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PLANNING FOR ENVIRONMENTAL CONSTRAINTS ON THE PJM SYSTEM

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EXECUTIVE SUMMARY

Purpose

This study was jointly sponsored by the United States Environmental Protection Agency and the United States Department of Energy to examine the implications of the Clean Air Act Amendments of 1990 on tightly coordinated power pools and to explore the prospects for pool-wide application of integrated resource planning (IRP) principles. The Pennsylvania-New Jersey-Maryland (PJM) system, comprised of 11 major electric utilities, was the topic of this case study.

A major goal of this study was to examine the issues and tradeoffs involved in meeting multiple environmental objectives in resource and compliance planning. The study explores the contributions that various resource alternatives can make to emissions control, and how these options could be combined to achieve a hypothetical "no regrets" resource acquisition strategy.

The study was not intended to provide a precise road map to meeting air emission constraints, nor was it intended to represent a full-fledged integrated resource plan. Moreover, it is not a critique of the resource or compliance plans of the individual PJM utilities. Rather, the study should be viewed as a scoping exercise that identifies possible combinations of options that could be used to meet several environmental constraints.

Reference Case

MSB Energy Associates, Inc. developed a reference case, depicting the current PJM system and its expected resource acquisitions, based on information obtained from individual utilities and publicly available sources about the utilities' plans. The reference case met Phase I SO₂ requirements and the March 1994 Title IV NO_x regulations for Phase I units. Because the utilities have not finalized their Phase II Clean Air Act compliance plans, the reference case did not meet the Clean Air Act's Phase II requirements for SO₂ reduction or any NO_x requirements beyond the March 1994 regulations. Nonetheless, it did provide a base against which to compare the alternate plans developed in this study on the basis of their ability to meet environmental constraints. It left open the opportunity to incorporate elements of the emission reduction options analyzed here into Phase II compliance plans.

Environmental Constraints

Next, we established emission constraints for SO₂, NO_x, and CO₂ that reflect existing

and/or possible future environmental regulations, including the SO₂ and NO_x provisions of the 1990 Clean Air Act Amendments and the Title IV NO_x regulations issued in March 1994. Although future environmental regulations cannot be known with certainty, it is possible to make educated guesses about emissions limits. This is a foundation for a "no regrets" policy regarding air pollutant emissions -- one in which the planning process recognizes the potential for new or more strict future regulation. For the purposes of this study, we assumed emissions constraints on the PJM system consisting of:

- SO₂ emissions limits equal to those required by Phases I and II of the Clean Air Act Amendments of 1990 (the reference case met the Phase I limits);
- Three variations on NO_x emission limits:
 - 1) NO_x emission rate reduced to between 0.45 and 0.5 pounds NO_x per MMBtu through the use of low-NO_x burners at all plants. (Use of low-NO_x burners at Phase I-affected plants as required by the March 1994 Title IV regulations was included in the reference case);
 - 2) NO_x emission rate reduced to about 10 percent of the uncontrolled rate (90 percent reduction in emission rate achievable through Selective Catalytic Reduction);
 - 3) NO_x emissions cap, limiting PJM emissions to 200,000 tons per year (40 percent of 1990 emissions) -- this was the limit used in developing alternate plans;
- CO₂ emissions stabilized at 1990 levels (125,000,000 tons of CO₂ per year for the PJM utilities).

By the year 2010, the emissions from the reference case exceeded the SO₂ constraint by 42 percent, the CO₂ constraint by 46 percent, and the NO_x constraint (200,000 ton/year cap) by nearly 2.5 times.¹ In these scenarios, the reference case system was dispatched to minimize operating cost. If the reference case system were instead re-dispatched to reduce emissions, the SO₂ constraint could be achieved, but not economically relative to other means of reducing SO₂. The CO₂ and NO_x constraints

¹ This is not to imply that the PJM utilities are not intending to comply with future environmental regulations or with voluntary efforts to reduce CO₂, only that plans are not yet in place. One PJM utility, Public Service Electric and Gas Co., recently announced its intention to voluntarily reduce its emissions of greenhouse gasses by five million metric tons by the year 2000 under DOE's "Climate Challenge" program. (Electric Utility Week, April 25, 1994)

could not be met using only system re-dispatching.

Development of Alternate Plans

Evaluating the effectiveness of using different energy resources to meet the environmental constraints described above was the central task of the project. We developed four "single-option" (aggressive use of one type of resource) planning scenarios to evaluate how far any one single option might be able to reduce SO₂, NO_x, and CO₂, and at what cost. After developing these resource options, we combined their best features into a composite plan, which sought to reduce emissions at lower cost. Alternate plans evaluated included:

- Plant-based plan relying on scrubbers for SO₂ control and low-NO_x burners and selective catalytic reduction for NO_x control. Also evaluated were fuel switching, conversion to natural gas, and supply-side efficiency improvements.
- Demand-side management-based plan relying on aggressive implementation of demand-side measures costing an average of five cents per kWh. DSM was used to eliminate about one third of the energy that would have been supplied in the reference case.
- Renewable-energy based plan relying on wind, photovoltaics, and the combustion of landfill gas and wood/agricultural/municipal wastes. Solar thermal and geothermal resources were also considered.
- Independent power producer-based (IPP) plan relying on purchasing electricity from non-utility sources operating natural gas-fired combined cycle units. Also considered were cogeneration projects and other fuel types. (Although the modeling used for this study ultimately relied upon gas-fired combined cycle units, utilities evaluating IPPs should analyze all locally available fuel types and IPP configurations.)
- Composite plan relying on a mix of demand-side resources (at an average cost of three cents per kWh), wind generation, combustion of wood/agricultural wastes, independent power producers (using gas-fired combined cycle units), and plant-based NO_x control. The composite plan was also designed to meet the secondary objective of lowering cost.

Plant-based options consist of add-on technologies to conventional utility facilities to meet environmental restrictions. These add-on technologies, such as scrubbers to reduce SO₂ and selective catalytic reduction or low-NO_x burners to reduce NO_x, are designed to reduce pollutant emission rates, and thus are used to meet emission *rate* standards. Reduced emission rates, depending on how much the facility is used, may

also help meet emission *cap* standards. The other three options rely on reducing utility fossil-plant usage to control emissions. These options are useful to meet emission *cap* standards and are of no value in meeting emission *rate* standards.

Emission Levels of Alternate Plans

None of the alternate plans met all of the environmental constraints. All five alternate plans were designed to meet the Phase II SO₂ constraint. The plant-based plan and the composite plan relying on plant-based technologies were the only plans that met the NO_x constraint (the 200,000 ton cap). Only the DSM-based plan met the CO₂ constraint. Although not specifically analyzed, it would follow that the DSM-based plan coupled with plant-based NO_x controls would have the greatest potential for meeting all the emissions constraints. The following table summarizes whether or not each plan met each environmental constraint.

**TABLE ES-1
MEETING OF SO₂, NO_x, AND CO₂ CONSTRAINTS BY
REFERENCE CASE AND ALTERNATE PLANS**

Plan	Sulfur Dioxide	Oxides of Nitrogen	Carbon Dioxide
Reference Case	No	No	No
Plant-Based Plan	Yes	Yes	No
DSM-Based Plan	Yes	No	Yes, after 2001
Renewables-Based Plan	Yes	No	?
IPP-Based Plan	Yes	No	No
Composite Plan	Yes	Yes, after 2001	No

Figure ES-1 illustrates the SO₂ levels associated with the alternate plans in the year 2010. Emissions of SO₂ were the same for all five plans because all the plans were designed to meet the SO₂ constraint. The reference case did not meet the Phase II Clean Air Act requirements.

Figure ES-2 shows that two of the plans -- the plant-based plan and the composite plan -- met the NO_x constraint (the 200,000 ton cap) in the year 2010. The DSM-based plan and the IPP-based plan did not meet the constraint, although emissions were lower than in the reference case. The renewables-based plan is not shown because it

was not possible to determine the level of NO_x emissions for that plan (as discussed in Chapter IV, "Comparison of The Five Alternate Plans"). We included the renewables-based plan in Table ES-1, however, because, although we could not determine the NO_x emissions level, it was definitely greater than the NO_x level associated with the DSM-based plan.

Figure ES-3 shows that only the DSM-based plan met the CO₂ constraint in the year 2010. The renewables-based plan is not shown because it was not possible to determine the CO₂ emissions for that plan, as discussed in Chapter IV, "Comparison of The Five Alternate Plans").

Cost Comparison of Alternate Plans

We analyzed the costs of the single-option plans and the composite plan as compared to the cost of the reference case. The reference case was treated as the base cost, and differences (both positive and negative) between it and the alternatives were determined. The costs reported are in 1992 dollars (without inflation). The costs for the plant-based plan included the cost of SO₂ and NO_x emission-reduction equipment. The costs for the DSM-based plan included the cost of sufficient DSM to reduce system SO₂ emissions low enough to meet Phase II requirements. Similarly, the costs for the renewables-based plan and the IPP-based plan included the cost of sufficient amounts of those resources to reduce system SO₂ emissions low enough to meet Phase II requirements. The composite plan costs included the cost of some DSM, some renewables, some IPPs, and some NO_x emission-reduction technologies.

The composite plan resulted in the lowest costs of the plans analyzed. This was because it relied heavily on DSM and renewable resources whose costs were less than the PJM pool's avoided costs. Since the average cost of resources in the DSM-based plan equalled the avoided cost of the reference case, the DSM-based plan had a comparative cost of zero. Each of the other alternate plans was forced to include resources whose costs, on average, exceeded the pool's avoided costs for the reference case. Nonetheless, these resources may still be cost-effective relative to the pool's avoided costs for a compliance plan, which would be the appropriate comparison if the pool were required to meet the environmental constraints. The following table compares costs of the plans. All costs were measured as a differential from the reference case. A zero means costs were equal to the reference case.

TABLE ES-2
ANNUAL COSTS OF ALTERNATE PLANS RELATIVE TO REFERENCE CASE
(Millions of dollars compared to the reference case)

Plan	2000	2005	2010
Reference Case	0	0	0
Plant-Based Plan	170	375	385
DSM-Based Plan	0	0	0
Renewables-Based Plan	0	921	1,275
IPP-Based Plan	0	127	154
Composite Plan	-258	-514	-560

Conclusions

More specific analysis would be necessary to finalize design prior to the implementation of any of the plans. We would expect, however, that the characteristics and trends observed in this study would be proven true in a more detailed analysis. Some generally applicable characteristics and trends observed in this study include:

- Demand-side management, overall, has the largest potential for economically achieving caps on all three pollutants: SO₂, NO_x, and CO₂. The ability to implement high levels of DSM sets the limit on the use of this cost-effective resource as an emissions reduction strategy.
- Plant-based options are needed for environmental constraints that are based on controlling emission rates.
- Rigorous constraints -- such as those established for this study -- require the application of more than one approach.
- Of the constraints assumed for this study, the SO₂ constraints are the least costly and most technically feasible to achieve, followed by a NO_x cap. Achieving a CO₂ cap of the magnitude assumed in this study would be the most difficult.
- Environmental dispatch used alone is not a cost-effective means of achieving

large amounts of emissions reductions.

The approach developed in this study -- comparing the emissions characteristics and costs of a wide range of alternatives designed to meet both current and future regulations -- could be used to help incorporate environmental goals into utility planning. This type of approach would provide maximum flexibility in the development of "no regrets" resource acquisition strategies.

Figure ES-1

Figure ES-2

Figure ES-3

I. INTRODUCTION

This report represents the culmination of a three-year project jointly sponsored by the United States Environmental Protection Agency and the United States Department of Energy. The study's purpose was to examine the implications of the Clean Air Act Amendments of 1990 on tightly coordinated power pools and to explore the prospects for pool-wide application of integrated resource planning (IRP) principles. The study did not address regional regulation approaches, which are the province of state and federal regulatory agencies. The Pennsylvania-New Jersey-Maryland (PJM) interconnection, comprised of 11 major electric utilities, was the topic of this case study.

The PJM system was first modeled to represent, as accurately as possible, the emissions and costs that would result from the PJM system being designed to meet only Clean Air Act Phase I SO_2 and NO_x constraints. The result of this modeling effort was the reference case.² Next, scenarios were created for current and possible future constraints in sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and carbon dioxide (CO_2). The emission reductions that would be required of the PJM system to meet these scenarios were then determined.

Next, to assess the contributions that various resource options could make to emissions control, four regional "single-option" approaches to meeting PJM's forecasted energy and capacity needs within the emissions constraints were developed and modeled. They included a plant-based plan (employing scrubbers, fuel-switching, selective catalytic reduction of NO_x , etc.), a demand-side management-based plan, a plan based on renewable energy resources, and a plan based on independent power production. The best features of these single-option cases were combined to form a fifth, composite plan. The emissions and costs impacts of these five alternate plans were compared with each other and with the reference case.

Although this study does not represent a precise road map to meeting air emissions requirements, the characteristics and trends identified herein as being associated with environmental compliance through the use of plant-based controls, DSM, renewables, independent power, and a composite approach are typical of what would be expected from a more detailed analysis. This approach -- comparing the emissions characteristics and costs of a wide range of alternatives on a regional basis to meet current and future regulations -- would permit utilities maximum flexibility in developing "no regrets" resource acquisition strategies.

² MSB Energy Associates, Inc., Integrated Planning in the PJM Power Pool: Reference Case. Revised Draft Report to the United States Environmental Protection Agency/Acid Rain Division, and the United States Department of Energy. January 30, 1992.

The study was not intended to represent a full-fledged, detailed integrated resource plan for the PJM system. Simplifying assumptions were necessary to data regarding existing plants and future resource options. Moreover, the study was not a critique of the resource or compliance plans of the individual PJM utilities. Rather, it should be viewed as a scoping exercise that identifies possible approaches and combinations of options that could be used to meet several environmental constraints.

II. ENVIRONMENTAL CONSTRAINTS ON THE PJM SYSTEM

This chapter provides a snapshot of the existing PJM system and identifies the environmental constraints that form the parameters for the regional approaches analyzed in this study. The chapter begins with a description of the PJM system and the costs and emissions levels of the pollutants under study associated with the reference case (the PJM system configured to meet only Clean Air Act Amendment Phase I SO₂ requirements and the March 1994 NO_x requirements affecting Phase I units)³. Next, the pollution-reduction scenario assumed for the purpose of the study, which covers the period 1995-2010, is described. Finally, the impacts of this pollution reduction scenario -- emissions that would need to be avoided on the reference case PJM system -- are identified. Modeling methods are described alongside the study's results.

A. THE PJM SYSTEM

System Description

The PJM Power Pool is an inter-state organization consisting of 11 major electric utilities and their associates. Some salient characteristics of the system are included below.

- Member utilities:
 - Atlantic City Electric Company (AECO)
 - Baltimore Gas and Electric Company (BG&E)
 - Delmarva Power and Light Company (DP&L)
 - Jersey Central Power and Light Company (JCP&L)
 - Metropolitan Edison Company (MetEd)
 - Pennsylvania Electric Company (Penelec)
 - Pennsylvania Power and Light Company (PP&L)
 - PECO Energy Company (PECO)
 - Potomac Electric Power Company (PEPCO)
 - Public Service Electric and Gas Company (PSE&G)
 - UGI Corporation (UGI)
- Approximately 32 percent of the system is coal fired, and 29 percent is powered by nuclear energy. Oil-fired generation powers approximately

³ Unless otherwise noted, all costs in this study are in constant 1992 dollars.

22 percent of PJM system capacity, and natural gas and hydro power make up 12 and 5 percent, respectively.

- Demand for 45,900 MWe in capacity and approximately 249 million MWh in energy is forecasted for 1995. By 2010, demand is forecasted to increase to 56,400 MWe and approximately 318 million MWh.
- The PJM system includes 10 EPA-designated Phase I-affected plants, comprised of 23 affected units, that are allocated 432,000 SO₂ allowances per year. The Phase II-affected units include all PJM fossil-fueled units except those with capacity of or under 25 MWe and natural gas-fired units. Phase II-affected plants are allocated a total of 660,000 SO₂ allowances per year. The PJM utilities will also earn a total of approximately 338,000 bonus allowances as a reward for Phase I scrubber installation.⁴

Modeling the Reference Case

The initial step in this study consisted of developing a reference case to represent all of the PJM utilities as a single integrated unit. The reference case detailed system expansion plans, current and future demand-side management (DSM) activities, and system operational patterns and costs through the 2010 time horizon. The reference case was used as the basis of comparison between alternate planning scenarios that analyzed the potential costs and benefits of emission reduction techniques and options. To the greatest extent possible, the reference case was intended to represent the PJM utilities' current plans, including compliance with the Phase I SO₂ requirements of the Clean Air Act Amendments and with March 1994 Title IV NO_x regulations. Utilities have not finalized their Phase II compliance plans, which are therefore not included in the reference case. (The alternate plans considered in the study, however, were designed to achieve Phase II compliance.)

To develop the reference case, an extensive data collection and analysis effort was carried out for each of the PJM utilities. Information regarding power plant performance characteristics and costs was obtained for every operating utility power plant and non-utility generating unit in the PJM system.

Plant information was obtained from one of two general sources. Six of the eleven PJM utilities provided plant-specific data that identified incremental heat rates, economic capacity blocks, operation and maintenance costs, outage rates, emission rates, and fuel types. The utility-provided data were not complete in all cases and

⁴ The Phase I and Phase II plants are identified in Appendix A.

were supplemented from documents filed by PJM utilities before state and federal authorities, such as FERC Form 1, EIA-767, and the NERC Generation Availability Report. Data for the remaining five utilities were also obtained from these documents.⁵

Following the data collection effort, a model was developed that dispatched the plants of the PJM utilities as a single system. A proprietary production-simulation model, MSB-MOD⁶, was used for this effort. The plant data obtained in the first task formed the basis of the model inputs. MSB-MOD simulated system operation and plant dispatch, provided year-by-year data on power plant operations, including average and marginal operating costs, plant-by-plant generation and emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂). Some of the data used in the model were, as previously stated, developed from publicly available information. As such, some of the data were not as detailed as they would be if they were provided by the utilities themselves. Specifically, average power plant heat rates were used in lieu of incremental heat rates for some plants for which incremental heat rate data were not available. In addition, fixed and variable operations and maintenance (O&M) costs had to be estimated. If comprehensive incremental heat rate data had been available, the results of the modeling would have been more precise, particularly over the near term. Given the model's fifteen-year time frame, however, the use of average heat rates and approximated fixed and variable O&M costs should lead to reasonable results. Likewise, the inevitable modifications to forecasts, plant parameters, and other factors since the data were collected in 1991 and updated in 1993 would be expected to result in some changes to emissions and costs but would not significantly change the basic trends reflected in the study.

Next in the development of the reference case was the identification of system-wide supply-side additions, retirements, and changes. These changes included both utility and non-utility generation capacity. The utility expansion plan was developed based on utility-provided data and publicly available data (IE-411), but these two sources covered system plans only through 2002. Beyond 2002, further capacity additions were made that would meet estimated future loads and maintain system reserve

⁵ CO₂ emissions data were derived from emissions information contained in Pace University Center for Environmental Legal Studies, Environmental Costs of Electricity, 1990. These data were not plant-specific, but were specific to type of plant by fuel. The more-recent 1993 EIA report, Emissions of Greenhouse Gases in the United States, 1985-1990, also lacked plant-specific data.

⁶ MSB-MOD is a production-simulation model developed by MSB Energy Associates, Inc. for the purpose of modeling the dispatch of power plants on a utility system and the resulting costs, fuel use, and emissions.

margins. As part of the expansion plan, all retired capacity was assumed to be replaced with similar capacity. A mix of gas combustion turbine and combined cycle (4712 MW) and pulverized coal (1800 MW) units was included to meet demand. Pulverized coal was selected in recognition of the fact that baseload additions will be necessary in addition to intermediate and peaking units, and pulverized coal provides a relatively economic and clean baseload option. The assumptions used for long-term projections of system additions are detailed in Table II-1.

**TABLE II-1
RESOURCE ADDITION ASSUMPTIONS: 2003 THROUGH 2010
(MWe)**

Unit Type*	2003	2004	2005	2006	2007	2008	2009	2010
CT 40MWe	32	0	0	0	0	0	0	0
CT 80MWe	160	0	160	80	80	160	80	0
CT 140MWe	420	280	280	420	280	140	280	0
CC 120MWe	0	0	120	0	120	240	120	0
CC 210MWe	0	630	210	210	0	210	0	0
PC 300MWe	300	300	300	300	300	0	300	0

* Unit types: CT=combustion turbine, CC=combined cycle, PC=pulverized coal.

For the plants assumed for the post-2002 period, variable and fixed operating and maintenance costs were derived from EPRI standardized plant descriptions (EPRI, 1989). Emission rates established by the Nevada Public Service Commission for fossil fuels were used to model emissions of plant additions in the reference case, and fuel costs were derived from averages over the PJM system. (Nevada Public Service Commission, 1991) A summary of technical performance data, costs, and emissions data for new plants is provided in Tables II-2 and II-3.

The non-utility expansion plan includes capacity from non-utility generators (NUGs) and system purchases. NUGs were categorized by fuel type and treated as individual plants in the production-simulation model, which allowed emissions identification and tracking.

To the extent that the expansion plan employed by the PJM utilities changes over time or differs from the assumptions made regarding the post-2002 period, emissions trends will change. Since the major driver of emissions on the PJM system is existing units, however, rather than new units being added, the impact of a changed expansion plan on total emissions would be minimal.

TABLE II-2

**CAPACITY COST AND PERFORMANCE DATA
OF PLANT ADDITIONS (1989\$)**

Unit Type	Capacity MWe	Heat Rate (BTU/kWhe)	Maint (wks)	Forced Outage Rate	Variable O&M (\$/MWh)	Fixed O&M (\$/kW-yr)	Fuel Type
CT 40MWe	40	12,600	2	0.035	10.50	1.0	Natural gas
CT 80MWe	80	12,200	2	0.035	8.01	0.7	Natural gas
CT 140MWe	140	11,500	2	0.035	7.70	0.7	Natural gas
CC 120MWe	120	8,000	2	0.055	4.06	4.1	Natural gas
CC 210MWe	210	7,500	3	0.055	3.85	3.9	Natural gas
PC 300MWe	300	9,500	6	0.038	4.68	29.2	Coal

TABLE II-3

**EMISSION RATES
OF PLANT ADDITIONS
lbs/MMBTU**

Unit Type	SO ₂	NO _x	CO ₂
CT 40MWe	0	0.0500	110
CT 80MWe	0	0.0500	110
CT 140MWe	0	0.0500	110
CC 120MWe	0	0.0500	110
CC 210MWe	0	0.0500	110
PC 300MWe	0.6	0.6000	209

Unit Types: CT = combustion turbine, CC = combined cycle, PC = pulverized coal.

