The New Clean Air Act: Compliance and Opportunity

A Primer for Electric Utilities, Independent Power Producers, and Major Industrial Sources

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B. Technological Options for Acid Rain Control

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1. Introduction

The electric utility industry has shown extraordinary growth since the early part of this century. Figure 1 shows electrical production from 1930 to 1985. This figure also illustrates the dominance of coal as the major source of the derived electrical generation. Although oil and gas were significant contributors to electrical production in the 1960s and 1970s and nuclear power was a significant contributor in the 1980s, coal continues to be the dominant fuel source. Electrical use has grown from only 1 quad (10^{15} Btu) of energy utilized in the 1930s to 26 quads used in 1985. These 26 quads represent over one-third of all the energy used in the U.S. which was 74 quads in 1985.

Unfortunately, the utilization of coal involves major environmental and safety problems throughout the fuel cycle. From mine safety and strip mining's ecological damage to air pollution associated with coal combustion to the ultimate disposal of fly ash and sulfur bearing sludge, coal use presents major challenges. Perhaps the most important of these challenges is to control gaseous emissions of important air pollutants associated with coal combustion. Table 1 describes the major regulated (criteria) and carbon dioxide (CO_2) pollutants for which coal combustion is an important source. SO_2, NO_x, and particulates are all currently regulated for both new and existing sources under the Act. Of course CO_2 is unregulated, but is a major contributor to potential global warming.

Table 1 also summarizes the major health and environmental concerns and the role of electrical production, particularly coal combustion, relative to other sources of pollution for each of these pollutants.

2. Acid Rain — The Near Term Challenge

Acid rain, the popular term for acid deposition, is most closely associated with damage to aquatic systems. It may also contribute to forest damage as well as damage to buildings, monuments, and other structures. Acid rain occurs when SO_2 (emitted primarily by coal-fired electric utilities) and NO_x (primarily from transportation sources and utilities) are chemically transformed, transported into the atmosphere, and returned to the earth in the form of wet or dry deposition. Based on this potential environmental damage, Congress has recently passed the Amendments that would control both SO_2 and NO_x emissions from existing electric utility plants.

3. Dealing with the New Acid Rain Legislation

The electric utility industry will have to make very many cost intensive decisions to comply with provisions of the legislation. For SO_2 control, the industry will have the choice of locating an adequate supply of low sulfur coal, selecting a control technology, or selectively burning natural gas. The utility will likely look for available low sulfur coal supplies from both Eastern and Western mines to determine the most economical fuel for that particular utility system. The utility will likely compare the coal switching option to the control technology options available. Table 2 describes current and emerging technologies for SO_2 and NO_x control. Included are control technologies available for current pulverized-coal boilers as well as those that could be applied as new boiler technology with inherent SO_2/NO_x control capabilities. The new SO_2/NO_x technologies in Table 2 reflect modified combustion where both SO_2 and NO_x are reduced in the process of fuel combustion. The Table briefly describes the technology, the estimated level of control of SO_2 and NO_x, and projected commercial availability, including comments primarily related to capability. Note that the overwhelming current choice of utilities for SO_2 control technology has been lime and limestone wet scrubbers.

