# Air Pollution Impacts of Increased Deregulation in the Electric Power Industry: An Initial Analysis

**January 15, 1998**

**Introduction:**

The Northeast states – which bear some of the nation's highest electricity costs – welcome efforts to restructure the U.S. utility industry. However, as a region hard hit by ozone smog, acid rain and other pollution problems, the Northeast states are also concerned that deregulation is proceeding without adequate national environmental safeguards. In particular, the Northeast states have argued that comparable environmental standards must be applied to all electricity generators as a precondition for truly equitable, economically efficient and environmentally sound competition in the nation's power markets. Absent a "level environmental playing field," the Northeast states are fearful that deregulated markets will result in significantly increased power production at low-cost, highly polluting coal-fired power plants. Many such facilities are clustered in the industrial Midwest. As was demonstrated in the recent Ozone Transport Assessment Group (OTAG) process, prevailing west to east wind patterns are capable of transporting pollutants from these power plants over long distances, exacerbating already severe air quality problems in the Northeast.

NESCAUM and others raised these concerns in comments on the Environmental Impact Statement (EIS) developed for FERC's Open Access Rule (Order 888). In this EIS, finalized in April of 1996, FERC asserted that open access to utility transmission lines would have negligible environmental impacts. This conclusion was based primarily on assumptions that the percentage of electricity generated by natural gas would continue to grow and that the Eastern Interconnection of the U.S. transmission grid could not accommodate significant additional power flows.

Recent evidence suggests that the Administration should re-examine these assumptions. First, data recently released on nationwide electricity generation in 1996 show an increase of 83 million Megawatt-hours (MWh) in coal-fired generation and a

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decrease of 44 million MWh in gas-fired generation compared to 1995 levels.[1] Second, data filed by utilities on interchange among power control areas indicate that growth in the use of the transmission system may have already outstripped FERC's longer-term growth assumptions.

Fully understanding the causes of this shift in resource use and power flows will require a much more thorough analysis than presented here. Relative fuel prices and nuclear outages are perennial drivers of shifts in the use of coal and gas, and separating the effects of these factors from industry restructuring will be difficult.[2] The data presented here, however, strongly suggest that industry restructuring played a significant role in both the shift from gas to coal in 1996 and changes in bulk power flows.

The following analysis represents an initial attempt to investigate whether evidence exists to link open power markets - particularly at the wholesale level - and increased power production at low-cost, highly polluting coal-fired power plants. Specifically, the NESCAUM Energy Workgroup was interested in exploring the following questions:

1. *Are power markets beginning to respond to increased access and competition? (Indicators might include levels of wholesale power flows and the presence of new market participants such as power marketers.)*

2. *Is any new demand for low-cost wholesale power resulting in increased production at less stringently regulated coal-fired power plants?*

3. *Have significant changes in utility emissions occurred between 1995 and 1996 concurrent with restructuring?*

4. *Is the existing transmission infrastructure capable of supporting a significant increase in transfers of electricity, thereby allowing low-cost, high pollution power to flow to new markets?*

The NESCAUM Energy Workgroup began its exploration of these questions by looking at 1995 to 1996 data from several utility companies, including Ohio-based American Electric Power (AEP), Indianapolis Power & Light (IPALCO), Illinois Power, and New England Electric System (NEES). Information supplied by these companies to the Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE) forms the basis for this analysis.

[1] U.S. Energy Information Administration. *Electric Power Monthly*, March, 1997, Table 4.

[2] Gas prices rose in relation to coal prices in 1996, however nationwide nuclear generation remained stable, rising by only 1.4 million MWh, or 0.2%.

NESCAUM recognizes this limited analysis is not adequate to establish long-term trends, or to gauge the overall impact of recent changes in the regulation of the electric utility industry. However, our preliminary findings suggest that increased competition is contributing to increased emissions at coal-intensive utilities, and that some form of mid-course public policy correction may be necessary. These findings underscore the need for comprehensive efforts to document the impacts of restructuring on air quality, and lend impetus to state and federal efforts to establish adequate emissions tracking and disclosure systems. Moreover, these findings suggest that equitable environmental standards must be made an integral part of ongoing competitive reforms.

**Background:**

In 1995, the NESCAUM Energy Workgroup sponsored a comparative analysis of the emissions and cost characteristics of three major power systems: AEP, the Pennsylvania-New Jersey-Maryland (PJM) pool, and the New England Power Pool (NEPOOL). The analysis indicated that the AEP system was characterized by substantially higher emissions of NOx, $SO_2$, and $CO_2$ per unit of electricity output than either the PJM or NEPOOL systems. At the same time, AEP was estimated to have a significant amount of production capacity available at relatively low cost. Specifically, the report estimated that AEP could generate approximately 60 million additional megawatt-hours (MWh) for 3 cents per kWh or less (see Attachment A). To put this into context, the total power supplied by the NEPOOL system in a typical year is less than 120 million MWh. Furthermore, the analysis estimated that the NEPOOL system could generate only 7 million additional megawatt-hours for 3 cents per kWh or less. The analysis concluded that if existing AEP power plants are utilized to the maximum extent practicable (i.e. 85% capacity factor), AEP NOx emissions can increase by about 60% over average daily NOx emissions during the 1985-92 time period (see Attachment A). Regardless of where the additional power is sent, increases in pollutant emissions at upwind power plants will affect downwind communities and sensitive environmental areas.

Recognizing that other upwind utilities besides AEP also own low-cost, high-emitting coal-fired capacity, the Northeast states began to express concern about the environmental impacts of open access, absent comparable emission standards for upwind power generators. An early and crucial forum for these concerns was the FERC's landmark rulemaking to promote competitive wholesale power markets by requiring utilities to provide open access to transmission services. Between 1995 and 1996, the Northeast states provided comment on this rulemaking process and on FERC's development of an accompanying environmental impact statement (EIS). In its final EIS, released in April of 1996, FERC concluded that its rulemaking would have negligible environmental impacts. FERC Order 888 establishing open access in wholesale electricity markets was promulgated shortly thereafter.

NESCAUM and other observers questioned FERC's assessment of the environmental impacts of increased competition encouraged by Order 888. In particular, the EIS was criticized for failing to assess these impacts against a true "no-action" base case and for making unduly modest assumptions about the ability of power markets - and particularly the transmission infrastructure - to respond to new market opportunities. According to FERC's projections, transmission constraints would continue to seriously restrict power flows such that power transfers between regions would continue to represent a relatively small share (< 5%) of overall generation in most regions, even as late as 2005.

In May of 1996, the Environmental Protection Agency (EPA) referred FERC Order 888 to the President's Council on Environmental Quality on grounds that the rule could, under certain circumstances, lead to increases in air pollution in the future. Nevertheless, EPA supported immediate implementation of the rule based on its assessment that "the open access rule is unlikely to have any significant adverse environmental impact in the immediate future." As part of the resolution of this referral, FERC, EPA, and the Department of Energy pledged to work together to track the impacts of open access over time. EPA agreed to take all available action under existing Clean Air Act authority to limit future NOx emissions, and FERC agreed to undertake additional actions in the future should EPA authority and the outcome of the OTAG process fail to be adequate to ensure against future adverse impacts. Subsequently, EPA proposed under Section 110 of the Clean Air Act the implementation of caps on NOx emissions throughout the eastern half of the United States, effective in the 2003 timeframe if promulgated. NESCAUM strongly supports the implementation of Section 110 NOx caps. In the meantime, however, power generators in the Northeast face widely disparate environmental standards from upwind competitors, leaving Northeast residents vulnerable to increased pollution transport. To the best of our knowledge, neither FERC, DOE, or EPA have begun to assess the environmental issues involved with the move to increased wholesale electricity competition. Therefore, the NESCAUM Energy Workgroup set out to begin the examination of the impacts of increased competition.

**Structure of the Analysis and Data Source:**

The following analysis is structured along the four main lines of inquiry summarized in the Introduction. Because the Energy Workgroup did not have the resources to undertake a comprehensive assessment, several specific utilities were selected to see if they provided any early evidence of trends in restructured electricity markets. The most in-depth analysis was undertaken for AEP, which is a particularly large and important Midwestern utility, and which had been the subject of the earlier work by NESCAUM described above. The Workgroup relied entirely on publicly available information in this effort. Data from 1993 through 1996 on power generation, purchases, and sales are from FERC 1 Forms and EIA 759 Forms. Data on power transfers between control areas are from FERC 714 Forms. Emissions were estimated using data from EPA's Acid Rain Database.

FINDINGS:

**Are power markets beginning to respond to increased access and competition?**

Judging by growth in wholesale sales and increased sales to non-traditional market participants, such as power marketers, the answer is clearly yes. Between 1995 and 1996, non-requirements wholesale sales increased at AEP by 9.6 million MWh (46%) (Figure 1).[3] Though smaller in absolute terms, other utilities registered similar growth in non-requirements wholesale sales between 1995 and 1996. Sales at Illinois Power Company increased by 1.4 million MWh (23%), and sales at IPALCO increased by 0.3 million MWh (84%) (Figure 2).