Emissions in the Reference Case

Total Emissions

Projected emissions for the PJM system were developed by running the production-simulation model of the PJM system as a jointly dispatched pool. This in fact reflects how the pool is actually dispatched. Each pool member provides the pool operating center with cost figures for each power plant, and the pool as a whole is dispatched to meet the total pool load on a least-cost basis. Emissions projections were based on the long-run system plans set forth by the various utilities in their public filings. These long-run system plans included forecasts, plant additions and retirement plans, and proposed SO₂ control additions. The proposed SO₂ control additions included in the modeling included those at Conemaugh, B. L. England, and Chalk Point (all Phase I-affected units, whose emission controls will bring the PJM system into compliance with Phase I).

The production-simulation model used plant heat rates (in Btus per kWh) and emission factors (in pounds per million Btus) to calculate plant emission rates (in pounds per kWh). For plants with flue gas desulfurization, the reduction in SO₂ emissions due to that process was also modeled into the calculation. Plant dispatch was based on variable operating costs. These included the cost of fuel and of variable operating and maintenance costs. With the passage of the Clean Air Act Amendments, SO₂ (from affected plants) became a real cost to utilities. The cost of SO₂ from affected plants was therefore included in the dispatch as a variable cost. In determining what cost to assume for SO₂ in the dispatch, we considered using both \$250 per ton and \$350 per ton. The effect of varying the cost over this range was very small -- typically affecting SO₂ emissions by well under one percent. Therefore, we settled on a middle-of-the-range value of \$300 per ton for modeling purposes.

Emissions from the perspective of the Clean Air Act Amendments are not the same as total emissions. This is especially true in the 1995 to 1999 time frame. During this period (the Phase I period) only 10 plants on the PJM system are classified as affected. These plants represent less than half of the total SO₂ emissions on the system. From the year 2000 on (the Phase II period), most of the SO₂ emitters on the PJM system become affected units. Since, for SO₂, the important question from the perspective of the Clean Air Act is the level of emissions from affected units, SO₂ emission levels are reported separately in Table II-4 for Clean Air Act-affected units and all PJM units.

Projected emissions of SO₂ from affected plants on the PJM system were approximately 526,000 tons per year in 1995, 385,000 to 389,000 tons per year from 1996 to 1999, and 999,000 to 1,035,000 tons per year from the year 2000 on (falling slightly in later years). Actual emissions (including those from non-affected plants)

were approximately 1,159,000 tons in 1995 and 1,025,000 tons per year from 1996 on. Emissions dropped in 1996 due to the addition of SO₂ controls on certain units in 1996. The allowable Phase I and Phase II emissions from affected units were approximately 432,000 tons from 1995 to 1999, 660,000 tons from 2000 to 2009, and 650,000 tons from 2010 on. Thus, under reference case assumptions, PJM would have exceeded its allowed emissions levels by approximately 350,000 to 370,000 tons per year from the year 2000 on, were it not for the utilities' attainment of a total of approximately 338,000 bonus allowances as a result of scrubbing during Phase I. These allowances kept the system in compliance until 2001. The pool was in compliance for Phase I in the reference case.

**TABLE II-4
EMISSIONS FROM THE PJM SYSTEM
(TONS)**

Year	SO ₂ Affected Plants	SO ₂ All Plants	NO _x All Plants	CO ₂ All Plants
1995	526,000	1,159,000	440,000	140,600,000
1996	385,000	1,025,000	447,000	143,400,000
1997	386,000	1,025,000	448,000	145,000,000
1998	388,000	1,025,000	449,000	147,200,000
1999	389,000	1,022,000	450,000	149,500,000
2000	1,033,000	1,034,000	459,000	153,500,000
2001	1,035,000	1,036,000	463,000	156,600,000
2002	1,033,000	1,034,000	466,000	159,100,000
2003	1,034,000	1,035,000	473,000	163,000,000
2004	1,028,000	1,029,000	476,000	165,300,000
2005	1,029,000	1,030,000	481,000	168,600,000
2006	1,016,000	1,017,000	485,000	171,800,000
2007	1,016,000	1,016,000	492,000	175,400,000
2008	1,004,000	1,005,000	489,000	177,400,000
2009	999,000	1,000,000	495,000	180,900,000
2010	1,001,000	1,002,000	501,000	183,500,000

In addition to SO₂ emissions, we identified emissions of NO_x and CO₂. NO_x emissions were estimated to be approximately 440,000 tons per year in 1995, increasing to 501,000 tons per year by 2010. CO₂ emissions were 141,000,000 tons per year in 1995, increasing to 183,000,000 tons per year in 2010.

PJM utilities will need to take additional actions to reduce SO₂ emissions beyond

those already planned in order to meet Clean Air Act Amendments SO₂ requirements in Phase II. Compliance with the March 1994 Title IV NO_x regulations (i.e., reductions in NO_x emissions for Phase I units to 0.45 - 0.50 lb/MMBtu) have been factored into the reference case and are reflected in Table II-4. Regulations further restricting NO_x (e.g., Title IV Group 2 regulations or State Implementation Plan requirements) and/or CO₂ emissions, were they to be promulgated, would also necessitate action by the PJM utilities.

Approaches to reducing emissions fall into two categories. One is what we have called "plant-based options." These are approaches that lead to reduced emissions at conventional generating plants and include such things as scrubbing, fuel switching, gas co-firing, and repowering. The other category we have termed "energy reduction options". These are approaches that lead to reduced MWh generation at conventional generating facilities and include such things as demand-side management, renewable energy generation, and independent power production.

Marginal Emissions

As a first step to evaluating the energy reduction approaches to emission reduction, we estimated marginal emission rates for the PJM system. These marginal emission rates provided guidance as to how much it would be necessary to reduce the MWh generation from the conventional generating system to bring the system into compliance with an emission constraint. We evaluated the marginal emission rates at three different levels, as illustrated in Table II-5.

Reductions in the amount of conventional generation, while still serving energy needs, could result from DSM, renewable energy, independent power production, or supply-side efficiency improvements. As a first approximation, these alternate resources reduce emissions by an amount equal to the amount of conventional energy they displace multiplied by the marginal emission rates. Thus, we can estimate the amount of conventional generation that would have to be displaced to reduce emissions enough to comply with the constraints.

To obtain emission rates that approximate true marginal rates, we evaluated system reductions of 500 MWe, approximately one percent of the PJM system load. We then evaluated a somewhat larger decrement, 2,500 MWe, approximately five percent of the system load. Finally, we determined how much MWh reduction would be necessary to meet the Phase II Clean Air Act Amendments requirements for SO₂ by energy reductions alone. (The details of this analysis are discussed later in the report, but the level of reduction required was approximately 10,000 to 12,000 MWe, varying over the years.) While there were some differences among the marginal emission rates of these different levels, the differences were less than might be expected.

TABLE II-5
DECREMENTAL EMISSION RATES ON THE PJM SYSTEM
(POUNDS PER KWH)

<u>Year 2000</u>	<u>SO₂</u>	<u>NO_x</u>	<u>CO₂</u>
On-Pk/500 MWe	0.00058	0.00401	1.283
Off-Pk/500 MWe	0.00631	0.00391	1.218
Annual/500 MWe	0.00508	0.00410	1.280
On-Pk/2500 MWe	0.00246	0.00436	1.417
Off-Pk/2500 MWe	0.00791	0.00411	1.259
Annual/2500 MWe	0.00607	0.00421	1.322
Phase II SO ₂ Compliance Through Energy Reduction	0.00855	0.00471	1.363
<u>Year 2005</u>	<u>SO₂</u>	<u>NO_x</u>	<u>CO₂</u>
On-Pk/500 MWe	0.00388	0.00403	1.281
Off-Pk/500 MWe	0.00454	0.00329	1.001
Annual/500 MWe	0.00411	0.00360	1.114
On-Pk/2500 MWe	0.00366	0.00364	1.217
Off-Pk/2500 MWe	0.00487	0.00346	0.998
Annual/2500 MWe	0.00468	0.00350	1.082
Phase II SO ₂ Compliance Through Energy Reduction	0.00532	0.00395	1.055
<u>Year 2010</u>	<u>SO₂</u>	<u>NO_x</u>	<u>CO₂</u>
On-Pk/500 MWe	0.00659	0.00319	1.284
Off-Pk/500 MWe	0.00230	0.00300	0.878
Annual/500 MWe	0.00366	0.00333	1.067
On-Pk/2500 MWe	0.00361	0.00366	1.197
Off-Pk/2500 MWe	0.00276	0.00282	0.799
Annual/2500 MWe	0.00311	0.00323	0.976
Phase II SO ₂ Compliance Through Energy Reduction	0.00509	0.00409	1.081

Costs of the Reference Case

Revenue Requirements

In this study, we took a differential approach to comparing the costs of alternate scenarios. Rather than undertaking a detailed year-by-year revenue requirements approach to each scenario, we focused on the differences between the reference case and other scenarios. Variable operating and maintenance costs, fixed operating and maintenance costs, and capital costs that varied between scenarios were included in the cost comparisons. Capital costs and fixed operating and maintenance costs associated with the existing system as currently configured were constant across all scenarios and were not included in the cost comparisons. The cost of the reference case was treated as a baseline against which other costs were compared.

As noted in the previous section, the reference case did not meet Clean Air Act Amendments SO₂ requirements in Phase II.⁷ Therefore, even under the utilities' proposed plans, additional investments will be necessary to meet the requirements of the law. These additional investments to meet Clean Air Act Amendments requirements were calculated and treated as variations from the reference case.

The costs reported for scenarios may be either positive or negative. Negative costs mean that the scenario was less expensive than the reference case scenario.

Operating Costs

Operating costs, shown in Table II-6, were for the most part developed using a production-simulation model of the PJM system. The model dispatched power plants against the system loads based on an economic dispatch modified to recognize the costs of SO₂ emissions. The model results did not, however, represent all of the operating costs. We included only the *variable* operating and maintenance costs for existing plants in the modeling. *Fixed* operating and maintenance costs for existing units were excluded because they were constant across all scenarios. Regardless of the level of operations at a power plant, the fixed operating and maintenance costs are incurred. Fixed operating and maintenance costs for *new* plant were included, since these costs may well be different between scenarios.

Some of the operating costs were developed outside the production-simulation

⁷ This is not to imply that the PJM utilities are not intending to comply with future environmental regulations or with voluntary efforts to reduce CO₂, only that plans are not yet in place.

model. Examples are the cost of renewable energy resources, demand-side management, and the operating cost of scrubbers needed to meet the Phase II Clean Air Act Amendments requirements. Treatment of the costs of purchases from independent power producers varied with the details of the purchase arrangement.

TABLE II-6
REFERENCE CASE: PEAK DEMAND, ENERGY REQUIREMENTS, AND
OPERATING COST OF THE PJM SYSTEM

Year	Peak (MWe)	Energy (MWh)	Operating Cost*
1995	45,900	248,800,000	\$4,836,000,000
1996	46,600	252,800,000	\$5,034,000,000
1997	47,300	257,800,000	\$5,161,000,000
1998	48,000	261,800,000	\$5,330,000,000
1999	48,700	265,800,000	\$5,498,000,000
2000	49,300	270,800,000	\$5,694,000,000
2001	50,000	275,800,000	\$5,928,000,000
2002	50,700	279,800,000	\$5,973,000,000
2003	51,400	284,800,000	\$6,154,000,000
2004	52,200	289,800,000	\$6,272,000,000
2005	52,900	294,800,000	\$6,411,000,000
2006	53,700	299,800,000	\$6,579,000,000
2007	54,400	304,800,000	\$6,744,000,000
2008	55,200	309,800,000	\$6,941,000,000
2009	56,000	314,800,000	\$7,114,000,000
2010	56,400	317,800,000	\$7,264,000,000

* Note that the operating costs as reported in this table do not include fixed operating and maintenance costs for existing units.

Capital Costs

In this study, capital costs were all treated as differentials from the reference case. This enabled us to avoid the necessity of calculating all of the capital costs and revenue requirements connected with the existing system and planned additions in the reference case. Instead, we focussed on the additional costs and/or savings connected with modifications to the reference case. These adjustments included such things as the cost of scrubbers or other clean-up approach used to meet Phase II Clean Air Act Amendments requirements, the cost of additional demand-side management, renewable resources, and/or independent power production, and the reductions in capital investment in conventional generation that demand-side

management, renewable resources, or independent power production would make possible.

B. ENVIRONMENTAL CONSTRAINTS AND THE PJM SYSTEM

Description of Constraints

Since the 1970s, federal, state and local air quality laws have been created and amended with some frequency. Although it is impossible to predict with certainty the future course of regulation, it is possible to make some educated guesses, based upon recent scientific, political, and legal activity, about possible future environmental requirements. By anticipating and planning for future constraints, utilities can minimize compliance costs. A resource acquisition policy that has been developed to minimize the cost of complying with future constraints can be thought of as a policy of "no regrets."

Constraints on three air pollutants were evaluated vis-a-vis the PJM system in this study. They included:

- The SO₂ emission reduction requirements of Title IV of the 1990 Clean Air Act Amendments. To achieve the goal of reducing annual SO₂ emissions nationwide by 10 million tons below the 1980 level, the law requires reductions in SO₂ emissions in 110 plants in 21 eastern states beginning in 1995 (Phase I), and reductions in most plants over 25 MWe beginning in the year 2000 (Phase II). The law creates a new tradable commodity, the SO₂ emission allowance, each of which represents the authorization to emit one ton of SO₂. Each electric utility has been allocated an annual number of allowances, based upon past emission rates and plant utilization. Allowances may be bought, sold, traded, or banked for use in future years.

Although further constraints on SO₂ emissions are the subject of current discussion (i.e., both shorter averaging periods for the ambient SO₂ standard and tighter ambient standards have been discussed), for the purposes of this study we have limited the constraint to the existing SO₂ regulations.

- Reductions in the level of NO_x emissions. Control of NO_x emissions falls under both Title I and Title IV of the 1990 Clean Air Act Amendments. Title IV requires a reduction in NO_x emission levels of two million tons below 1980 levels. Under Title IV, the U.S. Environmental Protection Agency promulgated regulations in March 1994 limiting NO_x to 0.45 to 0.50 lbs/MMBtu at Phase I-affected units. These regulations were factored into the reference case.

Title I, while not prescriptive, requires attainment of the national ambient air quality standard for ozone. As a first step toward attainment, most Eastern states have adopted Reasonably Available Control Technology (RACT) standards for all fossil fuel utility boilers. Although RACT rules vary from

state to state, generally NO_x emissions are limited to about 0.45 to 0.50 lbs/MMBtu, just as is required in Title IV.⁸ A system of marketable permits for NO_x emissions in the Northeast – similar to the allowance system now in place for SO₂ – is possible considering that agencies expect the ultimate level of NO_x reduction required for attainment will be large.

To reflect existing and possible future restrictions on NO_x emissions, we imposed on the PJM system for the purpose of this study three NO_x reduction scenarios: across-the-board application of combustion controls to reduce the NO_x emission *rate*, across-the-board application of post-combustion NO_x reduction technologies to all large NO_x emitters, also with the intention of reducing the NO_x emission *rate*, and a *cap* in NO_x emissions at 40 percent of 1990 NO_x levels. The cap approach was used in analyzing the cost and compliance of alternate plans. We also estimated the amount of NO_x reduction that will be associated with the implementation of the March 1994 NO_x restriction on Phase I units, which was included in the reference case.

- Stabilization of CO₂ emissions at 1990 levels. Although CO₂ emissions are not currently regulated, concern over the contribution of CO₂ to global warming has mounted greatly in recent years. The United States is a party to an international agreement to limit greenhouse gasses, the 1992 Framework Convention on Climate Change. The Clinton Administration's Climate Change Action Plan of October 1993 is designed to stabilize U.S. greenhouse gas emissions at 1990 levels by the year 2000.

Emissions Impacts of Environmental Constraints

Sulfur Dioxide (SO₂)

The emissions of SO₂ in the reference case did not meet the requirements of the Clean Air Act Amendments after the year 2000 (Phase II). The Act sets forth allowable SO₂ emissions from each affected power plant unit; however, these emission limits can be pooled among plants so as to keep the entire system emissions below the total of allowable emissions. This will require sale/purchase of emission allowances among the PJM utilities. Consistent with that, in this study we have treated emissions from the entire PJM pool as a single bubble. The allowance market is an important part of the Clean Air Act Amendments approach to SO₂ reduction, so this modeling approach should reflect a realistic picture of the intended SO₂ reduction regime.

⁸ For example, see memorandum of John R. Cline, re: RACT-NO_x in Maryland and Virginia, Potomac Electric Power Company, April 27, 1992.

Table II-7 sets forth the year-by-year SO₂ emissions (from affected plants), PJM allowances (including bonus allowances rewarded to the PJM utilities for scrubbing during Phase I), allowance balances, and the cumulative allowance account for the reference case.

TABLE II-7
SO₂ ALLOWANCE BALANCE IN REFERENCE CASE

Year	SO ₂ Tons	Base Allowances	Bonus Allowances	Allowance Balance	Cumulative
1995	526,000	432,000	99,000	5,000	5,000
1996	385,000	432,000	98,000	145,000	150,000
1997	386,000	432,000	47,000	92,000	242,000
1998	388,000	432,000	47,000	90,000	332,000
1999	389,000	432,000	47,000	90,000	422,000
2000	1,033,000	660,000		-373,000	49,000
2001	1,035,000	660,000		-375,000	-326,000
2002	1,033,000	660,000		-373,000	-699,000
2003	1,034,000	660,000		-374,000	-1,074,000
2004	1,028,000	660,000		-368,000	-1,442,000
2005	1,029,000	660,000		-369,000	-1,811,000
2006	1,016,000	660,000		-356,000	-2,167,000
2007	1,016,000	660,000		-356,000	-2,523,000
2008	1,004,000	660,000		-344,000	-2,867,000
2009	999,000	660,000		-339,000	-3,206,000
2010	1,001,000	650,000		-351,000	-3,557,000
Average 2000-2010				-362,000	
Average 2002-2010				-359,000	

The PJM utilities' basic allotment of SO₂ allowances is approximately 432,000 per year from 1995 to 1999, 660,000 per year from 2000 to 2009, and 650,000 per year from 2010 on. There is an additional allotment of bonus allowances, approximately 338,000 allowances, to which the PJM utilities are entitled as a result of Phase I scrubber installation. The PJM system will have a positive cumulative allowance balance until 2001. It will be, on average, 359,000 allowances short per year from 2002 to 2010.

The average required reduction of 359,000 tons per year from 2002 on represents a reduction of approximately 35 percent from the reference case. Achieving these

reductions will require major actions by the PJM utilities. Unlike the NO_x and CO₂ constraints discussed later, this SO₂ constraint is not a *possible* constraint but an *actual* real constraint that will face the PJM utilities.

Oxides of Nitrogen (NO_x)

Determining the system constraints for NO_x was more difficult than for SO₂ because only limited specific requirements for NO_x have been established to date. As a result we analyzed three different constraints. They are:

- **Burner Technologies** – This constraint on the NO_x emission *rate* requires retrofit of low-NO_x burner technologies at all large NO_x emitters. These technologies are relatively low cost (typically \$15 to \$32 per kWe), and reduce NO_x emissions from uncontrolled levels by approximately 33 to 53 percent. The reference case reflected the March 1994 EPA NO_x regulations limiting emissions to 0.45 to 0.50 lbs/MMBtu at Phase I-affected units. Low-NO_x burner applications beyond the March 1994 regulations were modeled as incremental changes to the reference case. This approach reduced the overall system NO_x emission *rate* without imposing a limit on the total tonnage of NO_x that could be emitted during any given year. Such a strategy does not give any credit to the emission reduction benefits of utility energy-reducing options such as demand-side management, renewables, or independent power producers.
- **Post-Combustion Technologies** – This NO_x *rate* constraint includes the addition of post-combustion NO_x reduction technologies to 28 large NO_x emitters beyond those Phase I-affected units addressed in the March 1994 Title IV regulations. These technologies are more costly than the burner technologies, but lead to significantly greater NO_x reductions. As with the burner technologies, this approach focuses on reducing the overall system NO_x emission *rate* per kWh rather than the total *level* of NO_x emissions. The resultant emission rate, however, would be quite a bit lower than under the previous strategy. As with the burner technology strategy, this strategy does not give any credit to the emission reduction benefits of energy-reducing options. For more details, see the plant-based plan section of the report.
- **NO_x Cap** – This constraint sets a total NO_x emission *cap* that cannot be exceeded. It allows the utilities to achieve NO_x reductions via the lowest-cost method. Since it focuses on a total system emission level, this strategy recognizes the emission reduction benefits of energy-reducing options. It also allows utilities to do more clean-up at plants with lower clean-up costs and less at plants with higher costs. This approach, similar to the SO₂ allowance trading approach, should be the most cost-effective way of reaching any

specified level of emission reduction. We have set the cap at 40 percent of 1990 NO_x emissions levels. A 40 percent cap would require higher reductions than would be achievable through NO_x Reasonably Available Control Technology but would achieve lower reductions than through universal application of selective catalytic reduction at all PJM major sources. It should be noted that EPA's Office of Air Quality Planning and Standards' presentations to the Ozone Transport Commission -- a commission comprised of gubernatorial representatives of the states from Virginia to Maine, charged with fashioning a regional approach to ozone control -- have recommended NO_x reductions as high as 75 percent.

A NO_x cap would likely be of great assistance in attaining Title I of the Clean Air Act, which, while not setting prescriptive standards, requires ozone attainment. Although the recently adopted Title IV NO_x rules set emission rate limitations for Group 1 boilers⁹, they alone are not likely to lead to attainment of the ozone standard in the Ozone Transport Commission region, based on EPA's preliminary analysis using the Regional Oxidant Model.

A cap of 40 percent of 1990 NO_x emissions translates into a cap of approximately 200,000 tons per year for the PJM utilities. Since the reference case NO_x emissions ranged from 440,000 tons in 1995 to 501,000 tons in 2010, this cap translates to a reduction level of from 240,000 tons in 1995 to 301,000 tons in 2010. It assumes unrestricted trading among PJM sources, including interstate trades.