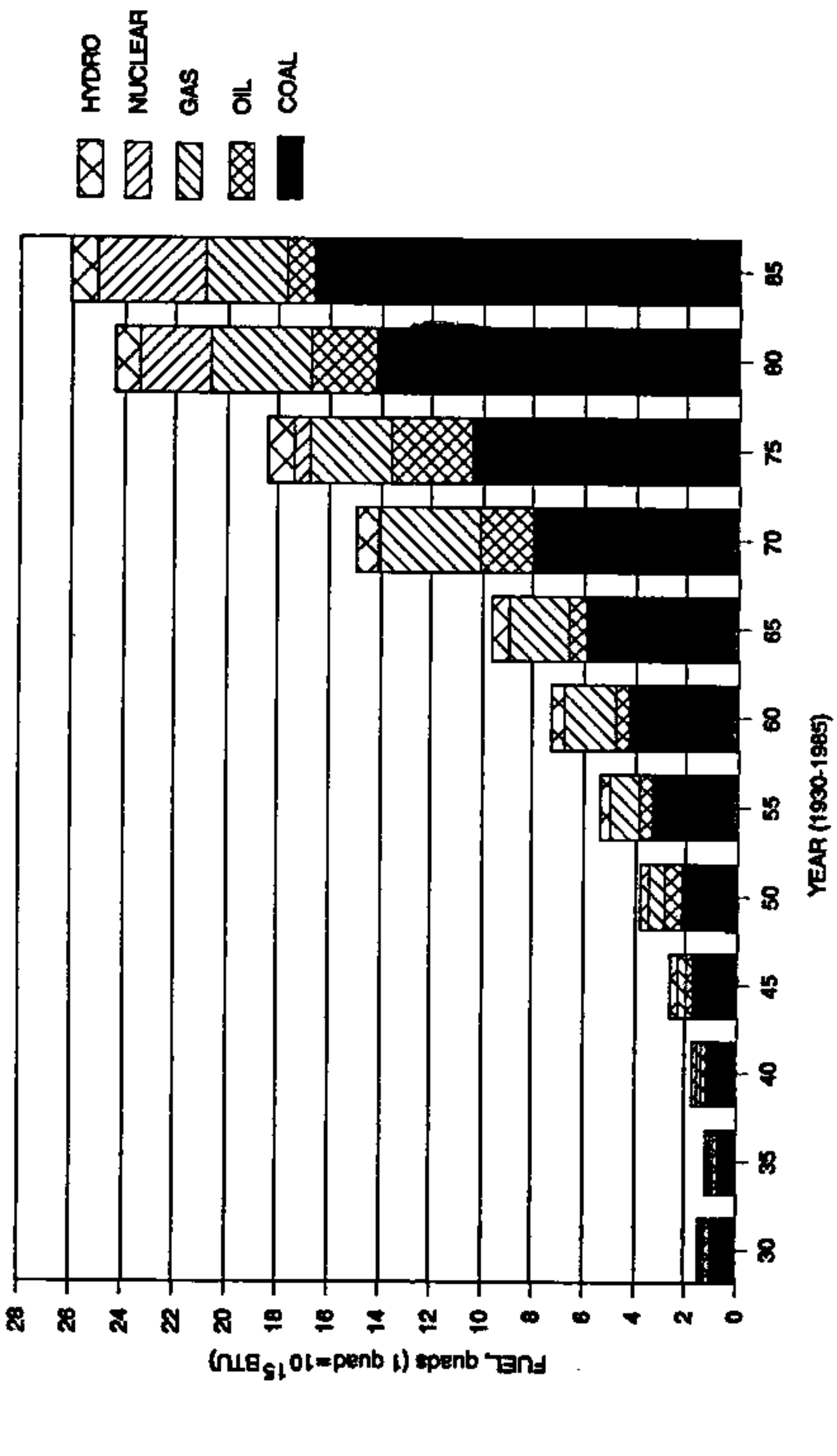

Figure 1. U.S. electrical production history by fuel, 1930-1985.

Table 1: Important Electric Power Plant Pollutants

Pollutant	Health Concern	Environmental Concern	Coal Role
Sulfur dioxide	- Respiratory tract problems. - Permanent harm to lung tissue.	- Acid deposition damage to lakes, streams, and forests. - Visibility.	Coal combustion is dominant source.
Nitrogen oxides	- Respiratory illness and lung damage.	- Acid deposition. - Increased ozone: forest damage.	Coal combustion and autos are major sources.
Airborne particulates	- Eye and throat irritation, bronchitis, lung damage.	- Visibility.	Power plants have diminished in importance.
Carbon dioxide	- Potential major impacts of global climate warming. - Indirect health impacts unknown.	- Destruction of sensitive eco-systems by global warming. - Increased air pollution.	Coal most important fuel due to large use and high carbon/hydrogen ratio.

Table 2: Sulfur Dioxide and Nitrogen Oxide Control Technologies for Coal-Fired Boilers

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial Availability**	Comments
		SO_2/NO_x Retrofit Boiler Systems			
Wet flue gas desulfurization (FGD)	Limestone or lime in water removes SO_2 in a scrubber vessel. Additives may be used to enhance SO_2 removal. A wet waste or gypsum is produced.	70-97	0	Current for new boilers and retrofit.	State-of-the-art for higher S coal and FGD. Certain retrofits difficult.
Dry FGD	Lime in water removes SO_2 in a spray dryer, which evaporates the water prior to the vessel exit. Produces a dry waste.	70-95	0	Current for low to moderate S coal for new boilers. High S coal retrofit, 5 yrs.	Demonstration for high S coal retrofit is necessary, but may be limited to 90% SO_2 removal.
E-SO_x/in-duct injection	Lime and water are injected in a boiler duct and/or ESP*** (E-SO_x) and react with SO_2 similar to a spray dryer.	50-70	0	Pilot scale only. Demonstrations required, 3-7 yrs.	Potentially low cost retrofits. May be site-specific limits.
Limestone injection multistage burners (LIMB)	Low NO_x burners and upper furnace sorbent injection. May use humidification to improve SO_2 cap-	50-70	40-60	Wall-fired, current; T-fired, 3-4 yrs.	T-fired and wall-fired demos complete. Applicable to ≤3% S coal retrofits.