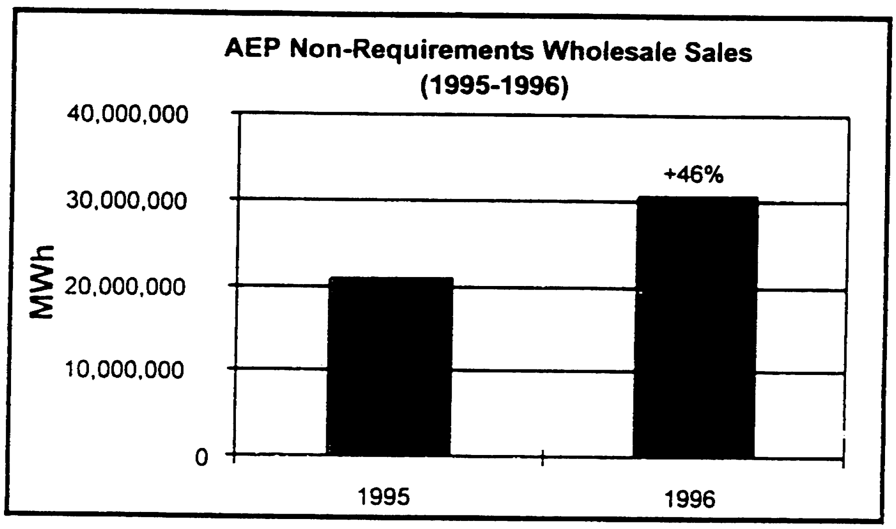


**Figure 1.** AEP non-requirements wholesale sales increased by 46% from 1995 to 1996.

[3] Non-requirements sales include energy sales not associated with long-term commitments that the company includes in projected load.

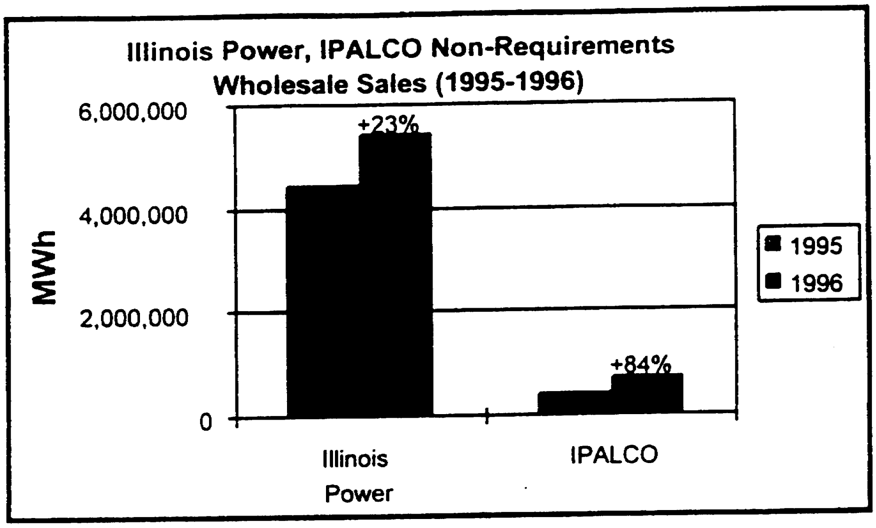


**Figure 2.** Illinois Power Company non-requirements wholesale sales increased by 23%. IPALCO's increased by 84%.

Furthermore, the kinds of contracts under which non-requirements energy was purchased from these utilities changed significantly between 1995 and 1996, as did the composition of the companies purchasing the energy (see, e.g., Attachment B, Tables 3, 7, & 11). First, much more energy was sold under short-term, non-firm contracts in 1996. For example, AEP's short-term sales to non-affiliated companies increased by 104%, or 8.5 million MWh, between 1995 and 1996. Second, far more wholesale energy was sold to energy marketing companies, as opposed to other utilities, in 1996. Clearly, new energy marketing companies have begun to fill a market niche created by industry restructuring. Unlike traditional utilities, power marketing companies do not have geographic service areas and, as of yet, have relatively few retail customers. In 1996, companies such as AES Power, Koch Power Services, Phibro, Inc., and Enron Power Marketing acted mainly as wholesale electricity brokers.

Looking at the ten largest purchasers of short-term wholesale energy from AEP, the percentage of energy (in MWh) going to marketing companies increased from zero in 1995 to 67% in 1996 (see Attachment B, Figure 3). At IPALCO, this percentage increased from 0.1% in 1995 to 29% in 1996 (see Attachment B, Figure 8). At Illinois Power, the increase was from 25% to 49% (see Attachment B, Figure 6). While we cannot definitively conclude that this shift from long-term to short-term sales and the increase in sales to power marketers is a response only to industry restructuring, these are precisely the kind of changes one would expect in response to increasingly open and competitive wholesale markets.

**Is new demand for low-cost wholesale power resulting in increased production at less stringently regulated coal-fired power plants?**

As noted above, nationwide coal-fired generation increased significantly in 1996 and gas-fired generation declined (see Attachment B, Figure 1). This change is attributable to a variety of factors, including changes in relative fuel prices, the generation sources available to offset a number of nuclear outages, and, we believe, industry restructuring. At this point, it is premature to suggest that a substantial driver of this shift is restructuring without environmental safeguards. But at three of the four utilities studied, it is clear that additional wholesale sales were made possible by increased generation at coal-fired power plants.

Between 1995 and 1996, coal-fired generation increased at AEP by 10.3 million MWh (10%). Coal-fired generation at Illinois Power Company increased by 1.6 million MWh (9.9%), while coal-fired generation at Indianapolis Power & Light (IPALCO) increased by 0.6 million MWh (4.2%). Coal-fired generation at NEES increased by 0.9 million MWh (9.7%), but a greater increase of 2.0 million MWh was provided by gas-fired generation (170% increase from 1995). While uncertainty remains for the reasons for these changes, there is no question that the increase in coal use is resulting in increasing pollution levels that are detrimental to public health and the environment.

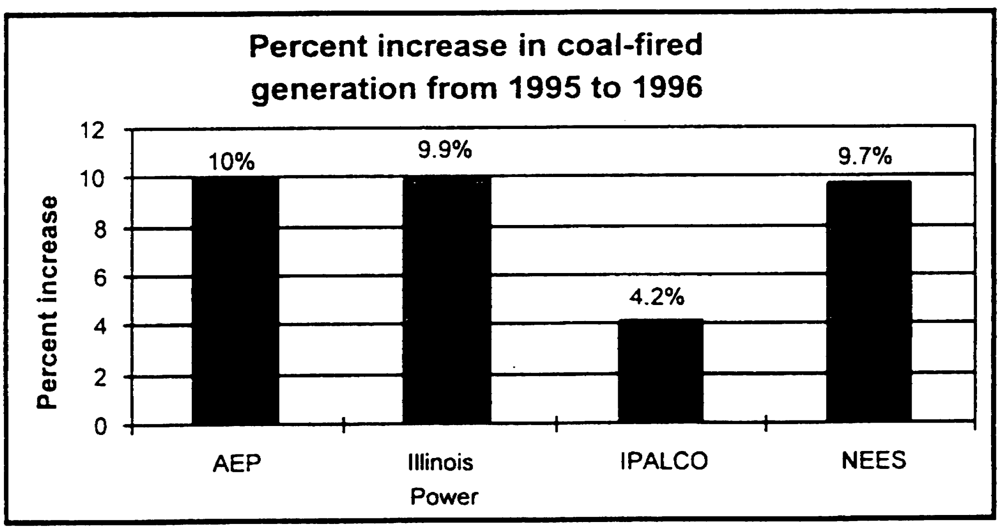


Figure 3. Increase in coal-fired generation increased from 1995 to 1996 at four utility systems.

**Have significant changes in utility emissions occurred between 1995 and 1996 concurrent with restructuring?**

Yes. Between 1995 and 1996, oxides of nitrogen (NOx) emissions increased by 51,518 tons at AEP coal-fired power plants. The increase by itself is greater than the total 1996 NOx emissions from all fossil fuel power plants (coal, oil, and natural gas) in the states of Massachusetts and New Hampshire combined.

In six Midwest states (IL, IN, KY, MI, OH and WV) where coal generation dominates the utility fossil fuel consumption, NOx emissions increased 6% from 1995 to 1996. The increase in 1996 occurred even though modest decreases are being made in NOx emission rates from Group I utility boilers due to the Clean Air Act Title IV acid rain provisions. This illustrates that decreasing the rate of NOx emissions (or any pollutant) from coal-fired power plants can be offset by increasing the amount of coal burned if total emissions are not capped.

Part of the increase in NOx emissions appears to be attributable to the increased utilization of the highest emitting coal power plants. Three of the five AEP plants that significantly increased generation in 1996 have extremely high NOx emission rates. At the Gavin plant, with a NOx rate of 12.9 lb/MWh, generation increased by 2.8 million MWh in 1996. At the Tanners Creek plant, with a NOx rate of 15.8 lb/MWh, generation increased by 855 thousand MWh. At Muskingum River, with a rate of 8.35 lb/MWh, generation increased by 2.7 million MWh. Illinois Power's Baldwin plant, with a NOx rate of 13.2 lb/MWh, increased its generation in 1996 by 650 thousand MWh.[4] By comparison, the average emission standards for large fossil fuel-fired boilers in the Northeast are between 3 and 4 lb/MWh.