This NO_x cap scenario is hypothetical, developed for the purpose of analysis. If a NO_x cap of this sort were to be used, it would require NO_x trading and would be much enhanced by harmonizing regulations among PJM member states and allowing interstate trading.

Carbon Dioxide (CO₂)

For the purposes of this study, we established a CO₂ constraint based on stabilizing CO₂ emissions at 1990 levels. For PJM, this is equivalent to a 125,000,000 tons-per-year cap.

In the reference case, CO₂ emissions grew continuously by between one-and-a-half and three percent per year so that by 2010 emissions reached 183,000,000 tons.

⁹ Group 1 boilers are those dry-bottom wall-fired and tangentially-fired boilers that are also Phase I-affected units under the SO₂ allowance trading provisions of the Clean Air Act Amendments of 1990.

Keeping emissions at or below the 125,000,000 ton target level would require a significant reduction – 32 percent by 2010. Options for controlling CO₂ emissions are limited. There are no readily available technologies that can reduce the CO₂ emission rate. We must therefore rely on demand-side management (which reduces the overall emissions of CO₂ by reducing the overall utilization of the generating system), natural-gas based repowering options (natural gas burning has an inherently lower CO₂ emission rate than oil or coal), and supply-side improvements (reducing transmission and distribution losses and improving plant efficiency delivers more electricity to the customer for a given amount of fuel burned).

Meeting Environmental Constraints Through System Re-Dispatching

Under some circumstances, it is possible that the emission constraints could be met by re-dispatching plants in the reference case to reduce emissions rather than to minimize direct costs (the usual criterion). We determined that this approach used alone would not be workable for the PJM system and the assumed environmental constraints. System re-dispatching could meet the SO₂ constraint, but not cost-effectively. Re-dispatching could not achieve the required emissions reductions for CO₂ and NO_x.

System re-dispatching calls for selectively choosing to dispatch plants with lower emission rates before those with higher rates, even if the operating cost for the lower-emission-rate plants is higher. This approach achieves reduced emissions at little or no capital cost. Its efficacy and cost-effectiveness depend on the differential emission rates and direct operating cost. This method, however, is useful only in the face of emission cap constraints; it is not applicable to constraints based on emission rates.

To analyze re-dispatching, we added a cost for pollutant emissions to each power plant based on its emission rate. A cost in dollars per pound was used for SO₂, NO_x, and CO₂. This served as a marginal shadow price for the pollutant. Then, the marginal shadow price was increased until the resultant changes in the dispatch order were sufficient to bring emissions down to the target level. The value used for the pollutant represented the marginal cost per pound of pollutant necessary to meet the constraints through system re-dispatching. The total difference in operating costs between the system with and without the added pollutant cost represented the average cost of meeting constraints through system re-dispatching.

A marginal shadow price of SO₂ of \$1.25 per pound, or \$2,500 per ton, was necessary to maintain emissions below the long-term Phase II emission limits. The average cost of reduction using this shadow price was approximately \$1,500 per ton of SO₂ eliminated. Thus, system re-dispatching alone was not a cost-effective way of meeting SO₂ Phase II requirements.

We increased the shadow price of NO_x in an attempt to achieve the 200,000 ton cap. We found that, without changing the emission rates on the power plants, emissions never came close to meeting the cap, regardless of how high a NO_x shadow price was used. Thus, system re-dispatching was not able to meet the NO_x cap.

As with NO_x , CO_2 emissions restrictions could not be met using only system re-dispatching. System re-dispatching was not able to reduce CO_2 emissions below approximately 130,000,000 tons per year.

III. FIVE ALTERNATE PLANS TO ACHIEVE ENVIRONMENTAL GOALS

In this chapter, five alternate plans to achieve the emissions reduction scenarios described in the previous chapter are described. First, four "single-option" plans were developed for the purpose of determining the contribution that each could make to reducing air emissions. Each plan -- a plant-based plan, a DSM-based plan, a renewables-based plan, and a plan based on independent power production -- strove to meet the environmental constraints identified earlier using a single compliance option. The DSM, renewables, and independent power-based plans each attempted, using a single resource, to accomplish the entire load decrement that would be required to bring the system into compliance. After these resources were identified and developed in single-option plans, their best elements were combined in an integrated, composite plan that met the environmental constraints in a cost-effective manner. The costs and emissions impacts of these plans are compared in Chapter IV.

A. PLANT-BASED PLAN

Description of Plant-Based Options

Emissions from power plants can be reduced using "plant-based options" through direct controls, efficiency improvements, and changes in fuels. Direct controls can be further subdivided into combustion controls and post-combustion controls.

SO₂ emissions are primarily reduced through the use of reduced sulfur fuels or through installation of post-combustion controls. Reduced sulfur fuels cause less SO₂ to be produced as a combustion product. Post-combustion controls (scrubbers) remove SO₂ from the flue gas, generally, by mixing flue gas with alkalis such as lime or limestone to precipitate out SO₂.¹⁰ Scrubbers are large, complex machines with relatively high capital and operating costs and with detrimental effects on plant efficiency. Scrubbers are, however, extremely efficient at removing SO₂ from the gas stream, typically reducing SO₂ emissions by 90 percent or better. Use of reduced sulfur fuels (fuel switching) typically is less effective at removing large amounts of SO₂. As a result, fuel switching strategies generally require actions at more plants to achieve the same level of reduction as scrubbing. We analyzed both approaches in this study.

Direct NO_x controls are of two types: combustion and post-combustion. Combustion

¹⁰ Scrubbers can take the form of wet flue-gas desulfurization (FGD) devices, devices that use a liquid slurry, and dry FGD devices that rely on dry sorbent injection.

controls are far less expensive and easier to install and operate than are post-combustion controls. Not surprisingly, combustion controls do not reduce the NO_x emission rate to the same degree as do post-combustion controls. State-mandated reductions (NO_x RACT--Reasonably Available Control Technology) will probably require combustion controls to achieve emission rates on the order of 0.45 - 0.5 lbs NO_x/MMBtu for most boiler types, as is required for Phase I boilers by the March 1994 Title IV regulations.

Stringent controls on NO_x are achieved through post-combustion selective reduction processes, which are capable of removing up to 95 percent of NO_x from the gas stream. These post-combustion controls are of two primary types: selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). In this report, we have focused on SCR because, although more expensive than SNCR, it is also capable of larger emissions reductions. Only SCR would be capable of meeting the NO_x emissions constraints assumed for this study.

The seasonal control of NO_x, while offering some reductions in NO_x and, hence, ozone, in summer months, would not be adequate to meet the emissions constraints assumed for the study and therefore was not included in the analysis.

Boiler efficiency improvements, because they reduce the amount of fuel burned to provide a given amount of electricity, can also contribute to SO₂, NO_x and CO₂ emissions reductions. Utility boilers have heat rates averaging 1000 Btu/kWh higher (worse) than their design heat rates; on average, 419 Btu/kWh of this is recoverable. (EPRI, 1986, p. 1-2) By improving heat rates, utilities can generate more electricity with the same energy input, or, conversely, can reduce their heat input and generate the same amount of electricity. As heat input is reduced, less fuel is burned and the emissions associated with burning those quantities of fuel are avoided. NO_x emission rates (lbs/MMBtu) are not as directly affected by the improvements as are lb/kWh rates. Emission rates (lbs/MMBtu) can be affected, depending on the exact boiler efficiency efforts implemented.

Fuel switching, the changing from one base fuel for the majority of firing needs to another base fuel, can also reduce NO_x, SO₂ and CO₂ emissions. We examined this option in two ways: a switch from one coal to another, and a switch from coal to natural gas. Sulfur emissions from coal-fired plants are a strong function of sulfur content in the fuel.

A widely used Clean Air Act Amendments compliance strategy involves switching from a high-sulfur coal to a lower-sulfur one. Coal-to-coal fuel switching can be a cost-effective alternative to scrubbing at some power plants now burning high-sulfur coal. Many utilities have found fuel switching to be a useful strategy for SO₂ reduction. Such a change has a negligible effect on NO_x and CO₂ emissions and emission rates (except insofar as heat rate or heat content changes).

Coal-to-gas fuel switching involves the replacement of coal boilers with natural gas boilers and/or gas-fired combustion turbines whose exhaust heat drives an additional steam-cycle boiler and generator (combined cycle). The capital cost for this option is reasonable, especially given that SO_2 is reduced (generating potentially saleable allowances), NO_x is reduced, and plant efficiency is increased. CO_2 emissions are also reduced, both because the efficiency of the units increases and because natural gas burning has an inherently lower CO_2 emission rate than oil or coal combustion. Operating costs increase due in large part to increased fuel costs. Overall, however, gas conversion remains attractive.

Plant-Based Plan Analysis

Introduction

The plant-based plan for emission reduction relied solely on technological modifications to new and existing power plants to reduce air pollutant emissions. These modifications, described above, included such things as flue-gas desulfurization and fuel switching for SO_2 control, new burner technologies and post-combustion clean-up for NO_x control, and repowering for overall pollutant reduction. The utilization of the power plants was assumed to be relatively unchanged -- thus such options as demand-side management, conversion to renewables, or purchase of power from independent producers were not considered in the plant-based plan. The plant-based approach represented, in a sense, the most traditional approach to addressing utility problems. That is, the utility adopts a technological fix to solve a particular problem (in this case air pollutant emissions). As the traditional approach to the problem of pollution abatement, the plant-based approach served as a good basis against which to compare the costs and emissions impacts of less-traditional options such as DSM, renewables, and IPPs.

Method

The plant-based plan was developed by determining, as was reported earlier, the levels of pollutant reductions that would be needed in the reference case to meet the environmental constraints assumed for this study. Then, technological strategies were developed that would meet these reduction levels. The costs of these strategies were calculated based on the best available data on the capital and operating costs and performance characteristics of the technologies used. The cost per unit of pollutant reduction was determined using the following method.

Capital costs for all of the alternatives were obtained and converted to annualized costs (in constant 1992 dollars) using a 10 percent real levelized carrying charge rate.

Fixed and variable operating and maintenance costs were also obtained. One of the characteristics of SO₂ scrubbers is that they typically require between one and two percent of the plant's capacity to run, thus causing a loss of usable capacity. This lost capacity has a value, and we added it to the cost of scrubbers at a constant rate of \$60 per kWe-year, the approximate cost of peaking capacity. These cost elements comprised an annual cost of each option that was partially fixed and partially a function of the plant's capacity factor.

Each pollutant control technology has a characteristic efficiency for removing pollutants from the plant flue gas stream. The amount of pollutant reduction is a function of that efficiency; however, it is also a function of the capacity factor of the plant. This is because the higher the capacity factor of the plant, the more pollutant is initially emitted, giving a larger base of pollutant to clean up. All other things being equal, since there are both fixed and variable costs for each clean-up option, a higher capacity factor (and thus more pollutant to spread the fixed costs among) will lead to a lower cost-per-ton reduction.

Sulfur Dioxide (SO₂)

We considered both a scrubber approach and a fuel-switching approach to SO₂ reduction. Fuel switching has the advantage of lower capital costs; however, the cost of lower-sulfur fuel must be borne over the life of the plant. Scrubbers generally provide a greater degree of clean-up at each plant where implemented (90 to 95 percent for scrubbing versus 25 to 75 percent for fuel switching). It is generally possible to get higher total amounts of SO₂ reduction on the system by using scrubbers than by using fuel switching. For any specific reduction target, however, it is necessary to analyze the specific plants and options to devise the best approach. We considered scrubber options and fuel-switching options separately.

The trading of SO₂ allowances among the PJM utilities to meet Clean Air Act requirements was implicitly assumed in this analysis; the total number of allowances allocated to all the PJM utilities was assumed to reduce the necessary emission reductions by that amount.

Scrubbing

Two very different approaches were available to developing a scrubbing strategy for SO₂ reduction. The first was to focus on SO₂ reduction at the largest emitters. This approach accomplished the necessary clean-up with the least number of actions. Specifically, it appeared that the SO₂ reduction needed to meet the Phase II requirements could be achieved by scrubbing Keystone, Morgantown, Shawville, Sunbury, and Brandon Shores (in addition to the actions already planned for

Conemaugh, Chalk Point, and B. L. England). This approach minimized the number of scrubber projects required, but was not the lowest-cost approach¹¹. A lower-cost approach was found to be scrubbing a larger number of plants that have lower costs per ton of SO₂ reduction. This approach required scrubbing eight plants (beyond those already planned) -- Holtwood, Sunbury, Shawville, Martins Creek, Indian River, C. P. Crane, Seward, and Keystone. The cost of the former approach was \$619 per ton of SO₂ removed, for an annual cost of \$241 million to remove 389,000 tons per year. The cost of the latter approach was \$489 per ton of SO₂ removed, for an annual cost of \$179 million to remove 366,000 tons per year.

The cost per ton of scrubbing identified above is higher than either the current SO₂ allowance market cost or the cost experienced to date for scrubbing. Long-range cost estimates for SO₂ scrubbing are expected to be higher than either of these costs. The SO₂ allowance market at this time represents a small number of transactions for a small number of allowances which utilities have developed almost incidentally as by-products of other required actions. They do not reflect the likely costs for much more significant levels of required SO₂ reduction. This fact has been recognized by many utilities in their own plans to add scrubbers to plants when the market cost of allowances appears to be lower than the scrubber cost. It is also clear that the average scrubbing cost to meet the CAAA requirements will be above the scrubbing cost for the first units chosen to be scrubbed. The utilities will generally choose their lowest-cost units (in terms of dollars per ton of SO₂ removed) to scrub first (to meet Phase I requirements). Subsequent scrubber additions to meet Phase II requirements will be at higher-cost units. As a result, higher levels of scrubbing will require higher average costs for that scrubbing.

One impact of SO₂ scrubbing is an increase in CO₂ emissions, created by the loss of efficiency (increase in heat rate) during scrubbing because additional power is needed to operate the scrubber and is unavailable for sale. Scrubbing the PJM plants to achieve SO₂ compliance resulted in an additional 285,000 to 370,000 tons annually of CO₂ (depending on the approach to scrubbing), an increase of 0.15 to 0.2 percent.

Fuel Switching

The SO₂ emission rates from PJM coal plants currently range from 1.1 pounds per MMBtu of fuel heat input to 6.25 pound per MMBtu. For the 20 largest emitters (not including those with emission rates less than 1.2 pounds per MMBtu and those for which SO₂ reduction plans currently exist) the average emission rate is 2.3 pounds per MMBtu (heat input weighted average). Reducing that rate to 1.2 pounds per

¹¹ These costs were developed using MSB-MOD and relied on EPRI's 1989 Technical Assessment Guide and various utility Clean Air Act Amendments compliance filings.

MMBtu would reduce emissions at those plants by 52 percent, decreasing total SO₂ emissions by approximately 370,000 tons per year. This reduction would be adequate to meet Phase II SO₂ reduction requirements; thus, switching from high sulfur to low sulfur coal would be a viable option for Phase II compliance.

The cost-effectiveness of fuel switching as an option is driven by the cost differential between fuels. The fuel cost differential is very plant-, site-, and contract-specific. As a result, we analyzed the fuel-switching option based on some very rough assumptions of cost differentials: \$0.10 per MMBtu, \$0.25 per MMBtu, and \$0.50 per MMBtu. These differentials lead to costs of meeting a 360,000 ton-per-year reduction of \$411 per ton, \$604 per ton, and \$1,050 per ton, respectively, for annual totals of \$148 million, \$217 million, and \$378 million, respectively. Thus, fuel switching at a cost of \$0.10 per MMBtu is less expensive than scrubbing, fuel switching at a cost of \$0.25 per MMBtu is similar in cost to scrubbing, and fuel switching at a cost of \$0.50 per MMBtu is more expensive than scrubbing. The break-even cost differential is approximately \$0.15 per MMBtu. First year costs, however, are not the only factor that will determine the cost-effectiveness of fuel-switching versus scrubbing. Other considerations include the size of the plant, its remaining life, the difficulty of retrofitting the plant, and regulatory risk.

Oxides of Nitrogen (NO_x)

For NO_x, three constraints were evaluated, two of which control NO_x *rates* and one that establishes a *cap*. For the rate constraints, emission reductions were determined by applying two different clean-up technologies (low-NO_x burners and selective catalytic reduction) on an across-the-board basis to the major emitters rather than setting forth a tonnage reduction target. Thus, rather than having two different approaches to achieving the same amount of clean-up (as with SO₂), two scenarios result that include both different costs and different amounts of clean-up. Since the costs of selective catalytic reduction (SCR) are uncertain, we used both a high- and low-cost estimate for the SCR scenario, which changed the costs but not the levels of reduction associated with SCR. Additionally, we analyzed the emissions impacts of compliance by the PJM utilities with the NO_x regulations that were finalized in March 1994 (compliance with which was included in the reference case).

Then, a third scenario was developed that calls for a cap in NO_x emissions at 40 percent of the 1990 NO_x emissions. This translated into a cap of approximately 200,000 tons per year for the PJM system. Since the reference case NO_x emissions ranged from 440,000 tons in 1995 to 501,000 tons in 2010, the 200,000 ton cap translated to a reduction level of 240,000 tons in 1995 to 301,000 tons in 2010.

The first scenario, low-NO_x burners, achieved a total NO_x reduction of 175,000 tons per year compared to the reference case. Actually, calling this a low-NO_x burner

scenario is a slight misnomer. Certain plants on the PJM system are not amenable to the use of low-NO_x burners. For these plants we assumed the use of SCR, even in the low-NO_x burner scenario. The cost of achieving the low-NO_x burner scenario was approximately \$73 million per year, for an average cost of \$417 per ton removed (in 1992 dollars).

The second scenario, selective catalytic reduction, achieved a total NO_x reduction of 300,000 tons per year compared to the reference case. The cost of achieving this level of reduction was \$248 million per year for the high SCR cost and \$213 million per year for the low SCR cost. These translate to \$828 per ton for the high SCR cost and \$710 per ton for the low SCR cost.

As previously discussed, the reference plan included the application of low-NO_x burners to Phase I-affected plants as required by EPA's March 1994 Title IV NO_x regulations. The impact of those regulations was to reduce NO_x emissions on the PJM system by approximately 80,000 tons per year. This reduction was built into the reference plan.

The third scenario, the 200,000 ton NO_x cap, required the use of selective catalytic reduction. The low-NO_x burners did not give enough NO_x reduction to meet the 200,000 ton cap, even in 1995. Table III-1 illustrates the amount of required NO_x reduction in each year to meet the cap (beyond the March 1994 regulations) and the cost of that reduction assuming low SCR costs. The column labeled "Actual Reduction" shows the result of adding the minimum amount of SCR required to at least meet the required reduction levels. The cost column represents the annualized cost of that amount of SCR. As shown in the table, a 55 percent reduction was required in 1995, a 56 percent reduction in the year 2000, and a 60 percent reduction in 2010. By 2010, full use of SCR was required. The cost per ton of NO_x removal in 1995 was \$640, for a total annual cost of \$164,000,000; \$648 per ton in the year 2000 for a total annual cost of \$170,000,000; and \$710 in 2010, for a total annual cost of \$213,000,000 (all in 1992 dollars).

TABLE III-1
REQUIRED ACTIONS TO MEET A NO_x CAP
(200,000 TONS PER YEAR MAXIMUM)

Year	Reference Case Tons	Cap	Required Reduction (Tons)	Actual Reduction (Tons)	Annual Cost (\$000,000)
1995	440,000	200,000	240,000	256,000	164
1996	447,000	200,000	247,000	256,000	164
1997	448,000	200,000	248,000	256,000	164
1998	449,000	200,000	249,000	256,000	164
1999	450,000	200,000	250,000	256,000	164
2000	459,000	200,000	259,000	263,000	170
2001	463,000	200,000	263,000	263,000	170
2002	466,000	200,000	266,000	268,000	175
2003	473,000	200,000	273,000	278,000	185
2004	476,000	200,000	276,000	278,000	185
2005	481,000	200,000	281,000	285,000	194
2006	485,000	200,000	285,000	285,000	194
2007	492,000	200,000	292,000	295,000	206
2008	489,000	200,000	289,000	295,000	206
2009	495,000	200,000	295,000	295,000	206
2010	501,000	200,000	301,000	300,000	213

Carbon Dioxide (CO₂)

The required reductions in CO₂ emissions to meet the cap we set as our target – 125 million tons per year -- were so high that we did not include meeting the CO₂ cap in our plant-based plan. The required reductions ranged from 10 percent in 1995 to 32 percent in 2010 (compared to reference case levels). There are no commercially available CO₂ scrubbing technologies that can reduce the CO₂ emissions from existing plants by such percentages.

Although conversion to natural gas burning would help reduce CO₂ emissions, meeting the cap would require essentially complete conversion of the PJM system to natural gas. Even with complete conversion, the 125 million ton cap would be exceeded by 2007. Maintaining emissions below the cap would require conversion to natural gas-fired combined cycle plants.

The cost of a massive switch to natural gas would be extremely high. Annual non-gas fossil fuel use on the PJM system is approximately 1.25 billion MMBtu. Assuming a cost differential of \$1.00 per MMBtu to switch to gas implies an annual cost of \$1.25 billion. Dividing the cost by the CO₂ reductions yields a cost per ton reduction of \$18 to \$20 (varying slightly over the years). This is purely the fuel cost differential and does not include any cost of conversion for the power plants. Nor does it consider the increased cost and reliability risk associated with the resultant lack of fuel diversity. Full conversion of the PJM system to natural gas-firing was found to not be a feasible approach to CO₂ emissions reduction.

Summary of the Plant-Based Plan

The single-option plant-based plan relied on scrubbers for SO₂ control and selective catalytic reduction for NO_x control. Scrubbers were added to eight plants, which resulted in the lowest cost of obtaining the required reduction. Because of bonus allowances that will be allocated by EPA to PJM utilities for Phase I scrubbing, the PJM system will be in compliance with the Clean Air Act Amendments requirements until 2001. The system will need an average additional reduction of 359,000 tons per year between 2002 and 2010. Although fuel switching to low sulfur coal is a possible alternative to scrubbing, we estimated the cost of fuel switching to be fairly similar to that of scrubbing, and have used the cost of scrubbing, \$489 per ton, as the cost of the SO₂ portion of the plant-based plan. The additional costs for SO₂ reduction would begin to be incurred in 2001.

