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Project Summary

Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study

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This document summarizes initial results from an ongoing National Acid Precipitation Assessment Program (NAPAP) study, the objective of which is to significantly improve engineering cost estimates for retrofit of the following control technologies at the 1980 "top 200" SO_2-emitting coal-fired power plants in the 31 eastern states: lime/limestone FGD, lime spray drying FGD, coal switching and cleaning, furnace sorbent injection with humidification (LIMB), duct sorbent injection, low NO_x burners, overfire air, natural gas reburn, and selective catalytic reduction. Retrofit cost factors and costs were developed for 12 coal-fired power plants: 5 in Ohio, and 7 in Kentucky and the TVA system (Tennessee, parts of Alabama, and Kentucky). Activities included: selecting plants with boilers representative of the top 200 population; conducting plant visits and collecting site specific data; developing boiler/control-specific retrofit difficulty factors; and developing boiler/plant-specific cost and performance estimates. Results from this effort are being used to develop simplified procedures to estimate the retrofit costs for a number of the remaining top 200 plants which are not visited.

This Project Summary was developed by EPA's Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

The National Acid Precipitation Assessment Program (NAPAP) is responsible for developing cost and performance information on various methods for reducing the emissions of acid rain precursors. Coal-fired utility boilers are major emitters of SO_2 and NO_x. However, estimating the cost and performance of SO_2 and NO_x controls for coal-fired power plants is difficult due to differences in plant layout and boiler design.

This report documents the initial results of an ongoing study conducted under NAPAP, the objective of which is to significantly improve the accuracy of engineering cost estimates used to evaluate the economic effects of applying SO_2 and NO_x controls to existing coal-fired utility boilers.

This report presents the SO_2/NO_x control technology cost and performance estimates developed for 12 coal-fired utility plants in Ohio, Kentucky, and the Tennessee Valley Authority (TVA) system. The following procedures were used to develop the cost performance estimates: select plants with boilers representative of the population, conduct plant visits and collect site-specific data, develop boiler/control specific retrofit difficulty factors, and develop boiler/plant-specific cost and performance estimates for the SO_2 and NO_x controls selected for evaluation. This performance and cost estimating process is dynamic: it incorporates recommendations from a technical advisory group and participating utilities, as well as experience from site visits and performance/cost evaluations.

Control Technologies Evaluated

The commercial and developmental SO_2 and NO_x control technologies selected for inclusion in the program are listed in Table 1. Evaluated qualitatively without cost estimates were FBC and CG. Additional technologies were at first considered – chemical coal cleaning, pressurized FBC, and advanced SO_2/NO_x (combined) control devices – were not included in this study due to their general inapplicability to retrofit situations and early development status.

All of the estimates were developed using computer-based simulation models. This approach was taken because of the large quantity of data which needed to be accessed, used in computation, and stored. Although a number of mainframe- and personal-computer-based models were evaluated, the Integrated Air Pollution Control Systems (IAPCS) cost model was finally selected for use in this study because of its versatility. The IAPCS model has been upgraded to include the technologies being evaluated in this program.

Plants Visited

Four criteria were used to select the plants to be visited: (1) plant selection focused on boiler types and sizes accounting for the majority of SO_2 emissions; (2) within the limits of criterion, the selected plants were representative examples of the diversity of the boiler population; (3) due to costs, the number of plants selected for detailed study were limited to less than 30; and (4) the plants selected contained multiple boilers of diverse types.

Boilers in the top 200 SO_2-emitting plants were categorized by generating capacity, coal percent sulfur, firing type, age, and capacity factor. The top 200 plants were ranked according to their diversity, and the 30 highest-scoring plants were evaluated by boiler category to see if a realistic, proportional sample had been achieved successfully. Plants near the bottom of the list (with disproportional, extreme ratings) were repla to ensure the representa-tiveness of sample. From this list of 30 plants, were chosen for evaluation: 5 in Ol and 7 in Kentucky and the TVA syst (Tennessee, parts of Ala-bama, a Kentucky).

The Ohio and Kentucky plants w selected for evaluation first because the opportunity to conduct the progr jointly with Ohio and Kentucky State A Rain (STAR) programs. In addition to c TVA plant in Kentucky, three TVA pla outside of Kentucky were includ through TVA's participation in t Kentucky STAR program. These w considered to be representative of t top 200 SO_2 emitting plants. Table 2 li the plant/boiler characteristics for the 12 plants.

Prior to the plant site visit, a pl profile was completed using sources public information; a primary referen with the Department of Energy's (DOE Energy Information Agency (EIA) Fo 767. The plant profile included information and data needed f performance/cost analyses. The pl

Table 1. *Emission Control Technologies Selected*

Control Technology	Species Controlled		Development Status		
	SO_2	NO_x	Commercial	Limited Commercial Experience	Near Commerical Demonstration
Lime/limestone (L/LS) flue gas desulfurization (FGD)	X		X		
Additive enhanced L/LS FGD	X		X		
Lime spray drying (LSD) FGD[a]	X		X		X
Physical coal cleaning (PCC)	X		X		
Coal switching and blending (CS/B)	X		X		
Low-NO_x combustion (LNC)		X		X	
Furnace sorbent injection (FSI) with humidification (LIMB)	X				X
Duct spray drying (DSD)	X				X
Natural gas reburning (NGR)[b]	X	X			X
Selective catalytic reduction (SCR)		X		X	
Fluidized bed combustion (FBC) or coal gasification (CG) retrofit[c]	X	X		X	

[a]*Commerical on low-sulfur coals, demonstrated at pilot scale on high sulfur coals.*
[b]*For wet bottom boilers and other boilers where LNC is not applicable.*
[c]*Evaluated qualitatively as combined life extension and SO_x/NO_x control option. No costs were developed.*

Table 2. Boiler Characteristics of Plants Evaluated Using Detailed Procedures

Plant (State)	Boiler No.	Net Dependable Generating Capacity Per Unit, MW	Age, yr	Capacity Factor, Percent	Coal Sulfur, Percent	Firing Type
Burger (OH)	1-4	30	40-43	29-30	3.4	Roof
	5-6	45	37	31	3.4	Roof
	7-8	75	32	38-56	3.4	Wall
Conesville (OH)	1-2	125	28-30	32-26	2.9	Cyclone
	3	165	25	37	2.9	Wall
	4	720	14	58	2.9	Tangential
	5-6	375	9-11	45-48	4.1	Tangential
Muskingum River (OH)	1-2	205	33-34	63	4.4	Wall (Wet Botom)
	3-4	215	29-30	55	4.4	Cyclone
	5	585	19	61	4.4	Wall
Sammis (OH)	1-4	180	25-28	44-57	0.9	Wall
	5	300	20	53	2.4	Wall
	6-7	600	16-18	44-51	2.4	Wall
J. M. Stuart (OH)	1-4	559	13-17	54-66	1.2	Wall (Cell Burner)
E. W. Brown (KY)	1	100	30	50	1.9	Wall
	2	156	24	65	1.9	Tangential
	3	410	16	65	1.9	Tangential
Elmer Smith (KY)	1	151	23	30	2.9	Cyclone
	2	265	13	50	2.9	Tangential
Big Sandy (KY)	1	260	24	63	1.2	Wall
	2	800	18	63	1.2	Wall
Paradise (KY)	1-2	704	24	30	2.9	Cyclone
	3	1150	17	30	2.9	Cyclone
Johnsonville (TN)	1-4	125	35-36	39	1.7	Tangential
	5-6	147	34-35	30	1.7	Tangential
	7-10	173	28-29	41	1.7	Wall
Cumberland (TN)	1-2	1300	14	60	2.9	Wall
Colbert (AL)	1-4	200	32	50	2.3	Wall
	5	550	22	50	2.3	Wall

profile data were verified and completed using information obtained during the 1-day site visit.

