TECHNOLOGICAL OPTIONS FOR ACID RAIN CONTROL

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ABSTRACT

Compliance with Title IV of the Clean Air Act Amendments (CAAA) of 1990 will require careful scrutiny of a number of issues before selecting control options to reduce sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions. One key consideration is the effect of fuel switching or control technology upon the existing dust collector, with particular emphasis on potential emissions of air toxics. A number of likely SO_2 and NO_x retrofit technologies and estimated costs are presented, along with results of retrofit case studies. New hybrid particulate controls are also being developed to meet future requirements.

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BACKGROUND

Title IV of the Clean Air Act Amendments (CAAA) of 1990 mandates reductions in acid rain precursors as follows:

- o By January 1, 1995 (deadline for Phase I) 5 million tons* of SO_2 will be reduced by reducing allowable emissions to 2.5 pounds per million Btu heat input ($lb/10^6$ Btu) for 110 of the largest emitting stations.
- o By the year 2000 (deadline for Phase II), virtually all power plants greater than 25 MW_e must meet a 1.2 $lb/10^6$ Btu SO_2 emission limit.
- o NO_x emissions are to be reduced by 1 million tons annually by the 110 Phase I plants, with specific emission limits for wall-fired (0.50 lb $NO_x/10^6$ Btu) and tangentially fired (0.45 lb $NO_x/10^6$ Btu) units.
- o SO_2 emissions are capped after the year 2000.

A number of allowances, exceptions, and issues involving compliance and emissions trading are acknowledged; however, this paper focuses on the technical options currently available to meet the above requirements. There is a danger, however, in isolating Title IV from the balance of the CAAA. Prudent decision-making must also include future requirements in air toxics (Title III), ozone-nonattainment, and carbon dioxide (global warming) issues. For example, conventional flue-gas desulfurization (FGD) systems, low-NO_x burners, or fuel switches which reduce unit efficiency may appear imprudent in the near future. Current technology choices which do not consider impacts on air toxics control or visibility issues may also be shortsighted. Solid waste issues not even mentioned in the CAAA may become critical at the state and local levels. In certain cases water consumption may also force technology decisions.

CANDIDATE TECHNOLOGIES AND COSTS

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 U.S. 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 1 describes current and

(*) Readers more familiar with metric units may use the conversion factors at the end of this paper to convert to that system.

emerging technologies for retrofit SO_2 and NO_x control.[1] Combined 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 tables briefly describe 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.

A considerable number of combined SO_2/NO_x technologies are not listed in Table 2, primarily due to the complexity and economic factors which make their choice unlikely for retrofits. These include atmospheric fluidized bed combustion, pressurized fluid bed/combined cycle combustion, and integrated gasification combined cycle technologies which are 5 to 10 years from commercial availability. Table 3 lists a number of novel combined SO_x/NO_x technologies which are near commercial use or demonstration today, but not economically attractive for acid rain retrofit.[2]

Although many decisions have already been made regarding Phase I and Phase II retrofits, essentially the decisions have been to use either wet flue gas desulfurization or lower sulfur fuels. We interpret the latter choice to be "deferred decision" on technology in that the utility may elect to use lower sulfur fuel until a more cost effective strategy/technology becomes commercially demonstrated or until the low-sulfur fuel strategy becomes more costly than available technology due to fuel price increases or air toxics legislation (discussed at the end of this paper).

The technologies shown in Tables 1 and 2 include three distinct technologies developed by the Air and Energy Engineering Research Laboratory (AEERL)--Limestone/Lime Injection Multistage Burner (LIMB), E-SO_x, and ADVACATE.

LIMB technology (Figure 1), which has been demonstrated at 60+% SO_2 removal and 45% NO_x control on a 105 MW_e wall-fired unit, is currently being demonstrated on a 180 MW_e tangential unit in Yorktown, Virginia.[3, 4] LIMB, as with most sorbent injection technologies, appears cost-effective with decreasing size, coal sulfur, and plant life expectancy compared to conventional FGD.

The E-SO_x technology has been evaluated at a 5 MW_e scale and appears capable of 50-60% SO_2 removal at a very low ($40/$kW_e$) capital cost, but is limited to larger electrostatic precipitators (>40 m^2/m^3/min specific collection area).[5, 6]

The ADVACATE technology (Figure 2) is perhaps the most competitive with conventional FGD technology, offering 90% SO_2 control at a lower cost.[7] To date ADVACATE has very limited field operation on a 10 MW_e pilot basis, but is being strongly considered for demonstration in the U.S. and Eastern Europe.

Table 2 includes natural gas reburning technology for NO_x which has been promoted by AEERL through demonstration at a 108 MW_e cyclone unit in Ohio[8] and is currently operating on a 300 MW_e wet-bottom, wall-fired boiler in the Ukraine. In both cases 50 to 65% NO_x control is being achieved over baseline coal operation. Technical papers on both demonstrations will be presented at the 1993 NO_x Control Symposium, co-sponsored by AEERL and the Electric Power Research Institute, May 23-27, 1993 in Miami Beach, Florida.

One major cost study on retrofit FGD technologies has been completed as reflected in Figures 3 and 4.[9] Figure 3 shows the results of an evaluation of 22 FGD technologies for capital investment retrofit cost when applied to a 300 MW_e plant burning 2.6% sulfur coal. Typical conventional wet FGD costs (Figure 3) average \$200/kW, while a number of dry sorbent injection systems including LIMB (FSI) and ADVACATE (ADV) are between \$50 and \$100/kW, and are generally applicable to older, lower-utilized plants. Figure 4 shows corresponding levelized annual costs in \$/ton of SO_2 removed. Here the wet FGD systems at \$500/ton SO_2 fare somewhat better than the lower capital dry systems except for two noteworthy exceptions--the Lurgi circulating fluid bed (CFB) absorber at \$400/ton SO_2 and ADVACATE (ADV) at less than \$300/ton SO_2. This is due largely to their inherently higher SO_2 removal capability (90%) than other dry removal systems (50-60%).

Costs of retrofit NO_x control technologies have been examined by EPA's Office of Air Quality Planning and Standards and are summarized in Table 4.[10] The wide range of costs in the combustion modification technologies reflects the number of issues encountered in altering the air/fuel delivery systems within a boiler. Since this study focuses on one size boiler, results are to be interpreted in a general sense. For Figures 3 and 4 and Table 4, refer to the glossary at the end of this paper for descriptions of acronyms.

RETROFIT CASE STUDIES

To elaborate on the choices facing the utility industry, it is worthwhile to summarize the results of a recent study sponsored by AEERL.[11] 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 the top 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:

- o Limestone FGD
- o Additive-enhanced limestone FGD
- o Lime spray drying FGD

- o Physical coal cleaning
- o Coal switching and blending
- o Low NO_x combustion
- o Furnace sorbent injection with humidification (LIMB)
- o Duct spray drying
- o Natural gas reburning
- o Selective catalytic reduction

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, and aerial photographs, obtained from state and federal agencies. The plant and boiler profile information was 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.[12] 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 5-8 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 5 summarizes the cost per ton of SO_2 removed for coal switching and blending. Coal price differentials (new vs. existing coal) 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% 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-S coal, even this relatively small coal price differential can yield substantially higher cost of controls per ton of sulfur removed. For the higher coal price differential, typically for plants far from available low sulfur coal, only 25% of the generating capacity in the 200 plant study 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 be the least expensive option.