Meeting a 200,000 ton NO_x cap required the eventual use of SCR at all major NO_x-emitting plants (beyond the Phase I plants affected by the March 1994 regulations). The use of SCR was phased in beginning in 1999 when only 250,000 tons of reduction were needed. Reduction of 250,000 tons did not require complete application of SCR. By 2010, the 300,000 ton level of reduction required, however, necessitated complete application of SCR. The cost of complete application of SCR was between \$710 and \$828 per ton of reduction. Costs for NO_x reduction began in 1999.

Meeting CO₂ constraints with plant-based options alone was not feasible. Although conversion of all generating capacity to natural gas combined cycle plants, along with the concomitant improvement in heat rate, would keep emissions under the cap through 2010, the cost would be extremely high and would have a negative impact on system reliability. Gas conversion alone was not, therefore, found to be a feasible approach to system CO₂ control.

B. DSM-BASED PLAN

Development of Target DSM Levels

In developing the demand-side management (DSM)-based plan, we first determined how much DSM would be *needed* to meet the SO₂ emission reduction targets of Phase II of the Clean Air Act. We then analyzed the DSM potential to determine whether the *needed* DSM levels were actually *achievable*. DSM is ideal as an emission-reduction strategy for meeting constraints such as emissions caps. It is not, however, useful as a strategy for meeting constraints based on reduced emission *rates*, since it does not change the emission rate per kWh generated.

TABLE III-2
ENERGY REDUCTION ON PJM SYSTEM REQUIRED TO MEET CLEAN
AIR ACT PHASE II SO₂ REDUCTION REQUIREMENTS WITH DSM

Year	Energy (MWh) Base Case	DSM Case	Fractional Reduction	MWh Reduction
2001	275,800,000	200,000,000	0.275	75,800,000
2002	279,800,000	200,100,000	0.285	79,700,000
2003	284,800,000	201,100,000	0.294	83,700,000
2004	289,800,000	203,100,000	0.299	86,700,000
2005	294,800,000	204,100,000	0.308	90,700,000
2006	299,800,000	206,500,000	0.311	93,300,000
2007	304,800,000	206,700,000	0.322	98,100,000
2008	309,800,000	208,600,000	0.327	101,200,000
2009	314,800,000	209,700,000	0.334	105,100,000
2010	317,800,000	207,900,000	0.346	109,900,000

The energy reductions shown in the table are large.¹² However, as will be discussed later, they are within the range of estimates of energy reduction due to DSM that are potentially technically available for most utilities. (EPRI, 1990; ACEEE, 1989; Koomey et al., 1991; BH&C, 1989; B&C, 1992) An estimate of the DSM potential on the PJM

¹² Capacity reductions are, of course, associated with the energy reductions identified in Table III-2. The focus here is on energy reductions since energy use and emissions are directly linked.

system is presented later in the section, following our estimation of the avoided costs used to determine which DSM options were cost-effective.

Development of Avoided Costs

Having identified the required levels of energy reduction to meet Phase II SO₂ requirements, we then used the production-simulation model to estimate the savings to the PJM system from avoiding this much energy use. These savings are the avoided costs.

There are three elements of avoided cost that we considered: the avoided operating costs, the avoided capital cost for new generation, and the avoided capital cost for transmission and distribution. The following table shows the avoided costs corresponding to the energy reduction levels required to meet the SO₂ constraint estimated in Table III-2.

TABLE III-3
AVOIDED OPERATING, CAPITAL, AND T&D COSTS ON THE PJM SYSTEM

Year	Avoided Operating Cost	Avoided Capital Cost	Avoided T&D Cost	Total
2002	0.0346	0.0068	0.0086	0.0500
2003	0.0348	0.0068	0.0086	0.0502
2004	0.0344	0.0068	0.0086	0.0499
2005	0.0342	0.0068	0.0086	0.0496
2006	0.0344	0.0068	0.0086	0.0498
2007	0.0344	0.0068	0.0086	0.0498
2008	0.0348	0.0068	0.0086	0.0502
2009	0.0349	0.0068	0.0086	0.0503
2010	0.0351	0.0068	0.0086	0.0505
Average	0.0346	0.0068	0.0086	0.0500

These costs are in 1992 \$/kWh.

Assumptions:

Avoided Capacity Cost @ \$60 per kWe-Yr.

Avoided T&D Cost @ \$75 per kWe-Yr.

Based on this table, we concluded that the average avoided cost for generation, transmission, and distribution is five cents per kWh (in 1992 dollars). The *net* cost of

DSM is the DSM cost per kWh minus \$0.05.

Status of PJM Utilities' DSM Efforts

All the PJM utilities already include DSM within their resource portfolios to some extent. Tables III-4 through III-6 summarize the current status of the PJM utilities' demand-side management efforts as reported in state planning documents and 1991 Energy Information Administration 861 forms. As indicated in Table III-4, the capacity impacts of the DSM programs of the PJM utilities as a whole are expected to rise from 1,655 MWe in 1993 to almost 5,000 MWe in the year 2000 and to over 7,000 MWe in 2010. The energy savings attributable to these programs, shown in Table III-5, are anticipated to equal approximately 920,400 MWh in 1993, rising to approximately 8,340,000 MWh in the year 2000 and to over 12,200,000 MWh in 2010.

Budgets for DSM programs are expected to rise along with the programs' impacts. As Table III-6 indicates, the DSM budgets for the PJM utilities as a group are expected to increase from about \$228 million in 1993 to almost \$540 million in 2001, the last year for which data are available for all PJM utilities.¹³

Some caveats regarding these data are in order¹⁴:

- These are self-reported data, and the types of DSM included are not consistent across utilities. One significant difference is that some utilities include impacts from interruptible customers whereas others do not. Some utilities include the negative impacts (increased energy use) of off-peak

¹³ We compared the DSM program data used for this analysis to DSM forecasts reported in the 1992 EIA Form 861s. Although the Form 861s potentially provide more consistent data across utilities than do individual state planning documents, the 1992 EIA Form 861s (unlike the 1991 Form 861s) provide data points for 1992, 1993 and 1997 only and could not be used for the DSM-based plan analysis. Although a year-by-year comparison was therefore impossible, we compared data in available years. PJM utility DSM energy impacts provided by the 1992 Form 861s are 35 percent higher in 1993 and five percent lower in 1997 than the impacts reported in state planning documents. See Appendix B for 1992 EIA Form 861 information. These variations may be due to differences in categories of DSM that the utilities included in their state planning reports versus the categories reported to EIA, or due to differences in the timing of the reporting of data.

¹⁴ See Appendix C, Footnotes to Tables III-4 - Table III-6, for information regarding the types of programs included in the reported data, data sources, and years and utilities for which data were assumed.

promotional programs, while others that also operate such programs may not include their impacts.

- These impacts and budgets are for currently planned programs only. Both anticipated impacts and planned budgets will undoubtedly be revised to reflect experience gained with DSM programs, implementation delays, regulatory actions, and other factors. Too, actual implemented programs may well produce either less or more savings than originally anticipated.
- The dates of the data sources vary in some cases. The most recent DSM impact forecasts, in most cases from 1992 or 1993, were obtained. Although DSM budget figures corresponding with these forecasts were used where available, in a few cases the budget data included here are those provided for 1991 in the Energy Information Administration Form 861. Some discrepancies may therefore exist between program impacts and budgets. These differences, however, should be insignificant in an analysis of a pool the size of PJM.
- Some discrepancies also exist between the dates of the DSM impact data and the demand and energy impact forecasts used for modeling the PJM system. The April 1, 1993 IE-411 provided the pool forecast; some of the utilities have since updated their forecasts, and the DSM impact forecasts reported here are based upon them. As above, any differences should be minor in light of the size of the PJM overall forecast.
- In cases where a utility's DSM impact or budget forecast did not extend for the entire time period under consideration, we assumed that the impact or the budget in the last year of the utility's data would be extended into the future.

Despite these caveats, on an aggregated, poolwide basis these data provide a useful snapshot of the current status of the PJM utilities' DSM efforts and future trends. As discussed below, these data were used to determine how much additional DSM would be required on the PJM system to achieve the energy reductions needed to bring the system into compliance with Phase II SO₂ requirements.

TABLE III-4

**PLANNED DEMAND-SIDE MANAGEMENT CAPACITY RESOURCES
FOR PJM UTILITIES
(MW)**

UTILITY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
AECO	75	103	104	122	136	147	152	160	180	184
BG&E	456	576	683	783	875	966	1,052	1,136	1,218	1,298
DP&L	197	209	218	229	240	288	298	308	317	326
ICP&L	44	89	123	160	193	225	258	290	323	323
Met Ed	3	14	24	37	55	69	85	100	116	131
Penelec	2	10	22	33	48	63	78	93	108	123
PP&L	206	271	339	367	393	418	443	468	492	516
PECO	0	10	26	44	62	80	95	107	117	122
PEPCO	444	534	464	784	892	975	1,053	1,131	1,201	1,271
PSE&G	228	346	473	607	740	859	957	1,053	1,143	1,233
UGI	0	0	0	0	0	0	0	0	0	0
TOTAL	1,655	2,162	2,476	3,166	3,634	4,090	4,471	4,846	5,215	5,527

UTILITY	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Notes
AECO	192	197	203	207	213	213	213	213	213	213	18,19,20
BG&E	1,381	1,462	1,541	1,619	1,692	1,692	1,692	1,692	1,692	1,692	17,20,21
DP&L	334	342	351	359	368	376	384	392	399	405	1,2,23
ICP&L	323	317	317	317	305	300	300	300	300	300	16
Met Ed	131	131	131	131	131	131	131	131	131	131	9,13
Penelec	123	123	123	123	123	123	123	123	123	123	6,10,13
PP&L	540	564	588	612	636	660	684	708	733	757	11,13
PECO	125	128	134	140	148	156	164	172	181	189	12,13,22
PEPCO	1,347	1,418	1,489	1,565	1,612	1,612	1,612	1,612	1,612	1,612	3,4,5,20
PSE&G	1,323	1,413	1,503	1,593	1,683	1,683	1,683	1,683	1,683	1,683	7,8,20
UGI	0	0	0	0	0	0	0	0	0	0	13,14,15
TOTAL	5,819	6,095	6,380	6,666	6,911	6,946	6,986	7,026	7,067	7,105	

Notes and References Can Be Found in Appendix C

TABLE III-5

**PLANNED DEMAND-SIDE MANAGEMENT ENERGY RESOURCES
FOR PJM UTILITIES
(MWh)**

UTILITY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
AECO	(17,000)	33,000	67,000	64,000	38,000	3,000	(41,000)	(84,000)	(133,000)	(179,000)
BG&E	216,000	329,000	462,000	619,000	793,000	980,000	1,170,000	1,364,000	1,552,000	1,736,000
DP&L	16,518	38,012	64,169	93,138	124,814	150,526	168,684	185,896	200,958	214,631
ICP&L	68,000	123,000	170,000	225,000	383,000	489,000	593,000	699,000	804,000	804,000
Met Ed	0	36,000	74,000	114,000	165,000	209,000	255,000	301,000	346,000	392,000
Penelec	0	34,000	73,000	112,000	161,000	208,000	258,000	308,000	358,000	408,000
PP&L	47,820	102,930	165,060	210,556	261,670	312,784	363,898	415,012	459,862	504,712
PECO	0	60,000	137,000	217,000	298,000	374,000	439,000	486,000	516,000	531,000
PEPCO	462,000	774,000	1,205,000	1,745,000	2,134,000	2,391,000	2,654,000	2,925,000	3,177,000	3,428,000
PSE&G	126,900	369,800	644,500	933,000	1,210,600	1,439,100	1,589,100	1,738,000	1,738,000	1,738,000
UGI	139	277	416	554	693	857	1,020	1,184	1,347	1,511
TOTAL	920,377	1,900,019	3,062,145	4,333,248	5,569,777	6,557,267	7,450,702	8,339,092	9,020,167	9,578,854

UTILITY	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Notes
AECO	(200,000)	(243,000)	(285,000)	(325,000)	(366,000)	(366,000)	(366,000)	(366,000)	(366,000)	(366,000)	15,16,17
BG&E	1,924,000	2,112,000	2,285,000	2,449,000	2,607,000	2,771,000	2,887,000	3,013,000	3,115,000	3,169,000	13,14,17,2
DP&L	228,448	242,345	256,374	270,510	284,490	298,593	312,538	325,980	336,222	337,459	1,2
ICP&L	800,000	773,000	767,000	767,000	767,000	749,000	745,000	745,000	745,000	745,000	12
Met Ed	392,000	392,000	392,000	392,000	392,000	392,000	392,000	392,000	392,000	392,000	6,9
Penelec	408,000	408,000	408,000	408,000	408,000	408,000	408,000	408,000	408,000	408,000	5,7,9
PP&L	549,563	594,413	639,263	684,113	728,963	773,814	818,664	863,514	908,364	953,214	8,9
PECO	538,000	543,000	568,000	597,000	628,000	662,000	696,000	731,000	766,000	800,000	9,10
PEPCO	3,680,000	3,934,000	4,176,000	4,421,000	4,421,000	4,421,000	4,421,000	4,421,000	4,421,000	4,421,000	3,4,18
PSE&G	1,738,000	1,738,000	1,738,000	1,738,000	1,738,000	1,738,000	1,738,000	1,738,000	1,738,000	1,738,000	19,20
UGI	1,674	1,837	2,002	2,165	2,329	2,492	2,656	2,820	2,982	3,147	11,9
TOTAL	10,059,685	10,495,595	10,946,639	11,403,788	11,610,782	11,849,899	12,054,858	12,274,314	12,466,568	12,600,820	

Notes and References Can Be Found in Appendix C

TABLE III-6

**PLANNED PJM UTILITY
DEMAND-SIDE MANAGEMENT BUDGETS 1991-2001
(\$1,000)**

UTILITY	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Notes
Atlantic City Electric Co	7,324	9,650	9,060	9,266	11,772	12,804	12,804	12,804	12,804	12,804	12,804	9
Baltimore Gas & Electric Co	16,212	19,313	30,711	42,092	50,434	56,613	61,991	61,405	66,659	76,522	89,670	
Delmarva Power & Light Co	7,700	9,500	10,500	9,800	11,100	11,500	9,900	10,900	11,600	10,000	10,100	
Jersey Central Power&Light Co	13,800	17,200	20,500	16,500	25,000	25,000	25,000	25,000	25,000	25,000	25,000	
Metropolitan Edison Co	4,324	4,400	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	1,2
Pennsylvania Electric Co	3,671	3,400	10,100	11,700	15,600	21,900	30,200	30,200	30,200	30,200	30,200	3,8
Pennsylvania Power & Light Co	12,619	13,000	17,790	18,680	19,610	20,600	21,630	22,710	23,840	25,030	26,290	4
PECO Energy	10,900	10,232	10,866	19,013	25,348	29,808	35,384	41,010	45,885	47,607	46,411	5
Potomac Electric Power Co	26,817	21,000	37,000	55,000	79,000	97,000	69,000	72,000	76,000	81,000	77,000	6
Public Service Electric&Gas Co	24,000	29,000	63,000	83,000	103,000	123,000	143,000	163,000	183,000	203,000	203,000	10,11,12
UGI Corp	47	170	204	118	124	130	137	145	152	160	168	7
TOTAL	127,414	136,865	227,731	283,169	358,988	416,355	427,046	457,174	493,140	529,323	538,643	

Source: EIA-861 Forms, 1991, unless otherwise noted.

Notes and References Can Be Found in Appendix C

Alternative DSM Scenarios for the PJM System

DSM ideally requires a "bottom-up" analysis. The basis for assessing the DSM resource and developing and implementing DSM programs is customer end-use of electricity. The building blocks of DSM are the potential improvements in energy efficiency (kWh) and modifications to customer demand (kWe) that can be made for each end-use of electricity. Due to data and budget limitations, it was not possible to perform such a "bottom-up" analysis as part of this study. Instead, we created two "top-down" DSM scenarios to illustrate the potential for DSM as a Clean Air Act Amendments compliance option and to achieve other environmental benefits from reduced utility generation of electricity. We do not believe that the overall projections of energy savings and costs would differ significantly from the those resulting from the "top down" method we employed.

In the first scenario, we analyzed whether it would be possible to use DSM as a "single-option" approach to meeting the environmental constraints described earlier. This DSM-based plan was based on meeting SO₂ compliance requirements through DSM at an average cost equal to the reference case system avoided cost of \$0.05/kWh. Although the DSM-based plan was highly optimistic about the potential impacts from DSM, we believe that the DSM-based plan would be possible. It illustrates an outer boundary of what is possible for the PJM system.

The other DSM scenario was the "achievable" case, in which DSM met a significant share of the compliance requirements at an average cost equal to three cents/kWh. This scenario was still optimistic about the potential impacts from pool-wide DSM, but we believe it is achievable given aggressive implementation of DSM by each PJM utility. In this scenario, DSM resources reduced total system energy requirements by 12 percent by the year 2006 after increasing from 1.2 percent in the year 1995. The achievable case represented the DSM portion of the Composite Plan, which is described in its entirety later in this chapter.

The "top-down" approach used to develop the DSM scenarios excluded the possibility of making explicit assumptions regarding the saturation of DSM technologies. Market saturation is technology specific; it is defined in terms of the number of actual applications compared to the maximum total number of applications. Implicit in our scenarios was the assumption of an accelerated rate of DSM technology implementation compared to existing utility plans. While we made no explicit assumption about saturation of specific DSM technologies, our composite DSM scenario implicitly assumed a saturation of DSM markets. Our estimate of achievable DSM took the shape of a logistic curve, which showed an initial "ramp-up" and a later "tapering off" as programs reached maturation and DSM markets, in aggregate, approached saturation.

Our DSM scenarios did not include any specific assumptions regarding the adoption

of supply-side efficiency improvements. To the extent that supply-side improvements could be the equivalent of a given amount of demand-side improvements, supply-side improvements could be subsumed within the overall DSM scenario. Again, our top-down approach assumed that the energy savings could be achieved with different types and sizes of both demand-side and supply-side efficiency programs. One specific group of demand-side technologies, heat pumps, is discussed in greater detail in Appendix D.

The two DSM scenarios are discussed in detail below. They are followed by a discussion of the impact of lost revenues upon the viability of utility DSM.

Single-Option DSM-Based Plan

As discussed previously, the single-option DSM-based plan required high levels of DSM resource acquisition. Specifically, the DSM-based plan required reductions in gross reference case energy requirements of approximately 28 to 35 percent for the years 2001 to 2010, respectively. Since the system forecasts included the impacts of DSM plans of the PJM utilities, the system energy reductions presented in Table III-2 are the amounts of new DSM resources needed to meet Phase II SO₂ Clean Air Act Amendments compliance requirements. These amounts of DSM savings were seven to eight times the projected DSM impacts from the PJM utilities (as shown in Table III-7).

While achieving such high levels of system-wide DSM savings may be improbable, these levels are possible, according to several regional and national studies. According to the Electric Power Research Institute (EPRI, 1990), the maximum technical potential for DSM on a national basis for the year 2000 is from 24 to 44 percent of electric energy consumption. This study did not consider cost-effectiveness of the DSM measures nor practical barriers to implementing DSM. Fickett et al. (1990) applied cost estimates to the EPRI study, showing that approximately a 27 percent reduction in energy use could be achieved at a cost of four cents per kWh or less. In this same article, Fickett et al. cited a Rocky Mountain Institute study that estimated electricity consumption could be reduced by over 70 percent at a cost of four cents per kWh or less.

In an analysis of the potential for electricity efficiency improvements in the U.S. residential sector, Koomey et al. (1991) estimated that residential electricity use could be reduced 40 percent at a cost of 5.4 cents per kWh or less. A similar type of analysis of the potential for electricity conservation in the State of New York found that the total cost-effective electricity conservation potential would reduce electricity consumption by approximately 35 percent (ACEEE, 1989). Broken down by sector, this study estimated that electricity consumption in the residential sector could be reduced by 32 percent at a cost of five cents per kWh or less. Similarly, in the

commercial sector, consumption could be reduced by 45 percent at a cost of five cents per kWh or less, and in the industrial sector, consumption could be reduced by 16 percent at a cost of five cents per kWh or less.

Analyses of several PJM utilities also showed that these levels of DSM are possible. A study of the Delmarva system estimated that the maximum technical potential (MTP) for this system is approximately 22 percent of system energy requirements in the year 2000 (BH&C, 1989). A similar study of the PEPCO system estimated the MTP is approximately 34 percent (B&C, 1992). Pennsylvania Electric Company and Metropolitan Edison Company used EPRI values to estimate the MTP for each of their systems, which are both approximately 35 percent in the year 2000 (Penelec, 1993; Met Ed, 1993).

Our estimate of the maximum technical potential for the PJM system for the year 2000, based on EPRI data, is from 24 to 43 percent of reference case energy, or 58,094 to 105,275 GWH. The mean value of our estimate is 81,685 GWH, or 33 percent of reference case energy requirements. We developed this estimate by compiling individual PJM utilities' estimates of sectoral energy demand (residential, commercial and industrial) to estimate pool-wide sectoral energy demands, then multiplied these sectoral demands by the potential savings identified by EPRI (in terms of percentage savings) to yield savings estimates for the entire pool. We lacked sufficient end-use data to perform a more detailed analysis.

These DSM analyses convinced us that the technical potential for DSM on the PJM system is great enough that the levels required for the single-option DSM-based plan exist as DSM potential. The costs included in the DSM studies described above suggested that the required levels of DSM exist as potential at costs (even at the margin) less than the PJM system avoided cost. To be conservative, however, we assumed an average rather than marginal cost of DSM of five cents per kWh, equal to the PJM system avoided cost. By using this conservative assumption, we built into the analysis the possibility that some of the DSM measures included in the plan might cost more than the avoided cost of five cents per kWh. These measures were counter balanced by measures that cost less than the PJM system avoided cost. However, *even* using this conservative assumption for the cost of DSM, the single-option DSM-based plan *as a whole* was cost-effective compared to the plant-based plan.

These analyses illustrate outer boundaries of the potential for widespread, aggressive implementation of DSM. For the purposes of this study, the DSM-based plan was useful to illustrate the potential environmental benefits from such an aggressive strategy.