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Table 2: Sulfur Dioxide and Nitrogen Oxide Control Technologies for Coal-Fired Boilers

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial Availability**	Comments
	ture and ESP performance.				
Advanced silicate (ADVACATE)	Several variations. Most attractive: adding limestone to boiler, generating lime. Lime/-fly ash collected in cylone and reacted to generate highly reactive silicate sorbent. Moist sorbent added to downstream duct.	Up to 90	0	Pilot scale only. Demo required, 3-7 yrs.	Most promising emerging retrofit technology. Capable of 90% removal with costs 50% of wet scrubber.
Low NO_x burners, over-fire air modifications	Burner/boiler design controls coal/air mixing to reduce NO_x formation.	0	40-60	Now, new boilers and retrofit.	Additional retrofit demos desirable.
Natural gas reburning	Boiler fired with 80-90% coal. Remaining fuel (natural gas) is injected higher in boiler to reduce NO_x. Air added to complete burnout. Sorbent may be injected to capture SO_2.	Without sorbent, 10-20; with sorbent 50-60	50-85	Demos starting, available in 3 yrs.	May be only combustion NO_x control for cyclones. Sensitive to natural gas price. New or retrofit.

(Continued)

Table 2: Sulfur and Nitrogen Oxide Control Technologies for Coal-Fired Boilers (Continued)

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial Availability**	Comments
Selective catalytic reduction (SCR)	Reacts NO with NH_3 over a catalyst at 500-700°F (260-370°C).	0	80-90	Pilot plant only in U.S., 4 yrs.	Catalyst cost and life main issues. Retrofit or new, if demos in U.S.
		SO_2/NO_x New Boiler Systems			
Atmospheric fluidized-bed combustion (AFBC)	Coal and air are burned in fluidized bed of sorbent which captures SO_2 and limits NO_x formation.	70-90	50-70	Now, for industrial boilers. Utility demo in progress (2-3 yrs).	Primarily for new boilers. Repowering (retrofit) applicability limited.
Pressurized fluidized-bed combined cycle (PFBCC)	Coal burned in a fluidized bed at elevated pressure to capture SO_2 and limit NO_x formation. Gas cleaned and run through gas turbine which generates electricity. Waste heat converted to steam to generate electricity.	90-95	70-80	Pilot plant data. DOE demo initiated, 5-10 yrs.	Primarily for new boilers. Repowering involves replacing the entire boiler.

(Continued)

Table 2: Sulfur and Nitrogen Oxide Control Technologies for Coal-Fired Boilers (Continued)

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial Availability**	Comments
Integrated gasification combined cycle (IGCC)	Gasifier converts coal/air to fuel gas, sulfur removed, and fuel gas burned in a combustion turbine. Waste heat used to generate steam. Electricity generated by both combustion and steam turbines.	95-99	40-95	Cool water demo conducted, economics questionable. Two DOE demos initiated, 5-10 yrs.	See PFBCC comments. Also, economic operation depends on hot fuel gas cleanup and high temperature turbines which are not demonstrated.

*Control efficiency is percent reduction from emission levels for uncontrolled coal-fired power plants.
**Estimated commercialization for some technologies is strongly dependent on successful demonstrations.
***Electrostatic precipitator.

EPA's Air and Energy Engineering Research Laboratory (AEERL) has been actively developing acid rain technology capable of low cost retrofit in anticipation of acid rain legislation. Three of the technologies listed in Table 2 have been actively developed by AEERL: LIMB, E-SO_x, and ADVACATE. LIMB technology, which was recently successfully demonstrated at a 100 MW boiler in Ohio, can be a cost effective choice for certain applications. LIMB appears particularly cost effective for older plants burning low to moderate sulfur coal with lower load factors. E-SO_x is another low cost option capable of 50-60 percent SO_2 removal. It is being pilot tested in Ohio. The ADVACATE technology, a novel concept of duct sorbent injection which uses a calcium silicate sorbent having unique properties of rapid SO_2 and moisture absorption, appears to have substantially lower costs than wet scrubbers for almost all retrofit applications. The ADVACATE sorbent is easily prepared from waste fly ash and lime. EPA hopes to successfully demonstrate this technology so that it can play a role in cost-effectively controlling SO_2 in the time frame associated with the likely Title IV implementation schedule. Figure 2 describes the major cost elements in terms of dollars per ton of SO_2 removed for LIMB, limestone ADVACATE, and conventional limestone FGD (flue gas desulphurization, a process commonly known as "scrubbing") technologies. As shown, FGD is dominated by capital and labor material costs; whereas LIMB is dominated by sorbent costs. The LIMB process utilizes a typically $70 a ton hydrate material; whereas ADVACATE and FGD utilize a lower cost limestone reagent. Note that ADVACATE has an advantage over FGD in all major cost categories, allowing it to cost approximately half that of the wet scrubber. Also note that ADVACATE is one of the few low cost technologies capable of achieving 90 percent SO_2 control.