Figure 6 summarizes the cost per ton of SO_2 removed for lime or limestone FGD technology. Two options were examined: 1) a standard system meeting new source performance standards with at least one absorber per boiler and maximum absorber capacity of 125 MW and one spare absorber per boiler, and 2) a low cost option with a maximum absorber capacity of 250 MW and no spare absorber. As shown, certain plants can be controlled for less than $1,000 a ton; but, for most, costs will be higher than that. For the most expensive, 25% controlled capacity, costs will be quite high, due primarily to difficulty of retrofit.

Figure 7 summarizes the cost per ton of SO_2 removal for LIMB technology. Two cases are studied corresponding to 50 or 70% SO_2 removal by the LIMB/humidification technology. For most cases, this technology is less expensive than wet FGD per ton of SO_2 removed, especially if 70% SO_2 removal is achievable for a given plant.

The last figure in this series, Figure 8, 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 natural gas reburning. However, for certain classes of boilers, such as cyclones, reburning may be the only feasible option. Also note that 75% of the generating capacity can be controlled with a low NO_x burner or overfire air system for costs below $500 per ton of NO_x removed.

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 Title IV of the CAAA of 1990.

In January 1990, the authors of the retrofit study (Reference 11) 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 ton reduction by retrofitting the top 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 those of wet FGD and retrofittability similar to that of wet FGD. Note that ADVACATE is not a demonstrated technology; cost savings should be considered only as an upper limit of what might be achievable if successfully demonstrated and freely selected by the utility industry, despite lack of extensive field operation experience.

Figure 9 shows the results of this analysis. For Cases 1 and 2, coal switching, FGD, and LIMB would all play 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.

OTHER CONSIDERATIONS

Perhaps overlooked in selecting control strategies for SO_2, NO_x, and air toxics control is the impact on the particulate matter collector. If early indications of massive fuel switching for CAAA compliance are correct, then profound effects upon operation of electrostatic precipitators (ESPs) can be anticipated. Existing ESPs are the dominant particulate matter control technology on U.S. utility boilers and are sensitive to the physical properties of flue gas and fly ash, especially particle size distribution and loading, electrical resistivity, and cohesivity. With the exception of wet FGD technology, which is usually located downstream of the ESP, all other NO_x and SO_x retrofit systems alter either gas or particle characteristics, or both, in ways which almost always degrade ESP performance.

In addition toxic air pollutants mentioned earlier add to the dust collection concerns because: (1) most of the heavy metals are contained in the coal ash, (2) the fine particulate matter emanating from the boiler presents the highest concentration of metals, (3) the most volatile elements--mercury, arsenic, selenium, and halogen compounds--may remain in the gas phase, but largely condense out into fine particulate matter, (4) scrubbing systems remove volatile trace metals efficiently except for mercury, and (5) Western low-sulfur coals may exhibit significantly higher concentrations of heavy metals than Eastern coals.[13]

If the objective is to remove toxics from the air, then a variety of options appear to be available in the choice and arrangement of back-end, flue-gas cleaning systems. To illustrate: most experts conclude that a fabric filter is superior to an ESP for collecting fine particulates, although tradeoffs may exist in the form of pressure drop across the bags, cost, significant releases of fly ash because of bag failure, etc. Wet FGD systems provide insurance against air-toxics emissions, except perhaps mercury.

Because of these concerns at least two new hybrid particulate controls have been developed. The COHPAC system, being evaluated by the Electric Power Research Institute, adds a small pulse-jet fabric filter immediately downstream of an existing ESP as a retrofit option.[14] A long-term goal is to eventually develop a hybrid system where the fabric filter is physically located inside the existing ESP housing. AEERL has recently patented and is currently licensing a hybrid system, Retrofit Electrostatic Filtration.[15] Figure 10 illustrates this concept where the last ESP stage is replaced by an electrostatically augmented fabric filter (ESFF) array. Because particles tend to follow electrostatic field lines rather than gas flow, the fabric penetration is one to two orders of magnitude lower than, and pressure drops are only a fraction of that for, conventional fabric filtration.[16] The better features of ESP and fabric filtration are combined--no reentrainment or sneakage, low pressure drops, and one to two orders of magnitude more efficient dust collection.

CONCLUSIONS

The utility industry will likely face major challenges in implementing acid rain provisions through the year 2000, and perhaps beyond 2000 as economics change and new technologies become available. In anticipation of the need for cost-effective technologies, AEERL has supported development of three SO_2 retrofit technologies, one NO_x retrofit technology, and a novel improved dust collection technology to meet these needs. As implementation of strategies takes place and new problems arise, AEERL will continue to sponsor research to minimize the cost of compliance.

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GLOSSARY

FGD Terminology (Figures 2, 3, and 4)

CSTR	Continuous Stirred Tank Reactor
LSFO	Limestone Forced Oxidation
LSWS	Limestone Wet Scrubbing
LSINH	Inhibited Oxidation

LSDBA	Dibasic Acid Enhanced Limestone Scrubbing
CT121	Chiyoda 121 Limestone FGD
PURE	Pure Air (Mitsubishi) FGD
MGL	Magnesium Enhanced Lime FGD
BSAF	Bischoff-Essen Limestone FGD
S-H	Saarberg-Hoelter Limestone FGD (Formic Acid Buffer)
KRC	Noell-KRC/Research Cottrell Double Loop FGD
NSP	Northern States Power Bubbler Scrubber
LDA	Lime Dual Alkali
LSDA	Limestone Dual Alkali
LSD	Lime Spray Drying
LIFAC	Tampella LIFAC (Furnace Injection and Spray Chamber)
CFB	Lurgi Circulating Fluid Bed Absorber
FSI	Furnace Sorbent Injection (LIMB)
EI	Economizer Injection
DSI	Duct Sorbent Injection
DSD	Duct Spray Drying
ADV	ADVACATE (ADVAnced SiliCATE)

NO_x Terminology (Table 4)

OFA	Overfire Air
LNB	Low-NO_x Burner
NGR	Natural Gas Reburning
CCOFA	Close-Coupled Overfire Air
SOFA	Separate Overfire Air

Metric Equivalents

1 Btu = 1.056 kJ
1 lb = 0.454 kg
1 ton = 907.2 kg

Table 1. SO_2 and NO_x Control Technologies for Coal-Fired Boilers

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial Availability**	Comments
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.
Advanced silicate (ADVACATE)	Several variations. Most attractive: adding limestone to boiler, generating lime. Lime/flyash collected in cylone and reacted to generate highly reactive silicate sorbent. Moist sorbent added to downstream duct.	Up to 90	0	Pilot scale only. Demonstrations required, 3-7 yrs.	Most promising emerging retrofit technology. Capable of 90% removal with costs 50% of wet scrubber.
Low NO_x burners, overfire air modifications	Burner/boiler design controls coal/air mixing to reduce NO_x formation.	0	40-60	Now, new boilers and retrofit.	Additional retrofit demonstrations desirable.

(Continued)

Table 1. SO_2 and NO_x 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 demonstrations in U.S.
Selective non-catalytic reduction (SNCR)	Reacts NO with NH_3 in furnace at 1400-1830°F (760-1000°C)	0	30-60	Several demonstrations completed.	N_2O generation, NH_3 slip, and bisulfate fouling of air heater are issues.

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

Table 2. Combined SO_2/NO_x Control Technologies for Coal-Fired Boilers

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial Availability**	Comments
Limestone injection multistage burners (LIMB)	Low NO_x burners and upper furnace sorbent injection. May use humidification to improve SO_2 capture and ESP performance.	50-70	40-60	Wall, current; T-fired, 2 yrs.	T-fired wall-fired demonstration complete. Applicable to $\leq$3% S coal retrofits.
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	50-60	Demonstrations in progress.	May be only combustion NO_x control for cyclones. Sensitive to natural gas price. New or retrofit.