Achievable DSM Scenario

Resource Assessment

Although the single-option DSM-based plan (i.e., meeting the SO₂ constraints solely through DSM) was found to be technically and economically *possible*, we also developed an estimate of the achievable potential for DSM, which represented a more *probable* scenario for DSM implementation on the PJM system and which was used in the development of the Composite Plan. This estimate of the achievable DSM potential accounted for the practical barriers to implementing cost-effective DSM measures. It still represented a large increase in the amount of DSM implemented as compared to the current levels planned by the PJM utilities. Figure III-1 illustrates this case. The "planned" amount of DSM in Figure III-1 is the total amount of DSM projected by PJM utilities in their planning documents. The "new" amount of DSM in Figure III-1 is the amount of additional DSM resources that we assumed is achievable. Table III-7 presents the data shown in Figure III-1 and also gives the fraction of total system energy requirements met through DSM in this scenario.

Although this scenario still would entail a large increase in the amount of DSM resources captured by the PJM system, at least one of the PJM utilities, PEPCO, is projecting DSM savings levels of this magnitude on its system. We believe that comparable levels of savings could be achieved across the PJM system. To achieve this level of DSM savings on a pool-wide basis, each PJM utility would need to offer a comprehensive menu of DSM programs and achieve a significant fraction of the savings potential for each program.

In this scenario, we assumed that this amount of DSM savings could be achieved at an average cost of conserved energy of three cents per kWh. Results from certain PJM utilities¹⁵ and from other North American utilities suggest that this is a reasonable, even conservative, estimate. In the following section, we present examples of programs that provide energy savings at costs less than three cents per kWh. Using an average cost of three cents per kWh means that higher-cost DSM resources (up to system avoided costs) can be acquired as part of an overall DSM resource portfolio that costs, on average, three cents per kWh. Consequently, utilities could spend more on certain programs to increase participation, such as for marketing or customer incentives.

¹⁵ See Baltimore Gas & Electric Co. and Potomac Electric Power Co. programs in Table III-8.

FIGURE III-1

Achievable DSM Potential PJM System

TABLE III-7

PJM ACHIEVABLE DSM SCENARIO

	SYSTEM NET ENERGY REQUIREMENTS REFERENCE CASE (MWH)	PJM PLANNED DSM (MWH)	SYSTEM GROSS ENERGY REQUIREMENTS (MWH)	ACHIEVABLE DSM (Percent of gross)	TOTAL ACHIEVABLE DSM (MWH)	NEW DSM (MWH)	NET SYSTEM REQUIREMENTS WITH NEW DSM (MWH)
1995	248,799,904	3,062,145	251,862,049	1.2%	3,099,833	37,688	248,762,216
1996	252,799,808	4,333,248	257,133,056	1.7%	4,360,487	27,239	252,772,569
1997	257,799,680	5,569,777	263,369,457	2.3%	6,131,474	561,697	257,237,983
1998	261,799,792	6,557,267	268,357,059	3.2%	8,612,983	2,055,716	259,744,076
1999	265,799,792	7,450,702	273,250,494	4.4%	12,093,283	4,642,581	261,157,211
2000	270,799,904	8,339,092	279,138,996	6.1%	16,976,100	8,637,008	262,162,896
2001	275,799,776	9,020,167	284,819,943	8.4%	23,810,606	14,790,439	261,009,337
2002	279,799,776	9,578,854	289,378,630	10.0%	28,937,863	19,359,009	260,440,767
2003	284,799,680	10,059,685	294,859,365	10.5%	30,960,233	20,900,548	263,899,132
2004	289,799,776	10,495,595	300,295,371	11.0%	33,032,491	22,536,896	267,262,880
2005	294,799,872	10,946,639	305,746,511	11.5%	35,160,849	24,214,210	270,585,662
2006	299,799,808	11,403,788	311,203,596	12.0%	37,344,432	25,940,644	273,859,164
2007	304,799,776	11,610,782	316,410,558	12.0%	37,969,267	26,358,485	278,441,291
2008	309,799,840	11,849,899	321,649,739	12.0%	38,597,969	26,748,070	283,051,770
2009	314,799,648	12,054,858	326,854,506	12.0%	39,222,541	27,167,683	287,631,965
2010	317,799,936	12,274,314	330,074,250	12.0%	39,608,910	27,334,596	290,465,340

We assume that the above DSM resources
can be achieved at an average cost of 3 cents/kWh.

Cost Estimation

As previously mentioned, we were not able to develop a "bottom-up" analysis of the costs and potential for DSM resource acquisition in the PJM system. Such an analysis would yield a curve for the cost of conserved energy (CCE), which could then be used to develop integrated resource plans. Instead, we analyzed existing DSM plans of the PJM utilities and DSM experience from other utilities to develop an estimate of the amount of DSM resources that we believe is achievable in the PJM system. We also developed a cost estimate of three cents per kWh for the average cost of this achievable amount of DSM. This cost estimate was, again, based on a review and analysis of DSM data and experience from selected PJM utilities (i.e., BG&E and PEPCO) and other utilities. (IRT Environment, Inc., 1992) This review and analysis allowed us to identify and characterize a number of "sure winner" DSM programs, which would need to be included in the achievable DSM scenario.

The examples profiled below illustrate the types of program results that we believe are possible for the entire PJM system. These examples do not represent a complete list of the types of programs that would need to be included in this achievable DSM scenario. Other types of programs may be needed. A comprehensive analysis of DSM resources in the PJM system would be necessary to develop the specific program types necessary to achieve this level of energy savings most cost-effectively.

Certain demand-side measures are so cost effective that they are universally included in utility DSM programs. For example, commercial lighting programs consistently produce energy savings at less than two cents per kWh (including both customer and utility costs). (Wellinghoff and Flanigan, 1992) This is well below the avoided cost of energy and capacity for almost all U.S. electric utilities. (As a case in point, we have calculated the current avoided capacity, energy, and transmission and distribution costs for the PJM system to be five cents per kWh.) To identify other "sure winner" DSM programs, we compared each program's cost of conserved energy to the utility's avoided cost.

In lieu of more detailed analysis, we derived the utilities' cost of conserved energy for a demand-side program from utilities' benefit-cost ratios for DSM programs. The cost of conserved energy was calculated by dividing the utility's avoided cost by the benefit-cost ratio for the program. We show below that the approach does in fact yield the cost of conserved energy.

$$\begin{aligned}
\frac{\text{Avoided cost per kWh saved}}{\text{Benefit-Cost Ratio}} &= \frac{\frac{\text{Benefits}}{\text{kWh saved}}}{\frac{\text{Benefits}}{\text{Costs}}} \\
&= \frac{\text{Benefits}}{\text{kWh saved}} \times \frac{\text{Costs}}{\text{Benefits}} \\
&= \frac{\text{Costs}}{\text{kWh saved}} \\
&= \text{Cost of conserved energy}
\end{aligned}$$

This formula is valid as long as the avoided cost used in the formula is the same as that used in calculating the benefit-cost ratio. In this case we use the five cents per kWh avoided cost calculated for the PJM system. Then the formula becomes:

$$\text{cost of conserved energy} = \frac{5.0 \text{ cents per kWh}}{\text{Benefit-Cost Ratio}}$$

Some might question whether our estimate of the avoided cost is the relevant figure to use in estimating the cost of conserved energy since the utility may have used a different avoided cost to calculate the benefit-cost ratio. For example, what if the utility's estimate of the avoided cost for its benefit-cost calculation was only 2.5 cents per kWh, and not the five cents per kWh we estimated? Inspection of the formula reveals that using the lower avoided cost will *lower* the utilities' cost of conserved energy for the DSM programs by 50 percent. So if our calculated avoided cost is too high, the cost of conserved energy for the DSM programs that we report here would also be too high.

Remember that the utility has found these programs to be cost-effective and it is reporting the benefit-cost ratio. If a program has a two-to-one benefit-cost ratio when the avoided cost is 5.0 cents per kWh, the program must cost 2.5 cents per kWh. If it has a two-to-one benefit-cost ratio when the avoided cost is 2.5 cents per kWh, the program must cost 1.25 cents per kWh. The cost of conserved energy reported below would be too low only if: (1) we understated the utilities' avoided cost, or (2) the utilities overstated the cost-effectiveness of their DSM programs.

"Sure Winner" DSM Programs

Table III-8 lists our calculated cost of conserved energy for PEPCO's and BG&E's DSM programs that cost less than three cents per kWh.

**TABLE III-8
"SURE WINNER" DSM PROGRAMS**

PEPCO Demand-Side Program	CCE (cents/kWh)
Water heater rebate	0.5
New building design	0.8
Comprehensive rebate	1.0
Lighting rebate	1.4
Shared savings	1.9
Weatherization	2.2
Remove second refrigerator	2.3
Compact fluorescent	2.3
Small commercial shop doctor	2.4
Small commercial load reduction	2.6
BG&E Demand-Side Programs	CCE (cents/kWh)
Natural gas air conditioning	1.0
Comprehensive construction	1.2
Residential HVAC	1.4
Efficient lighting	1.4
Residential new construction	1.8
Industrial motors	1.8
Industrial equipment replacement	2.4
Low-Income program	2.9

The Impact of Lost Revenues on Utility DSM

When a utility reduces the demand for its product via DSM programs, it reduces its revenues collected. Although the utility also reduces some costs when it sells less electricity (most notably fuel costs), in almost all cases the revenue shortfall exceeds the costs avoided in the short term. That happens because electric rates are designed to collect not only variable costs but fixed costs as well. Since reducing electric sales avoids only the variable costs, the fixed costs are not recovered when sales are reduced. This unrecovered fixed cost component is referred to as "lost revenues." Lost revenues lead to lower short-run earnings for the utility and are therefore considered disadvantageous by most utility managers.¹⁶

In our modeling, lost revenues do not occur. That is because our revenue requirements model, like most revenue requirements models, assumes that rates are raised immediately to collect any net revenue shortfall. Conversely, if sales increase to the point that excess revenues would occur, the model assumes that rates are lowered immediately to eliminate the extra revenue.

The EPA believes that aggressive utility investment in DSM is discouraged by traditional ratemaking due to concern over lost revenues. State regulators may need to adopt policies (like decoupling or net lost revenue adjustments) to fully address the lost revenue problem, as commissions in several PJM states have begun to do.

For example, in Maryland PEPCO collects lost revenues via its demand-side surcharge. (Barakat and Chamberlin, 1993, p. 92) In Maryland, BG&E can collect lost revenues if it is earning less than its allowed return on equity. (*Ibid*, p. 95) In New Jersey, PSE&G and JCP&L collect lost revenues via demand-side adjustment factors. (*Ibid*, p. 153) In Pennsylvania, lost revenues can be accrued in a balancing account and collected in the next base rate proceeding. (Pennsylvania Public Utility Commission, 1993a, p. 73) In the District of Columbia, the Commission allows recovery of lost revenues in principle, subject to certain restrictions. PEPCO's request for lost revenue recovery for 1992 and 1993, however, was permanently disallowed. (District of Columbia Public Service Commission Formal Case 929, Order Number 10387, April 4, 1994.)

¹⁶ Reducing load via DSM may offer long run financial benefits, even if lost revenues are not recovered directly. That is because slowing the growth of the utility reduces its capital requirements. See, for example, Steven G. Kihm, "Why Utility Shareholders Don't Need Incentives to Support Demand-Side Management," The Electricity Journal, June 1991.

DSM on a Pool-wide Basis

While modeled on a pool-wide basis for the purposes of this study, in practice DSM is conducted on an individual utility basis. Conducting DSM on a pool-wide basis, however, could produce a number of benefits for the member utilities of the pool. These potential benefits include:

- Certain economies of scale are possible. "Sure winner" DSM programs could be readily replicated, much like a franchise. Program expertise, personnel and promotional materials could be readily exchanged and shared among pool members.
- More rapid deployment of DSM programs would be possible. This is a benefit from shared experience and expertise. Full-scale programs could be established without going through "pilot" or "limited" stages.
- The consistency and quality of end-use and other DSM-related data could be greatly improved through shared program experience.
- DSM resources could be effectively "wheeled" across the system. Conducting DSM analysis and planning at a pool-wide level could yield overall cost savings by assuring that the most cost-effective DSM resources are developed first, wherever they occur, much like the guiding principle behind the development of the SO₂ allowance trading system.

Summary of the Single-Option DSM-Based Plan

The single-option DSM-based plan relied solely on DSM to reduce the level of needed generation at PJM power plants and thus to reduce the levels of emissions. The DSM-based plan was based on meeting SO₂ emission limits for Phase II compliance. The plan was focused on SO₂ emission reduction because we were unable to devise a DSM plan that would meet the constraint imposed by the 200,000 ton NO_x cap. (As discussed earlier, a DSM-based plan could not meet any constraints based upon emission rates, since DSM would not change the emission rate per kWh generated.)

Because of the Phase I bonus allowances for the two new scrubbers, the DSM-based plan did not need not begin reducing SO₂ emissions until 2001. Required energy use reductions ranged from approximately 75,800,000 MWh in 2001, to 90,700,000 MWh by 2005, and to 109,900,000 MWh by 2010. The cost of the DSM measures was

assumed to average five cents per kWh, equal to the avoided cost. Thus, the *net* cost of the DSM-based plan was zero. We have not further refined the DSM costs or designed a ramp-up period in the single-option DSM-based plan because the levels of DSM were so aggressive that we believed it to be a low-probability scenario.

Although implementation of the single-option DSM plan would not be needed before 2001 for the purpose of Phase II SO₂ compliance, earlier implementation would lead to reductions in NO_x emissions (although not enough to meet the cap) and to earlier compliance with the CO₂ constraint.

C. RENEWABLES-BASED PLAN

Description of Renewables Options

Twelve renewable energy resource options were considered for application in the PJM system. The system-wide use of renewables can provide zero- or low-emission and cost-effective sources of energy at or near the availability levels of conventional fossil-fuel-fired units. Renewables also decrease a utility's risk of fuel price shocks and safeguard against the need to comply with additional, more stringent emissions legislation. Since renewables tend to be modular in design and construction, capacity can be installed in any required capacity almost anywhere power is most needed. The distributed utility approach of renewables system integration allows the system planner to realize significant savings due to location-specific peak load reduction and avoided transmission and distribution costs.

Of the 12 resources analyzed, eight are classified as "zero-emitters"; that is, no regulated airborne emissions are produced during unit operation. Two of the remaining four options -- biomass landfill gas and biomass wood/agriculture waste -- emit some pollutants at significantly lower levels than conventional energy sources and therefore provide significant emission reduction possibilities. Municipal solid waste (MSW) waste-to-energy projects also emit less of certain pollutants (although concerns are sometimes raised about toxic air emissions and the disposal of ash at these facilities). Dual benefits are provided by landfill gas electricity production. Landfill gas generation reduces greenhouse gas emissions by utilizing methane gas that would otherwise be flared or released into the atmosphere. In addition, since some landfills may require gas collection and flaring systems for mitigation of volatile organic compound emissions, the revenues from landfill electricity production could offset the costs of these systems. The last option, pumped hydro, produces emissions according to the fuel and combustion process used to drive the pump. Pumped hydro is not technically a renewable resource because fuels are consumed to drive the pump. It is included here, however, to accommodate the broader definition of renewables that typically includes hydroelectric generation.

Each resource has distinct advantages and disadvantages in its application. The resource or combination of resources ultimately employed will be a function of capacity and energy cost, capacity factor, availability, technical maturity, and siting requirements and constraints. It is reasonable to expect that as the technologies mature and find more applications, the associated costs will decrease, and capacity factors and availabilities will increase.

The PJM region does not rely upon nor produce significant amounts of renewable energy. In 1990, renewables accounted for 2000 MW of capacity and 4475 million kWh. Of that amount, over 1600 MW was produced from hydroelectric facilities. Furthermore, over 300 MW of non-hydroelectric renewable production was from

municipal solid waste non-utility generators (NUGs), who held fixed-cost energy contracts with the PJM utilities.

The costs of the renewable resources considered in this study are identified in Table III-9.¹⁷ It should be noted that wind energy is the second least-expensive resource, and according to recent studies the PJM region has a potential of over 6800 MW. (Hamrin and Rader, 1992, Appendix A) These cost figures for wind represent the low end of available cost data.

**TABLE III-9
RENEWABLE RESOURCE ALTERNATIVES**

RESOURCE	CAPITAL COST (\$/kWe)	O&M (cents/kWh)	CAPACITY FACTOR (%)	TOTAL COST (cents/kWh)
Wind (a)	650	1.00	30	3.47
Pumped Hydro (b)	750	0.30	15	6.01
Solar Thermal Parabolic Dish (b)	1,249	0.80	25	6.50
Landfill Gas (b)	1,500	2.75	85	4.76
Wood/Ag Waste (b)	1,570	0.90	70	3.46
Small Hydro (b)	1,750	0.20	50	4.20
Photovoltaic (a)	2,000	0.20	25	9.33
Solar Central Receiver (b) (200MW)	2,200	0.60	29	9.26
Solar Thermal Parabolic Trough (b)	2250	1.40	37	8.34
Geothermal (b)	2,750	1.00	90	4.49
Solar Central Receiver (b) (100MW)	2,910	1.40	39	9.92
Municipal Solid Waste (a)	3,000	3.00	85	7.03

¹⁷ These costs do not include the 1.5 cent/kWh production tax credit provided for under the 1992 Energy Policy Act. Source of costs for resources identified as (a) in Table III-9: America's Energy Choices: Investing in a Strong Economy and Clean Environment, Technical Appendices, Table E3, P. E-19. Union of Concerned Scientists. 1992. Source of costs for resources identified as (b): Investing in the Future -- A Regulator's Guide to Renewables, Toolbox: Appendices. Appendix B. Hamrin/Rader. 1992.

Renewables-Based Plan Analysis

To develop a single-option renewables-based plan for PJM, renewable resources that might be applicable to the PJM system were first identified. Next, we determined if the target levels of energy and capacity reductions identified in the DSM-based plan analysis discussed previously could be replaced solely by renewable energy resources, and if so, at what cost?

The twelve renewable options identified in Table III-9 were first screened for their appropriateness to the PJM system. No formal screening methods were used in this initial step; rather, each resource was evaluated according to previously published renewable energy assessment studies in the region, geographical factors, and current and estimated future availability levels.

As a result of the initial screening, the solar central receiver, solar thermal, and geothermal options (other than heat pumps) were dropped from further consideration. The PJM region has insufficient solar insolation, excessive land procurement costs, and marginal ground heat capacity, which work against any significant development of these resources at competitive production prices. It should be noted, however, that the regional geography is capable of supporting residential and small commercial ground-sourced heat pumps. Significant increases in solar technology efficiency and power conversion are required before it can become a viable large-scale source of power for PJM.

Of the renewable resources currently in use in the PJM region, 80 percent of the total capacity is provided from utility and non-utility hydroelectric capacity -- both conventional and pumped storage. It is believed that additional development of these resources will be limited. Siting restrictions due largely to natural resource concerns hinder the ability to construct new river dams and generating stations in the PJM region. Existing facilities will most likely experience difficulties obtaining authority to re-power units in light of FERC's tightly regulated hydro re-licensing process. Due to the foregoing concerns, we constrained conventional and pumped storage plants to 100 MW or less over the planning horizon.

The most promising PJM renewable resources are wind, biomass (landfill gas and wood/agriculture waste), photovoltaics, and municipal solid waste-to-energy plants. These five options and the two hydroelectric options were evaluated using a linear optimization program. The program was set up to minimize annual system costs while simultaneously meeting 1) specified target energy levels (as defined in Table III-2) and 2) minimum (or maximum) installed capacity levels (as established by MSB based on available information) for each renewable resource. Once the optimal renewable supply mix was determined, their annual operating costs were calculated based on the fixed and variable costs of each resource as previously shown in Table III-9. Capacity costs were levelized using a 10 percent real levelized carrying charge.

Summary of Renewables-Based Plan

Phase II SO₂ compliance could theoretically be achieved by relying solely on aggressive implementation of renewable energy resources. Tables III-10 and III-11 describe the resulting renewables-based plan in the years 2002 and 2010 respectively. Emission restrictions, as defined in the DSM-based plan section, required an energy reduction of 79,716 GWh in 2002 and 109,938 GWh in 2010. To meet these targets, 14,329 MW and 18,712 MW of renewables capacity would be required respectively in each year. On average, the defined renewable resource configurations would provide PJM system dispatchers with an energy resource operating with an effective capacity factor of 64 percent in 2002, increasing to 67 percent in 2010.

In 2002, the required renewable energy supply-side resources would be available at a cost of \$4.0 billion based on a capital cost of \$282/kWe and a total cost of 5.07 cents/kWh. In 2010, costs would increase to \$5.8 billion and capital and total costs to \$311/kWe and 5.30 cents/kWh respectively. Compared to PJM system current and projected system costs, the aggressive renewables-based energy plan presents a competitive solution to emission reductions.

TABLE III-10
2002 OPTIMIZED AGGRESSIVE RENEWABLES PLAN

OPTION	MW	GWh
Wind	5,000	13,140
Pumped Hydro	100	131
Landfill Gas	3,000	22,338
Wood/Ag Waste	1,500	9,198
Small Hydro	100	438
PV	0	0
MSW	4,629	34,471
TOTAL	14,329	79,716
Total System Cost (millions)	4,045	
\$/kWe	282	
cents/kWh	5.07	

TABLE III-11
2010 OPTIMIZED AGGRESSIVE RENEWABLES PLAN

OPTION	MW	GWh
Wind	5,500	14,454
Pumped Hydro	100	131
Landfill Gas	4,000	29,784
Wood/Ag Waste	1,500	9,198
Small Hydro	100	438
PV	0	0
MSW	7,512	55,933
TOTAL	18,712	109,938
Total System Cost (millions)	5,824	
\$/kWe	311	
cents/kWh	5.30	

D. IPP-BASED PLAN

Description of IPP Options

Independent power producers (IPPs), as their name implies, are non-utility suppliers of wholesale electricity. IPPs may be energy service companies created specifically to generate power for sale to electric utilities. Other IPPs may generate electricity as a by-product or sidelight of other manufacturing activities. Utilities may purchase power from IPPs to supplement their own capacity or to avoid the need to build additional new capacity.

Types of Projects

The types of projects proposed by IPPs can range widely.

Renewable Energy Projects: These are often based on wind, solar, biomass, geothermal or hydroelectric resources. Renewable energy projects, whether developed by utilities or by IPPs, are addressed in the renewable energy options section of this report and will not be discussed here.