While increases in pollution due to increases in power generation at one utility could be offset by decreases in generation at another utility, the increases described above are at some of the highest emitting coal power plants in the country. Therefore, it is very unlikely that an increase in pollution levels at these power plants will be completely offset by decreases in emissions elsewhere due to displaced power generation.

New England Electric System (NEES) also experienced increasing non-requirements wholesale sales (170%) from 1995 to 1996, as well as an increase of 21% in overall generation that resulted in an increase in NOx emissions by 1,390 tons. Unlike the utilities described above, however, a large part of the increased generation at NEES was provided by a newly repowered gas-fired power plant, resulting in an increase in gas-fired generation of 170%. Along with the large increase in gas-fired generation, coal-fired generation increased 9.7%. It appears that the increases in fossil fuel-fired generation at NEES in 1996 were likely due to nuclear outages within the region. Overall, air emissions from NEES power plants increased over 1995 levels due to the replacement of nuclear generation (see discussion in Attachment B).

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[4] These figures are based on 1995 NOx emission rates, which are not likely to have changed significantly in 1996.

In addition to NOx, increases in $SO_2$ and $CO_2$ emissions from coal-fired generation also occurred from 1995 to 1996 at the four utility systems studied. Figure 4 below shows the relative increases for AEP, Illinois Power, IPALCO, and NEES from 1995 to 1996.

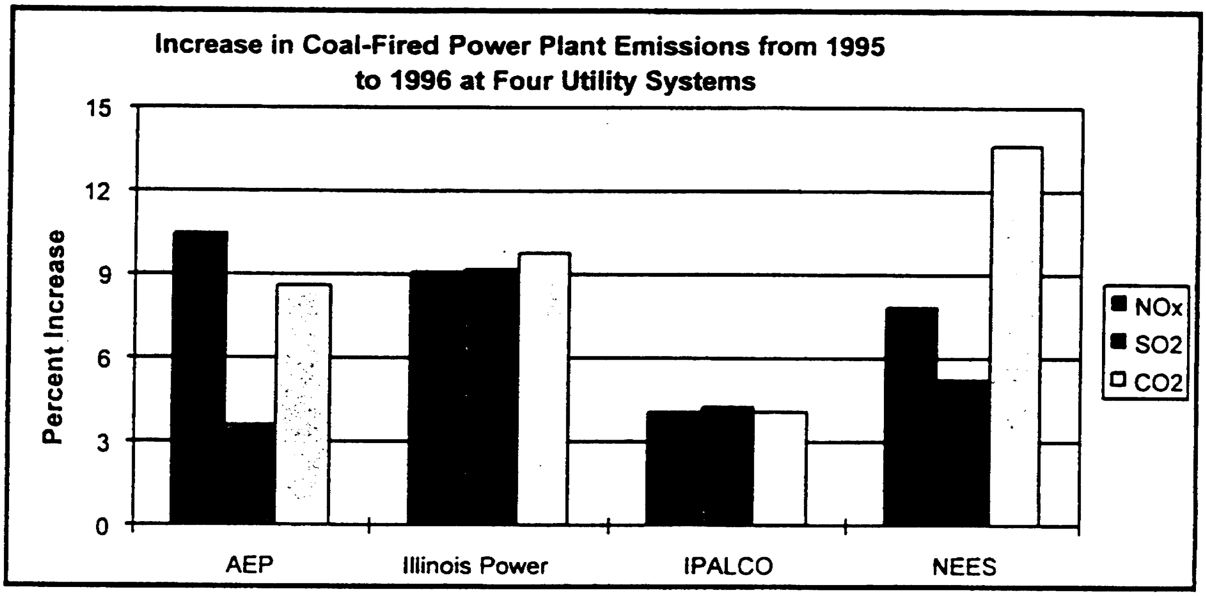


**Figure 4.** Relative increases in NOx, $SO_2$ and $CO_2$ emissions from coal-fired generation at four utility systems between 1995 and 1996.

Nationally, $CO_2$ emissions from all fossil fuel-fired generation increased by about 4.7% from 1995 to 1996. This one-year increase is greater than the cumulative increase in $CO_2$ emissions between 1990 and 1995. Coal contributed a disproportionately large part of the increase because coal combustion emits more carbon per kilowatt-hour of electricity generated than the other fossil fuels.[5]

**Is the existing transmission infrastructure capable of supporting a significant increase in transfers of electricity, thereby allowing low-cost, high pollution power to flow to new markets?**

Again, the answer appears to be yes. Gross exports from the AEP system rose 17.5% to 70.5 million MWh between 1995 and 1996. Net exports rose by 8.8 million MWh (161%) to a total of 14.3 million MWh. AEP's net exports to three control areas that form connections to control areas farther east increased by 7.6 million MWh (96%)

[5] U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1996*, Rept. No. DOE/EIA-0573(96) p. 16 (Washington, DC, October 1997).

(see Attachment B, Figure 4). In turn, the net exports of these three control areas to the Pennsylvania-New Jersey-Maryland (PJM) control area rose by 9.5 million MWh (69%).

The capacity of the transmission system is a key issue in the debate over the environmental implications of electric utility restructuring. In concluding that Order 888 would have little or no environmental impact, FERC made an important assumption that transmission prices, *but not capacity*, would change substantially in response to open access. As a result, FERC assumed that power transfers between regions would remain relatively small even after competition was well underway. For instance, as its environmental worst case, FERC modeled a "Competition Favors Coal" scenario. Even under that scenario, FERC projected that the coal intensive East North Central region (which includes the states of Ohio, Indiana, Michigan, Illinois, and Wisconsin) would export just 1 million net MWh in the year 2000. While this projection, which is for an entire region, can't be compared to the performance of a single utility, AEP alone exported a net of 14.3 million MWh - most of it to power systems outside the East North Central region - in 1996.

In response to criticisms that it had used unduly constrained transmission assumptions, FERC also modeled an "Expanded Transmission" case in combination with the "Competition Favors Coal" scenario. The effect of this case was to increase projected net exports from the East North Central region from the 1 million MWh noted above to a total of 10.9 million MWh in the year 2000. Although FERC asserted that the expanded transmission assumptions underlying this projection were highly unrealistic, 10.9 million MWh are still significantly below the 14.3 million MWh of net exports attributed to AEP alone in 1996.

In short, the initial NESCAUM analysis indicates that the existing transmission infrastructure is capable of supporting substantial increases in power flows between systems. Moreover, as NESCAUM argued in earlier comments to FERC on its EIS, it is entirely reasonable to expect that transmission capacity will continue to be enhanced in response to emerging market opportunities.

**Policy Implications:**

*Emission caps*

The increase in NOx emissions from increased coal-fired generation demonstrates a clear need for aggressive, overall NOx emission caps for states as proposed by EPA under Section 110 of the Clean Air Act. Regardless of the reasons for the pollution increases in 1996, an environmental policy is needed to prevent such increases in the future. Moreover, EPA needs to accelerate implementation of a national NOx emissions cap in order to prevent continued increases prior to 2003. Furthermore, NOx emissions have a large role in acidic and nitrogen deposition on lakes, forests and estuaries, in addition to summertime ozone formation and other health and environmental impacts. The Administration must consider the year-round harms from NOx emissions in establishing a national NOx cap. Attention must also be paid to capping $CO_2$ emissions in order to meet the terms of international climate change treaties.

*Full disclosure*

Informed decisions depend on ready access to accurate information. The federal government to date has not provided or required sufficient data for a comprehensive assessment of current trends due to restructuring. From the questions raised in this analysis, it is clear that much more information must be made available in a concise and timely manner to evaluate the impacts of the changing utility industry. Customers, too, must have access to comprehensive information on the fuel mix and emissions profiles of competing suppliers. Markets alone are unlikely to provide comprehensive information to customers; suppliers must be required to provide full information about fuel sources and emissions.

*Comparable environmental performance*

From the potential trends noted in this paper, EPA, DOE, FERC, and the Administration's Council on Environmental Quality need to live up to the commitments made with regard to FERC Order 888. National restructuring legislation and state reforms should include environmental safeguards applicable to all market participants. Equivalent environmental standards such as generation performance standards (in lb/MWh) must be established and enforced. Progress made over the years in improving the nation's air quality need not be sacrificed in order to reap the benefits of a more competitive electricity market.

## Conclusion

The initial investigation presented here does not yield a single definitive answer about the impact increased wholesale competition is having on environmental quality. It does suggest, however, that the NESCAUM states and all interested parties should continue to be concerned about increasing pollution from utility restructuring without public health and environmental safeguards. Of course, it is not certain that the trends apparent in these data on 1996 generation, sales, and net interchange represent long-term trends. But from recent industry projections and statements, these trends appear consistent with the direction in which coal-intensive utilities are heading. For example, in announcing record third-quarter earning in 1997, AEP chairman Linn Draper said, "The improvement can be attributed to increased wholesale sales and non-operating income .... Wholesale energy sales were up 43% as a result of power marketing transactions and coal conversion services."[6]

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[6] AEP Press Release, October 27, 1997.