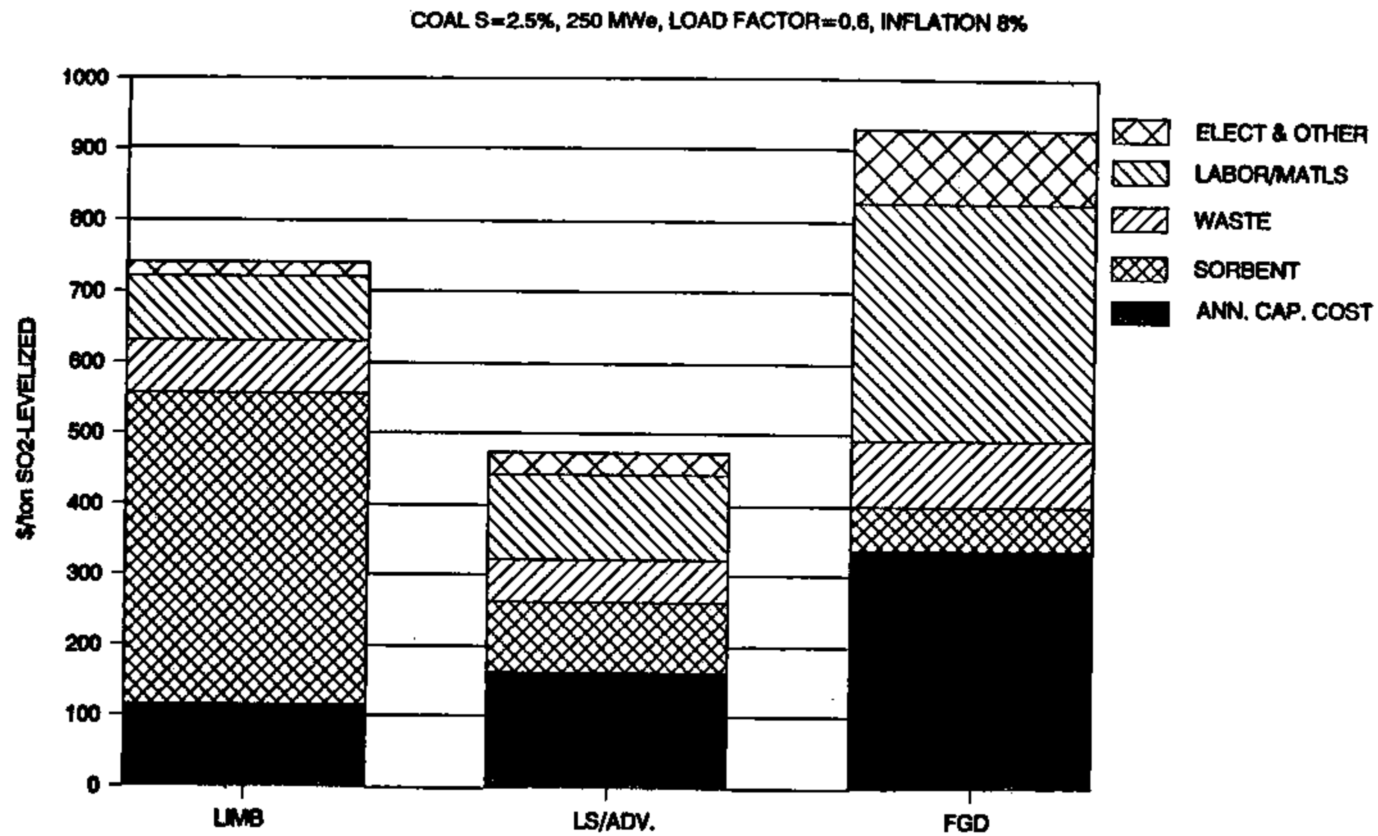

Figure 2. Relative cost of LIMB, limestone ADVACATE, and FGD processes.

To elaborate on the choices facing the utility industry, it is worthwhile to summarize the results of a recent study (Emmel and Maibodi, 1989)[97] sponsored by AEERL. The objective of this study was to significantly improve the accuracy of engineering cost estimates used to evaluate the economic effects of retrofitting SO_2 and NO_x controls to 200 SO_2-emitting coal-fired utility boilers. This project was conducted in several phases. In Phase 1, detailed, site specific procedures were developed and used to evaluate retrofit costs at 12 actual plants. In Phase 2, simplified procedures were developed to evaluate the site specific costs, and these procedures were used to evaluate retrofit costs at 50 plants. In Phase 3 all remaining 138 plant costs were evaluated. This recently published report presents the cost estimates developed for 576 boilers in 188 plants using the simplified procedures. The study evaluated retrofit costs for the following technologies:

- Limestone FGD
- Additive-enhanced limestone FGD
- Lime spray drying FGD
- Physical coal cleaning
- Coal switching and blending
- Low NO_x combustion
- Furnace sorbent injection with humidification (LIMB)
- Duct spray drying
- Natural gas reburning
- Selective catalytic reduction
- Fluidized-bed combustion or coal gasification retrofit

To generate retrofit costs for each plant, a boiler profile was completed using sources of public information. Additionally, boiler design data were obtained from power plants, from a data base maintained by POWER magazine (Elliot, 1985),[98] and aerial photographs obtained from state and federal agencies. The plant and boiler profile information is used to develop the input data for the performance and costs models. To enhance the credibility of cost information, which is almost always controversial, the performance and cost results incorporate recommendations from utility companies and a technical advisory group. This group included the utility industry, FGD vendors, and government agency representatives. All the cost estimates were developed using the integrated air pollution control systems (IAPCS) cost model. The IAPCS model was upgraded to include the technologies being evaluated in this program.