Cogeneration Projects: Large amounts of steam and electricity are used at many types of industrial facilities. Many industries have installed cogeneration equipment at their facilities to improve overall thermal efficiency by using high temperature/pressure steam to generate electricity and then using the resultant lower temperature/pressure steam for heating and process use. Cogeneration facilities often capture in excess of 50 percent of the energy content of the fuel for productive use, compared to 30 to 40 percent for typical new base load utility plants. Cogeneration projects can be initiated by the host industry, by an energy service company contracting with a host industry, or by the utility contracting with the host industry.

"Conventional" Electricity Projects: Sometimes IPPs build natural gas-fired simple or combined cycle electric power plants that are fairly similar to conventional utility plants. These units are often compact, modular designs that can be easily and quickly installed. Natural gas-fired units have relatively low emissions and low up-front capital costs, making them quite attractive as long as fuel supplies are available at reasonable prices. The thermal efficiency of combined cycle units approaches 50 percent, meaning less fuel is used and fewer pollutants are emitted than from existing utility power plants. Other "conventional" IPP projects may use fuels other than natural gas, such as coal or petroleum coke, and steam-cycle equipment rather than combustion turbines. These IPP projects have higher pollutant emission rates

and construction costs than the natural gas-fired combustion turbine designs. They, however, presumably take advantage of opportunities to secure lower-cost fuels to make them cost-competitive overall.

IPP Effect on Emissions

Utilities look to IPPs as part of their response to environmental constraints because IPPs reduce the amount of utility-owned generation required and will thus reduce the amount of utility-generated emissions. Whether IPP projects reduce the overall emissions depends on the nature of the project and the specific applicability of future environmental regulations. Certainly, IPP projects based on renewable energy resources have low or no pollutant emissions and will reduce net global emissions. Other IPP projects, such as cogeneration, capitalize on improved thermal efficiency and will emit pollutants at a reduced rate, again reducing net global emissions. Other IPP projects, such as natural gas-fired combustion turbines, employ the same equipment typically used by utilities, and will probably not significantly affect global emission rates in comparison to utility construction projects of the same type. Nonetheless, these projects may be attractive to utilities because they transfer the risk of meeting environmental constraints from the utility to the IPP.

It is also possible that future environmental regulations may not apply equally to all utilities and IPPs. Exemptions, or different standards, may apply to some IPPs based on size or type of project. For example, stricter regulations may be applied to utilities' facilities because they are large central station sources that are easier and more economical to control than many small dispersed sources. Similarly, small IPP projects may be exempt from regulations while larger IPP projects are typically required to meet the same standards as utility facilities. Thus, it is possible that specific IPP resources could increase the net emissions of air pollutants relative to new utility-owned generation.

Current IPP Utilization

Most of the PJM utilities purchase some energy and/or capacity from independent power producers. They purchased approximately 3600 MWe of capacity in 1993, and expect to increase that figure within the next 10 years.

This IPP capacity accrues from several different sources, including conventional methods such as pulverized coal and gas-fired combined cycle projects, cogeneration projects using coal, gas, and bituminous waste, and renewable resources such as hydro, landfill gas projects, municipal solid waste (MSW), and waste wood burning projects. The capacity available from each of these projects varies from 0.001 MWe for a small hydro project to 230 MWe for a cogeneration combined cycle project.

IPP Source Availability

The trend thus far suggests that IPP potential exceeds the PJM utilities' IPP capacity requirements. PJM utility solicitations of 100 MWe to 200 MWe have resulted in anywhere from 10 to 40 proposals¹⁸. Even when using a competitive bidding process for the first time, utilities tend to receive overwhelming responses from IPP generation sources. Metropolitan Edison Company, for example, was the first Pennsylvania utility to use a competitive bidding process to obtain 200 MWe of IPP generation. Thirty-nine bidders proposed 5004 MWe of projects in response to the pilot RFP. The following table shows that other PJM utilities have similarly seen IPP project bids far exceed the solicited amounts of capacity.

**TABLE III-12
PJM MEMBER UTILITY IPP BID RESULTS**

UTILITY	YEAR	SOLICITED MWe	PROPOSALS	MWe BID	NOTES
DP&L	1989	100	10	870	1, 2
DP&L	1992	150	27	3200	1
PEPCO	1990- 1992		10	2000	3
MetEd	1992	200	39	5004	4
JCP&L	1989	150	NA	700-900	5

NOTES:

1. Proposals from 1989 and 1992 combined included two or three MSW projects, two urban wood waste projects, a bituminous waste project, and anthracite waste project among others. Most of the proposals were for gas-fired combined cycle, and a little more than half were cogeneration projects. (Source: Delmarva Power and Light, November 1993)
2. Approximately 870 MWe of projects were bid.
3. Source: Potomac Electric Power Co., November 1993.
4. Thirty-nine bidders responded to the Company's solicitation. Twenty-four bids were based on natural gas, five on renewable energy sources, and the rest on coal and nuclear power. (Source: Metropolitan Edison Company, November 1993)
5. Source: Jersey Central Power & Light Co., November 1993.

¹⁸ Personal communications with PJM member utilities, November 1993.

In addition to the large amount of capacity available, the utilities are finding a wide choice of fuel options in proposed IPP projects. Currently, existing and expected IPP capacity on the PJM system consists of approximately 10 percent renewable resources (including landfill gas and municipal solid waste), 15 percent cogeneration, and 50 percent natural gas-fired combustion turbines, with the remainder being coal and other fossil fuels. We expect that projects based on coal and high-sulfur fuel oil will be less likely in the future since the Clean Air Act Amendments make such projects more expensive to operate relative to natural gas-fired projects.

Utility solicitations for independent power generation in other parts of the United States have received responses similar to PJM's solicitations. In 1993, for example:

- The North Carolina Membership Corporation solicited up to 330 MWe, and attracted 15 bids from 12 non-utility generators. The bids proposed building 4600 MWe of gas- or oil-fired combined cycle combustion turbines. (Electric Utility Week, August 2, 1993)
- Sierra Pacific Power solicited bids for two 100 MWe blocks. It received 35 bids for 1857 MWe for the first block, 89 percent of which was gas- and oil-fired. It received 29 bids for 3175 MWe for the second block, 84 percent of which was gas- and oil-fired. (Electric Utility Week, May 10, 1993)
- Georgia Power Company requested bids for 1500 MWe of capacity. Thirteen companies bid 38 projects totaling 15,000 MWe. (Electric Utility Week, July 26, 1993)
- Clark Public Utilities in Vancouver, Washington received 30 proposals totaling 4080 MWe in response to a solicitation for 150 MWe. Sixty-four percent of the proposed capacity was from natural gas-fired combined cycle units, and an additional 24 percent was from gas-fired cogeneration units. (Electric Utility Week, August 2, 1993)
- Wisconsin Electric Power Company received 22 proposals, representing in excess of 2,000 MWe, in response to a solicitation for 210 MWe. The bid capacity was about 40 percent of Wisconsin Electric's load. (Wisconsin Public Service Commission, 1993)

IPP-Based Options Analysis

Method

Analysis of IPPs as an alternate emission reduction strategy followed the approach

used for analyzing demand-side management and renewables. In the DSM analysis, we determined how much reduction of usage of the conventional generating system would be necessary to bring SO₂ emissions into compliance with Title IV of the Clean Air Act Amendments. It is clear that *any* technology that reduces the use of the conventional generating system without creating its own pollutant emissions will have the same effect on overall system emissions as DSM. Depending on the technology used, IPPs will do just that for certain pollutants. For example, gas-fired combined cycle units produce essentially no SO₂ emissions. They produce NO_x and CO₂ emissions, but in less quantity than conventional coal-fired generation. In contrast, coal- or coke- fired IPPs may produce as much (or more) pollutants as conventional utility generation.

We did not perform an independent analysis of the availability of independent power as a resource alternative for the PJM utilities. As described previously, many utilities across the country (including PJM utilities) that have issued RFPs for independent power have received large numbers of bids to provide power. Thus, we believe that the availability of IPP bids would be sufficient to meet the levels of power that would be needed if IPPs were relied on to meet the Clean Air Act standards.

Recent utility experience with IPP proposals suggests that natural gas-fired projects predominate. For purposes of this analysis, we assumed that IPPs will use natural gas-fired combined cycle technology (GFCC), a highly efficient and low-pollution-emitting technology. Utilities conducting their own, more detailed analyses, however, should analyze all locally available fuel types and IPP configurations.

Cost of Gas-Fired Combined Cycle Plants

The gas-fired combined cycle plant, while more expensive to build than a combustion turbine, is much more efficient. As a result it becomes possible under many circumstances to burn a higher-priced fuel (natural gas) in a cost-effective manner to produce a large amount of energy. Typical gas-fired combined cycle plants cost approximately \$800 to \$1,000 per kWe to build. This is twice the cost of building a combustion turbine, but only about half the cost of a coal-fired plant. Because of the conversion cycle used, GFCC plants can typically achieve heat rates as low as 7,800 to 8,000 Btus per kWh. This is in comparison to combustion turbine heat rates of 12,500 to 14,500 Btus per kWh, and coal plant heat rates of close to 10,000 Btus per kWh. As a result, the cost per kWh of GFCC plants is (in 1992 dollars):

- Capital Cost -- \$1,000 per kWe times a constant dollar capital cost recovery factor of 15 percent (higher than the 10 percent assumed for utilities because of an assumption that higher returns are required on investment for IPPs) leads to an annual cost of \$150 per kWe. Assuming a capacity factor of 92 percent yields 8,060 kWh per kWe per

year. The capital cost per kWh is (\$150/8060) or \$0.0186 per kWh.

- Fuel Cost -- In most cases the cost of gas for gas-fired power plants on the PJM system is about \$2.60 per MMBtu. Most of these plants are peaking plants, and we could assume that the cost of gas for the base-loaded operations typical of IPPs would be lower on a cost-per-MMBtu basis. To be conservative, however, we have assumed the same cost of \$2.60. Using a heat rate of 8,000 Btus per kWh leads to a fuel cost of \$0.0208 per kWh.
- Fixed Operating and Maintenance Cost -- Based on the EPRI Technical Assessment Guide (TAG), which sets forth likely expected costs for various generating technologies, we have estimated a fixed O&M cost of \$7.00 per kWe per year. (EPRI, 1989) Using the same capacity factor conversion we used for converting capital costs to dollars per kWh costs, we estimate a cost of \$0.0009 per kWh for fixed O&M.
- Variable Operating and Maintenance Cost -- Based again on the EPRI TAG we have estimated a variable O&M cost of approximately \$ 2.50 per MWh, or \$0.0025 per kWh. (EPRI, 1989)

Thus, the total estimated cost of power from a gas-fired combined cycle plant is \$0.0428 per kWh. This includes the assumption of a higher required return for IPPs than for utilities. We see no reason to expect a RFP issued by PJM utilities to bring in bids with costs significantly higher than this, since the principle behind competitive bidding for power is that all of the participants can estimate their own and other participants' costs reasonably accurately, and must bid close to those estimated bids to win. For example, in the Wisconsin bidding discussed above, the range of costs between the various offers was very narrow (the actual bids are confidential and therefore cannot be reported here).

Emissions from Gas-Fired Combined Cycle Plants

Emissions of SO₂ from gas-fired combined cycle (GFCC) plants are, for all practical purposes, equal to zero. Emissions of NO_x from uncontrolled GFCC plants are typically about two thirds those of new uncontrolled coal-fired plants -- 0.4 pounds per MMBtu as compared to 0.6 pounds per MMBtu. New GFCC plants are, however, unlikely to be uncontrolled. As a result, the expected emission rate is approximately 0.05 pounds per MMBtu. With a heat rate of approximately 8,000 Btu/kWh, the emission rate is approximately 0.0004 pounds per kWh, or approximately 10 percent of the system decremental emission rate.

Emissions of CO₂ are similarly reduced. The emission rate for gas-fired plants is

about 110 pounds per MMBtu, while the CO₂ emission rate for coal plants is about 210 pounds per MMBtu. Factoring in the heat rates results in an emission rate for coal of about 2.1 pounds per kWh, while the emission rate for GFCC is 0.88 pounds per kWh. This is 42 percent of the coal plant emission rate. The decremental emission rate, however, is not 2.1 pounds per kWh but rather 1.3 pounds per kWh. Thus, the GFCC emission rate is 68 percent of the decremental emission rate.

Avoided Cost on the PJM System for IPPs

In the section on the DSM-based plan, we developed avoided cost estimates for the PJM system. While for DSM we included an avoided cost of transmission and distribution, this may not be appropriate for IPPs since many of these units would probably be sited on the transmission system and would not avoid any T&D. Therefore the applicable avoided cost is the sum of the avoided energy cost and the avoided capacity cost. The average avoided cost (from the DSM section) is \$0.0346 (energy) + \$0.0068 (capacity) or \$0.0414 per kWh.

Independent Power Producers as an Emission Reduction Option

The avoided cost on the PJM system was less than the estimated cost of GFCC IPP power (\$0.0428 per kWh) by \$0.0014 per kWh. Thus, it appears that IPP power would not be cost-effective on a direct cost basis. The cost difference, however, was equivalent to SO₂ emission reduction at a cost of approximately \$300 per ton. This was less than the plant-based cost of SO₂ reduction which is \$489 to \$619 per ton of SO₂. IPP power appears to be cost-effective on a total cost basis; the relative cost-effectiveness will vary with conditions specific to the projects and utility.

Summary of the IPP-Based Plan

The single-option IPP-based plan was similar to the DSM plan in that it was designed to meet the Phase II Acid Rain compliance requirements for SO₂. It was designed in this way for the same reason as the DSM plan – because we were unable to develop an IPP plan that met the NO_x constraints. The IPP plan relied on natural gas-fired combined cycle units to provide the same yearly amounts of energy as set forth in the DSM plan – approximately 75,800,000 MWh in 2001, growing to 90,700,000 MWh by 2005, and to 109,900,000 MWh by 2010. The applicable avoided cost was \$0.0414 per kWh, giving a net cost of IPP power of \$0.0428 to \$0.0414, or \$0.0014 per kWh. Costs for the single option IPP plan began to be incurred in 2001. Earlier implementation would not be necessary for meeting SO₂ reduction requirements and would not be adequate to meet the 200,000 ton NO_x cap.

E. COMPOSITE PLAN

Method

The next step, after developing cost and performance estimates for the four "single option" emission reduction scenarios, was to combine elements of these scenarios together into a composite plan that met the constraints at lower cost. It quickly became clear that it would be very difficult to derive a single best plan that met all the emissions constraints assumed for the system. The best approach for one pollutant may not meet the constraints imposed on another. For example:

- Plant-based strategies require separate technologies for each pollutant. SO₂ scrubbers will not lead to any CO₂ or NO_x reduction, and will in fact make the NO_x and CO₂ problems slightly worse because they have a negative impact on plant efficiency. NO_x reduction through burner technologies or post-combustion technologies will not have any impact on SO₂ or CO₂. None of the plant-based approaches will fully meet the CO₂ constraint.
- The energy reduction strategies (DSM, renewable resources) are effective at reducing SO₂ and CO₂ emissions. However, they do not address at all the first two NO_x scenarios (which are based purely on mandated technologies at specific plants), and are inadequate on their own to meet the NO_x cap scenario.
- The independent power strategies can meet SO₂ constraints, but are not adequate to meet NO_x and CO₂ constraints.

Further complicating the development of a composite plan was the fact that, in determining the level of DSM to be included, we needed to consider not only cost-effectiveness, but also how much DSM was actually achievable. The analysis demonstrated that more DSM was cost-effective than could reasonably be assumed to be achievable. As a result, we included some technologies as part of the composite plan that were likely to be less cost-effective than some DSM that was deemed to be not achievable.

Our composite plan was developed using the following steps:

1. We first included all the DSM that was found to be reasonably achievable. The achievable DSM resource was the most cost-effective element of the composite plan. It also had the greatest impact on both SO₂ and CO₂ emissions. DSM was very effective at reducing total NO_x emissions, but it did not affect NO_x emission rates. DSM in the composite plan began to be implemented in 1997 to reflect the ramp-up period needed to fully implement the DSM resource by the time it was needed to meet the SO₂ constraint.

2. We then included the amount of wind generation that was deemed achievable. As an energy reduction strategy, wind generation shares with DSM the benefit of directly eliminating both SO₂ and CO₂. As with DSM, wind generation reduces total NO_x emissions, but not the NO_x emission rate.
3. We then assumed sufficient independent power to meet the system needs while still maintaining compliance with the SO₂ standard.
4. We next estimated the impact of these strategies on the system NO_x emissions. We then assumed sufficient NO_x controls to meet a NO_x cap of 200,000 tons per year, beginning in 1999, for the PJM utilities.

Based on the analysis described in the previous sections, we determined the gross and net cost per kWh of the various alternative emission reduction options. The gross cost per kWh was the actual cost of the option. The net cost per kWh was the cost of the option minus the applicable avoided cost. The applicable avoided cost varied somewhat for different options. The avoided cost used for analyzing DSM included a component for avoided transmission and distribution investments. In most jurisdictions where this has been investigated, it has been found that DSM, since it involves reducing energy usage *at the customer's premises*, reduces the need for transmission and distribution facilities. The extent to which the need is reduced and the value of the reductions depends on the specific nature of the system in question. We included an estimate of the transmission and distribution savings of \$75 per kWh-year in the avoided cost applicable to DSM. This component was *not*, however, included in the avoided cost applicable to supply options, since these options do not reduce the need for facilities to bring power from the generating site to the customer's premises. The following table shows the gross and net cost per kWh for various options. The cost per ton of SO₂ removal for each option was also calculated; the entire net cost per kWh was assigned to SO₂ removal.

TABLE III-13
COMPARISON OF THE COST OF DSM, RENEWABLE AND IPP OPTIONS

	Direct Cost per kWh	Applicable Avd Cost per kWh	Net Cost per kWh	Decremental SO ₂ Pounds per kWh	Cost/ Ton SO ₂ Removed
Demand-Side Mgt.	\$0.0300	\$0.0500	(\$0.0200)	0.007	(\$5,718)
Small Hydro	\$0.0420	\$0.0414	\$0.0006	0.007	\$171
Wood/Agr. Waste	\$0.0346	\$0.0414	(\$0.0068)	0.007	(\$1,947)
Wind Generation	\$0.0347	\$0.0414	(\$0.0067)	0.007	(\$1,918)
IPPs	\$0.0428	\$0.0414	\$0.0014	0.007	\$ 396
Landfill Gas	\$0.0476	\$0.0414	\$0.0062	0.007	\$1,771
Municipal Solid Waste	\$0.0703	\$0.0289	\$0.0289	0.007	\$8,257

Based on the values in the table, the best approach would appear to be greater reliance on DSM as an emission reduction approach since its net cost was negative. As discussed previously, however, we do not believe this would be a reasonably achievable scenario at this time. Similarly, small hydro, wood/agricultural wastes, and wind generation also had negative net costs. However, as with DSM, we do not believe it would be possible to rely on these options to the extent necessary to meet system needs and the required levels of emission reductions. Therefore, in the composite plan we included all achievable DSM, small hydro, wood/agricultural waste, and wind generation. We included enough natural gas-fired combined cycle IPP power to reduce the generation from conventional SO₂ emitting power plants far enough to reduce SO₂ emission levels to below the Clean Air Act Amendments Phase II requirements.

Although we did not include any landfill gas or municipal solid waste-to-energy generation in the composite plan, we recognize that many of these resource options are in fact being installed on the PJM system. In many cases, their contribution to the solution of other environmental problems (e.g., landfills) and the revenue stream that results make these projects very attractive. Unfortunately, these projects are very situation-specific and cannot be evaluated on the general system level used for this study. When the circumstances are appropriate, landfill gas and municipal waste-to-energy generation should be developed as alternatives. We cannot, however, make generalized system-wide assumptions of the applicability of these technologies.

Summary of the Composite Plan

The composite plan contained the following elements:

- Demand-Side Management -- 8.6 million MWh in 2000, 19.4 million MWh in 2002, 24.2 million MWh in 2005, and 27.3 million MWh in 2010 at a net cost of -\$0.02 per kWh.
- Wind Generation -- 13.4 million MWh in 2001, 13.8 million MWh in 2005, and 14.5 million MWh in 2010 at a net cost of -\$0.007 per kWh.
- Wood and Agricultural Waste -- 9.2 million MWh per year at a net cost of -\$0.007 per kWh.
- Small Hydro -- 0.4 million MWh per year at a net cost of -\$0.0006 per kWh.
- Gas-Fired Combined Cycle IPPs -- 37.2 million MWh in 2001, 43.0 million MWh in 2005, and 58.5 million MWh in 2010 at a net cost of \$0.001 per kWh.
- Plant-Based NO_x Emission Controls -- Low-NO_x burners to reduce NO_x emissions by 175,000 tons in the year 1999 at an average cost of \$417 per ton.

Emissions associated with the composite plan are identified in Table III-14.

TABLE III-14
EMISSIONS ASSOCIATED WITH COMPOSITE PLAN

	2000	2005	2010
SO ₂ (tons)	1,035,000	660,000	650,000
NO _x (tons)	214,575	149,030	159,829
CO ₂ (tons)	134,952,200	133,528,760	143,182,920

The cost of the composite plan was less than the cost of the reference case. The cost of DSM, wind, and wood/agricultural waste generation was less than the avoided cost. The resultant savings were \$331 million in 2000, \$587 million in 2005, and \$633 million in 2010. These annual savings would be reduced, however, by the cost of required NO_x reduction. The remaining required 175,000 ton reduction would cost about \$73 million per year. Even with these added costs, the net cost of the composite plan was less than the cost of the reference case. The composite plan, however, failed to meet the CO₂ constraint.

IV. COMPARISON OF THE FIVE ALTERNATE PLANS

In this chapter, the five plans developed in the previous chapter, including the four single-option plans and the composite plan, are compared with each other and with the reference case on the bases of emissions and costs.

A. COMPARISON OF EMISSIONS

With the exception of Phase I SO₂ requirements and the March 1994 Title IV NO_x regulations affecting Phase I units, the reference case did not meet any of the constraints we established for this study – meeting the Clean Air Act Amendments requirements for SO₂ and NO_x, a 60 percent reduction in NO_x emissions from 1990 levels, and stabilizing CO₂ emissions at 1990 levels. Its SO₂ emissions were in excess of Clean Air Act Amendments Phase II requirements by on average approximately 359,000 tons per year from 2002 on. NO_x emissions surpassed the 200,000 ton cap assumed as a constraint by 240,000 tons in 1995, growing to 301,000 tons by 2010. The average excess over the period was 270,000 tons. Emissions of CO₂ exceeded the target constraint of 125,000,000 tons per year by an amount ranging from 16,000,000 tons in 1995 to 58,000,000 in 2010.