The NESCAUM states support the opportunity to access inexpensive electricity and greater competition within the utility industry as a result of restructuring. In addition, the states support increasing profits for utility industry participants adept in working the evolving power market. The market, however, must not evolve to the detriment of public health and the environment.

The NESCAUM states look forward to working with interested parties in continuing to monitor the progress of utility market competition and environmental quality. Emission caps are needed that will reduce the total amount of pollution released into the atmosphere. Full disclosure of market transactions, including fuel mix and emissions information, must be made available so that informed decisions are made. Comparable environmental standards must be established to ensure competition is consistent with public health and environmental goals. With adequate information and appropriate safeguards, the dual goals of a more competitive electricity market and improved environmental quality can be met.

# GROUNDS FOR CONCERN

## A Comparison of Production Costs and Pollution Emissions In Two Regional Power Pools

The following graphs compare emissions and costs for two large power systems, Ohio-based American Electric Power (AEP) and the New England Power Pool (NEPOOL). These two systems are comparably sized, dispatching approximately 25,000 and 20,000 megawatts (MW) of generating capacity respectively.

Figure 1 shows emissions of nitrogen oxides (NOx), compared to power production costs, for the two power systems. NOx is a key ingredient in ozone smog. It is also a precursor for fine particle pollution and contributes to the eutrophication of water systems. The AEP plants are clearly characterized by lower costs and higher NOx emissions rates compared to the NEPOOL plants.

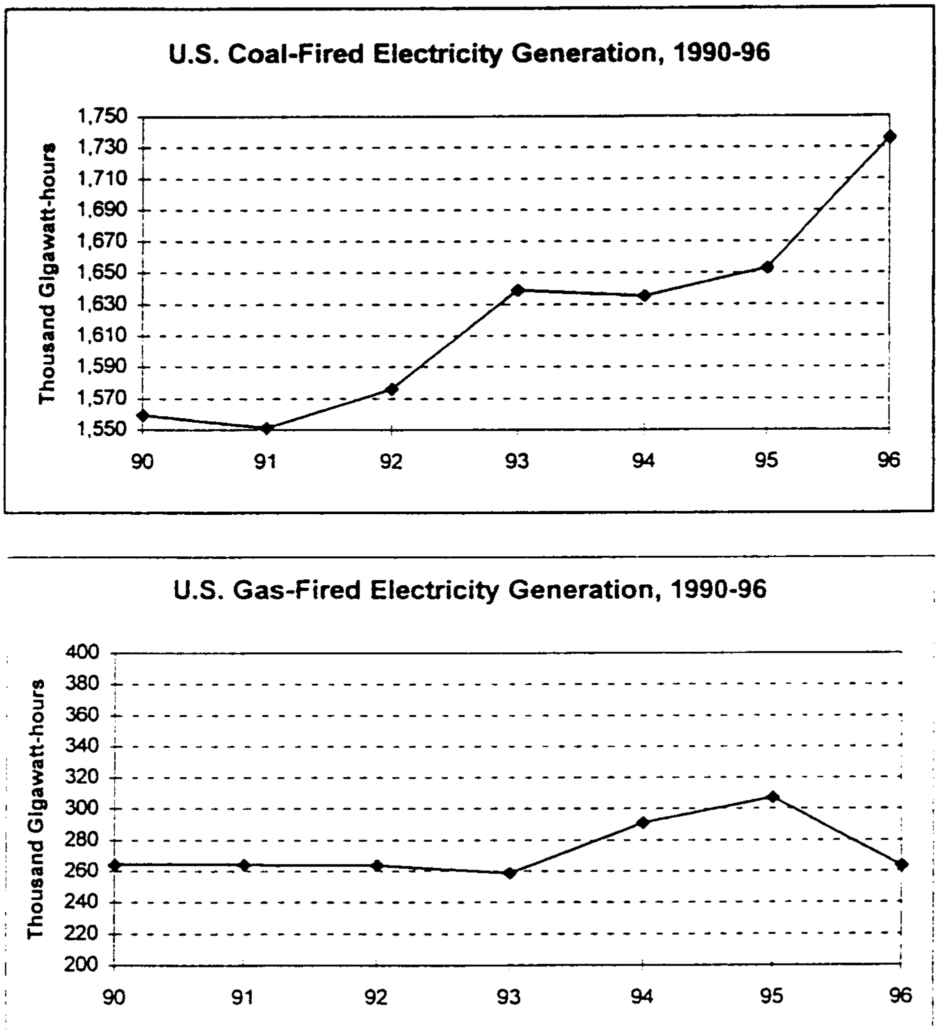
Figure 2 shows the potential for pollution increases in both systems if existing plants were utilized to the maximum extent practicable (i.e. 85% capacity factor). Total NOx emissions for the AEP system, which are already much higher than NEPOOL's, could grow far more dramatically in response to increased demand and fuller plant utilization.

Moreover, available power on the AEP system would be very cost-competitive. In a year, AEP could generate approximately 60 million additional megawatt-hours for 3 cents per kwh *or less* . That's more than half the total power typically supplied by NEPOOL in a year. By contrast, the NEPOOL system could generate only 7 million additional megawatt-hours for 3 cents per kwh.

**The upshot**: if we do not first level the environment playing field, unconstrained competition is likely to increase demand for power from cheap, but dirty power plants such as those in the AEP system. The result could be significantly higher emissions. *These emissions will blow toward the Northeast regardless of where the power is sold.*

# Attachment B: Data

Data recently released on nationwide electricity generation in 1996 show an increase of 83 million Megawatt-hours (MWh) in coal-fired generation and a decrease of 44 million MWh in gas-fired generation compared to 1995 levels.



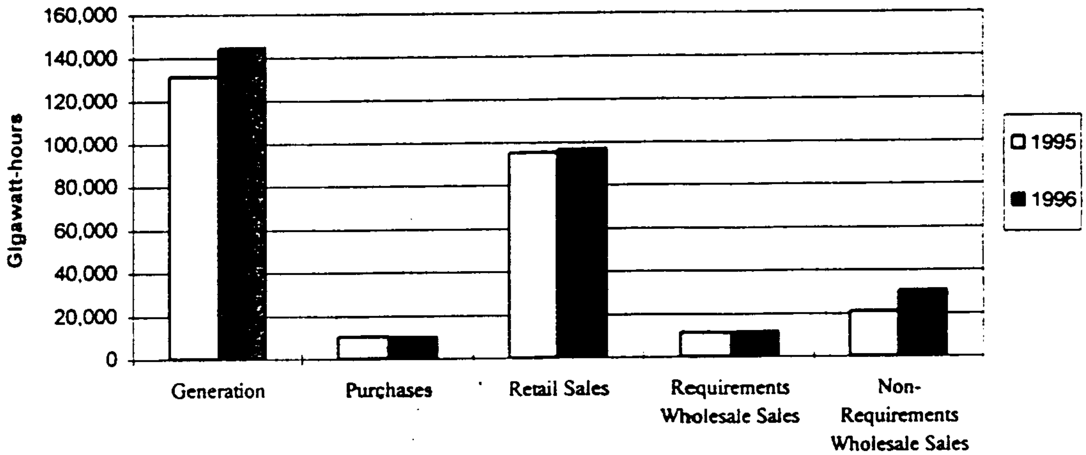

*Source: U.S. Energy Information Administration.*

**Figure 1.** U.S. coal-fired and gas-fired electricity generation trends (1990-1996).

## American Electric Power

AEP's annual generation increased by 13.0 million MWh, or 9.9%, between 1995 and 1996. The company's purchases from other companies dropped by 471 thousand MWh, or 4.6%. Non-requirements sales for resale increased by some 9.6 million MWh, or 46%. The category of non-requirements sales for resale includes energy sales not associated with long-term commitments the company includes in projected load. Requirements sales for resale—the long-term commitments the company does include in system planning—rose by 188 thousand MWh, or only 1.7%, and sales to ultimate customers rose by 1.6 million MWh, also 1.7%.[1]

**Figure 2: American Electric Power**
**Generation, Purchases and Sales, 1995-96**




*Source: FERC form 1, EIA Form 759.*

The vast majority of AEP's incremental generation between 1995 and 1996 was produced using coal. The company's coal-fired generation increased by 10.3 million MWh, or 9.0%. This is roughly 12% of the total national increase in coal-fired generation.

**Table 1. AEP Generation by Fuel Type, 1993-1996**

| | Annual Generation (MWh) | | | |
|---|---|---|---|---|
| Fuel | 1993 | 1994 | 1995 | 1996 |
| Coal | 108,707,259 | 115,624,988 | 116,061,204 | 126,449,226 |
| Nuclear | 16,313,243 | 9,291,420 | 13,999,316 | 16,395,865 |
| Oil | 276,503 | 299,050 | 262,960 | 314,608 |
| Hydro | 1,024,374 | 965,846 | 890,824 | 1,104,464 |
| Total: | 126,321,379 | 126,181,304 | 131,214,304 | 144,264,162 |

*Source: EIA Forms 759.*

The composition of AEP's wholesale power sales changed significantly between 1995 and 1996. Short-term, non-firm transactions (categorized in Table 2 as "Other Service") became a significantly larger portion of total wholesale sales in 1996.