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

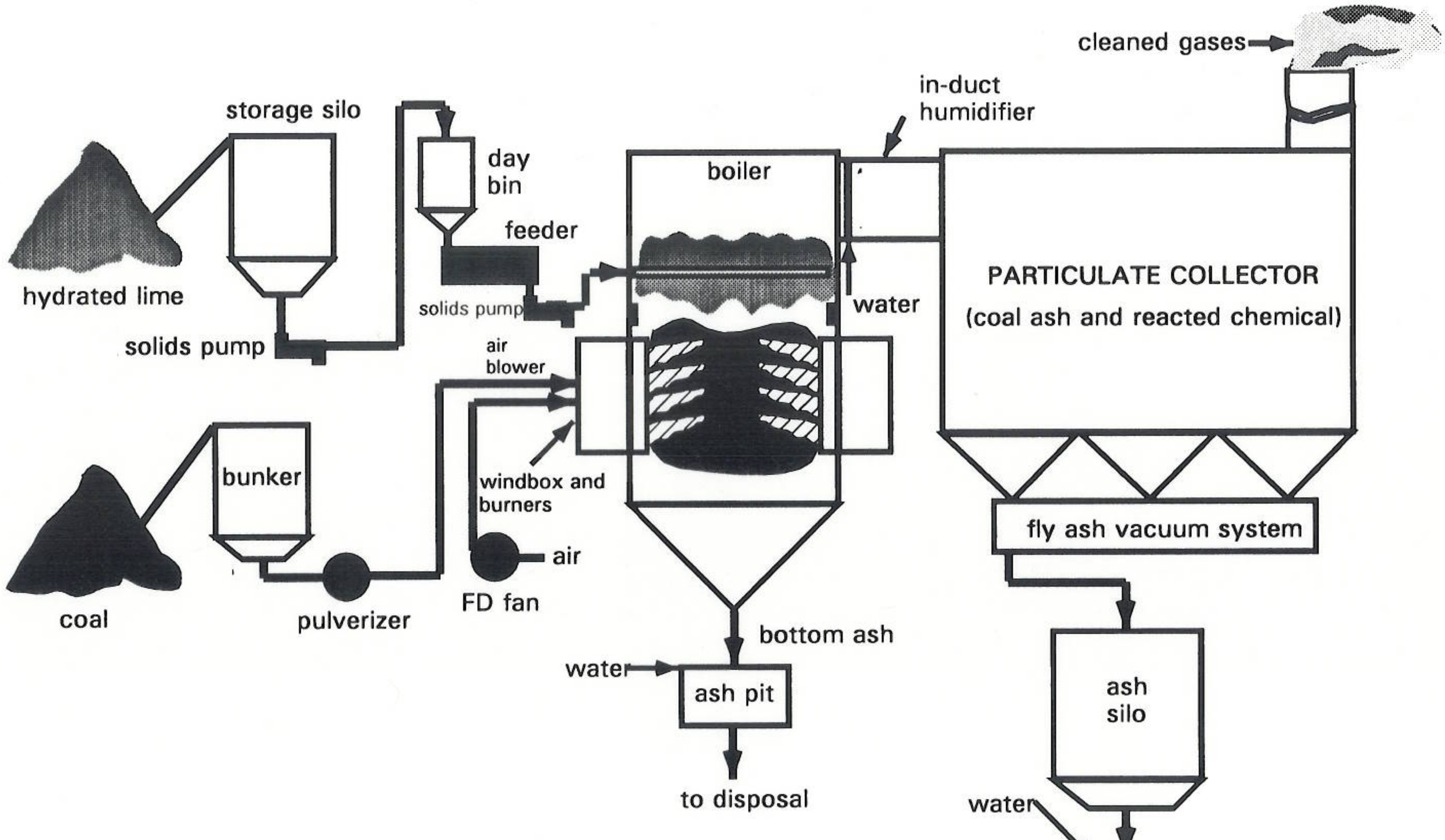
Table 3. Combined SO_2/NO_x Technologies Near Commercialization

Technology	Description	Control, % SO_2	Control, % NO_x	Commercial Status/Comments
SNRB	NH_3 and lime/sodium injection upstream of catalyst-coated baghouse	90	90	5 MW_e pilot plant in operation
NO_xSO	SO_2/NO_x absorption on alumina in fluid bed reactor	90	90	5 MW_e pilot plant in Clean Coal Technology program
WSA-SNO_x	Catalytic reduction of NO and oxidation of SO_2 in two stages. Sulfuric acid recovery	95	90	35 MW_e pilot in CCT program; 1 unit in Denmark
$NONO_x$	Ozone/NH_3 promoted absorption of SO_2/NO_x in wet scrubber	95	75-95	Commercial construction in Europe
Activated char	NH_3 injection and absorption of SO_2/SO_3 on char; NO reduction	90	70	Operational on 3 plants in Europe, 1 in Japan
$DESONO_x$	One step variant of WSA-SNO_x above	85	80	20 MW_e demo operating in Germany
Amine absorption	Amine absorption of SO_2 and NO_x followed by regeneration; acid production	90+	90+	Several vendors/processes; pilot-scale systems in operation
Ferrous chelate additive	Ferrous chelate added to magnesium/calcium FGD solubilizes NO	90	30-70	3 MW_e pilot plant in operation

Table 4. Retrofit NO_x Control Costs for Coal-Fired 200 MW_e Boiler

Boiler Firing Type	NO_x Control Technology[a]	Uncontrolled NO_x Level ($lb/10^6$ Btu)	Estimated Range in NO_x Control Levels ($lb/10^6$ Btu)	Control Costs: Total Capital Requirement ($/kW)	Control Costs: Levelized Busbar (mills/kWh)	Control Costs: Cost Effectiveness ($/ton)
Wall-firing	OFA	0.95	0.70 - 0.80	20	0.49 - 0.75	410 - 1,100
	LNB	0.95	0.45 - 0.60	20	0.43 - 0.69	160 - 450
	LNB + OFA	0.95	0.35 - 0.55	40	0.88 - 1.7	270 - 800
	NGR	0.95	0.40 - 0.50	42	2.1 - 2.9	710 - 1,200
Tangential-firing	LNB w/CCOFA	0.60	0.40 - 0.45	24	0.52 - 1.0	490 - 1,270
	LNB + SOFA	0.60	0.30 - 0.45	30	0.67 - 1.3	420 - 1,590
	NGR	0.60	0.25 - 0.35	42	2.1 - 2.9	1,110 - 2,180
Cyclones	NGR	1.28	0.50 - 0.70	42	2.1 - 2.5	500 - 800
Wall-firing	SNCR	0.95	0.50 - 0.65	18	1.9 - 3.0	590 - 1,100
	LNB + SNCR	0.60	0.35 - 0.45	18	1.0 - 1.4	760 - 1,680
	SCR	0.95	0.15 - 0.25	192	7.0 - 12	1,650 - 3,220
	LNB + SCR	0.60	0.10 - 0.20	148 - 192	5.1 - 12	2,100 - 4,970
Tangential-firing	SNCR	0.60	0.30 - 0.40	18	1.0 - 1.4	630 - 1,260
	LNB + SNCR	0.45	0.25 - 0.35	18	0.84 - 1.2	790 - 2,200
	SCR	0.60	0.10 - 0.15	192	7.0 - 12	2,600 - 4,970
	LNB + SCR	0.45	0.05 - 0.10	148 - 192	5.1 - 12	2,200 - 6,370

[a] Technologies are defined in Glossary.