The plant-based plan met both the SO₂ and the NO_x constraints. It did not meet the CO₂ constraint. We do not know of any existing plant-based control technology that would meet the CO₂ constraint. A massive shift of the existing system to gas-fired combined cycle plants would keep CO₂ emissions below 125,000,000 tons per year, but at an unacceptable cost in both dollars and reliability.

The DSM-based plan met the SO₂ constraint and the CO₂ constraint after 2001. It did not, however, meet the NO_x constraint. It reduced emissions by approximately 178,000 tons per year, leaving a required further reduction of approximately 125,000 tons of NO_x per year to meet the 200,000 ton assumed cap.

The renewables-based plan's emissions characteristics were similar to those of the DSM-based plan. The SO₂ impacts were the same because no SO₂-producing renewables technologies were included. The CO₂ and NO_x impacts were difficult to judge because there is little information on net emissions from burning landfill gas, wood/agricultural waste, and municipal solid waste. We can assume, however, that the NO_x levels associated with the renewables-based plan would equal or exceed those of the DSM-based plan. Although we were unable to calculate CO₂ emissions for the renewables-based plan, it is important to note that use of landfill gas for generation has an important benefit relative to greenhouse gases. Methane (the gas burned in this technology) is very reactive in the atmosphere and has significant greenhouse implications. Although burning landfill gas emits CO₂, it emits less CO₂

per kWh than if the power was generated by burning oil or coal. In addition, burning the gas rather than allowing it to be released reduces the levels of highly reactive methane gas going into the atmosphere.

The IPP-based plan met the SO₂ requirements because of the heavy use of natural gas. It did not meet either the NO_x constraint or the CO₂ constraint.

The composite plan met the SO₂ constraint and the NO_x constraint after 2001. It met the SO₂ constraint through reduced energy generation on existing SO₂-emitting plants. It met NO_x constraints through the addition of plant-based technologies to the major NO_x emitting plants. The composite plan did not meet the CO₂ constraint.

TABLE IV-1
CONFORMITY OF THE REFERENCE CASE AND FIVE ALTERNATE
PJM PLANS WITH CONSTRAINTS
(DOES THE PLAN MEET THE CONSTRAINTS?)

Plan	Sulfur Dioxide	Oxides of Nitrogen	Carbon Dioxide
Reference Case	No	No	No
Plant-Based Plan	Yes	Yes	No
DSM-Based Plan	Yes	No	Yes, after 2001
Renewables-Based Plan	Yes	No	?
IPP-Based Plan	Yes	No	No
Composite Plan	Yes	Yes, after 2001	No

Figures IV-1 - IV-6 portray the impacts of the different plans on emissions of SO₂, NO_x, and CO₂. Note that the renewables-based plan is not included in the NO_x and CO₂ graphs (Figures IV-3 to IV-6) because we were unable to estimate NO_x and CO₂ emissions for this plan.

Figure IV-1

Figure IV-2

Figure IV-3

Figure IV-4

Figure IV-5

Figure IV-6

Sulfur Dioxide

Figure IV-1 illustrates the SO₂ levels associated with the alternate plans in the year 2010. Only the SO₂ emissions of Clean Air Act Amendments-affected plants were included; however, in 2010 this represented almost all SO₂ emissions.

Because all five plans were designed to meet the 650,000 ton constraint imposed by the Clean Air Act Amendments, emissions of SO₂ are the same for all five plans – 650,000 tons per year from affected plants. Emissions in the reference case were 1,000,000 tons – it did not meet the Phase II Clean Air Act Amendments requirements.

Figure IV-2 identifies SO₂ emissions for the five plans from 1995-2010. Again, only those emissions of SO₂ from affected plants were included. This noticeably affected the emissions shown in Figure IV-2 from 1995 to 1999. Actual SO₂ emissions were more than 1,000,000 tons during those years, but only a small number of plants were Clean Air Act Amendments Phase I-affected units. The dramatic increase in emissions from 1999 to 2000 (when we would expect the emissions to go down as a result of the beginning of Phase II of the Clean Air Act Amendments requirements) reflected the fact that the emissions from many more units were included as of the year 2000. The bulge in SO₂ emissions in the years 2000 and 2001 for all five plans was a result of the utilities being able to utilize bonus allowances that built up during Phase I. These were used up in 2000 and 2001, and the emission levels then declined to the Phase II-constrained level.

Oxides of Nitrogen

As Figure IV-3 indicates, NO_x emissions in the reference case were just over 500,000 tons in 2010. Two of the plans – the plant-based plan and the composite plan – met the constraint of 200,000 tons in the year 2010. These plans were designed to meet this constraint, and the costs of doing so were built into the cost of these plans. The DSM-based plan and the IPP-based plan did not meet the constraint, although the emissions were lower than those associated with the reference case. The level of DSM needed to reduce SO₂ emissions to 650,000 tons was not sufficient to reduce NO_x emissions to 200,000 tons. Much higher levels of DSM would be required to meet this level. Calculation of NO_x emissions from the renewables-based plan was not possible because of the difficulty of estimating emissions from solid waste and landfill-gas burning plants. It is clear, however, that NO_x emissions from the renewables-based plan would be at least as high as the emissions from the DSM-based plan, and thus would not meet the NO_x constraint.

Figure IV-4 illustrates the NO_x emissions of the five plans throughout the 1995-2010 time period. The 200,000 ton constraint was assumed to go into effect in 1999.

Carbon Dioxide

Only the DSM-based plan met the CO₂ constraint in 2010. Control technologies for CO₂ are not currently commercially available, and hence were not included in any of the plans. The DSM-based plan reduced CO₂ strictly by reducing the usage of the generating system. The plant-based plan emits the same level of CO₂ as does the reference case because we could not identify any plant-based approaches to reducing CO₂. The IPP-based and composite plans had lower CO₂ emissions than the reference case because some of the resource alternatives had inherently lower CO₂ emission rates. Calculating the CO₂ emissions associated with the renewables-based plan was not possible because of the difficulty of estimating emissions from wood/agricultural/municipal waste and landfill gas burning plants. To the extent that wood and agricultural wastes are burned, these simply recycle carbon fixed from the atmosphere through photosynthesis. To the extent that municipal wastes containing petroleum- or coal- based carbon are burned, the atmospheric balance of CO₂ would increase.

B. COST COMPARISON

The reference case was used as the basis for comparing the costs of the five alternate plans; the cost of the reference case was set as zero. All other plans were compared to it; therefore, the costs of the other plans can be either positive or negative. Table IV-2 sets forth the year-by-year costs of each plan. The reference case included the impact of the March 1994 Title IV NO_x regulations (which affect Phase I units only) and the Phase I SO₂ requirements.

The plant-based plan included either scrubbers or fuel switching for SO₂ and selective catalytic reduction (SCR) for NO_x. It did not include any CO₂ reduction. Since the costs for fuel switching and SO₂ scrubbing were similar (depending on the fuel-cost differential used) we used the cost of scrubbing as the basis for the cost of this plan. Furthermore, we assumed the lower-cost approach of scrubbing a greater number of lower-cost plants.

The single-option DSM-based plan included large amounts of DSM at an average cost of five cents per kWh, which was the same as the avoided cost of the reference case. Therefore, the net cost of the single-option DSM-based plan was equal to the reference case.

The single-option renewables-based plan had an average cost per kWh (based on a weighted average of the costs of the different renewables components) of 5.1 cents per kWh in the year 2002 and 5.3 cents per kWh in 2010. The avoided cost applicable to the renewables-based plan was less than that for the DSM-based plan because it did not include an avoided transmission and distribution component. Removing the transmission and distribution component yielded an avoided cost of 4.1 cents per kWh. Thus, the net cost of the renewables-based plan was 0.9 cents per kWh in the year 2002 and 1.2 cents per kWh in 2010.

The single-option IPP-based plan included gas-fired combined cycle plants at an estimated cost of 4.3 cents per kWh. The applicable avoided cost, as with the renewables-based plan, did not include an avoided transmission and distribution component, and was therefore 4.1 cents per kWh. Thus, the net cost of the IPP-based plan was 0.2 cents per kWh.

The composite plan contained a mix of DSM, renewables, independent power, and plant-based resources. Because it did not go as far as the single-option plans in pursuing any particular resource, it was a less-costly approach than any of the single-option plans. Since many of the more cost-effective resources were less costly than the system avoided cost, the net cost of the composite plan was less than the cost of the reference case. There was a plant-based component included in the composite plan. NO_x reduction technology -- in most cases, low-NO_x burners -- was required on many plants to meet the NO_x constraint of 200,000 tons per year. There was no need,

however, for SO₂ reductions beyond those already planned because the other resource options maintain SO₂ emissions below Clean Air Act Amendment-Phase II requirements.

TABLE IV-2
COST COMPARISON AMONG REFERENCE CASE AND FIVE
ALTERNATE PLANS
(ALL COSTS IN MILLIONS OF DOLLARS
COMPARED TO THE REFERENCE CASE)

Year	Reference Case	Plant Based Plan	DSM Based Plan	Renewables Based Plan	IPP Based Plan	Composite Plan
1995	0	0	0	0	0	-1
1996	0	0	0	0	0	-1
1997	0	0	0	0	0	-11
1998	0	0	0	0	0	-41
1999	0	164	0	0	0	-20
2000	0	170	0	0	0	-258
2001	0	329	0	700	106	-382
2002	0	314	0	741	112	-423
2003	0	326	0	802	117	-451
2004	0	326	0	856	121	-483
2005	0	333	0	921	127	-514
2006	0	333	0	975	131	-549
2007	0	339	0	1,053	137	-552
2008	0	339	0	1,115	142	-557
2009	0	339	0	1,189	147	-562
2010	0	345	0	1,275	154	-560

C. SENSITIVITY ANALYSIS

Although no formal sensitivity analysis was performed as part of this analysis, sensitivity of the results to several important input parameters *was* examined in the process of doing the study. Among the sensitivities considered were the following:

- Cost of SO₂ to be included in the dispatch algorithm;
- Impact of higher oil and gas cost escalation rates;
- High and low SCR capital cost for NO_x cleanup;
- Different approaches to SO₂ scrubbing;
- High/low sulfur coal cost differential.

In the analysis of the impact of different SO₂ costs in the dispatch algorithm, we analyzed the use of \$250 per ton and \$350 per ton as variants on the \$300 per ton used in the bulk of the modeling. Compared to the \$300 per ton base, the impact of using \$350 per ton was to increase the direct cost by 0.02 percent while decreasing the SO₂ emissions by 2,000 tons per year (in 2010), or 0.2 percent. Using a value of \$250 per ton led to increased emissions of 4,000 tons per year (in 2010), a 0.4 percent increase, at a decrease in cost of 0.005 percent.

The analysis of higher oil and gas cost escalation rates looked at the impact of using an eight percent real escalation rate for these fuels rather than the four percent used in the base case. The impact of this change was a 9,000 ton change (0.9 percent) in SO₂ emissions in the year 2010, and a cost increase of 1.9 percent (in net present value).

The impact of using low versus high SCR capital costs for NO_x cleanup was discussed in Chapter III A, "Plant-Based Plan." The difference was \$123 per ton of NO_x reduced, or \$842 vs. \$719 per ton.

The impact of different approaches to SO₂ scrubbing was also discussed in Chapter III A. We analyzed the impact of applying scrubbers at three large plants (beyond those already planned for scrubbing) versus scrubbing nine smaller plants (beyond those already planned). The cost was lower for scrubbing the eight smaller plants -- \$489 per ton to meet Phase II requirements -- than for scrubbing the largest plants -- \$619 per ton to meet the same targets.

Chapter IIIA also included a discussion of the impact of different low/high sulfur coal cost differentials. The base case assumed a differential of \$0.25 per MMBtu which led to a cost for SO₂ removal by fuel switching of \$604 per ton. Use of a \$0.10 per MMBtu differential would reduce the cost of fuel switching to \$411 per ton of SO₂ removed. Increasing the differential to \$0.50 per MMBtu would increase the cost for SO₂ removal by fuel switching to \$1,050. If the differential were \$0.10 per MMBtu, fuel switching would be cost-effective compared to scrubbing; if the

differential were \$0.50 per MMBtu, fuel switching would not be cost-effective compared to scrubbing. The break-even cost for fuel switching is \$0.15 per MMBtu compared to the cost of scrubbing that was used.

V. CONCLUSIONS

In this analysis of the use of integrated resource planning methods to reduce air emissions in the PJM power pool, four single-option plans were developed to assess the contributions that various resource options could make to the control of SO₂, NO_x, and CO₂. The best features of these plans were combined to form a fifth, composite plan, which sought to meet the emissions constraints established for the study at lower cost. These five plans were compared to a reference case (which, because the PJM utilities have not yet finalized their Phase II compliance plans, met only the Phase I SO₂ requirements and the March 1994 Title IV NO_x regulations which affect Phase I units). The five alternate plans included:

- Plant-based plan relying on scrubbers for SO₂ control and low-NO_x burners and selective catalytic reduction for NO_x control. Also evaluated were fuel switching, conversion to natural gas, and supply-side efficiency improvements.
- Demand-side management-based plan relying on aggressive implementation of demand-side measures costing an average of five cents per kWh. DSM was used to eliminate about one third of the energy that would have been supplied in the reference case.
- Renewable-energy based plan relying on wind, photovoltaics, and the combustion of landfill gas and wood/agricultural/municipal wastes. Solar thermal and geothermal resources were also considered.
- Independent power producer-based plan relying on purchasing electricity from non-utility sources operating natural gas-fired combined cycle units. Also considered were cogeneration projects and other fuel types. (Although the modeling used for this study ultimately relied upon gas-fired combined cycle units, utilities evaluating IPPs should analyze all locally available fuel types and IPP configurations.)
- Composite plan relying on a mix of demand-side resources (at an average cost of three cents per kWh), wind generation, combustion of wood/agricultural wastes, independent power producers (using gas-fired combined cycle units), and plant-based NO_x control. The composite plan was also designed to meet the secondary objective of lowering cost.

These five plans were compared on the basis of their ability to meet existing and/or possible future constraints on SO₂, NO_x, and CO₂ emissions. The scenarios analyzed for these pollutants included:

- SO₂ emissions limits equal to those required by Phases I and II of the Clean

Air Act Amendments of 1990 (the reference case met the Phase I limits);

- Three variations on NO_x emission limits:
 - 1) NO_x emission rate reduced to between 0.45 and 0.5 pounds NO_x per MMBtu through the use of low-NO_x burners at all plants. (Use of low-NO_x burners at Phase I-affected plants as required by the March 1994 Title IV regulations was included in the reference case);
 - 2) NO_x emission rate reduced to about 10 percent of the uncontrolled rate (90 percent reduction in emission rate achievable through Selective Catalytic Reduction);
 - 3) NO_x emissions cap, limiting PJM emissions to 200,000 tons per year (40 percent of 1990 emissions) -- this was the limit used in developing alternate plans;
- CO₂ emissions stabilized at 1990 levels (125,000,000 tons of CO₂ per year for the PJM utilities).

The reference case was not designed to meet any of the constraints beyond the Phase I SO₂ requirements and the March 1994 Title IV NO_x requirements.¹⁹ By the year 2010, the emissions from the reference case exceeded the SO₂ constraint by 42 percent, the CO₂ constraint by 46 percent, and the NO_x constraint (200,000 ton/year cap) by nearly 2.5 times.

After developing cost and performance estimates for the four "single option" emission reduction scenarios, elements of these scenarios were combined into a composite plan that met the constraints at lower cost. It quickly became clear that it would be very difficult to derive a single best plan that met all of the emissions constraints assumed for the system. The best approach for one pollutant may not meet the constraints imposed on another. For example:

- Plant-based strategies require separate technologies for each pollutant. SO₂ scrubbers will not lead to any CO₂ or NO_x reduction, and will in fact make the NO_x and CO₂ problems slightly worse because they have a negative impact on plant efficiency. NO_x reduction through burner technologies or post-

¹⁹ This is not to imply that the PJM utilities are not intending to comply with future environmental regulations, only that plans are not yet in place. One PJM utility, Public Service Electric and Gas Co., recently announced its intention to voluntarily reduce its emissions of greenhouse gasses by five million metric tons by the year 2000 under DOE's "Climate Challenge" program. (Electric Utility Week, April 25, 1994)

combustion technologies will not have any impact on SO₂ or CO₂. None of the plant-based approaches will fully meet the CO₂ constraint.

- The energy reduction strategies (DSM, renewable resources) are effective at reducing SO₂ and CO₂ emissions. However, they do not address at all the first two NO_x scenarios (which are based purely on mandated technologies at specific plants), and are inadequate to meet the NO_x cap scenario.
- The independent power strategies can meet SO₂ constraints, but are not adequate to meet NO_x and CO₂ constraints.

Specifically, none of the plans met all of the environmental constraints. Excluding the reference case, all met the Phase II SO₂ constraint. The plant-based plan, and the composite plan relying on plant-based technologies, were the only plans that met the NO_x constraint (the 200,000 ton cap). Only the DSM-based plan met the CO₂ constraint. Although not specifically analyzed, it would follow that the DSM-based plan coupled with plant-based NO_x controls would have the greatest potential for meeting all the emissions constraints. Table V-1 summarizes whether or not each plan met each environmental constraint.

**TABLE V-1
MEETING OF SO₂, NO_x, AND CO₂ CONSTRAINTS BY
REFERENCE CASE AND ALTERNATE PLANS**

Plan	Sulfur Dioxide	Oxides of Nitrogen	Carbon Dioxide
Reference Case	No	No	No
Plant-Based Plan	Yes	Yes	No
DSM-Based Plan	Yes	No	Yes, after 2001
Renewables-Based Plan	Yes	No	?
IPP-Based Plan	Yes	No	No
Composite Plan	Yes	Yes, after 2001	No

The composite plan resulted in the lowest cost of the plans analyzed. This was because it relied heavily on DSM and renewable resources whose costs were less than the PJM pool's avoided costs for the reference case. Since the average cost of

resources in the DSM-based plan was equal to the avoided cost of the reference case, the DSM-based plan had a comparative cost of zero. Each of the other alternate plans was forced to include resources whose costs, on average, exceeded the pool's avoided costs for the reference case. Nonetheless, these resources may still be cost-effective relative to the pool's avoided costs for a compliance plan, which would be the appropriate comparison if the pool were required to meet the environmental constraints. Table V-2 compares the costs of the alternate plans. All costs were measured as a differential from the reference case. A zero means costs were equal to the reference case in that year.

TABLE V-2
ANNUAL COSTS OF ALTERNATE PLANS RELATIVE TO REFERENCE CASE
 (Millions of dollars compared to the reference case)

Plan	2000	2005	2010
Reference Case	0	0	0
Plant-Based Plan	170	375	385
DSM-Based Plan	0	0	0
Renewables-Based Plan	0	921	1,275
IPP-Based Plan	0	127	154
Composite Plan	-258	-514	-560

More specific analysis would be necessary to finalize design prior to the implementation of any of the plans. We would expect, however, that the general characteristics and trends observed in this study would be proven true in a more detailed analysis. Some generally applicable characteristics and trends observed in this study include:

- Demand-side management, overall, has the largest potential for economically achieving caps on all three pollutants: SO₂, NO_x, and CO₂. The ability to implement high levels of DSM sets the limit on the use of this cost-effective resource as an emissions reduction strategy.
- Plant-based options are needed for environmental constraints that are based on controlling emission rates.
- Rigorous constraints -- such as those established for this study -- require the application of more than one approach.

- Of the constraints assumed for this study, the SO₂ constraints are the least costly and most technically feasible to achieve, followed by a NO_x cap. Achieving a CO₂ cap of the magnitude assumed in this study would be the most difficult.
- Environmental dispatch, used alone, is not a cost-effective means of achieving large amounts of emissions reductions.

The approach developed in this study – comparing the emissions characteristics and costs of a wide range of alternatives designed to meet both current and future regulations – could be used to help incorporate environmental goals into utility planning. It would provide maximum flexibility in the development of "no regrets" resource acquisition strategies.

Additional research related to this approach that could prove fruitful includes:

- Additional sensitivity analysis of the effect of changes in key variables on the five alternate plans and the reference plan.
- Quantification of the savings and costs of a regional IRP approach versus planning on an individual utility basis, and the distribution of these savings and costs among member PJM utilities.
- Analysis of the costs and benefits of a regional approach to transmission and distribution planning in the PJM region.
- Analysis of the unique circumstances of a power pool such as PJM as it faces the challenges and opportunities presented to the conventional utility generating system today by retail wheeling, independent power production, renewable energy resources, electric vehicles, and increased environmental legislation.