The results of this study confirm that costs of various acid rain retrofit options vary considerably from plant to plant. What might be an economical approach at one plant could be prohibitively expensive at another plant due to unique local conditions, such as lack of space or other site-specific factors. Figures 3-6 summarize some of the results of this study. They describe the costs of retrofit control for coal switching, lime/limestone desulfurization, LIMB (for SO_2 control) and three combustion technologies for NO_x control. Figure 3 summarizes the cost per ton of SO_2 removed for coal switching and blending. Price differentials of both $5 and $15 per ton of coal were assumed in this cost analysis since they bracket the likely differential for many existing boilers in the Eastern U.S. Note that, for about 50 percent of the applicable boilers for a $5 price differential, the levelized cost of control will be substantially less than $1,000 per ton of sulfur removed. (All costs were calculated on a levelized basis; i.e., they were increased over first year costs to take into account likely inflation over the control's lifetime.) However, for boilers already burning relatively low sulfur coal, even this relatively small coal price differential can yield substantially higher cost of controls per ton of sulfur removed. For the higher priced differential, typically for plants far from available low sulfur coal, only 25 percent of the boilers can be controlled at less than $1,000 per ton. Utilities will likely look very closely at the low sulfur coal option which in many cases will likely be the least expensive option.

Figure 4 summarizes the cost per ton of SO_2 removed for lime or limestone FGD technology. As shown, certain plants can be controlled for less than $1,000 a ton; but, for about 75 percent of the plants, costs will be higher than that. For the most expensive 25 percent of boilers, costs will be quite high due primarily to difficulty of retrofit.

Figure 5 summarizes the cost per ton of SO_2 removal for LIMB technology. Two cases are studied corresponding to 50 or 70 percent SO_2 removal from the LIMB/humidification technology. For most cases, this technology is less expensive per ton of SO_2 removed, especially if 70 percent SO_2 removal is achievable for a given plant.

The last figure in this series, Figure 6, summarizes costs per ton of NO_x removed utilizing three low NO_x combustion technologies: low NO_x burners (LNB), natural gas reburning (NGR), and overfire air (OFA), another combustion modification technology. As shown, the combustion technologies LNB and OFA are considerably less expensive than NGR. However, for certain classes of boilers, such as cyclones, NGR may be the only feasible option. Moreover, 75 percent of the boilers can be controlled with a LNB or OFA system for costs below $500 per ton of NO_x removed.

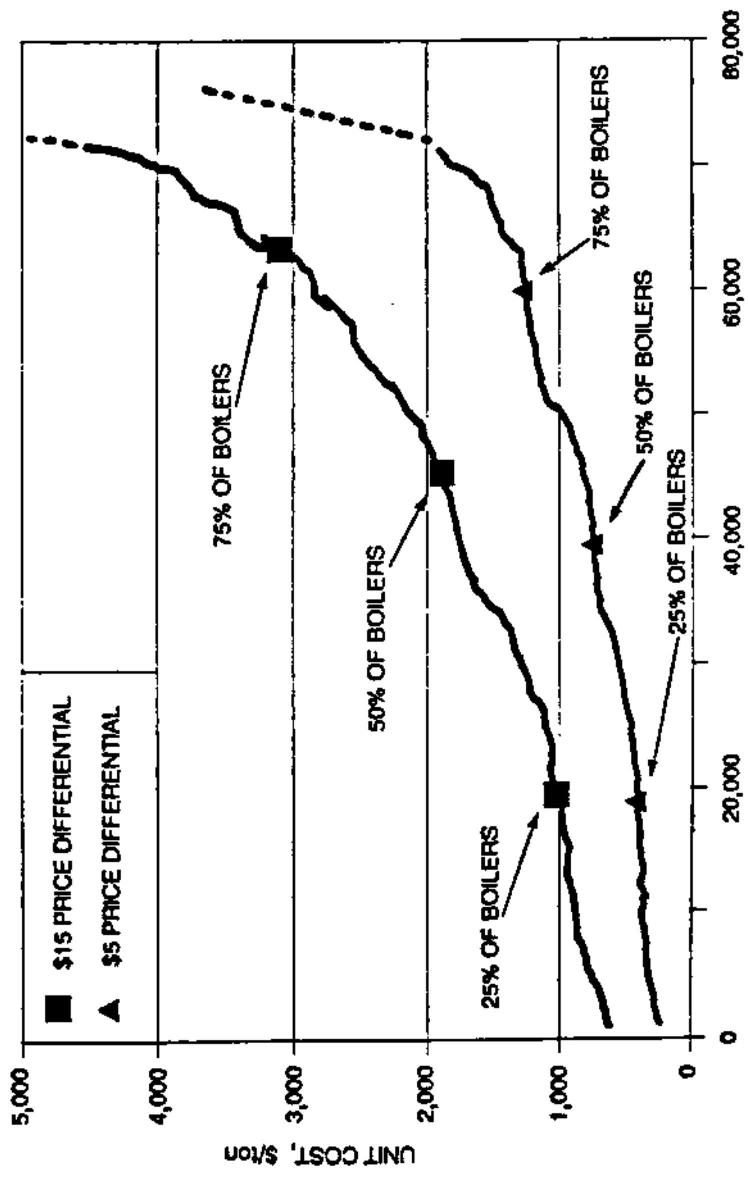

Figure 3. Summary of cost per ton of SO_2 removed results for coal switching and blending.