Summary of Performance and Cost Estimates

Using the data and information obtained from the plant visits, site-specific cost estimates were developed using the IAPCS cost model. These cost estimates reflect site-specific retrofit costs because retrofit factors, scope (cost) adders, and performance estimates were developed and input to the model. Figure 1 shows the methodology used to develop the retrofit costs using the IAPCS cost model.

For all technologies, retrofit factors and scope adders were developed using the Electric Power Research Institute (EPRI) report, "Retrofit FGD Cost Estimating Guidelines." Retrofit factors are process area multipliers which adjust the cost model to reflect the following location and retrofit effects:

- Location – regional material and labor costs, foundation and support structure costs related to soil conditions and seismic zone, and freeze protection costs.
- Retrofit – access/congestion, underground obstructions, and distance between process areas.

Scope adders are additional costs that are included in the cost of retrofit but not in the cost model algorithm bases. These cost adders include: a new chimney liner, draft control modifications, equipment demolition and replacement, and particulate control modifications.

For CS, fuel cost differentials were developed from the cost of currently used coals using data from FERC Form 423. Two fuel price differentials (FPDs) were evaluated: the current low to high sulfur coal FPD and the current FPD plus $15 a ton. The $15 a ton fuel cost addition was assumed to span the potential fuel price premium that would result if extensive CS occurred due to acid rain legislation. For PCC, the incremental fuel cost was determined by assuming that the plant coal had properties similar to one of the six coals contained in the IAPCS cost model PCC module.

Performance estimates were developed for the spray drying technologies and the low NO_x combustion technologies. LSD, FGD and DSD SO_x performance estimates were developed based on flue gas temperature and particulate control type: ESP or fabric filter. Low NO_x burner and over-fire air performance estimates were developed by evaluating the furnace heat release rates versus flue gas residence time and coal properties.

The full report describes in detail the procedures used to develop the retrofit factors, scope adders, and LNC control NO_x reduction estimates. However, a brief summary of the cost results arranged by control technology follows. The costs presented are levelized annual costs based on August 1987 dollars. The capital recovery and operating cost levelization factors are based on the 1986 EPRI Technical Assessment Guidelines report and are: 0.18 capital recovery factor and 1.45 operating cost levelization factor.

FGD Cost Estimates

Figure 2 and Table 3 summarize the plant level cost estimates developed for conventional L/LS FGD. Figure 2 shows the annual cost versus SO_x reduction for the 12 plants evaluated. Table 3 summarizes the plant level average annual unit cost of control and retrofit difficulty range for each boiler/plant.

Note that L/LS FGD was applied only to units 6 and 7 at the Sammis Plant. This was due to the extreme retrofit difficulty for unit 6. The retrofit difficulty and annual cost of control would be much greater for units 1-5 than for unit 6, making it unlikely that conventional FGD would be applied to units 1-5. The plants having the lowest unit cost of control were Cumberland and Muskingum River. The Cumberland units are large (1300 MW each), fire a 2.9% high sulfur coal, and have moderate retrof difficulty. The Muskingum River Pla units have low unit cost of control eve though units 1-4 have high retrof difficulty factors; these units have hig capacity factors (40 to 60%) and burn very high 4.4% sulfur coal.

Figure 3 and Table 4 summarize th plant level cost estimates developed fo lime spray drying. Two control option were considered for the retrofit of th technology: (1) reuse of the existing ES and (2) a new fabric filter. For units wher the SCA of the existing ESP was sma (< 43.3 m^2/act. m^3/sec) or the addition o new plate area was impractical (e.g., ro mounted ESPs), reuse of the existin ESP was not considered. In such case

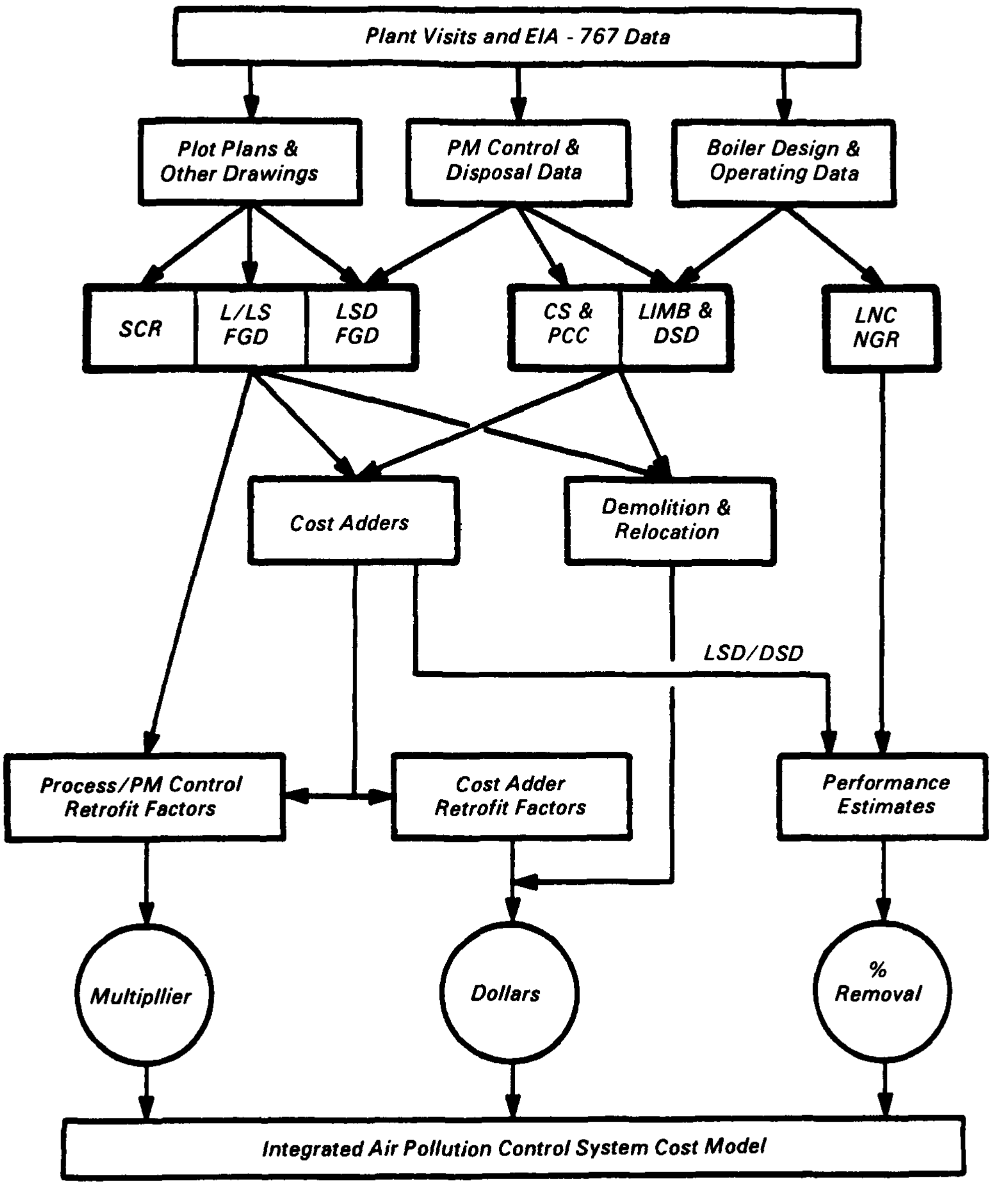


Figure 1. Methodology using IAPCS cost model.