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APPENDIX A

**PJM PLANT
CLEAN AIR ACT DESIGNATIONS**

PHASE I - AFFECTED UNITS

State	Plant	Unit
Maryland	C.P. Crane	1,2
Maryland	Chalk Point	1,2
Maryland	Morgantown	1,2
New Jersey	B.L. England	1,2
Pennsylvania	Brunner Island	1,2,3
Pennsylvania	Conemaugh	1,2
Pennsylvania	Martin's Creek	1,2
Pennsylvania	Shawville	1,2,3,4
Pennsylvania	Portland	1,2
Pennsylvania	Sunbury	3,4

PHASE II- AFFECTED UNITS

State	Plant	Units
Delaware	Edge Moor	3,4,5
Delaware	Hay Road	**3
Delaware	Indian River	1,2,3,4
Delaware	McKee Run	3
Delaware	Vansant	**11
Delaware	Delaware City	
D.C.	Benning	15,16
Maryland	Brandon Shores	1,2
Maryland	C.P. Crane	1,2
Maryland	Chalk Point	1,2,3,4
Maryland	Chalk Point	**GT3,**GT4
Maryland	Chalk Point	**GT5,**GT6
Maryland	Coal Gas Cc 1	**CT1,**CW1
Maryland	Coal Gas Cc 2	**CT3,**CT4
Maryland	Dickerson	1,2,3
Maryland	Easton 2	**26,**27
Maryland	Gould Street	3
Maryland	Herbert A Wagner	1,2,3,4
Maryland	Morgantown	1,2
Maryland	Nanticoke	**ST1
Maryland	Perryman	**52,**61,**62
Maryland	Riverside	1,2,3,4,5
Maryland	Vienna	8
Maryland	Westport	3,4
New Jersey	B.L. England	1,2,3
New Jersey	Bergen	1,2
New Jersey	Burlington	7
New Jersey	Butler	**4
New Jersey	Deepwater	1,3,4,5,6,8,9
New Jersey	Gilbert	01,02,03,04
New Jersey	Gilbert	05,06,07
New Jersey	Hudson	1,2
New Jersey	Kearny	7,8
New Jersey	Linden	2,4
New Jersey	Linden	11,12,13
New Jersey	Mercer	1,2
New Jersey	Na 3 - 7141	**1,**2
New Jersey	Na 4 - 7142	**1
New Jersey	Na 5 - 7217	**1,**2
New Jersey	Na 6 - 7218	**1,**2
New Jersey	Sayreville	02,03,05
New Jersey	Sayreville	06,07,08
New Jersey	Sewaren	1,2,3,4,5
New Jersey	Werner	04
Pennsylvania	Brunner Island	1,2,3
Pennsylvania	Conemaugh	1,2
Pennsylvania	Cromby	1,2
Pennsylvania	Delaware	71,81
Pennsylvania	Eddystone	1,2,3,4
Pennsylvania	Front Street	7,8,9,10
Pennsylvania	Holtwood	17
Pennsylvania	Homer City	1,2,3
Pennsylvania	Hunlock Power	6
Pennsylvania	Keystone	1,2
Pennsylvania	Marcus Hook Refine	1
Pennsylvania	Martins Creek	1,2,3,4
Pennsylvania	Montour	1,2
Pennsylvania	Portland	1,2
Pennsylvania	Richmond	63,64
Pennsylvania	Schuylkill	1
Pennsylvania	Seward	12,14,15
Pennsylvania	Shawville	1,2,3,4
Pennsylvania	Southwark	11,12,21,22
Pennsylvania	Springdale	77,88
Pennsylvania	Sunbury	3,4,1A,1B
Pennsylvania	Sunbury	2A,2B
Pennsylvania	Titus	1,2,3
Pennsylvania	Warren	1,2,3,4
Pennsylvania	Williamsburg	11
Virginia	Potomac River	1,2,3,4,5

APPENDIX B

EIA 1992 FORM 861 DSM DATA

TABLE B-1a

**DEMAND-SIDE MANAGEMENT CAPACITY RESOURCES
(MW)**

UTILITY	1992	1993	1997
Atlantic City Electric Co.			
Energy Efficiency	19	26	48
Direct Load Control	43	43	42
Interruptible Load	28	23	10
Other Load Management	13	18	54
Other DSM Programs	0	0	0
Load Building	(1)	(3)	(12)
Baltimore Gas & Electric Co.			
Energy Efficiency	36	0	0
Direct Load Control	257	282	445
Interruptible Load	6	52	110
Other Load Management	54	65	97
Other DSM Programs	0	0	0
Load Building	0	0	0
Delmarva Power & Light Co.			
Energy Efficiency	9	4	23
Direct Load Control	92	107	127
Interruptible Load	0	83	121
Other Load Management	3	3	6
Other DSM Programs	0	0	0
Load Building	0	0	0
Jersey Central Power & Light			
Energy Efficiency	21	39	127
Direct Load Control	21	17	84
Interruptible Load	29	29	29
Other Load Management	2	3	8
Other DSM Programs	0	0	0
Load Building	0	0	0
Metropolitan Edison Co.			
Energy Efficiency	28	30	39
Direct Load Control	0	0	0
Interruptible Load	48	55	85
Other Load Management	300	316	380
Other DSM Programs	0	0	0
Load Building	0	0	0
Pennsylvania Electric Co.			
Energy Efficiency	40	53	101
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0

TABLE B-1b

DEMAND-SIDE MANAGEMENT CAPACITY RESOURCES
(MW)

UTILITY	1992	1993	1997
Pennsylvania Power & Light Co.			
Energy Efficiency	11	20	29
Direct Load Control	0	0	0
Interruptible Load	79	185	265
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0
PECO Energy			
Energy Efficiency	4	4	5
Direct Load Control	38	38	43
Interruptible Load	0	343	343
Other Load Management	0	2	3
Other DSM Programs	0	0	0
Load Building	0	0	0
Potomac Electric Power Co			
Energy Efficiency	22	67	406
Direct Load Control	0	166	227
Interruptible Load	0	64	95
Other Load Management	138	147	164
Other DSM Programs	0	0	0
Load Building	0	0	0
Public Service Electric & Gas			
Energy Efficiency	25	116	433
Direct Load Control	18	0	129
Interruptible Load	127	0	197
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0
UGI Corporation			
Energy Efficiency	0	0	0
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0
TOTAL	1,509	2,397	4,263

Note: Capacity resources reflect actual peak reduction (and actual peak growth for load building) unless otherwise specified.

Because Baltimore Gas & Electric did not report actual peak reduction values, potential peak reduction values are used.

FIGURE B-1

State Planning Reports vs. 861 Forms
DSM Energy Impacts (MWhe)

TABLE B-IIa

**DEMAND-SIDE MANAGEMENT ENERGY RESOURCES
(MWhe)**

UTILITY	1992	1993	1997
Atlantic City Electric Co.			
Energy Efficiency	55,265	59,005	45,241
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	220	372	1,473
Other DSM Programs	0	0	0
Load Building	(16,591)	(38,697)	(122,843)
Baltimore Gas & Electric Co.			
Energy Efficiency	115,600	197,100	728,900
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	300	500
Other DSM Programs	0	0	0
Load Building	0	0	0
Delmarva Power & Light Co.			
Energy Efficiency	30,058	15,322	125,577
Direct Load Control	873	1,231	1,496
Interruptible Load	0	0	0
Other Load Management	0	(32)	(305)
Other DSM Programs	0	0	0
Load Building	0	0	0
Jersey Central Power & Light			
Energy Efficiency	57,730	124,755	428,383
Direct Load Control	0	0	0
Interruptible Load	7,920	7,920	7,920
Other Load Management	1,095	2,195	6,595
Other DSM Programs	0	0	0
Load Building	0	0	0
Metropolitan Edison Co.			
Energy Efficiency	32,148	37,695	59,883
Direct Load Control	0	0	0
Interruptible Load	14,321	16,541	25,421
Other Load Management	230,329	239,173	274,549
Other DSM Programs	0	0	0
Load Building	0	0	0
Pennsylvania Electric Co.			
Energy Efficiency	58,924	62,913	223,613
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0

TABLE B-IIb

**DEMAND-SIDE MANAGEMENT ENERGY RESOURCES
(MWhe)**

UTILITY	1992	1993	1997
Pennsylvania Power & Light Co.			
Energy Efficiency	19,954	29,421	59,060
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	0	0
Other DSM Programs	204	3,468	0
Load Building	0	0	0
PECO Energy			
Energy Efficiency	21,779	35,736	51,438
Direct Load Control	29,854	30,064	33,837
Interruptible Load	0	1,372	1,372
Other Load Management	175	439	494
Other DSM Programs	0	0	0
Load Building	0	0	0
Potomac Electric Power Co			
Energy Efficiency	107,284	326,302	1,976,807
Direct Load Control	231	8,506	11,522
Interruptible Load	963	3,620	5,459
Other Load Management	105,576	123,601	140,486
Other DSM Programs	0	0	0
Load Building	0	0	0
Public Service Electric & Gas			
Energy Efficiency	58,000	126,000	1,205,000
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0
UGI Corporation			
Energy Efficiency	35	127	290
Direct Load Control	0	0	0
Interruptible Load	0	0	0
Other Load Management	0	0	0
Other DSM Programs	0	0	0
Load Building	0	0	0
TOTAL	931,947	1,414,449	5,292,168

Source: EIA Form 861, 1992 data.

TABLE B-III

DEMAND-SIDE MANAGEMENT BUDGETS
(\$1,000)

UTILITY	1992	1993	1997
Atlantic City Electric Co.	10,934	11,793	12,000
Baltimore Gas & Electric Co.	29,791	64,837	102,987
Delmarva Power & Light Co.	8,820	12,698	15,026
Jersey Central Power & Light	26,535	104,178	119,805
Metropolitan Edison Co.	9,875	9,499	8,671
Pennsylvania Electric Co.	3,368	3,471	30,200
Pennsylvania Power & Light Co.	17,387	17,895	24,550
PECO Energy	10,253	10,809	12,166
Potomac Electric Power Co	42,167	78,907	103,457
Public Service Electric & Gas	43,570	71,247	206,698
UGI Corporation	79	110	110
TOTAL	202,779	385,444	635,670

Source: EIA Form 861, 1992 data.

APPENDIX C

**NOTES AND REFERENCES FOR DSM CAPACITY IMPACTS,
ENERGY IMPACTS,
AND BUDGET TABLES (TABLES III-4 - III-6)**

APPENDIX C

FOOTNOTES TO TABLE III-4 ("DEMAND-SIDE MANAGEMENT CAPACITY IMPACTS")

- 1 Includes Contractual Interruptible, Direct Control, and Passive DSM.
- 2 Source: "Load/Capacity Plan - (Official Expansion Plan)" Table 2 and "Demand and Supply-Side Update, Table 2-1", June 1993.
- 3 Includes Conservation and Energy Use Management.
- 4 Source: "1992 Integrated Least-Cost Resource Plan", Table 11-5, Main Report Volume.
- 5 Source for 2007: "Load/Capacity Plan - (Official Expansion Plan)" Table 2.
- 6 Source: "Pennsylvania Electric Co. Annual Resource Planning Report", 1993. 1994-1997 from Table 1, page 12-14; 1998-2012 from Form 138-K, page 12-1.
- 7 Includes Passive DSM and Active DSM.
- 8 Source: PSE&G Electric Resource/Demand Forecast, September 28, 1993.
- 9 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 115.
- 10 Source for 1993: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 139.
- 11 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 187.
- 12 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 211.
- 13 Includes Conservation and Load Management.
- 14 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 247.
- 15 UGI currently assessing residential off-peak rate.
- 16 Source: "GPU System 1993 Economic, Sales and Peak Load Forecasts, 1993-2012", p.10.
- 17 Source: "Load/Capacity Plan - (Official Expansion Plan)" Table 2.
- 18 Includes peak reductions due to cogeneration (but not capacity or energy supplied for resale) and load management.
- 19 Source: "Atlantic City Electric Company 1993 Load Forecast," February 1993, p. 11.
- 20 Impacts in 2008-2012 assumed to equal impacts in 2007.
- 21 Includes direct control, dispersed generation/contract interruptible, and passive DSM.
- 22 Does not include interruptible (per "Consolidated IRP, Part 2, Annual Resource Planning Report Summary 1993-2012", May 1993, Exhibit 1, p.4. Interruptible = 343 MW annually.
- 23 Contractual interruptible = 83 MW annually.

FOOTNOTES TO TABLE III-5 ("DEMAND-SIDE MANAGEMENT ENERGY RESOURCES")

- 1 Includes Contractual Interruptible, Direct Control, and Passive DSM.
- 2 Source: "Demand and Supply-Side Update", Table 2-1, June 1993.
- 3 Includes Conservation and Energy Use Management.
- 4 Source: "1992 Integrated Least-Cost Resource Plan", Table 11-5, Main Report Volume
- 5 Source: "Pennsylvania Electric Co. Annual Resource Planning Report", 1993. 1994-1997 from Table 1, page 12-14; 1998-2012 from Form 138-K, page 12-1.
- 6 Source: "Electric Power Outlook for Pennsylvania 1992-2012", p. 115.
- 7 Source for 1993: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 139.
- 8 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 187.
- 9 Includes Conservation and Load Management.
- 10 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 211.
- 11 Source: "Electric Power Outlook for Pennsylvania, 1992-2012", p. 247.
- 12 Source: "GPU System 1993 Economic, Sales and Peak Load Forecasts, 1993-2012", p.10.
- 13 Source: BG&E "Integrated Resource Plan, 1993-2007", Table III-A-2.
- 14 Includes Passive, Active, and Contract Interruptible/Dispersed Generation.
- 15 Source: "Atlantic City Electric Company 1993 Load Forecast," February 1993, p. 12.
- 16 Includes reduction in demand met by cogeneration facilities, but not energy or capacity supplied for resale.
- 17 Impacts in 2008-2012 assumed to equal impacts in 2007.
- 18 Impacts in 2007-2012 assumed to equal impacts in 2006.
- 19 Source: PSE&G forecast, via Brian Daly, PSE&G.
- 20 Savings in 2001-2012 assumed to equal savings in 2000.
- 21 Source for 2008-2012: BG&E "Integrated Resource Plan, 1993-2007", Table III-A-2.

**FOOTNOTES TO TABLE III-6 ("DEMAND-SIDE MANAGEMENT BUDGETS
1991-2001")**

- 1 Source for 1992-1997: "Electric Power Outlook for Pennsylvania, 1992-2012", p.103. Assume \$90M for 1993-1997 equally divided among years.
- 2 Assume annual budgets 1998-2001 will equal 1993-1997.
- 3 Source for 1992: "Electric Power Outlook for Pennsylvania," 1992-2012", p.126. Reported budget 1993-7 equals 861 data.
- 4 Source for 1992: "Electric Power Outlook for Pennsylvania," 1992-2012", p.174. Reported budget 1991-3 equals 861 data.
- 5 Source for 1992-1993: "Consolidated IRP, Part 3, Annual Conservation Report for 1992", p.5.
- 6 Source for 1992-2001: PEPCO "1992 Integrated Least-Cost Resource Plan", Table II-3.
- 7 Source for 1992 and 1993: UGI "1993 Least-Cost Plan", Form ACR-3. Source for 1994-2001: UGI "1993 Least-Cost Plan", Form 138-L.
- 8 Assumed 1998-2001 budgets will equal 1997.
- 9 Assumed budgets for 1997-2001 will equal budget in 1996.
- 10 Source for 1993-2000: Personal Communication with Brian Daly, PSE&G.
- 11 Assumed 2001 budget will equal 2000.
- 12 Represents \$33 M annually for "core" programs (e.g., rebate, low-income), \$10 M annually for "tariff" programs (TOU and curtailable rates), and \$20M in 1993 (then increasing \$20M annually) for "performance" programs (standardized bidding offer for reductions of >200kW).

APPENDIX D

HEAT PUMPS

APPENDIX D

HEAT PUMPS

Introduction

This appendix discusses the current and potential role of the heat pump as a demand-side management (DSM) resource in the PJM system. The heat pump is unique as a DSM tool in that it has the potential to be used both for load-building and efficiency improvements. The heat pump was chosen as an example technology for three reasons. First, PJM utilities have engaged in active promotion and marketing of heat pump systems for residential heating and cooling. Second, while high efficiency heat pumps conserve energy and decrease system load, they also have the potential to increase system load. Lastly, heat pump efficiency in the heating mode is inversely related to ambient air temperatures; therefore, as temperatures decrease and the heating loads increase, the efficiency of the heat pump decreases to the point where auxiliary heating is required.

The application of heat pumps in the PJM system will be discussed only in general terms. It is not the intent of this appendix to enter the debate surrounding the success or direction of PJM utility heat pump programs. The focus is instead on the types of heat pumps in use and the related advantages and disadvantages of each. The heat pump's contribution to PJM peak winter load will also be approximated to the degree possible.

Heat Pumps and the PJM System

Within the past few years, PJM utilities have been actively promoting the use of heat pumps within their service territories. Heat pump installation in new building construction and the retrofit of conventional heating and cooling systems to heat pumps have received significant utility program marketing attention. Incentives are typically provided in the form of direct rebates to customers who purchase and install heat pump systems. In some cases, heat pump marketing programs have been successful. PP&L for example increased its ground source heat pump installations from 200 in 1992 to 500 in 1993. (Hoske, 1993) On the other hand, JCP&L reports that even with rebate programs, heat pumps are difficult to market because of long-standing customer beliefs that heat pumps are effective only in milder climates and that heat pumps are not as reliable as conventional systems. (Dahir, 1991)

Heat pumps may be installed in one of two situations. First, the heat pump may be used to replace separate air conditioning and electric space heating systems. Second,

the heat pump may replace separate air conditioning and non-electric space heating systems.

In cooling mode, energy savings and emission reductions depend on the cooling system being replaced. If inefficient window air conditioners or old central air conditioners are replaced, utility summer demand and emissions can be expected to decrease. However, if the heat pump replaces a relatively efficient central air conditioner, then energy demand is expected to remain relatively constant, and utility generation and emissions will remain unchanged.

In heating mode, however, differences in energy demand and utility emissions may be significant. To the extent that heat pumps replace electric resistance heaters, winter demand and power plant emissions will decrease. To the extent that heat pumps replace other forms of non-electric space heating, net utility loads and, hence, emissions, may actually increase.

The number of heat pumps currently installed in the PJM region is estimated at 641,000. The majority of units are residential installations. This number was derived by extrapolating data from the number of known utility heat pump installations as a fraction of the number of customers in the utilities' service territory¹. Of the 641,000, over 99 percent are believed to be air-sourced heat pumps. The remainder are geothermal (earth- or water-sourced) and dual-fuel, air-sourced configurations.

The average residential heat pump has an estimated size of 3 tons with an average Seasonal Energy Efficiency Ratio (SEER) of 8. It is assumed that these units are designed for an ASHRAE Winter 99% Design Temp of 10 degrees F (-12 degrees C)² and operate with a connected load of 8 kW at winter design day conditions. Furthermore, it is assumed that these units operate with a 70 percent diversity. Peak winter system load can then be calculated as follows;

$$\text{WINTER_LOAD}_{\text{peak}} = \text{Number of Units} \times \text{Connected Load} \times \text{Diversity}$$

Using the above data:

$$\text{WINTER_LOAD}_{\text{peak}} = 3,590 \text{ MW}$$

¹ Actual data obtained from PECO, PEPCO, and PENELEC and was used as the basis for winter peak load calculation.

² The ASHRAE 99 percent winter design temp is specified for Philadelphia, PA which represents an acceptable geophysical average location for the PJM region.

In 1993, the PJM forecast winter peak load was 38,928 MW. Therefore, heat pumps accounted for approximately 9.2 percent of the expected system load.

Heat pumps do not generate energy but instead transfer energy from one location (outside air, ground, or water) to another location (the conditioned space) and therefore provide an efficient means of providing space conditioning when compared to conventional means. The efficiency improvement can be translated into an emission reduction potential, but that potential is a function of the specific heat pump technology and of the electricity generation energy source. For example, a heat pump supplied with energy from a natural gas power plant that replaces a home fuel-oil heating system will accrue greater emission reductions than the same heat pump ultimately driven by a coal-burning power plant.

Heat Pump Designs

An extensive literature search indicates that the use of electric heat pumps in residential and commercial installations can be expected to increase. (Lannus, 1993) Heat pumps are available in three design configurations: air-source electric, geothermal (ground or water-source) electric, and dual-fuel air-source. Heat pump manufacturers and designers are also working on solar electricity air-source heat pumps which would provide heating and cooling using available solar insolation as the primary energy source.

As previously stated, single speed air-sourced heat pumps supplemented by electric resistance heating accounts for over 99 percent of PJM system installations. New units exhibit higher efficiencies and coefficients of performance (COP) as compared to their predecessors of the 1970s and 1980s. However, at approximately 10 to 20 degrees F (-12 to -7 degrees C) auxiliary heating capacity is required due to the thermodynamic limitations of the heat pump Carnot cycle and the need to defrost the outdoor components of the heat pump. Extremely cold temperatures limit the ability of the heat pump to efficiently absorb heat from outside air and transfer it to the conditioned space. For example, a heat pump operating at 40 degrees F (4 degrees C) may have a COP of 3 (one unit of energy input is required for every three units of heat output). However, at zero degrees F (-18 degrees C), the COP may decrease to 1 (one unit of input energy is required for every one unit of heat output). As a result, air-sourced heat pumps have a potentially adverse system peak load impact during periods of extreme cold weather.

An alternative system is the geothermal heat pump which uses either the ground or bodies of water to act as a heat sink. The temperature of the earth at depths below the frost line, or of sufficiently large thermal ponds, maintain a relatively constant temperature regardless of ambient air temperature. Heat pump heat exchangers installed in either location enable the heat pump to operate with little or no auxiliary

heating. The initial cost of geothermal heat pumps is higher than that of air-source heat pumps owing to the installation of buried or submerged heat exchangers, but because supplemental heating needs are reduced or eliminated, life cycle costs are often less.

A third option is that of the dual-fuel heat pump. This system operates as a conventional electric air-source heat pump during the cooling season and into the late fall and early spring. During the winter, however, the heat pump monitors outside temperatures and is also calibrated to alternative fuel prices. During periods of extreme cold weather, when the heat pump would operate inefficiently, the electric portion of the heat pump deactivates and then an alternative fuel, oil or natural gas, is burned and the heat pump operates as a conventional forced hot-air furnace.

Conclusion

The heat pump has the potential to reduce utility loads and emissions. Conversely, the heat pump may increase utility loads and emissions. The net effect depends in part on the age and type of heating and cooling system being replaced. The air-source heat pump has the potential to amplify peak load demand during periods of extreme cold weather. Advanced air-source heat pump designs may lessen this effect. Additional analysis would be required to make a firm conclusion as to the effect of the air-sourced heat pump on emissions in the PJM service territory.

Geothermal heat pumps, on the other hand, despite a greater initial cost, seem to offer favorable heating and cooling performance characteristics with less sensitivity to weather conditions. Dual-fuel heat pumps solar heat pumps also would appear to present the PJM utilities with efficient heating and air-conditioning systems, but again, a more detailed analysis is required to provide substantive recommendations.

Of final consideration is the subject of ozone depleting compounds (ODCs). All of the heat pump systems described herein employ refrigerants for proper operation and performance of the thermal vapor cycle. Chlorofluorocarbons (CFCs) or hydrochlorofluorocarbons (HCFCs) are typical refrigerants which are proven ozone-depleting agents, although the impact of HCFCs is less than that of CFCs. CFCs and HCFCs may potentially be displaced by advanced refrigerants such as hydrofluorocarbons (HFCs) now under development. In addition to atmospheric benefits, the transition to HFCs would serve to protect the PJM utilities if ODCs are completely banned or if they incur externality charges during rate cases.