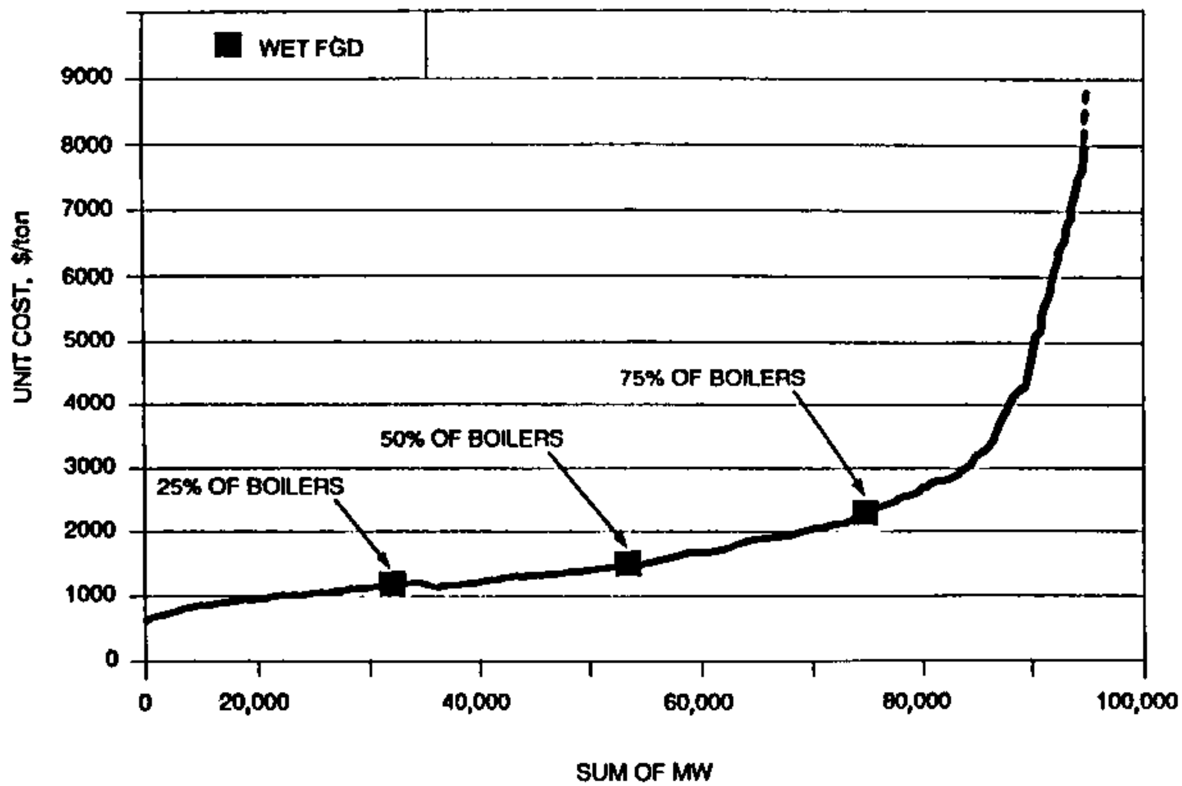

Figure 4. Summary of cost per ton of SO_2 removed results for lime/limestone flue gas desulfurization.