Table 3. *Summary of L/LS FGD Cost and Performance Estimates*

Plant	Boiler No.	FGD Retrofit Difficulty	Levelized Annual Costs $/ton SO_2	Levelized Annual Costs mills/kWh	SO_2 Reduction, tons/yr
Burger	1-6	1.30	1,218	32.2	14,500
	7	1.26	1,112	29.4	13,300
	8	1.29	845	22.3	19,500
Sammis	6	3.01	1,397	24.2	46,200
	7	1.86	1,122	19.5	39,900
Muskingum River	1-2	1.70	671	22.8	76,600
	3-4	1.66	704	23.9	71,300
	5	1.54	496	26.9	106,800
Conesville	1	1.54	1,961	40.2	7,100
	2	1.54	1,779	36.5	8,100
	3	1.51	1,526	31.3	10,900
	4	1.55	703	14.4	74,500
J. M. Stuart	1	1.43	1,429	13.1	25,200
	2	1.45	1,449	13.3	24,900
	3	1.44	1,469	13.5	24,300
	4	1.44	1,283	11.8	29,700
E. W. Brown	1	1.70	2,306	30.2	5,700
	2	1.60	1,526	20.0	11,600
	3	1.41	1,035	13.5	30,000
Elmer Smith	1	1.66	1,906	42.5	8,900
	2	1.26	867	19.4	26,000
Big Sandy	1	1.50	2,018	16.4	11,600
	2	1.54	1,416	11.5	35,800
Paradise	3	1.35	956	18.0	63,300
Cumberland	1	1.46	598	12.6	141,000
	2	1.40	575	12.1	141,000
Johnsonville	1-10	1.48	1,213	16.7	60,000
Colbert	1-4	1.54	1,222	22.2	69,200
	5	1.38	807	14.7	44,200

a new fabric filter was required for particulate control after the spray drying reactor. However, reuse of the ESP was considered impractical for many units. Boilers where LSD with ESP reuse (LSD + ESP) and LSD with new fabric filters (LSD + FF) were applied are identified on Figure 3 and Table 4. Note that the cost of retrofitting new fabric filters results in a high retrofit difficulty factor and a high cost of control. For the Sammis plant, only unit 7 was evaluated because retrofit of LSD FGD would be very costly for units 1-6.

Coal Switching and Cleaning

Figure 4 and Table 5 summarize the plant level cost estimates developed for coal switching (CS). For these technologies a number of plants and units were not considered applicable for CS for the following reasons: the units already burn a low sulfur coal; the plant receives coal by conveyor from local mines and the construction of truck, rail, and barge receiving facilities would be very costly; and the units have wet bottom boilers which can burn only coals having special ash fusion properties. As Figure 4 shows, the unit cost of control for CS is very dependent upon the fuel cost differential. The impact of particulate control and coal handling upgrades are generally small by comparison.

Table 6 summarizes the plant level cost of physical coal cleaning (PCC). A number of plants were not evaluated for PCC because the coal already is extensively cleaned, and the IAPCS coal cleaning costs are based on cleaning run-of-mine coals. As Table 6 shows, the unit cost and the amount of SO_2 reduction obtained by PCC are both low.

Sorbent Injection Cost and Performance Estimates

Two sorbent injection technologies in active research and development were evaluated in this study: furnace sorbent injection (FSI) with humidification (LIMB) and duct spray drying (DSD). Figure 5 and Table 7 summarize the plant level cost estimates developed for these technologies. Not all boilers were considered good candidates for these technologies for the following reasons:

- LIMB and DSD with ESP reuse were not considered practical for boilers having an ESP SCA of <43.3 m^2/act. m^3/sec, and
- DSD with ESP reuse was not considered if the duct residence time from the injection point after the air heater to the ESP inlet was less than 2 sec (<100 ft–30.5 m–of duct length).

For boilers where ESP reuse was not considered practical, DSD with new fabric filter was evaluated. The costs presented for FSI assume 70% SOx control and 35% sorbent utilization.

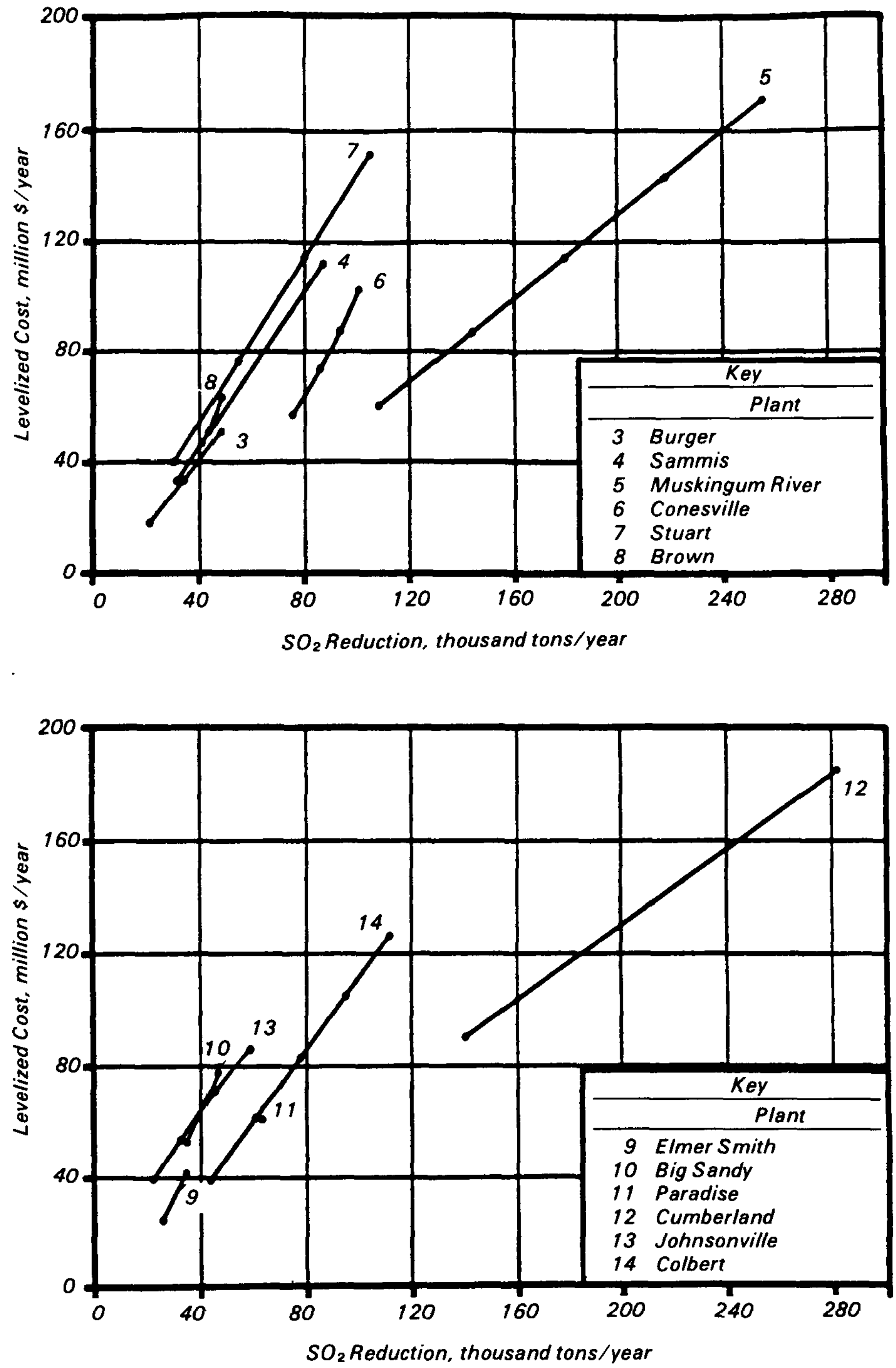


Figure 2. L/LS FGD cost versus SO_2 reduction.