[1] "Requirements sales for resale" refers to "service which the supplier plans to provide on an ongoing basis (i.e. the supplier includes projected load for this service in its system resource planning)." All other sales for resale are "non-requirements sales for resale."

**Table 2. AEP Wholesale Power Sales by Contract Type**

| Contract Type | 1995 MWh | 1995 % of Total | 1996 MWh | 1996 % of Total |
|---|---|---|---|---|
| Requirements Service: | 11,199,396 | 35.0% | 11,418,329 | 27.3% |
| Unit and Firm Service: | 12,633, 836 | 39.5% | 13,762,248 | 32.9% |
| Other Service: | 8,168,345 | 25.5% | 16,641,211 | 39.8% |
| Total: | 32,001,577 | 100.0% | 41,821,788 | 100.0% |

*Source: FERC forms 1.*

AEP sold far more "OS" category energy to marketing companies in 1996 than in 1995. Companies that purchased no energy from AEP in 1995 are marked with an asterisk.

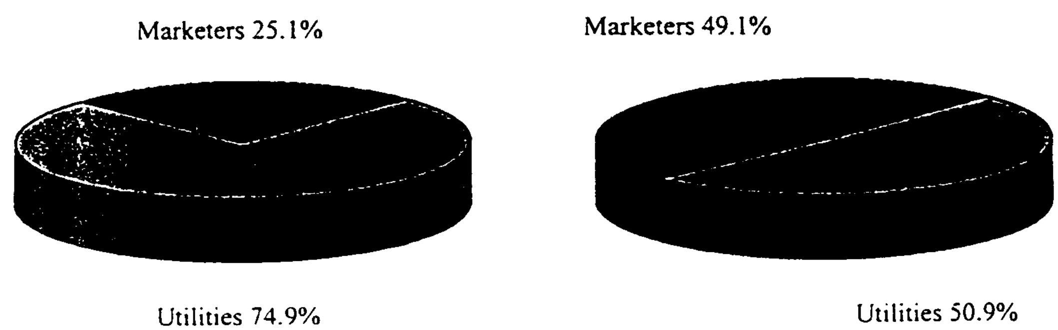
**Table 3. The Ten Companies Purchasing the Most "OS" Category Energy from AEP, 1995-96**

| Company | 1995 MWh | Percent of Total | Company | 1996 MWh | Percent of Total |
|---|---|---|---|---|---|
| Consumers Power | 1,938,182 | 27.5 | *AES Power | 2,616,557 | 20.1 |
| Allegheny Power | 1,929,402 | 27.4 | *PECO Energy | 2,409,918 | 18.5 |
| West PA Power Co. | 906,920 | 12.9 | *Koch Power Services | 1,560,548 | 12.0 |
| Commonwealth Ed | 461,187 | 6.5 | Consumers Power | 1,500,263 | 11.5 |
| TVA | 436,381 | 6.2 | Citizen Lehman | 1,315,624 | 10.1 |
| American Mun. Pwr | 346,780 | 4.9 | *Commonweatlh Ed. | 1,040,674 | 8.0 |
| Ohio Edison | 345,558 | 4.9 | *Phibro, Inc. | 780,424 | 6.0 |
| Virginia Electric Power | 280,395 | 4.0 | Carolina P&L | 752,660 | 5.8 |
| Richmond P&L | 217,763 | 3.1 | TVA | 573,059 | 4.4 |
| Duquesne P&L | 184,002 | 2.6 | *Buckeye Power | 477,448 | 3.7 |
| Total "OS" Sales | 7,046,570 | 100.0 | Total "OS" Sales | 13,027,175 | 100.0 |

*Source: FERC forms 1.*

The charts in Figure 3 include the same companies as shown in Table 3, above. AES, PECO, Koch, Citizen Lehman and Phibro are categorized as marketing companies.

**Figure 3. Composition of the Ten Companies Purchasing the Most "OS" Category Power from Illinois Power**



In 1995 AEP reported gross exports from its control area of 60.0 million MWh. In 1996 that number jumped to 70.5 million MWh, an increase of 10.5 million MWh, or 17.5%. Taking into account power flowing into the AEP system, net exports were 5.5 million MWh in 1995 and 14.3 million MWh in 1996, an increase of 8.8 million MWh, or 161%. The majority of these net imports went to these control areas to the east of AEP (Virginia Electric Power, Cleveland Electric Illuminating and Allegheny Power System).[2]

**Table 4. Net Energy Exports from AEP to Control Areas with Connections to the East**

| Control Area | Net Interchange (MWh) 1995 | 1996 |
|---|---|---|
| VEPCo | 2,476,000 | 4,134,000 |
| CEI | 53,000 | 779,000 |
| APS | 5,376,000 | 10,567,000 |
| Total | 7,905,000 | 15,480,000 |

The figure below shows the relative position of the power control areas discussed in this report. The AEP system is centrally located and is also interconnected to more control areas than any other system in the Eastern Interconnection. Cleveland Electric Illuminating Co. (CEI), Allegheny Power System (APS), and Virginia Electric Power Co. (VEPCo) form connecting bridges between AEP and power control areas farther to the east. There are other control areas in this region, but these three are the link between AEP and the east coast power pools: the Pennsylvania-New Jersey-Maryland pool (PJM), the New York Power Pool (NYPP) and the New England Power Pool (NEPOOL). Other major control areas connected to the AEP system include the Michigan ECS, Public Service of Indiana (PSI), part of the Cinergy Corporation, and the Tennessee Valley Authority (TVA).[3]

[2] Net exports to these three control areas are greater than the total net exports from the AEP system, due to significant AEP imports from several other control areas such as Dayton Power & Light and TVA..
[3] Note that the cells in this figure only approximate the location of these control areas.

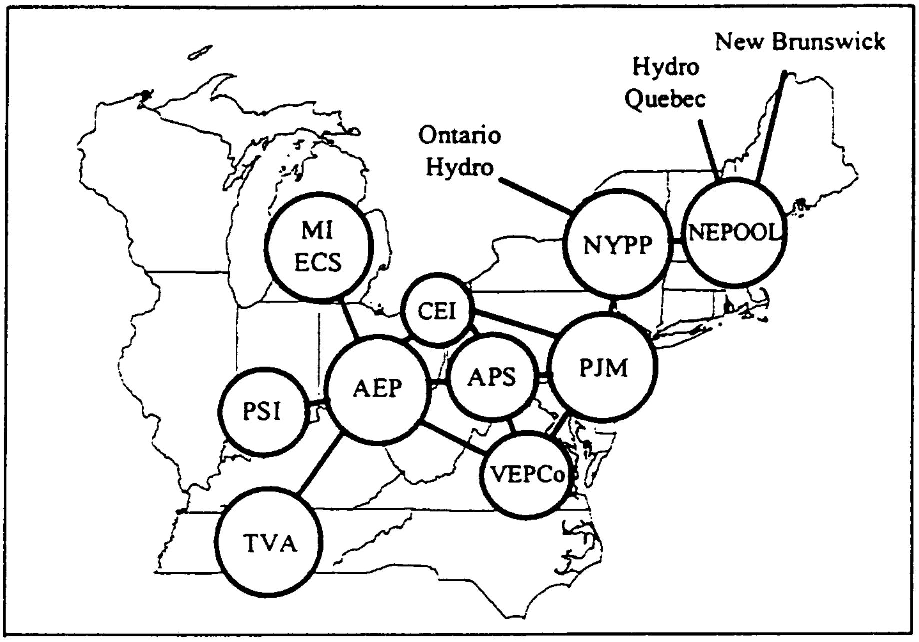



**Figure 4.** Power control areas in the northeastern U.S.

The figures cited above indicate that the transmission system was able to move almost twice the amount of energy east from AEP in 1996 than in 1995.

In turn, CEI, APS and VEPCo increased their combined net deliveries to PJM between 1995 and 1996. In 1995, these systems delivered a net 13.8 million MWh to the PJM control area, and in 1996 this number climbed to 23.3 million MWh—an increase of 9.5 million MWh, or 69%. PJM, in turn, increased its net deliveries to NYPP from 4.4 million MWh in 1995 to 8.4 million MWh in 1996—an increase of 92%. Finally, NYPP increased its net deliveries of energy to NEPOOL from 3.1 million MWh in 1995 to 6.1 million MWh in 1996—an increase of 99%.

Thus, it appears that a significant amount of power exported east from the AEP system displaced generation on the east coast. This conclusion is supported by significant purchases directly from Midwestern utilities by northeastern utilities.[4] For example,

[4] The conclusion is also supported in purchases by northeastern utilities from the marketing companies purchasing from AEP.

PECO Energy purchased 2.4 million MWh of "OS" category power from AEP in 1996 after purchasing none in 1995.[5]

Analysis of 1995 and 1996 generation in these control areas also supports the conclusion that a significant amount of Midwestern power displaced generation on the east coast. Generation in the APS system increased by only 945 thousand MWh during this period, while APS's net imports into PJM increased by 6.8 million MWh. Generation in the PJM area declined by roughly 1.5 million MWh (1.5%) in the face of annual load growth between 1 and 2% and significantly increased net exports to NYPP.