PROCESS CHEMISTRY

$$2\ CaO + 2\ SO_2 + O_2 \longrightarrow 2\ CaSO_4$$

Figure 1. LIMB Process.

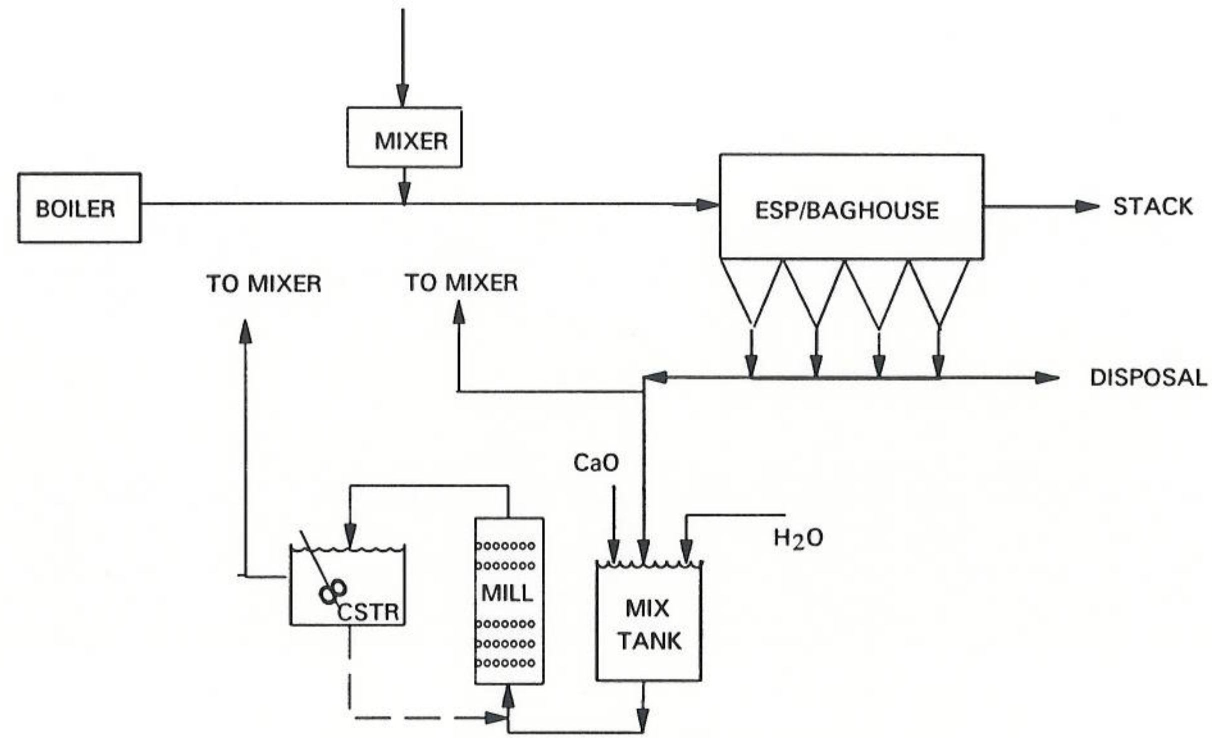
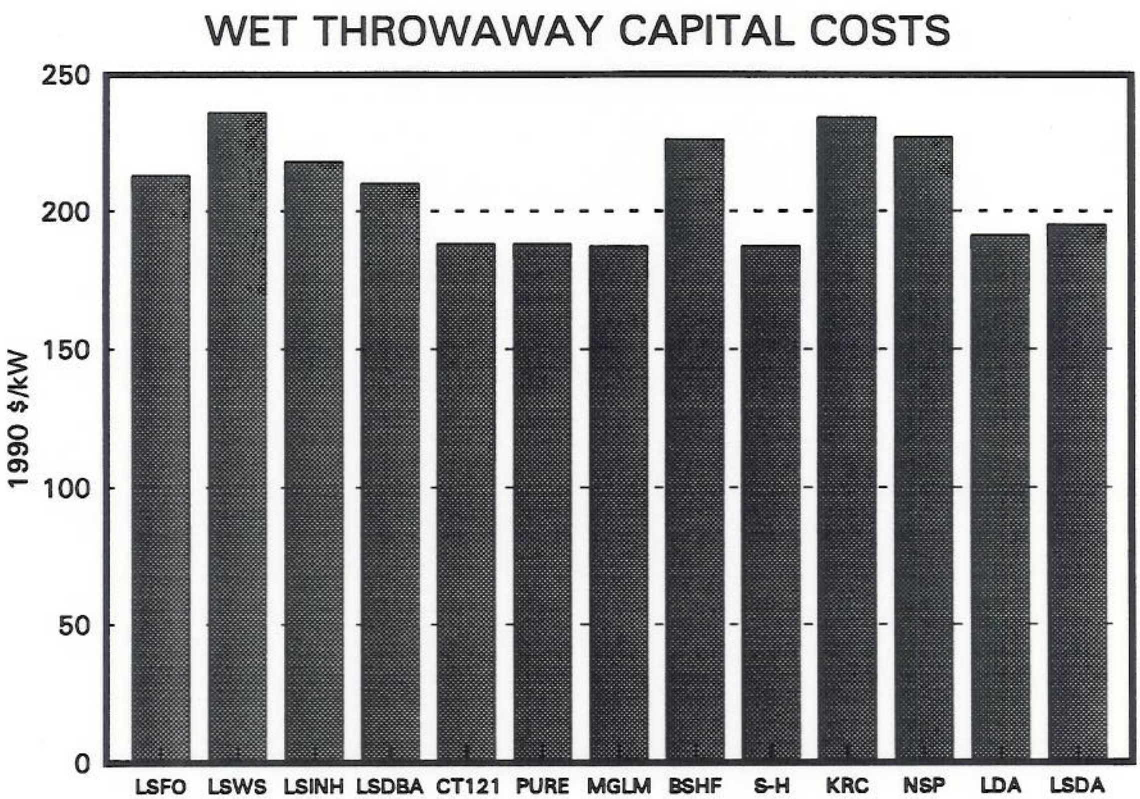


Figure 2. ADVACATE Process.