Table 4. Summary of L/LS FGD Cost and Performance Estimates

Plant	Boiler No.	FGD Retrofit Difficulty	Levelized Annual Costs $/ton SO_2	Levelized Annual Costs mills/kWh	SO_2 Reduction, tons/yr
Burger	1-6	1.50[a]	1,463	37.1	13,900
	7	1.19	954	17.9	9,400
	8	1.19	704	13.2	13,900
Sammis	7	1.93	1,012	12.5	28,400
Muskingum River	1-2	2.01[a]	612	19.1	70,200
	3-4	1.96[a]	650	21.2	68,500
	5	1.70	501	11.0	69,000
Conesville	1	1.63	1,649	28.7	6,100
	2	1.63	1,479	25.7	6,800
	3	1.60	1,260	21.9	9,300
	4	2.07[a]	751	14.8	71,600
J. M. Stuart	1	1.70	1,634	8.8	14,900
	2	1.72	1,678	9.1	14,700
	3	1.71	1,709	9.2	14,400
	4	1.70	1,422	7.7	17,600
E. W. Brown	1	2.00[a]	2,016	25.3	5,500
	2	1.69	1,194	13.2	9,800
	3	1.25	814	8.5	24,000
Elmer Smith	1	1.88[a]	1,923	41.4	8,600
	2	1.38	846	13.9	19,100
Big Sandy	1	1.88[a]	1,953	14.8	10,900
	2	1.75[a]	1,507	11.8	34,400
Paradise	3	1.71	947	15.1	53,700
Cumberland	1	1.66	624	10.3	110,000
	2	1.32	555	9.2	110,000
Johnsonville	1-10	1.82[a]	1,350	17.9	57,500
Colbert	1-4	1.80[a]	1,171	19.7	64,000
	5	1.30	784	10.1	31,300

[a]*This retrofit difficulty includes fabric filter; all others assume reuse of ESP.*

As Figure 5 shows, the cost of FSI at Big Sandy and Johnsonville is very high as a result of the need to retrofit new fabric filters.

Retrofit of Fluidized Bed Combustion and Coal Gasification

The retrofit potential of FBC or CG with reuse of the existing steam turbine and other plant facilities was qualitatively assessed for each boiler using the following criteria: boiler size, boiler heat rate, boiler capacity factor, boiler age, particulate control performance, and SO_2/NO_x emission levels. The following boilers were found to qualify as potential candidates, based on the boiler age and size criteria: Burger boilers 1-8, Sammis boilers 1-4, Muskingum River boilers 1-4, Conesville boilers 1-3, Smith boiler 1, Big Sandy boiler 1, Johnsonville boilers 1-10, and Colbert boilers 1-4. However, other criteria are also important and are discussed in more detail for each plant in the full report.

Low NO_x Combustion

Figure 6 and Table 8 summarize the plant level cost and performance estimates for application of low NO_x burners on dry-bottom wall-fired boilers, over-fire air on tangential-fired boilers, and natural gas reburn on other boilers (wet bottom and roof fired). As Figure 6 and Table 8 show, the unit cost of low NO_x burners and over-fire air is low (<$400/ton). However, for plants/boilers where NGR is applied, the unit costs are much higher ($800 to $1200 per ton). This is due to the high cost of natural gas relative to coal ($2 per million Btu fuel price differential).

Selective Catalytic Reduction Cost Estimates

Figure 7 and Table 9 summarize the plant level cost estimates for application of SCR. Except for Sammis units 1-6, tail-end systems were assumed (reactor downstream of particulate control or scrubbers). For Sammis units 1-6, space limitations require that a hot-side, high-dust system configuration be used after the economizer and before the air heater. Use of the tail-end system minimizes unit downtime, which reduces the uncertainty of estimating the cost of replacement power, and maximizes the catalyst life (cost trade-off with energy penalty associated with flue gas reheating).

The cost estimates for SCR presented in this report are based on 1 year of catalyst life. German and Japanese experience indicates that a 3- to 5-year

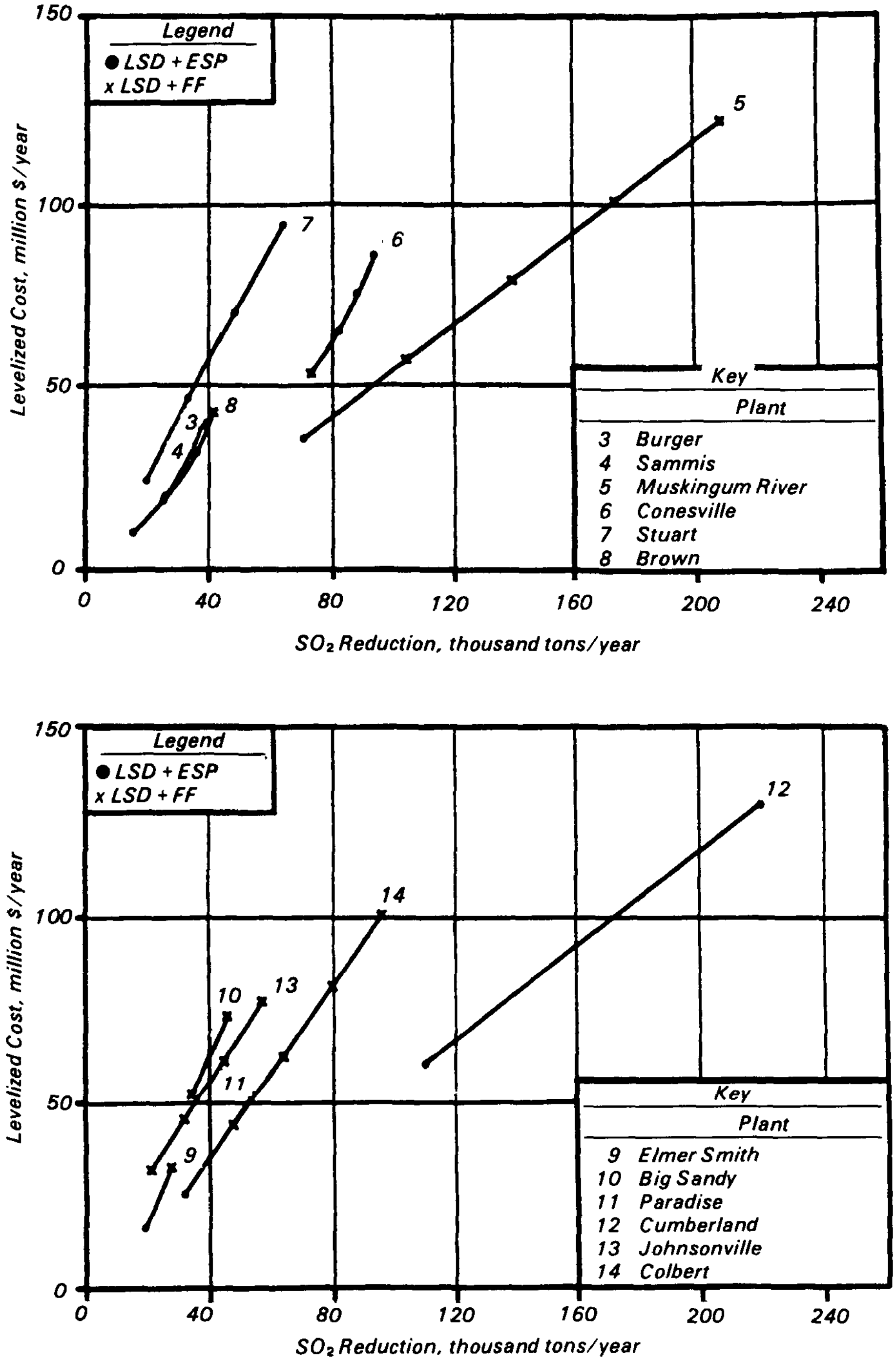


Figure 3. *LSD FGD cost versus SO_2 reduction.*

life is probable for many applications. If a 3-year catalyst life is assumed, the annual cost of SCR would be 40-50% less than that presented in this report.