The table below shows the emissions associated with the additional fossil-fired generation at AEP in 1996.[6] Using 1995 emission rates, the table takes into account all of AEP's fossil-fired generators, including units that reduced production as well as those that increased production.[7]

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[5] Note that the actual output of AEP generators would not have been physically delivered across the APS system to the east coast. There is a "daisy chain" dynamic in long distance energy sales, in which energy generated in one control areas makes available a roughly equal amount of energy in a contiguous area for export. In this case, for example, APS generators may have generated the energy that fulfilled AEP's contractual obligation to PECO. However, the important point from an emissions perspective, is that the output of AEP's generators increased, displacing the output of Northeastern generators.

[6] These plants burned a small amount of oil in 1996, however, over 99% of this generation was coal-fired.

[7] Since utilities were required to meet the requirements of Phase I of the Acid Rain Program before 1996, it is unlikely that the emission rates at more than one or two of these generating plants changed significantly between 1995 and 1996.

**Table 5. Increase in Air Emissions at AEP Fossil Plants, 1995-96**

| Plant | Nox Increase (tons) | CO2 Increase (tons) | SO2 Increase (tons) |
|---|---|---|---|
| Big Sandy | -4,235 | -1,295,912 | -12,846 |
| Beckjord | 125 | 44,470 | 328 |
| Breed | | no generation | |
| Cardinal | -2,615 | -559,100 | -6,185 |
| Clifty Creek | 1,148 | 185,570 | 1,704 |
| Clinch River | 2,214 | 339,828 | 1,928 |
| Conesville | 569 | 225,108 | 2,760 |
| Fourth Street | 0 | 0 | 0 |
| Gavin | 17,744 | 3,163,271 | 4,567 |
| Glen Lyn | 172 | 71,166 | 475 |
| Stuart | -725 | -156,823 | -1,088 |
| Amos | 11,717 | 3,506,754 | 22,465 |
| Kammer | -1,113 | -168,689 | -4,589 |
| Kanawha River | 4,748 | 767,554 | 4,654 |
| Kyger Creek | -659 | -97,620 | -1,095 |
| Mitchell | -292 | -118,990 | -857 |
| Mountaineer | 3,969 | 1,460,628 | 7,628 |
| Muskingum River | 11,221 | 2,802,125 | 56,614 |
| Sporn | 1,208 | 235,059 | 2,365 |
| Picway | 835 | 328,465 | 8,181 |
| Rockport | -1,821 | -1,191,156 | -38,219 |
| Tanners Creek | 6,769 | 940,709 | 8,270 |
| Tidd | | no generation | |
| Zimmer | 538 | 244,499 | 625 |
| Total | 51,518 | 10,726,918 | 57,685 |

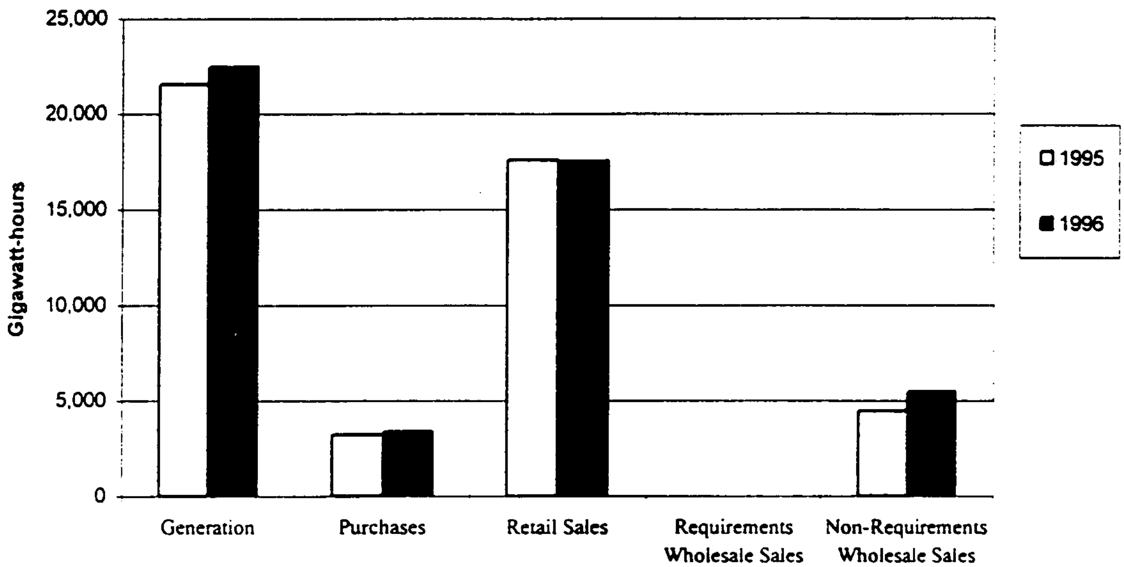
Three of the five plants showing significant increases in generation have unusually high $NO_x$ emission rates. The $NO_x$ rate at Gavin is 12.9 lb/MWh, the rate at Tanners Creek is 15.8 lb/MWh and Muskingum River emits 8.35 lb/MWh. The weighted average emission rate of all of AEP's fossil-fired units in 1995 was 8.43 lb/MWh. The net increase in $NO_x$ emissions at AEP power plants from 1995 to 1996 is estimated to be over 50,000 tons.

## Illinois Power Company

Illinois Power's total generation increased by 915 thousand MWh, or 4.3% between 1995 and 1996, however coal-fired generation rose by 1.6 million MWh, or 9.9%, offsetting decreases in nuclear and gas-fired generation. Non-requirements sales for resale increased by 1.0 million MWh, or 23%, while the company's retail sales dropped by 58 thousand MWh, or 0.3%. Thus, all of Illinois Power's increased generation in 1996 was produced for sale into wholesale markets.

**Figure 5. Illinois Power Company**

**Generation Purchases and Sales, 1995-96**




*Source: FERC form 1, EIA Form 759.*

**Table 6. Illinois Power Generation by Fuel Type, 1993-96**

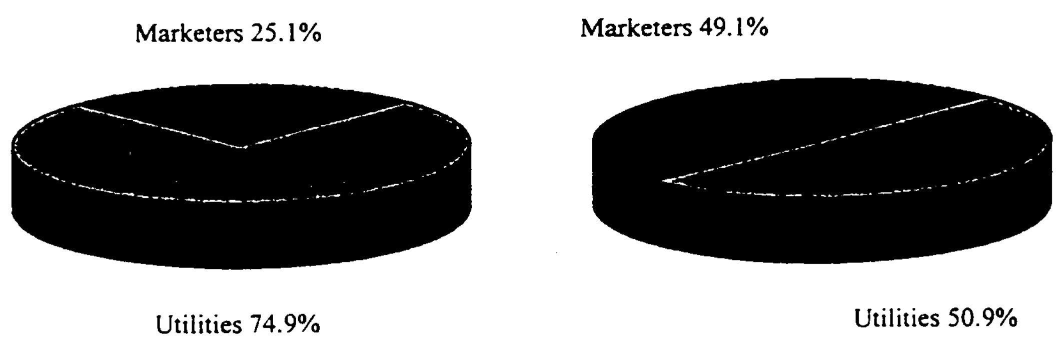
| | Annual Generation (MWh) | | | |
|---|---|---|---|---|
| Fuel | 1993 | 1994 | 1995 | 1996 |
| Coal | 14,282,481 | 14,567,861 | 15,978,878 | 17,564,268 |
| Nuclear | 5,085,610 | 6,431,430 | 5,296,169 | 4,615,693 |
| Oil | 66,770 | 47,033 | 18,116 | 34,444 |
| Gas | 155,750 | 46,645 | 160,587 | 88,804 |
| Wood | 0 | 0 | 853 | 162 |
| Waste | 0 | 0 | 67,053 | 133,434 |
| Totals | 19,590,611 | 21,092,969 | 21,521,656 | 22,436,804 |

**Table 7. The Ten Companies Purchasing the Most "OS" Category Power from Illinois Power, 1995-96**

| Company | MWh | % of Total | Company | MWh | % of Total |
|---|---|---|---|---|---|
| Soyland Power Coop. | 1,234,375 | 28.8 | Electric Energy, Inc. | 1,735,635 | 34.3 |
| TVA | 1,017,597 | 23.8 | Soyland Power Coop. | 1,148,744 | 22.7 |
| Electric Energy, Inc. | 905,871 | 21.1 | Commonwealth Edison | 535,164 | 10.6 |
| Commonwealth Edison | 567,859 | 13.3 | Union Electric Co. | 510,366 | 10.1 |
| Union Electric Co. | 330,543 | 7.7 | TVA | 380,634 | 7.5 |
| Enron Power Marketing | 95,770 | 2.2 | Enron Power Marketing | 240,089 | 4.7 |
| Louis Dreyfus Marketing | 44,684 | 1.0 | LG&E Power Marketing | 208,181 | 4.1 |
| Central Illinois Light Co. | 36,891 | 0.9 | *Koch Power Services | 176,029 | 3.5 |
| MidAmerican Energy Co. | 27,752 | 0.6 | MidAmerican Energy Co. | 76,739 | 1.5 |
| Central Illinois PS | 22,972 | 0.5 | Rainbow Energy Mrkting. | 43,614 | 0.9 |
| Total | 4,284,314 | 100.0 | Total | 5,055,195 | 100.0 |

The charts in Figure 6 represent the data shown in Table 7. Enron, Louis Dreyfus, MidAmerican, LG&E, Koch and Rainbow are categorized as marketing companies.