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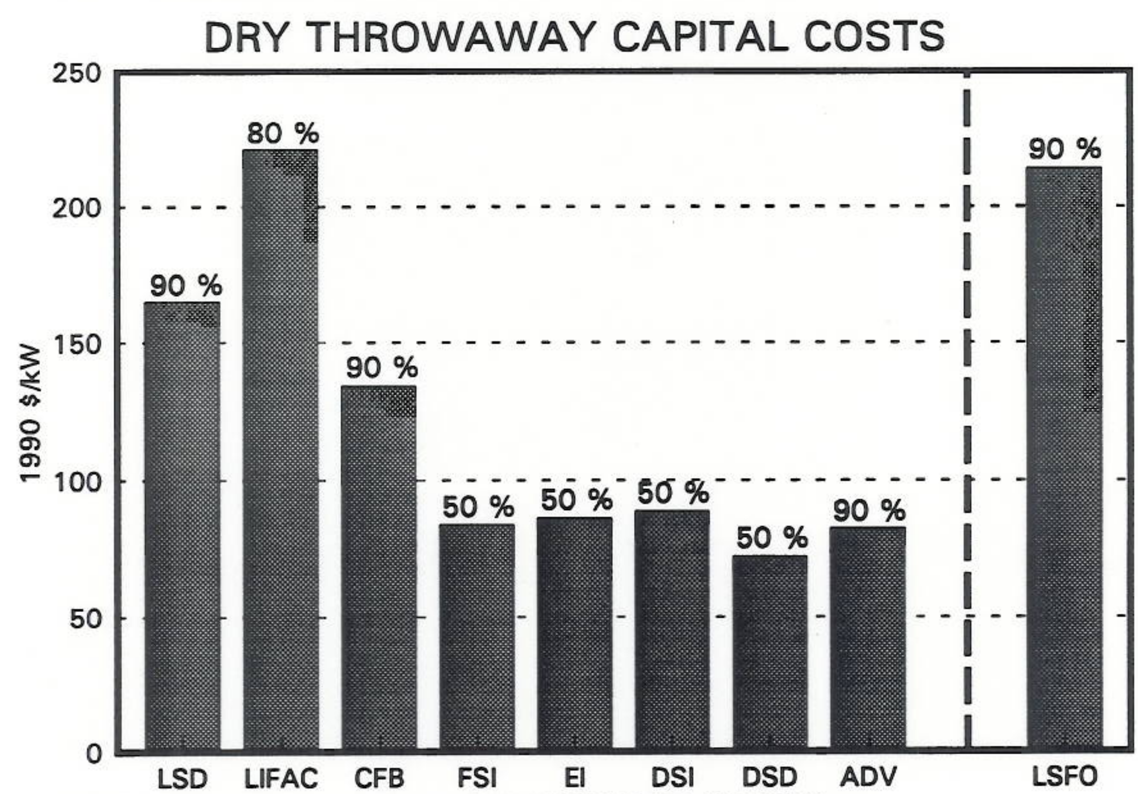

VALUES ESTIMATED FROM ORIGINAL DRAWINGS; TECHNOLOGIES DEFINED IN GLOSSARY

Figure 3. Flue gas desulfurization capital costs, retrofit, 300 MWe, 2.6% S.

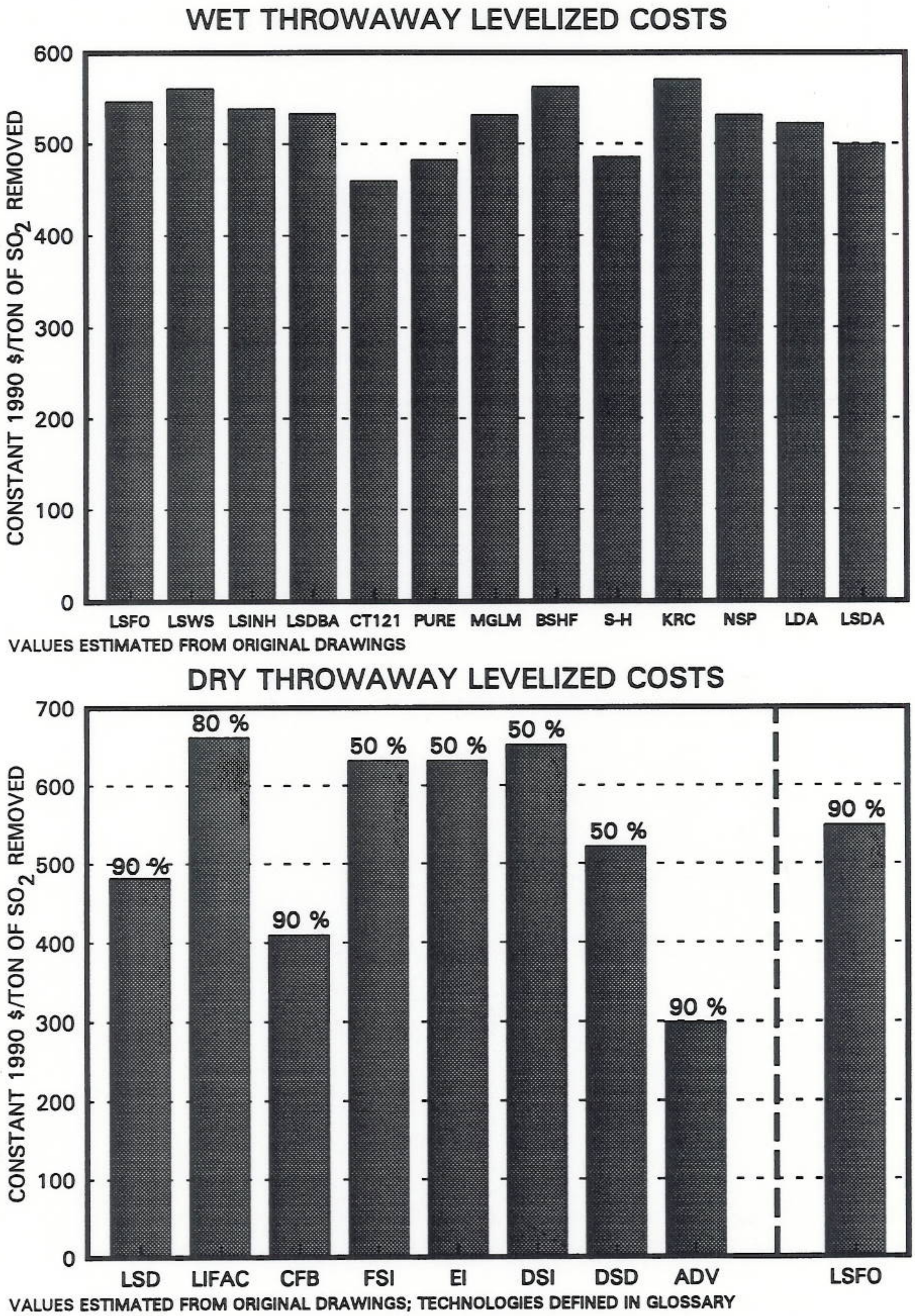

Figure 4. Flue gas desulfurization levelized annual costs, retrofit, 300 MW_e, 2.6% S.