Conclusions

For each of the SO_2 and NO_x control technologies evaluated during this program, a number of factors will affect control cost and performance for retrofit applications at coal-fired boilers. These boilers were built or were under construction before the 1971 New Source Performance Standards, and plant layout and boiler design did not consider the application of SO_2 and NO_x controls.

Although many factors can affe retrofit cost/performance, Table identifies those which were found to ha significant effect on cost/performanc For the L/LS FGD technologies, si access/congestion and flue gas ductii distances were major factors. For LS FGD, the need to add new particula control also was a major factor.

Table 5. *Summary of Coal Switching Unit Cost Estimates*

Plant	Boiler No.	Levelized Annual Cost: Baseline FPD[a] $/ton SO_2	Levelized Annual Cost: Baseline FPD[a] mills/kWh	Levelized Annual Cost: Baseline FPD + $15/ton $/ton SO_2	Levelized Annual Cost: Baseline FPD + $15/ton mills/kWh	SO_2 Reduction, tons/yr
Burger	1-6	571	12.9	1,044	23 4	12,900
	7	480	10.8	945	21.2	11,300
	8	459	10 3	913	20.5	16,600
Sammis	5	584	7.1	1,467	17 8	16,800
	6	585	7.1	1,471	17.8	32,300
	7	591	7 2	1,484	18.0	27,900
Muskingum River	1-4[b]					
	5	176	5.4	523	16.0	96,300
Conesville	1-2[b]					
	3	458	7.2	1,158	18 1	8,300
	4	392	6.1	1,073	16.8	56,900
J. M. Stuart	1	763	2.5	3,862	12.7	9,000
	2	764	2.5	3,865	12 7	9,000
	3	769	2.5	3,874	12 7	8,700
	4	736	2.4	3,811	12.5	10,700
E. W. Brown	1[c]					
	2	838	6.2	2,117	15.6	6,500
	3	777	5.7	2,056	15.1	16,900
Elmer Smith	1	395	6.7	981	16.6	6,700
	2	238	4.0	802	13 6	19,600
Big Sandy	1	2,235	9.6	4,313	18.5	6,100
	2	2,226	9.5	4,304	18.4	18,100
Paradise	3[b]					
Cumberland	1-2	189	3.0	809	13.0	106,900
Johnsonville[c]						
Colbert	1-4	182	2.2	693	8.6	11,800
	5	146	1.8	657	8.1	30,100

[a]FPD = fuel price differential.
[b]Coal switching was not evaluated for wet bottom boilers.
[c] Coal switching was not evaluated for boiler at this plant, since boilers have small roof-mounted ESPs. Adding additional plate area is not possible, and the use of SO_3 conditioning is likely to be marginally beneficient

For CS and PCC, the major retrofit factors, excluding fuel price differential, were particulate control upgrade costs and boiler performance impacts. The latter was not assessed because detailed coal analyses were not available. As a result, CS was not evaluated for wet bottom boilers, since boiler performance impacts are likely to be significant.

For the sorbent injection technologies, FSI and DSD, particulate control upgrade costs would have the greatest impact. Additionally, for DSD, sufficient duct residence time must be available to ensure good droplet drying.

For LNC and NGR, boiler type and configuration are important. Low NO_x burners were applied only to dry-bottom wall-fired boilers. Overfire air was applied only to tangential-fired units. NGR was applied to wet bottom boilers and other miscellaneous boiler types. Boiler heat release rates and residence times in different furnace zones would have significant effects on NO_x removal efficiency for LNC and NGR.

SCR costs would be greatly affected by access and congestion near the economizer area for high dust applications and the chimney area for tail-end applications and by flue gas ducting distances. For high dust systems, boiler downtime costs and catalyst life would be significant cost/performance factors. For tail-end systems, the energy penalty for preheat is balanced by increased catalyst life and reduced catalyst costs.

As discussed earlier, the objective of the program is to improve significantly the cost/performance estimates used to evaluate impacts of potential acid rain legislation. The information presented in this document is very useful in that regard. However, cost comparisons have not been made for retrofit options for specific boilers at each plant. For example, costs have bee projected for L/LS FGD and the other SO2 control technologies (LSD FGD, CS, PCC, FSI, and DSD), but no comparison has been made regarding the best option.

From the utility company's perspective, a decision concerning which retrofit control to apply to a given boiler is very complex and would be based on the following criteria:

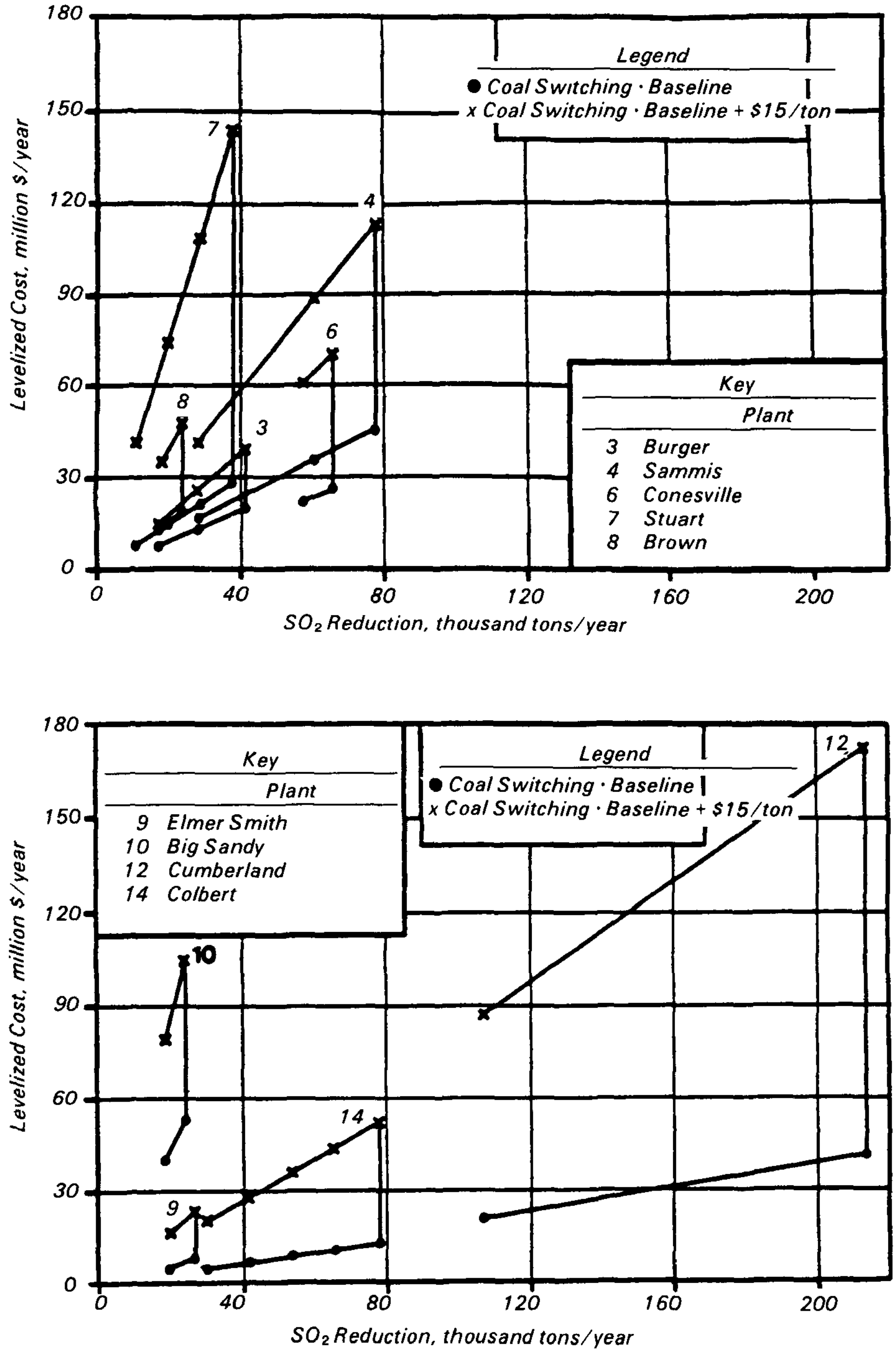


Figure 4. *Coal switching costs versus SO_2 reduction.*

- system reduction target and degree of flexibility regarding means to achieve the target,
- current and future load pattern for each boiler with or without controls,
- cost of purchased power and planned new capacity
- cost of capital and current/future financial strength, and
- public utility commission and state/region regulatory agency attitudes.

Although the cost/performance information presented is a realistic guide regarding the degree of retrofit difficulty for each control option evaluated, most of the technologies evaluated in this study have not been developed commercially. For this reason there is a higher degree of uncertainty regarding commercial cost/performance for these technologies. As such, no attempt has been made in this study to identify a best option for each plant/boiler.

Table 6. Summary of Coal Cleaning Unit Costs Estimates

Plant	Boiler No.	Levelized Annual Cost Baseline FPD[a] $/ton SO_2	mills/kWh	SO_2 Reduction, tons/yr
Burger	1-6	600	5.7	5,200
	7	397	3.7	4,700
	8	363	3.4	6,900
Sammis	5	381	2.5	9,200
	6	382	2.5	17,700
	7	386	2.6	15,300
Muskingum River[b]				
Conesville[b]				
J. M. Stuart	1	1,546	3.2	5,700
	2	1,549	3.2	5,600
	3	1,556	3.2	5,500
	4	1,502	3.1	6,700
E. W. Brown	1[c]			
	2	389	3.2	7,400
	3	375	3.1	19,100
Elmer Smith	1	843	5.9	2,800
	2	527	3.7	8,100
Paradise[c]				
Cumberland[b]				
Johnsonville[c]				
Colbert	1-4	676	3.7	5,300
	5	595	3.3	13,400

[a]FPD = fuel price differential.

[b] Physical coal cleaning (PCC) was not evaluated because coal presently is washed to reduce sulfur and ash prior to firing. Insufficient data were available to evaluate the cost/performance of advanced coal cleaning.

[c] PCC not evaluated, since boilers have small roof-mounted ESPs. Adding additional plate area is not possible, and the use of SO3 conditioing is likely to be marginally beneficient.

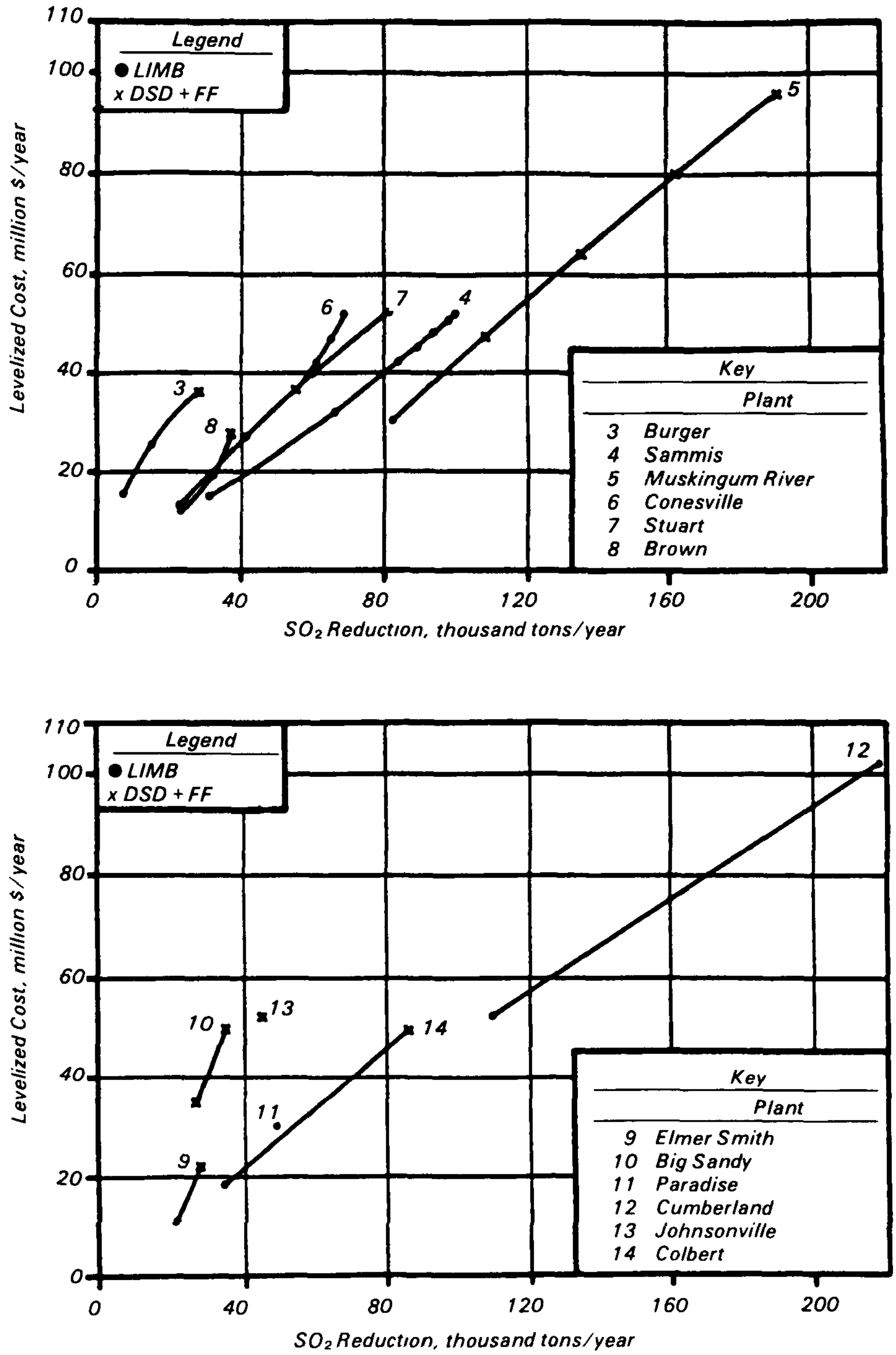
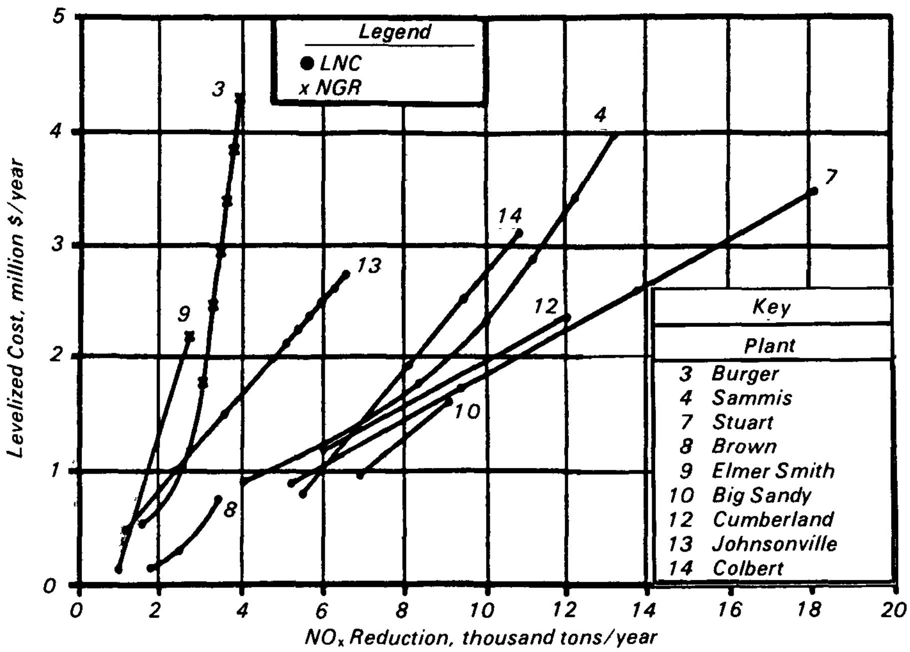