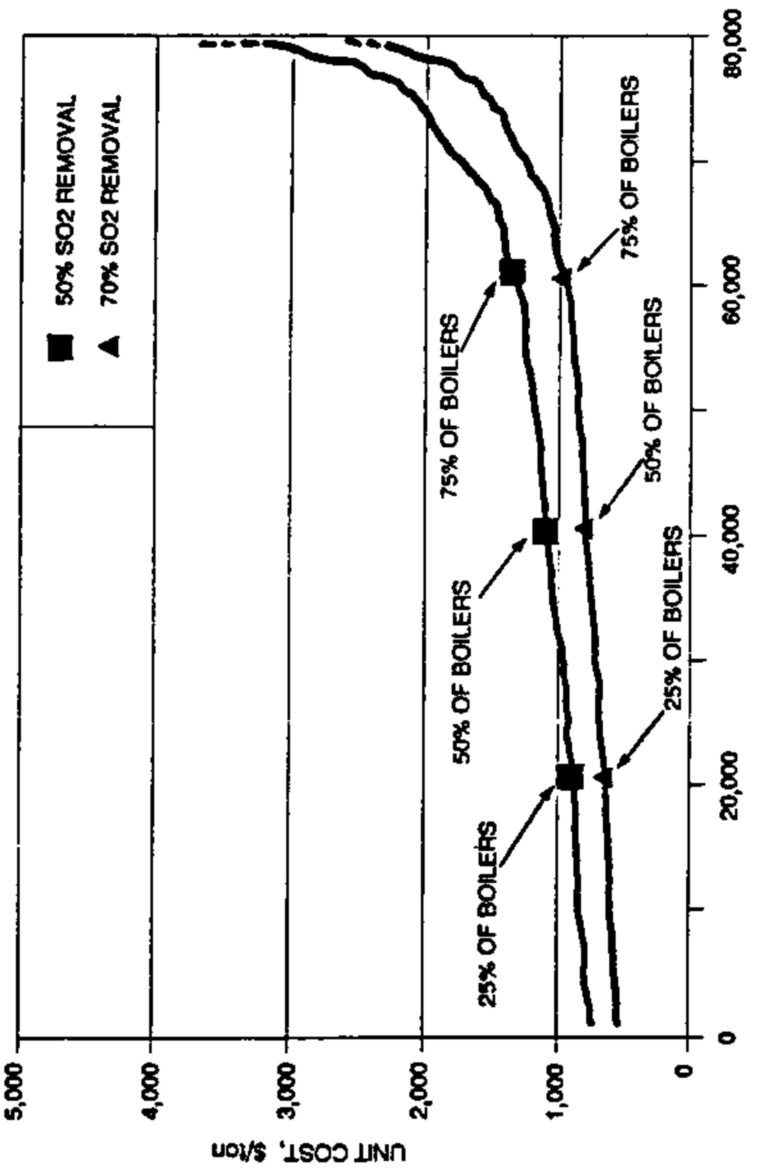

Figure 5. Summary of cost per ton of SO_2 removed for furnace sorbent injection (LIMB).

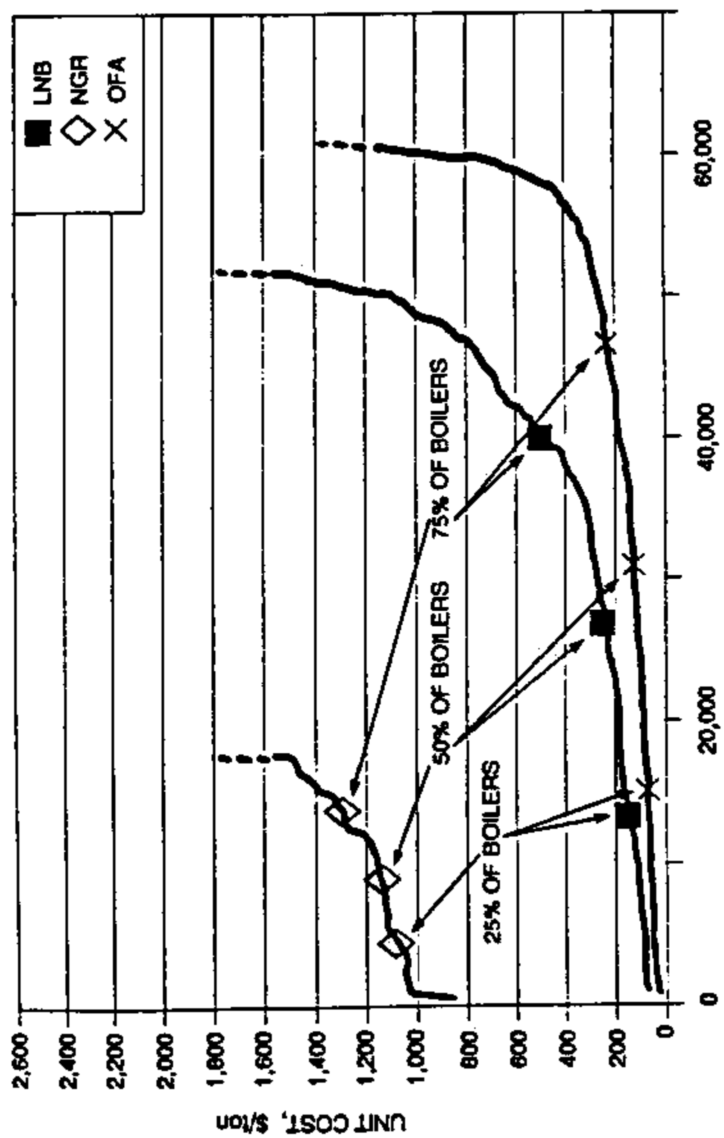

Figure 6. Summary of cost per ton of NO_x removed for low NO_x combustion.

Results of this study should be useful to utilities, states, and others who will likely be making or monitoring the difficult choices of control mandated by the expected acid rain legislation.

In January 1990, the authors of the retrofit study (Emmel and Maibodi) were asked to apply the results of this study to a hypothetical 10 million ton per year SO_2 reduction program (from 1980 emission levels). The objective was to estimate the maximum potential benefit of emerging technologies (i.e., LIMB and ADVACATE) to an acid rain retrofit program.