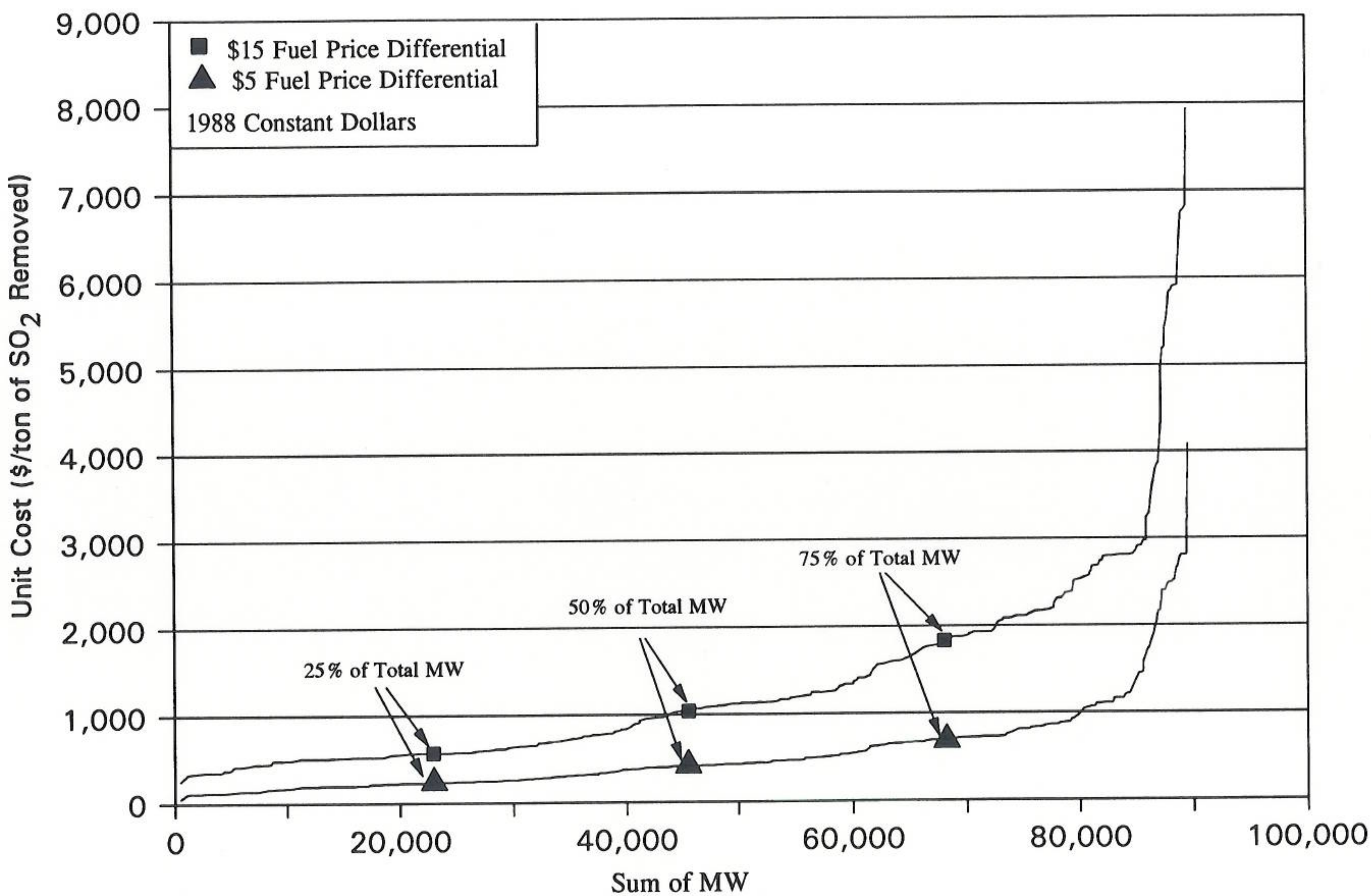

Figure 5. Summary of cost per ton of SO_2 removed results for coal switching and blending.

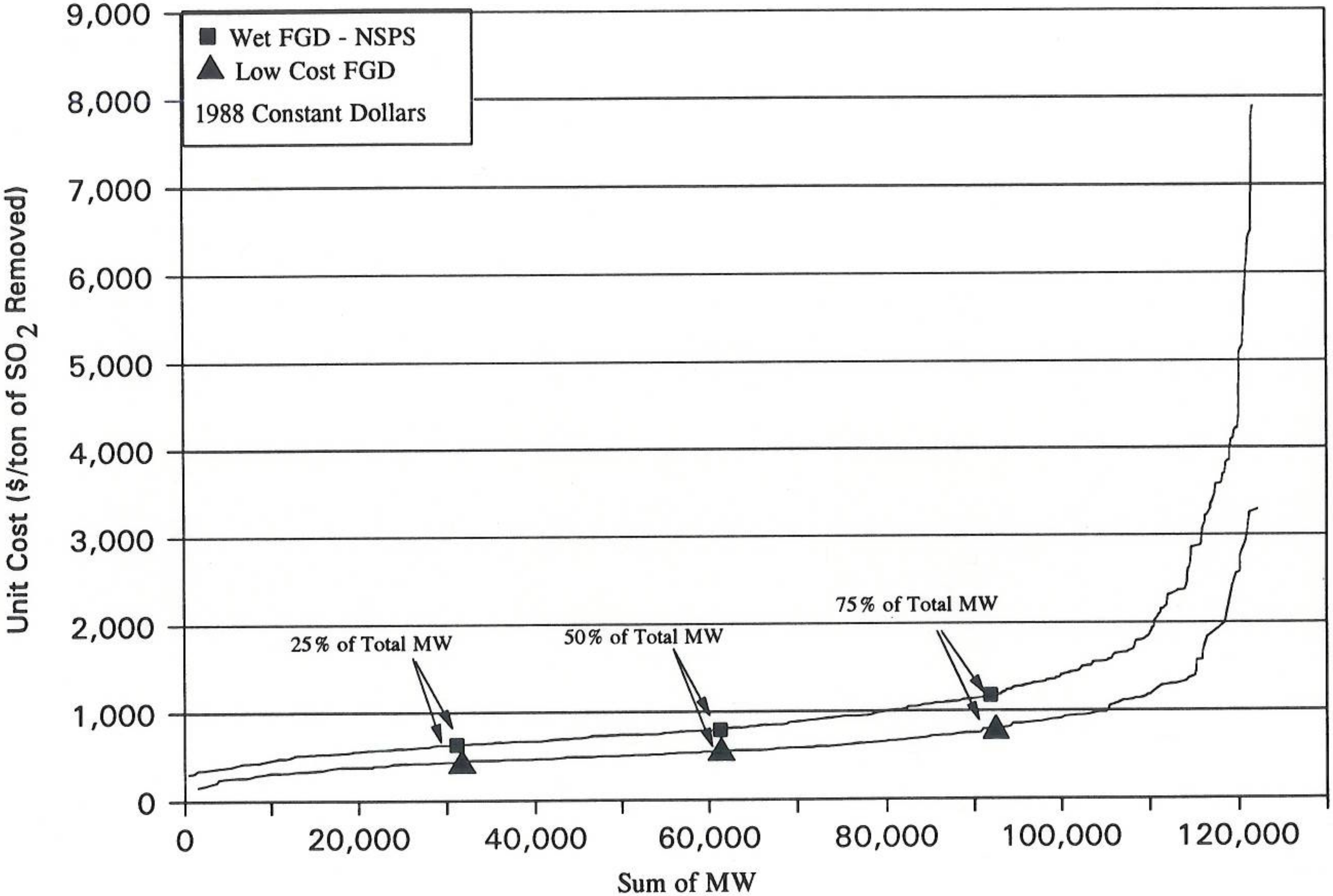

Figure 6. Summary of cost per ton of SO_2 removed results for lime/limestone flue gas desulfurization.