Figure 5. LIMB (70% removal) and DSD costs versus SO_2 reduction

Table 7. *Summary of Sorbent Injection Cost and Performance Estimates*

Plant	Boiler No.	Technology	Levelized Annual Costs: \$/ton SO_2	Levelized Annual Costs: mills/kWh	SO_2 Reduction, tons/yr
Burger	1-6	DSD-FF	1,284	25.4	10,900
	7	LIMB	602	12.4	10,300
	8	LIMB	519	10.6	15,200
Sammis	1	LIMB	736	3.7	3,500
	2	LIMB	725	3.6	3,500
	3	LIMB	693	3.5	3,800
	4	LIMB	622	3.1	4,500
	5	LIMB	540	7.3	18,600
	6	LIMB	476	6.4	35,900
	7	LIMB	499	6.7	31,000
Muskingum	1	DSD-FF	581	14.3	27,800
	2	DSD-FF	583	14,4	27,700
	3	DSD-FF	628	16,0	27,100
	4	DSD-FF	640	6,3	26,400
	5	LIMB	364	9,6	83,100
Conesville	1	LIMB	597	14.3	5,600
	2	LIMB	832	13.3	6,300
	3	LIMB	754	12.0	8,500
	4	DSD-FF	652	10.0	55,900
J. M. Stuart	1	LIMB	655	4.7	19,600
	2	LIMB	688	4.8	19,400
	3	LIMB	607	4.3	18,900
	4	LIMB	577	4.1	23,100
E. W. Brown	1	DSD-FF	1,814	17.8	4,300
	2	LIMB	713	7.3	9,000
	3	LIMB	563	5.7	23,300
Elmer Smith	1	DSD-FF	1,583	26.6	6,700
	2	LIMB	588	10.2	20,200
Big Sandy	1	DSD-FF	1,684	10.0	8,600
	2	DSD-FF	1,302	7.9	26,900
Paradise	3	LIMB	613	9.0	49,300
Cumberland	1-2	LIMB	469	7.7	219,400
Johnsonville	1-10	DSD-FF	1,141	11.8	44,900
Colbert	1-4	DSD-FF	585	8.2	53,100
	5	LIMB	567	8.0	34,400



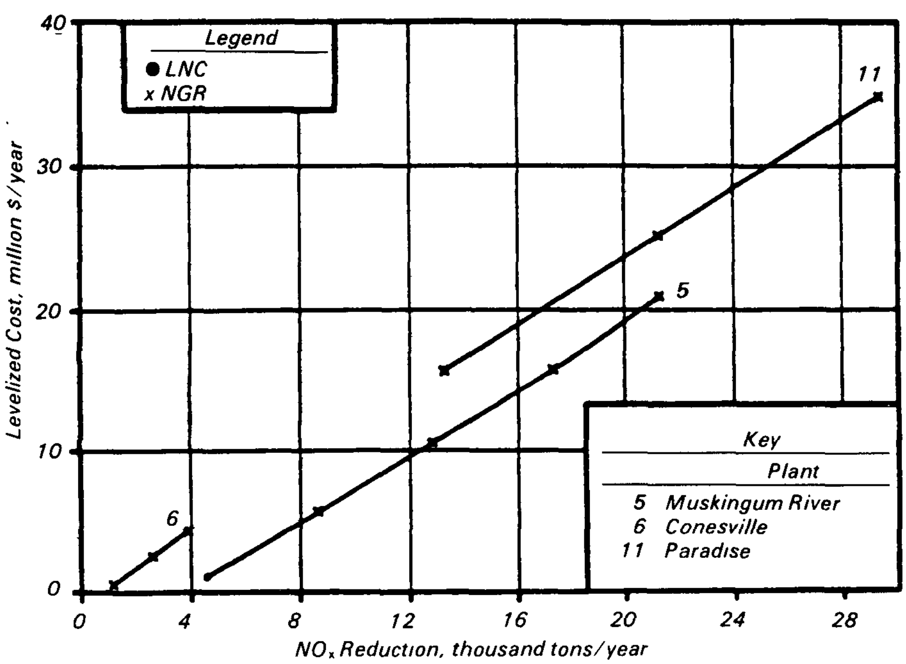


Figure 6. Low NO_x (LNC/NGR) combustion costs versus NO_x reduction.

