120	40.0%	220.0	$5.6	$30.6
Barrett A/B	SCR	$115,416,345	$9,537,505	0.240	0.048	80.0%	SCR	$21,120,000	$9,537,505	0.240	0.048	80.0%	385.0	$299.8	$54.9
Far Rockaway A/B	LNCFS	$989,537	$21,586	0.240	0.144	40.0%	LNCFS	$3,570,000	$21,586	0.240	0.144	40.0%	115.0	$8.6	$31.0
Oswego 5	SCR	$250,323,010	$21,782,018	1.160	0.232	80.0%	SCR	$28,900,000	$21,782,018	1.160	0.232	80.0%	850.0	$294.5	$34.0
Oswego 6	SCR	$244,067,275	$21,000,586	0.300	0.060	80.0%	SCR	$28,900,000	$21,000,586	0.300	0.080	80.0%	850.0	$287.1	$34.0
Albany A/B	SCR	$118,382,977	$9,799,062	0.350	0.070	60.0%	SCR	$37,248,000	$9,799,062	0.350	0.070	80.0%	400.0	$296.0	$93.1
Lovett 1-3	SCR.	$39,307,234	$2,995,916	0.320	0.064	80.0%	SCR	$7,314,000	$2,995,916	0.320	0.064	80.0%	106.3	$369.8	$68.8
Lovett 4,5	SCR	$70,889,022	$5,645,717	0.664	0.133	80.0%	SCR	$50,000,000	$5,645,717	0.664	0.133	80.0%	387.2	$183.1	$129.1
Poletti A/B	SCR	$236,757,321	$20,076,031	0.330	0.066	80.0%	SCR	$34,650,000	$20,076,031	0.330	0.086	80.0%	825.0	$287.0	$42.0
Port Jeff. 1-2	LNCFS	$848,880	$18,517	0.280	0.168	40.0%	LNCFS	$2,652,000	$23,254	0.280	0.168	40.0%	94.0	$9.0	$28.2
Northport 4	SCR	$111,247,105	$9,201,799	0.200	0.040	80.0%	SCR	$37,485,000	$9,201,799	0.200	0.040	80.0%	370.0	$300.7	$101.3
Danskammer 3	SCR	$30,192,387	$2,072,336	0.590	0.118	80.0%	SCR	$19,040,000	$2,072,336	0.590	0.118	80.0%	136.0	$222.0	$140.0
Danskammer 4	SCR	$45,177,233	$3,281,808	0.580	0.116	80.0%	SCR	$27,600,000	$3,281,808	0.580	0.116	80.0%	230.0	$196.4	$120.0
Kintigh	SCR	$119,725,814	$9,833,654	0.550	0.110	80.0%	SCR	$59,082,000	$9,833,654	0.550	0.110	80.0%	684.0	$175.0	$86.4
Oswego 3,4 A/B	SCR	$56,469,163	$4,514,536	0.507	0.101	80.0%	SCR	$56,469,163	$4,514,536	0.507	0.101	80.0%	165.0	$342.2	$342.2
Greenidge 3	SCR	$18,140,461	$1,196,832	0.820	0.164	80.0%	SCR	$11,605,000	$1,196,832	0.820	0.164	80.0%	55.0	$329.8	$211.0
Dunkirk 1,2	SCR	$39,500,831	$2,928,999	0.700	0.140	80.0%	SCR	$30,420,000	$2,928,999	0.700	0.140	80.0%	180.0	$219.4	$169.0

OTHER AGRICULTURAL ECONOMICS WORKING PAPERS

No. 93-05	Dynamic Aggregate Milk Supply Response with Biological Constraints on Dairy Herd Size	Chinhwa Sun Olan D. Forker Harry M. Kaiser
No. 93-06	Measurement of Generic Milk Promotion Effectiveness using an Imperfect Competition Model	Nobuhiro Suzuki John E. Lenz Harry M. Kaiser Kohei Kobayashi Olan D. Forker
No. 93-07	A Spatial Model of Forest Conversion Using a Geographic Information System Part I: Conceptual Outline	Steven W. Stone
No. 93-08	Exchange Rate Reform and Its Effects on Ecuador's Traditional Agricultural Export Sector	Xavier Bejarano David R. Lee Duty Greene
No. 93-09	Processed Sweet Potato: Responding to Kenya's Urban Food Needs	Njeri Gakonyo
No. 93-10	Estimating Consumer Energy Demand Using International Data: Theoretical and Policy Implications	Dale S. Rothman Jong Ho Hong Timothy D. Mount
No. 93-11	Monitored Retrievable Storage of Spent Nuclear Fuel in Indian Country: Liability, Sovereignty, and Socioeconomics	Jon D. Erickson Duane Chapman Ronald E. Johnny
No. 93-12	Urban Influences on Farmland Use in New York State	Thomas A. Hirschl Nelson L. Bills
No. 93-13	An Empirical Evaluation of Incremental Conditional Damages and Benefits	Gregory L. Poe Richard Bishop
No. 94-01	Income and Dietary Change: International Comparisons Using Purchasing-Power-Parity Conversions	Thomas T. Poleman Lillian Thomas