**Figure 6. Composition of the Ten Companies Purchasing the Most "OS" Category Power from Illinois Power**




The air emissions associated with Illinois Power's incremental 1996 generation (calculated using 1995 emission rates) are shown in Table 8, below. The Baldwin plant, which increased its generation in 1996 by 650 thousand MWh, had the highest 1995 $NO_X$ emission rate (13.2 lb/MWh) of any Illinois Power plant. The weighted average $NO_X$ rate of the company's fossil-fired plants in 1995 was 10.1 lb/MWh.

**Table 8. Increase in Air Emissions at Illinois Power Fossil Plants, 1995-96**

| Plant | Increase in NOx (tons) | Increase in CO2 (tons) | Increase in SO2 (tons) |
|---|---|---|---|
| Baldwin | 4,296 | 676,144 | 17,504 |
| Havana | 134 | 70,441 | 254 |
| Hennepin | 1,209 | 436,985 | 10,393 |
| Joppa Steam | 14 | 12,818 | 39 |
| Vermillion | -279 | -118,597 | -1,349 |
| Wood River | 2,052 | 650,974 | 3,652 |
| Totals | 7,426 | 1,728,765 | 30,492 |

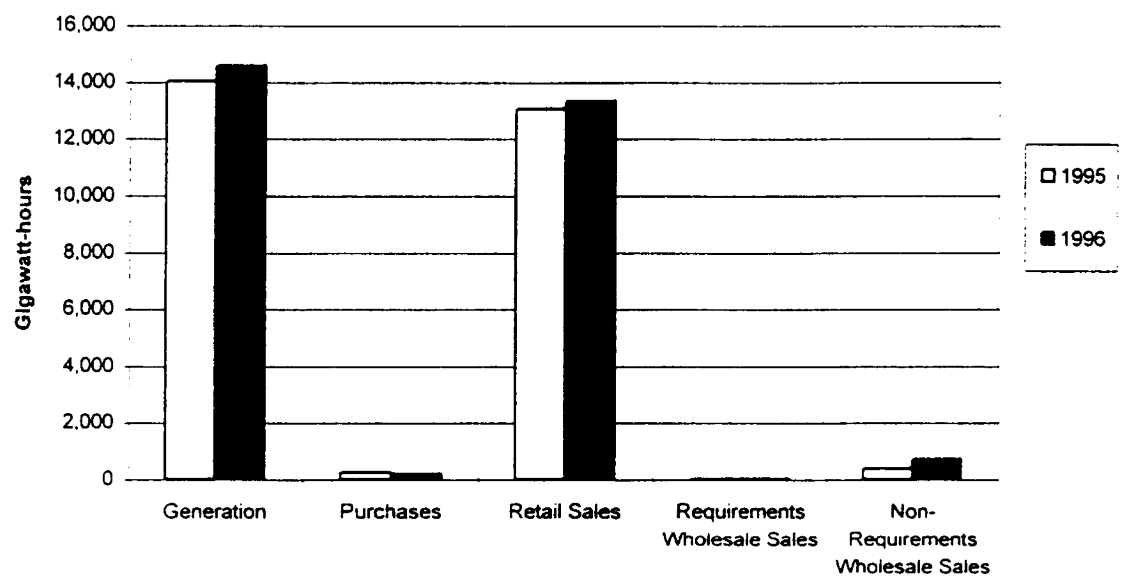
Like AEP, Illinois Power incurred the cost of using $SO_2$ allowances in order to increase its $SO_2$ emissions, but was allowed to increase its $NO_X$ and $CO_2$ emissions by the amounts shown at no cost.

## Indianapolis Power & Light Co.

IPALCo's 1996 non-requirements wholesale sales rose 84% over 1995 levels—almost twice the increase seen at AEP and Illinois Power. Further, IPALCO relied entirely on self-generated power in providing this increased wholesale power.

**Figure 7. Indianapolis Power & Light**

**Generation, Purchases and Sales, 1995 to 1996**




*Source: FERC Form 1, EIA From 759.*

**Table 9. IPALCO Generation by Fuel Type, 1993-96**

| Fuel | Annual Generation 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|
| Coal | 13,216,575 | 13,520,422 | 13,970,573 | 14,555,424 |
| Oil | 23,969 | 40,829 | 25,623 | 20,596 |
| Gas | 44 | 6,715 | 25,940 | 11,104 |
| Hydro | 12,417 | 10,010 | 9,662 | -1,370 |
| Total | 13,253,005 | 13,577,976 | 14,031,798 | 14,585,754 |

**Table 10. IPALCO Wholesale Sales By Contract Type**

| Contract Type | 1995 MWh | 1996 MWh | Change MWh | Percent Change |
|---|---|---|---|---|
| Requirements Service: | 27,624 | 28,866 | 1,242 | 4.5% |
| Unit and Firm Service: | 275 | 1,851 | 1,576 | 573% |
| Other Service: | 393,857 | 723,507 | 329,650 | 83.7% |

The companies purchasing the most "OS" category power from IPALCO in 1995 and 1996 are shown in Table 11. Companies purchasing no power from IPALCO in 1995 are marked with an asterisk.

**Table 11. Ten Companies Purchasing the Most "OS" Category Power from IPALCO, 1995-96**

| Company | 1995 MWh | % of Total | Company | 1996 MWh | % of Total |
|---|---|---|---|---|---|
| Wabash Valley Pwr. Assoc. | 122,573 | 31.1 | Hoosier Rural Elec. Coop. | 194,913 | 26.9 |
| So. Indiana Gas & Electric | 113,280 | 28.8 | *LG&E Power Marketing | 161,025 | 22.3 |
| Cinergy | 90,151 | 22.9 | Cinergy | 138,191 | 19.1 |
| Hoosier Rural Elec. Coop. | 61,637 | 15.6 | So. Indiana Gas & Electric | 92,780 | 12.8 |
| Indiana Michigan Power | 5,713 | 1.5 | Wabash Valley Pwr. Assoc. | 66,436 | 9.2 |
| Emron Power Marketing | 503 | 0.1 | Enron Power Marketing | 36,535 | 5.0 |
| | | | Indiana Michigan Power Co. | 13,485 | 1.9 |
| | | | *Indiana Mun. Power Assoc. | 7,610 | 1.1 |
| | | | *Duke/Louis Dreyfus | 6,807 | 0.9 |
| | | | *Vitol Gas & Electric | 5,725 | 0.8 |
| Total "OS" Sales | 393,857 | 100 | Total "OS" Sales | 723,507 | 100 |

*Source: FERC Form 1.*

The companies shown in the Table above are represented in the charts below. LG&E, Enron, Duke/Louis Dreyfus and Vitol are classified as marketers. Cinergy and Indiana Michigan (an AEP subsidiary) are classified as hybrid companies, utilities aggressively marketing wholesale power.