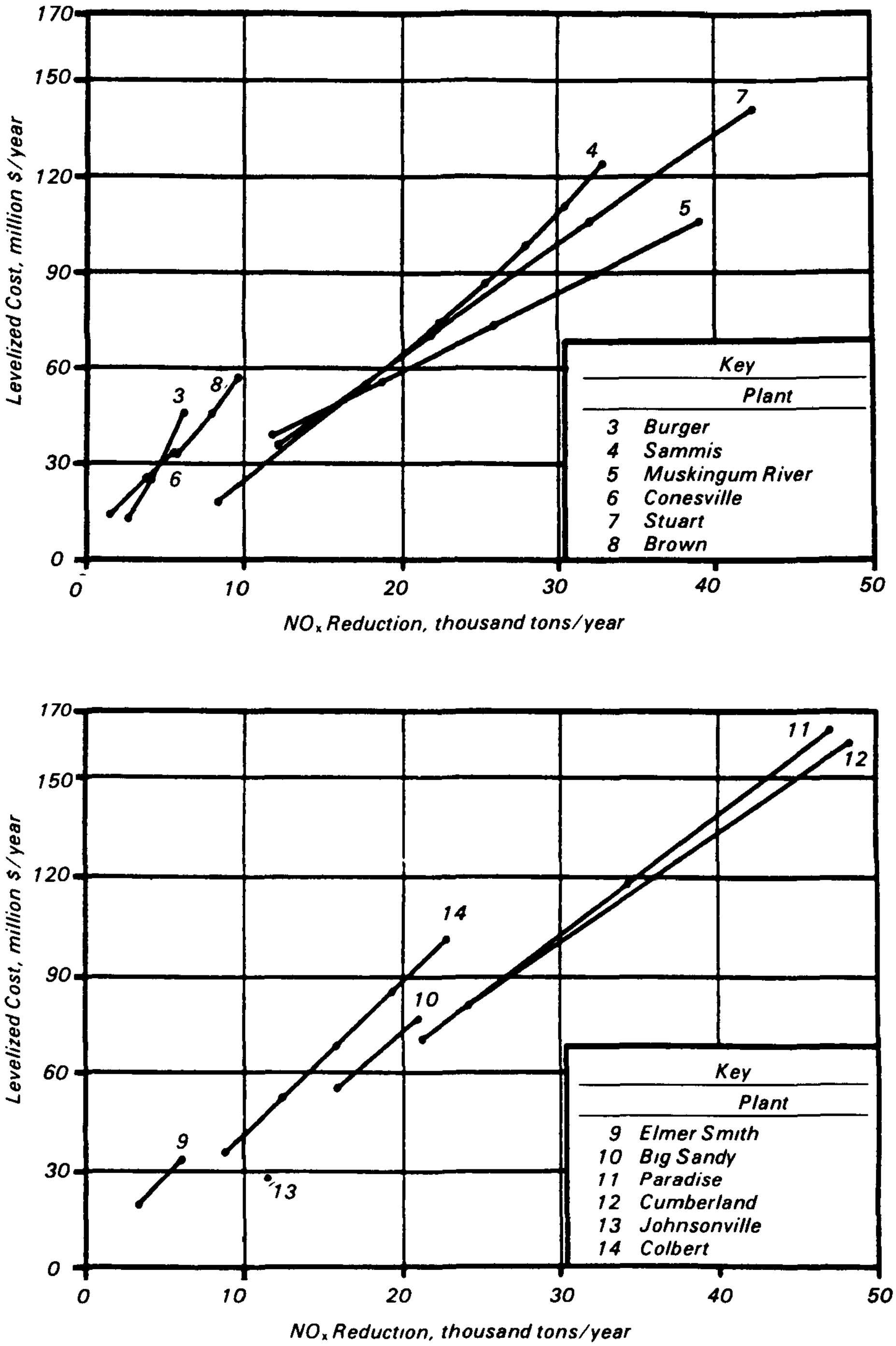


Figure 7. SCR costs versus NO_x reduction.

Table 8. *Summary of Low NO_x Combustion Cost and Performance Estimates*

Plant	Boiler No.	LNC Type[a]	Levelized Annual Costs: $/ton NO_x	Levelized Annual Costs: mills/kWh	NO_x Reductions: Efficiency, %	NO_x Reductions: tons/yr
Burger	1-2	NGR	2,797	6.0	50	160
	3-4	NRG	2,765	5.9	50	170
	5	NGR	2,631	5.4	50	260
	6	NGR	2,536	5.4	50	300
	7	LNB	478	1.0	50	1,070
	8	LNB	325	0.7	50	1,570
Sammis	1	LNB	527	0.8	35	1,000
	2	LNB	515	0.8	35	1,000
	3	LNB	482	0.7	35	1,100
	4	LNB	407	0.6	35	1,400
	6	LMB	194	0.3	40	4,600
	7	LNB	224	0.4	40	4,000
Muskingum River	1-2	NGR	1,237	4.6	50	4,200
	3	NGR	1,147	4.7	50	4,300
	4	NGR	1,150	4.7	50	4,200
	5	LNB	203	0.3	30	4,400
Conesville	1	NGR	1,389	5.2	50	1,300
	2	NGR	1,359	5.1	50	1,500
	3	LNB	473	1.0	50	1,100
J. M. Stuart	1	LNB	197	0.3	35	4,400
	2	LNB	199	0.3	35	4,400
	3	LNB	204	0.3	35	4,200
	4	LNB	167	0.3	35	5,200
E. W. Brown	1	LNB	456	1.0	50	1,000
	2	OFA	183	0.1	25	700
	3	OFA	103	0.1	20	1,800
Elmer Smith	1	NGR	1,192	5.2	50	1,700
	2	OFA	152	0.1	25	1,000
Big Sandy	1	LNB	281	0.4	35	2,400
	2	LNB	144	0.2	35	6,930
Paradise	1-2	NGR	1,200	4.7	50	8,000
	3	NGR	1,182	4.7	50	13,300
Cumberland	1	OFA	200	0.2	20	6,000
	2	OFA	200	0.2	20	6,100
Johnsonville	1-6	LNB	370	0.3	25	300
	7-10	LNB	427	1.0	50	1,200

[a]LNC Types: Low NO_x burners (LNB) for dry-bottom dwall-fired boilers and overfire (OFA) for tangential-fired boilers; and natural gas reburning (NGR) used on all other boilers.

Table 9. Summary of SCR Unit Cost Estimates

Plant	Boiler No.	System Type	Levelized Annual Costs[a] $/ton NO_x	mills/kWh	NO_x Reductions Efficiency, %	tons/yr
Burger	1-6	Tail-End	10,940	38.6	80	1,900
	7	Tail-End	7,272	24.8	80	1,700
	8	Tail-End	5,004	17.1	80	2,500
Sammis	1	High-Dust	5,048	17.4	80	2,400
	2	High-Dust	4,940	17.0	80	2,400
	3	High-Dust	4,632	16.0	80	2,600
	4	High-Dust	3,937	13.6	80	3,100
	5	High-Dust	4,094	14.2	80	4,800
	6	High-Dust	3,992	13.8	80	9,200
	7	Tail-End	2,242	7.8	80	8,000
Muskingum River	1	Tail-End	2,352	14.1	80	6,800
	2	Tail-End	2,363	14.1	80	6,700
	3	Tail-End	2,585	16.8	80	6,900
	4	Tail-End	2,567	16.7	80	6,700
	5	Tail-End	3,302	12.2	80	11,600
Conesville	1	Tail-End	5,705	34.	80	2,100
	2	Tail-End	5,071	30.2	80	2,300
	3	Tail-End	8,067	27.3	80	1,800
J. M. Stuart	1	Tail-End	3,497	12.8	80	10,000
	2	Tail-End	3,527	12.9	80	10,000
	3	Tail-End	3,600	13.2	80	9,700
	4	Tail-End	2,977	10.9	80	11,900
E. W. Brown	1	Tail-End	6,548	22.8	80	1,500
	2	Tail-End	5,846	14.6	80	2,200
	3	Tail-End	5,704	14.2	80	5,700
Elmer Smith	1	Tail-End	5,272	36.9	80	2,800
	2	Tail-End	5,847	16.6	80	3,300
Big Sandy	1	Tail-End	4,161	15.0	80	5,200
	2	Tail-End	3,474	12.5	80	15,900
Paradise	1	Tail-End	3,612	22.9	80	12,900
	2	Tail-End	3,694	23.4	80	12,900
	3	Tail-End	3,304	20.9	80	21,300
Cumberland	1-2	Tail-End	3,346	12.1	80	24,100
Johnsonville	1-10	Tail-End	2,428	6.4	80	11,400
Colbert	1-3	Tail-End	4,728	17.1	80	3,500
	4	Tail-End	4,864	17.6	80	3,500
	5	Tail-End	4,004	14.5	80	8,800

[a]Costs are based on 1-year catalyst life. Costs based on 3-year catalyst life would be 40-50% less.

Table 10. *Retrofit Factors Affecting Cost/Performance*

Control Technology	Access and Congestion	Ducting Distance	Particulate Control	Additional Boiler Type	Boiler Configuration
Lime/Limestone Flue Gas Desulfurization	X	X			
Lime Spray Drying	X	X	X		
Coal Switching/ Blending			X	X	
Physical Coal Cleaning			X	X	
Furnace Sorbent Injection with Humidification (LIMB)			X		
Duct Spray Drying		X	X		
Low NO_x Combustion				X	X
Natural Gas Reburning				X	X
Selective Catalytic Reduction	X	X		X	

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***Julian W. Jones** is the EPA Project Officer (see below).*
The complete report, entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study," (Order No. PB 88-244 447/AS; Cost: $49.95, subject to change) will be available only from:
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
Telephone: 703-487-4650
The EPA Project Officer can be contacted at:
Air and Energy Engineering Laboratory
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