The methodology involved selecting the lowest cost option for a particular plant, ultimately achieving the required 10 million ton reduction by retrofitting 200 SO_2-emitting plants.

For this analysis, the following limited sets of available control options were assumed:

Cases 1 & 2	*Cases 3 & 4*
Coal Switching/Blending	Coal Switching/Blending
Limestone FGD	Limestone FGD
LIMB (50% removal)	LIMB (50% removal)
	ADVACATE (limestone, 90% removal)

Cases 1 and 3 assumed a low sulfur coal incremental cost of \$5/ton, whereas Cases 2 and 4 assumed a \$15/ton differential. Cases 3 and 4 included the ADVACATE process to estimate the impact of such a technology assuming costs half that of wet FGD and retrofittability similar to that of wet FGD. Note that this is not a demonstrated technology; cost savings should be considered only an upper limit of what might be achievable if successfully demonstrated and freely selected by the utility industry, despite lack of extensive field operating experience.

Figure 7 shows the results of this analysis. For Cases 1 and 2, coal switching, FGD, and LIMB would all play major roles, with coal switching particularly important at the low (\$5 per ton) coal price differential (Case 1). For Cases 3 and 4, ADVACATE would play the major role, essentially displacing all other options for the high (\$15 per ton) coal price differential (Case 4). Maximum possible annual cost savings associated with ADVACATE technology availability are in the order of \$2 billion.

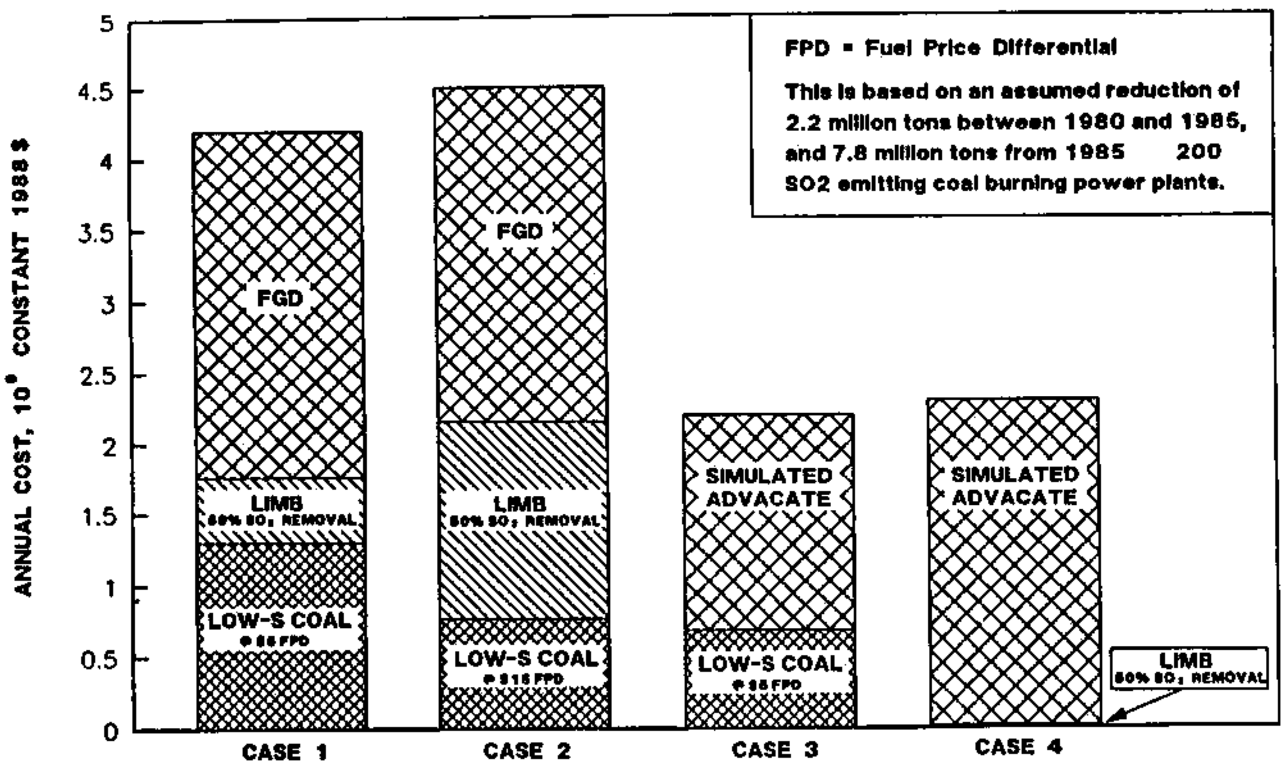

Figure 7. Annual cost of achieving a 10 million ton reduction of SO_2 per year from 1980 emission levels in the eastern region of the United States.

4. Conclusions

The utility industry will likely face a major environmental challenge in implementing the new acid rain provisions over the next 10 years. Utilities will likely be able to select the most cost-efficient option from available alternatives: coal switching, wet FGD, and such emerging technologies as LIMB and possibly ADVACATE.