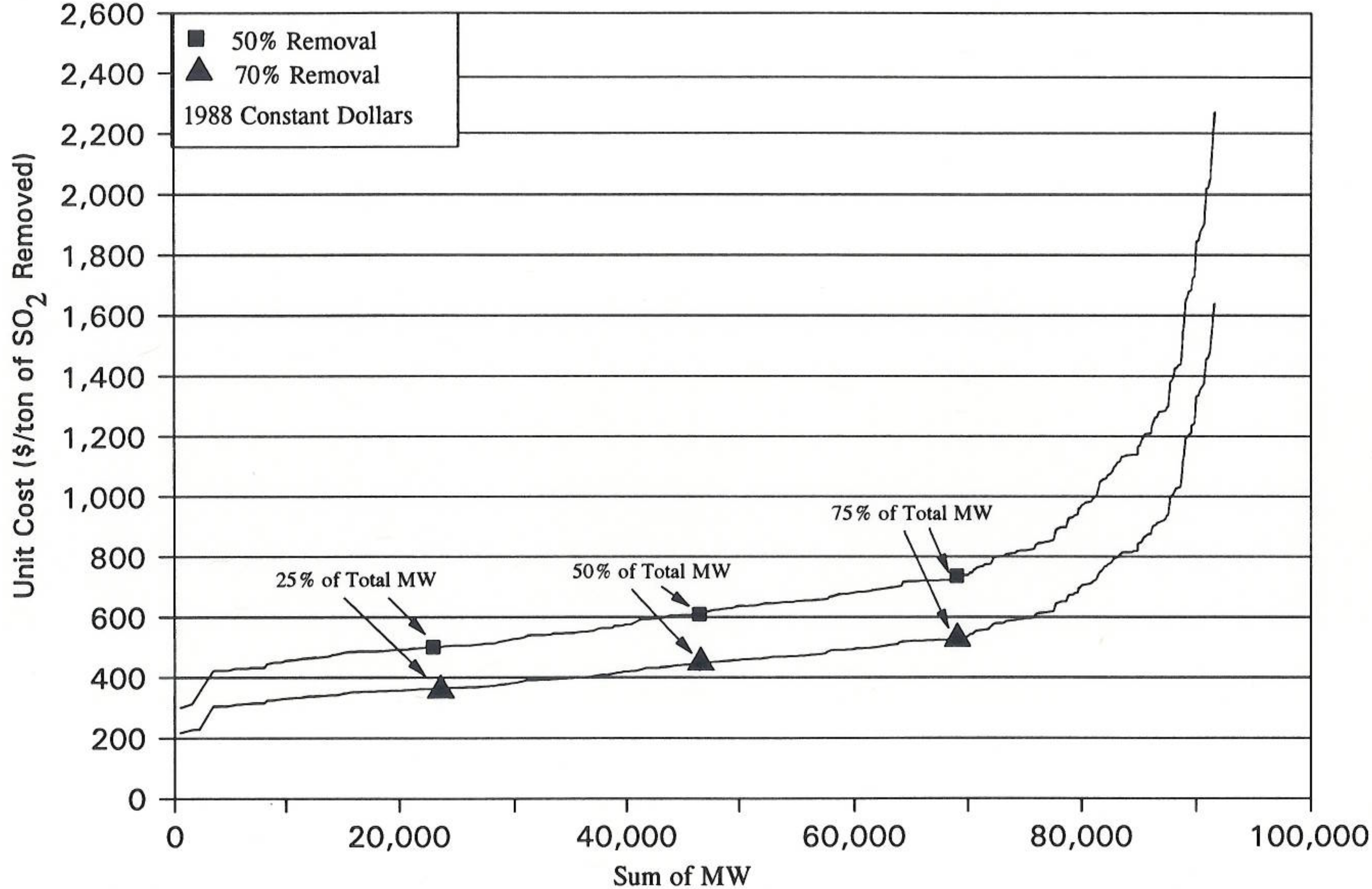

Figure 7. Summary of cost per ton of SO_2 removed results for furnace sorbent injection (LIMB).

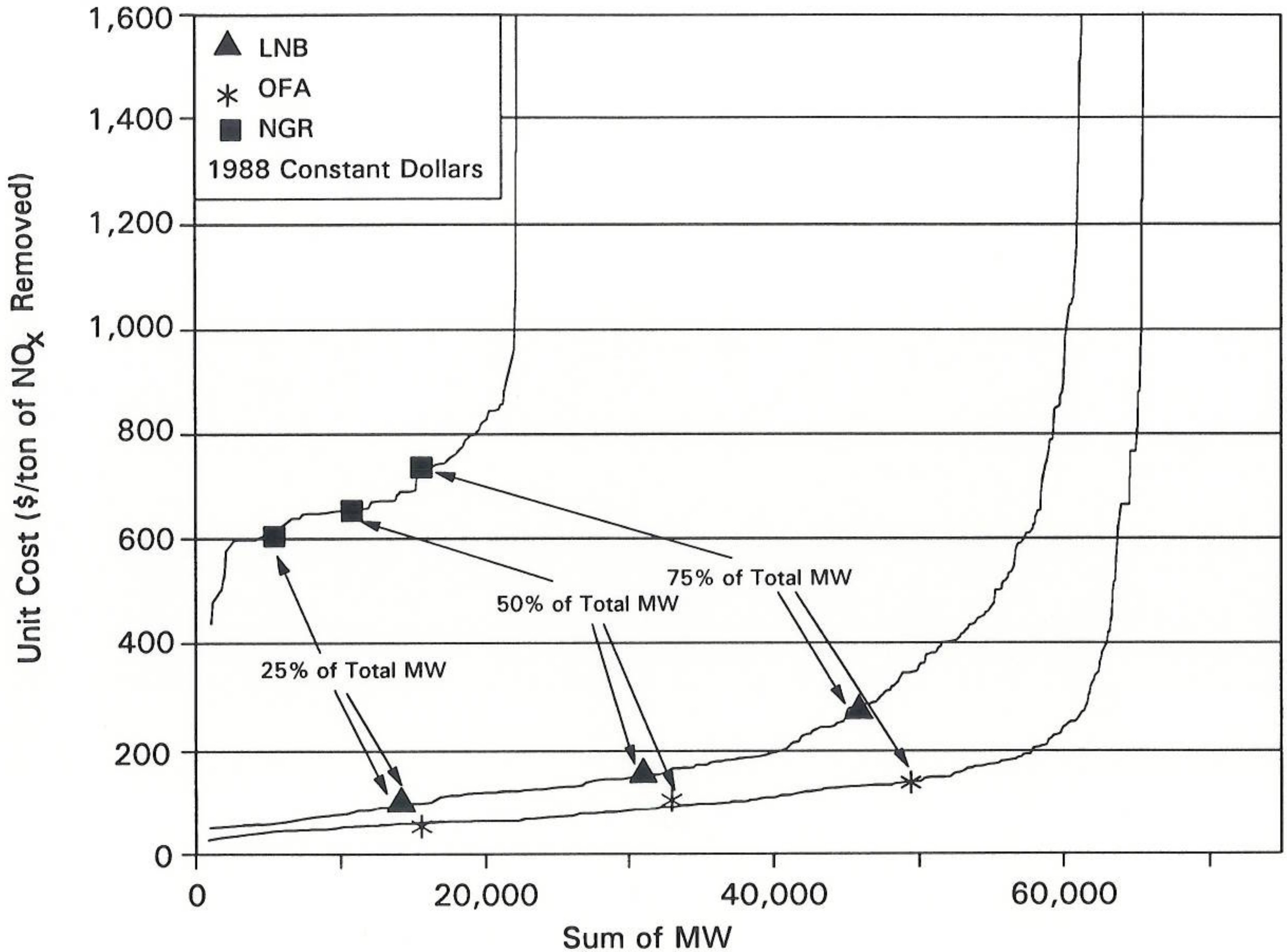

Figure 8. Summary of cost per ton of NO_x removed results for low NO_x combustion.