**Figure 8. Composition of top the Ten Companies Purchasing the Most "OS" Category Power from IPALCo**

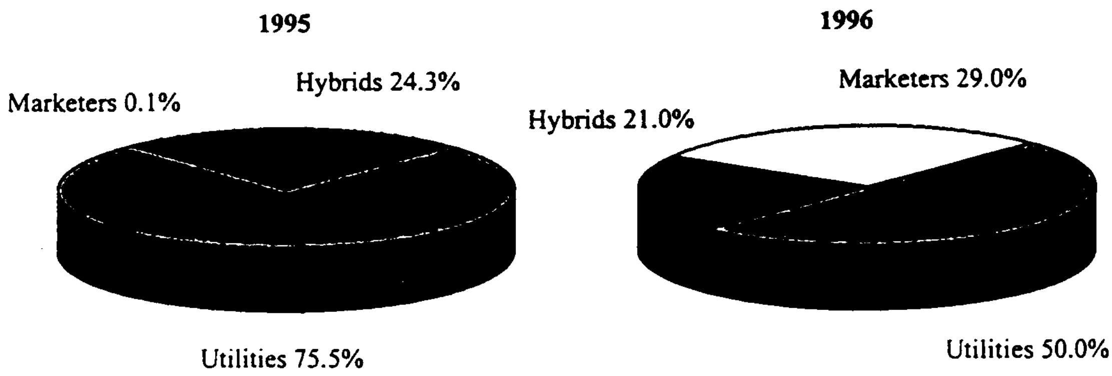


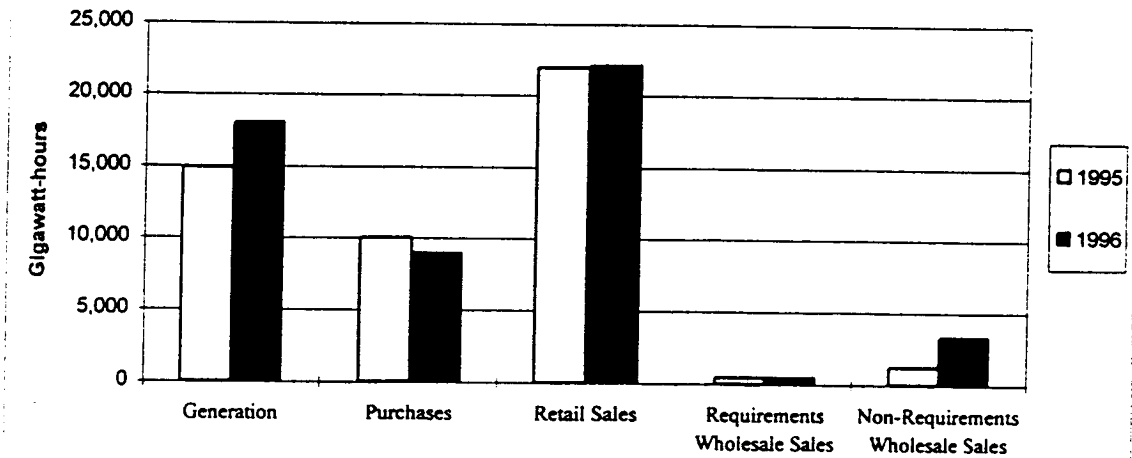

**Table 12. Increase in Air Emissions at IPALCO Fossil Plants, 1995-96**

| Plant | NOx Increase (tons) | SO2 Increase (tons) | CO2 Increase (tons) |
|---|---|---|---|
| Stout | 339 | 2,293 | 187,689 |
| Pritchard | 124 | 608 | 59,444 |
| Perry K&W | 0 | 0 | 0 |
| Petersburg | 755 | 3,535 | 405,779 |
| Totals | 1,218 | 6,436 | 652,912 |

## V. New England Electric System

New England Electric System (NEES) is a utility holding company operating in Massachusetts, New Hampshire and Rhode Island. Until 1997 the company owned a diverse portfolio of generating resources: NEES' 1995 generation was 60% coal, 15% nuclear, 10% gas and 8% hydropower. Between 1995 and 1996, the company's generation increased by 3.1 million MWh, or 21%. Power purchases decreased by 1.1 million MWh, or 11%. NEES' retail sales and requirements sales for resale remained relatively stable during this period, while non-requirements wholesale sales increased by 2.1 million MWh, or 170%.

**Figure 9. New England Electric System**
**Generation, Purchases and Sales, 1995-96**




*Source: FERC Form 1, EIA From 759.*

Unlike the Midwestern companies analyzed above, the majority of NEES' incremental 1996 generation was produced with gas (due primarily to the introduction of a newly repowered gas-fired plant late in 1995). Coal-fired generation increased by 871 thousand MWh, or 9.7%.

**Table 13. NEES Generation by Fuel Type, 1993-96**

| | Annual Generation (MWh) | | | |
|---|---|---|---|---|
| Fuel | 1993 | 1994 | 1995 | 1996 |
| Coal | 8,698,672 | 8,750,062 | 9,025,402 | 9,896,029 |
| Nuclear | 2,439,211 | 2,072,573 | 2,199,283 | 1,584,453 |
| Oil | 2,907,461 | 1,918,413 | 1,071,304 | 1,348,606 |
| Gas | 55,473 | 319,358 | 1,545,207 | 3,537,760 |
| Hydro | 1,051,494 | 1,151,555 | 1,067,191 | 1,623,455 |
| Total | 15,152,311 | 14,211,961 | 14,908,386 | 17,990,302 |

Data reported on NEES' wholesale energy sales indicate that nuclear outages, and not market opportunities associated with restructuring, were the primary drivers of the 1996 increase in generation and sales. Northeast Utilities, with 2,600 MW of nuclear capacity unavailable, increased its "OS" category purchases from NEES by 196 thousand MWh between 1995 and 1996.

**Table 14. Ten Companies Purchasing the Most "OS" Category Power from NEES, 1995-96**

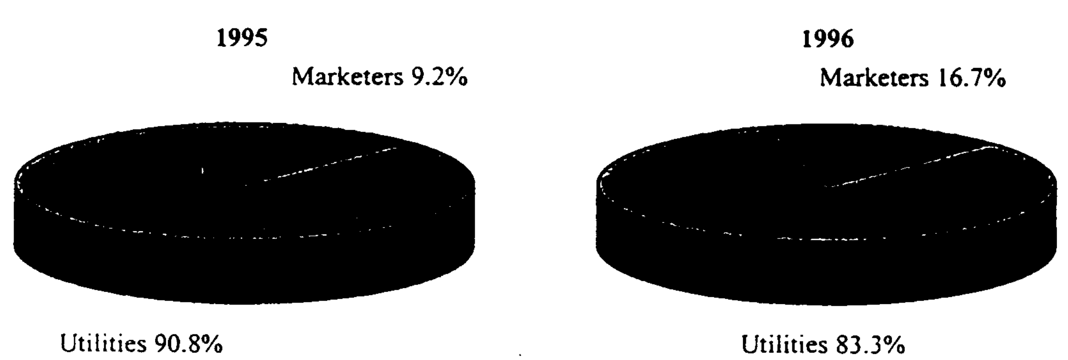
| Company | 1995 MWh | % of Total | Company | 1996 MWh | % of Total |
|---|---|---|---|---|---|
| Bangor Hydro Electric | 200,866 | 39.1 | Northeast Utilities | 227,755 | 24.2 |
| Boston Edison | 142,877 | 27.8 | Commonwealth Electric | 165,500 | 17.6 |
| Commonwealth Electric | 41,161 | 8.0 | Boston Edison | 100,250 | 10.6 |
| Northeast Utilities | 31,325 | 6.1 | Enron Power Marketing | 98,510 | 10.4 |
| Montaup Electric | 28,070 | 5.4 | Montaup Electric | 90,095 | 9.5 |
| CNG Power Services | 19,330 | 3.7 | MA Mun. Wholesale | 73,722 | 7.8 |
| Electric Clearing House | 16,160 | 3.1 | CNG Power Services | 58,122 | 6.1 |
| Enron Power Marketing | 11,560 | 2.2 | Bangor Hydro Electric | 49,000 | 5.2 |
| Hudson L&P Dept. | 11,011 | 2.1 | Fitchburg G&E | 43,728 | 4.6 |
| Fitchburg G&E | 10,962 | 2.1 | Hudson L&P Dept. | 32,659 | 3.4 |
| Totals | 513,322 | 100.0 | Totals | 939,341 | 100.0 |

*Source: FERC Form 1.*

NEES also increased its unclassified sales to NEPOOL from 8,200 MWh in 1995 to 1.1 million MWh in 1996—an increase of over 13,000%. Most of this energy also probably served to replace energy previously provided by the Millstone plant. The idea that NEES' incremental 1996 generation was not driven primarily by new market opportunities is also supported by the fact that the NEPOOL control area was a net importer of electricity in both 1995 and 1996. Net imports in 1995 were 15.9 million MWh, and net imports in 1996 were 18.3 million MWh.

The companies listed in Table 14 are represented in Figure 10. CNG, Electric Clearing House and Enron are classified as marketing companies.

**Figure 10. Composition of Top Ten Purchasers of "OS" Category Power from NEES**



Perhaps the key question regarding NEES' 1996 activity is, what would the company's generation and sales have been had the outage at Millstone not occurred? In this case, would some marketers have turned to NEES rather than to Midwestern utilities for wholesale energy? NEES reported 1996 *average* operating costs at Salem Harbor and Manchester St. of 3.4 cents per kWh, and 2.5 cents/kWh at Brayton Point. Operating at a high capacity factor, the plants' marginal costs would be significantly below these levels. Thus, NEES' fossil generation would probably have been attractive to marketers in emerging competitive markets absent the outage at Millstone.

The emission rates of NEES fossil-fired units are significantly lower than the rates at many Midwestern plants cited above. The 1995 $NO_x$ rate of the Brayton Point plant was 2.7 lb/MWh; that of the Salem Harbor plant was 4.9 lb/MWh; and that of the Wyman plant was 3.4 lb/MWh.

**Table 15. Increase in Air Emissions at NEES Fossil Plants, 1995-96**

| Plant | Increase in Nox (tons) | Increase in CO2 (tons) | Increase in SO2 (tons) |
|---|---|---|---|
| Wyman | -21 | -13,169 | -64 |
| Brayton Point | 170 | 135,930 | 791 |
| Manchester St. | 332 | 1,122,874 | 27 |
| Salem Harbor | 909 | 480,582 | 3,139 |
| Totals | 1,391 | 1,726,217 | 3,891 |

Thus, compared to other utilities, the incremental energy NEES produced was not from high-emission generation. However, in that this generation replaced nuclear generation, it represents a significant increase in regional emissions.