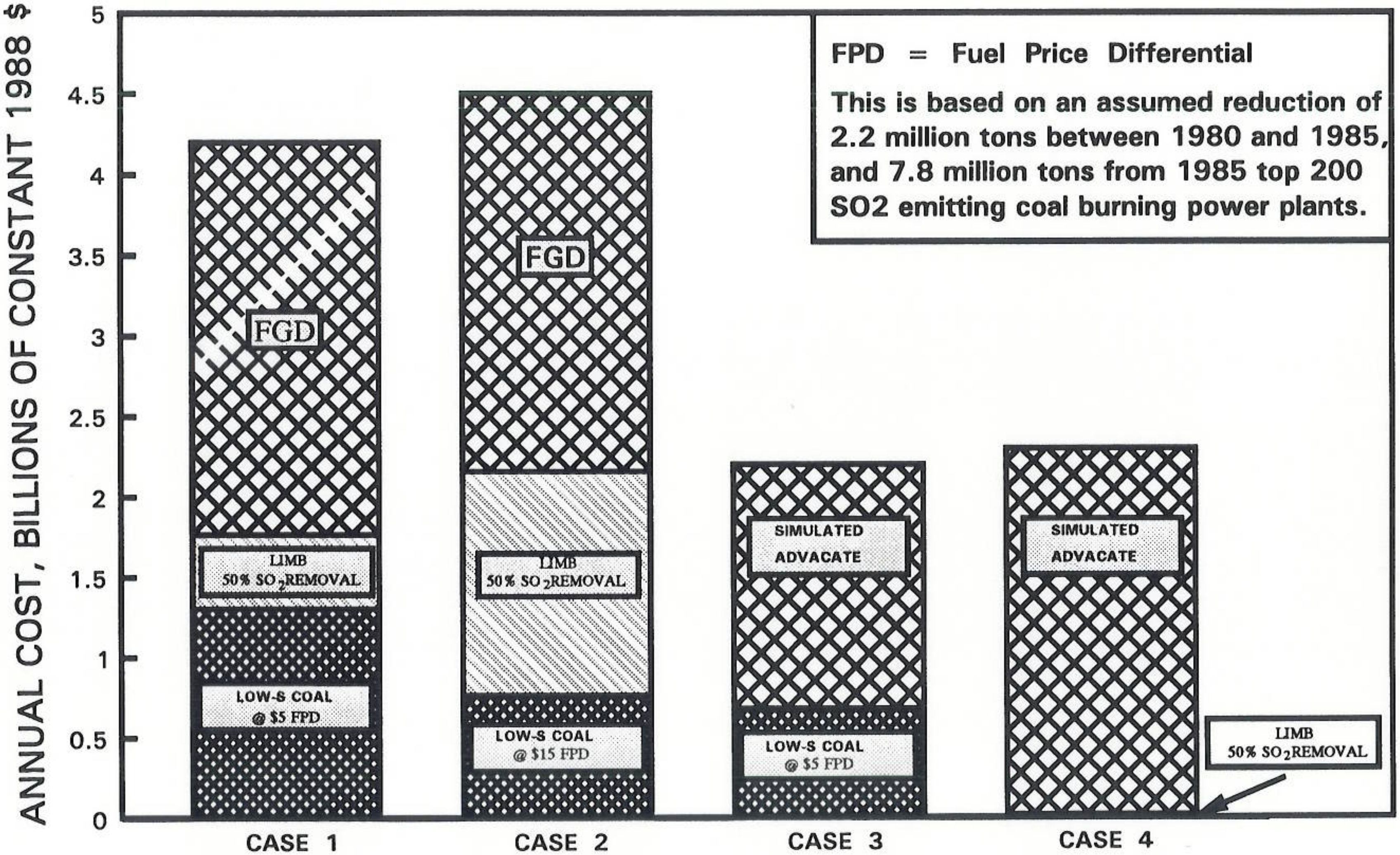

Figure 9. Annual cost of achieving a 10 million ton reduction of SO_2 per year from 1980 emission levels in the eastern region of the United States.

1. PARTICLE LADEN GAS
2. ESP FIELDS
3. EXIT DUCT
4. INLET DUCT
5. INLET TRANSITION SECTION
6. ESP HOUSING
7. TRANSFORMER/RECTIFIER (T/R) UNITS
8. DIFFUSION PLATES
9. TUBE SHEET
10. T/R POWER SUPPLY
11. ESFF SECTION
12. PLENUM
13. OUTLET TRANSITION SECTION
14. BAFFLE PLATE
15. ESFF HOPPER
16. HOPPERS

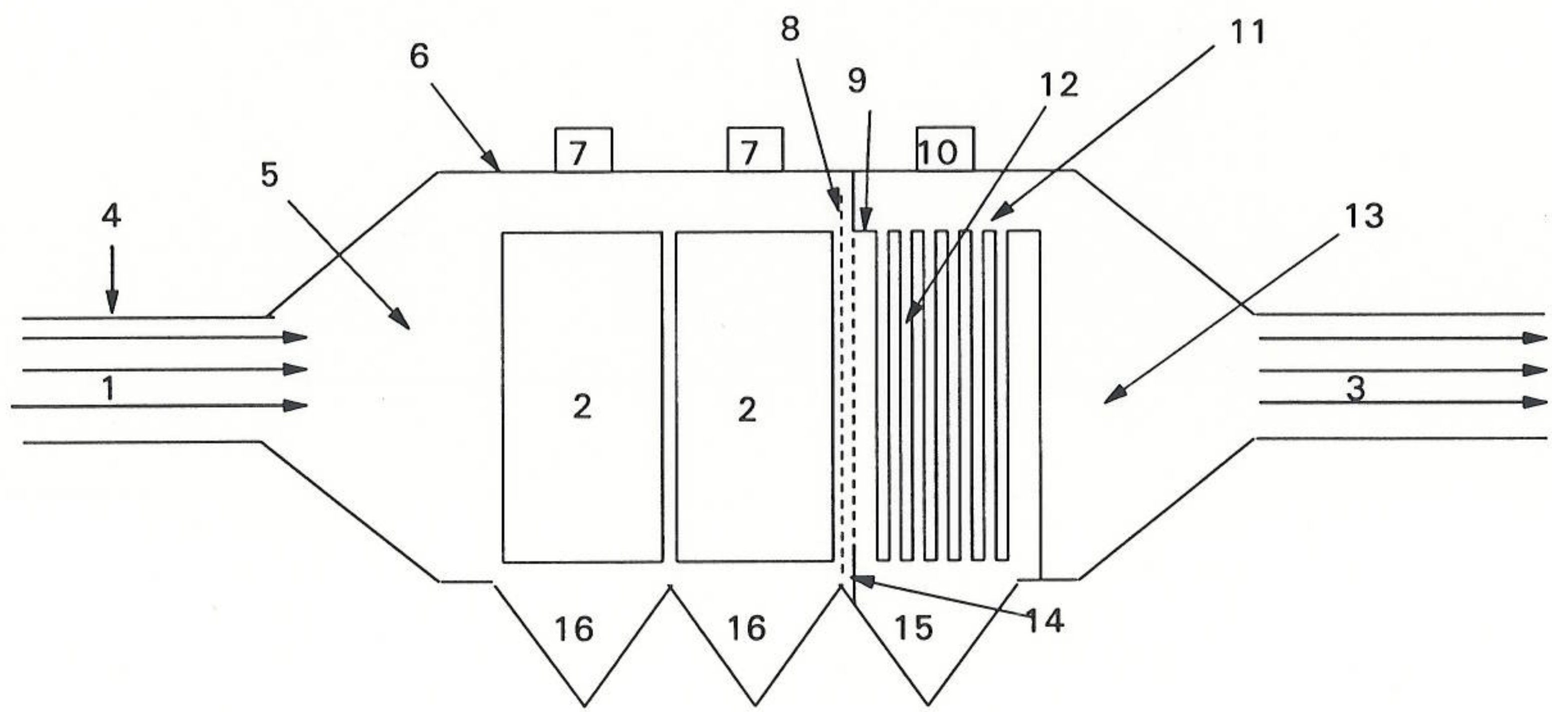

Figure 10. Retrofit Electrostatic Filtration.